Report on Industrial Boiler New Source Performance Standards

JUNE 1986

THE NATIONAL COAL COUNCIL

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U.S. DEPARTMENT OF ENERGY

The National Coal Council is a Federal Advisory Committee to the Secretary of Energy.

The sole purpose of the National Coal Council is to advise, inform, and make recommendations to the Secretary of Energy on any matter requested by the Secretary relating to coal or the coal industry.

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THE NATIONAL COAL COUNCIL

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June 3, 1986

The Honorable John S. Herrington
Secretary of Energy
Washington, DC 20585

Dear Mr. Secretary:

I am pleased to transmit, on behalf of the National Coal Council, the attached report on Industrial Boiler New Source Performance Standards. This report has been prepared in response to your request of January, 1986, and approved by the Council on June 3, 1986. As you may be aware, the Environmental Protection Agency (EPA) has just proposed New Source Performance Standards (NSPS) which would require 90% reduction of sulfur dioxide emissions and a maximum limitation of 1.2 LB SO_2/MMBTU from all new coal-fired industrial boilers with a heat input greater than 100 MMBTU/HR. The public comment period will end on September 2, 1986.

The primary purpose of the report is to analyze the impact these proposed regulations will have on the national policy of increased coal use, as it relates to U.S. industry.

The National Coal Council has found that these proposed NSPS will practically eliminate coal as a viable fuel choice for new industrial boilers. This finding is supported by the following specific conclusions:

- o These regulations would increase the cost of steam from new coal-fired industrial boilers by at least \$0.70/MMBTU, or roughly \$17/ton, thus causing the displacement of about 5.6 million tons/year of potential coal use by natural gas by 1990. (In fact, the most recent EPA press release (6/12/86) admits that only 5% of the new industrial boiler population would be coal-fired, displacing over 10 million tons per year of potential coal sales);
- o New technologies lack sufficient operating data upon which to base nationwide NSPS;
- o Total emissions from new industrial boilers will be insignificant because:

- Under EPA's worst case scenario, total potential emissions from all new industrial boilers above 100 MMBTU/HR, even without further regulation, would amount to less than 1.5% of the total U.S. SO_2 emissions.

- Regardless of any NSPS, industrial boiler emissions will continue to decline because of energy conservation, reductions in heavy industrial capacity, existing state and local emission standards, and the fact that most new boilers are installed to replace older units, resulting in a stable or declining industrial boiler population.

o The smaller boiler population segment between 100 and 250 MMBTU/HR, deserves special consideration because:

a. It replaces only 18% of the aggregate new boiler capacity;
b. Its SO_2 emissions will contribute less than 0.3% of the U.S. total;
c. Capital-related costs are disproportionally higher due to a lack of an economy of scale;
d. Coal transportation costs will be higher because volume shipping savings are not available to these users.

Based upon these conclusions, the National Coal Council offers the following recommendations for consideration in the Department of Energy comments:

1. Support extension of the existing 1.2 LB SO_2/MMBTU maximum emissions regulation for new industrial boilers with a heat input of 250 MMBTU/HR or greater.
2. Oppose the mandatory 90% reduction requirement for industrial boilers greater than 100 MMBTU/HR.
3. Support a reasonable SO_2 emission standard for new boilers in the 100 to 250 MMBTU/HR range, established at the point which balances both delivered coal costs and overall SO_2 emissions, based on a study of the geographic availability of coals with various sulfur contents;
4. Seek to ensure that NSPS regulations for new technologies be proposed only after careful analysis of emissions data from commercial units in the applicable size ranges.

We are confident that this report will prove useful and timely in advising you concerning the potential impact of the proposed regulation for New Source Performance Standards currently under consideration. We stand ready to provide you with any additional information in this matter, as you may desire.

Sincerely,

John N. Dalton

Honorable John N. Dalton
Chairman

B. R. Brown
Acting Chairman

Executive Summary

The Environmental Protection Agency (EPA) is currently developing nationally applicable emission limitations for "industrial fossil fuel-fired steam generators" in accordance with Section 111 of the Clean Air Act. The present regulations require a flat 1.2 LB SO_2/MM BTU maximum emission limitation for all new industrial boilers with a thermal heat input of 250 MM BTU/HR or greater. The draft standards being developed by the EPA would require 90% reduction of sulfur dioxide emissions and a maximum limitation of 1.2 LB SO_2/MM BTU from all new coal-fired industrial boilers which have a heat input greater than 100 MM BTU/HR.

At the request of the Secretary of Energy, the National Coal Council (NCC) convened a work group to analyze and report on the potential impacts of the EPA's pre-proposed industrial boiler standards. The attached report, approved by The National Coal Council on June 3, 1986, is in response to the Secretary's request.

Conclusions

Based on an examination of published EPA documents, consultations with actual industrial boiler operators and manufacturers and other pertinent sources, the following conclusions were drawn.

- The draft regulations would increase the cost of steam from new coal-fired industrial boilers by at least \$0.70/ MM BTU or roughly \$17/ton with existing flue gas desulfurization technologies. These additional costs would cause a significant shift from coal to natural gas use. By 1990, it is expected that 70% of the new industrial boiler capacity above 100 MM BTU/HR heat input would be gas fired, displacing about 5.6 million tons/year of potential coal sales if the draft EPA rules are instituted.
- New technologies, such as fluidized bed combustion, although promising, currently lack sufficient operating data upon which to base New Source Performance Standard regulations.
- The total emissions from new industrial boilers will be relatively insignificant for two reasons:
  —Under a worst case EPA scenario, the total potential emissions from all new industrial boilers above 100 MM BTU/HR, if left completely unregulated, would amount to less than 1.5% of the total U.S. SO_2 emissions.
  —Industrial boiler emissions have declined and are expected to continue to decline regardless of any additional federally implemented New Source Performance Standards. Between 1973 and 1983, all U.S. industrial SO_2 emissions have decreased 46%. This reduction is a result of energy conservation, reductions in smelter and other heavy industrial capacity, declining industrial boiler population, the replacement nature of the new boiler market (new boilers tend to replace old ones) and existing state and local emission standards.
- The boiler population segment between 100 and 250 MM BTU/HR deserves special consideration because:
  a. Only 18% of the aggregate capacity of new industrial boilers falls in this size range.
  b. SO_2 emissions from this segment will contribute at the most 0.3% of the total U.S. emissions.

c. Capital related costs incurred by this segment are disproportionally higher than the larger boilers due to a lack of an economy of scale.

d. Coal transportation costs are liable to be higher because overall coal consumption is lower and therefore volume shipping savings enjoyed by larger users are foregone.

Recommendations

The NCC recognizes that the EPA is legally compelled to develop standards for new industrial boilers. Therefore, it is recommended that:

1. The Secretary of Energy should support the existing flat 1.2 LB SO_2/MM BTU maximum emission regulation for new industrial boilers with a heat input of 250 MM BTU/HR or greater.
2. The Secretary of Energy should *not* support the draft EPA regulations for industrial boilers greater than 100 MM BTU/HR, which includes a mandatory 90% SO_2 reduction.
3. The Secretary of Energy should support a reasonable SO_2 emission standard for new boilers above 100 MM BTU/HR heat input. Between 100-250 MM BTU/HR, the limitation should be established at the point which minimizes both delivered coal costs for the small industrial boiler and overall SO_2 emissions. The level should be *no lower* than 1.2 LB SO_2/MM BTU; 1.6 LB is used for illustration purposes in the report. The exact limitation should be based on a study of the geographic availability of coals with various sulfur contents and associated impacts on delivered coal costs and overall emissions.
4. The Secretary of Energy should ensure that NSPS regulations for new technologies be based upon careful studies of actual commercial units in the applicable size ranges. This is consistent with recommendations made by the NCC Report on Clean Coal Technology.

Introduction

The Environmental Protection Agency (EPA) is currently developing nationally applicable emission limitations for "industrial fossil fuel fired steam generators" in accordance with Sec. 111 of the Clean Air Act. The present regulations require a flat 1.2 LB SO_2/MM BTU maximum limitation of all new industrial boilers with a thermal heat input of 250 MM BTU/HR or greater. The draft standards being developed by the EPA would require 90% reduction of sulfur dioxide emissions and a limitation maximum of 1.2 LB SO_2/MM BTU from all new coal fired industrial boilers which have a heat input of 100 MM BTU/HR or greater.

At the request of the Secretary of Energy, the National Coal Council (NCC) has convened a work group to analyze and report on the potential impacts of the EPA's pre-proposed industrial boiler standards. This report is in response to the Secretary's request.

Most of the conclusions in this report regarding impacts are based on an analysis of EPA Development Documents and actual industrial boiler sales, cost, and operating data.[1] All of the actual industrial boiler data is attached in Appendices B through F. An examination of legal issues surrounding the EPA-NSPS requirements is provided in Appendix A.

The EPA Development Documents attempt to project new industrial boiler growth based on various economic and financial assumptions. Of primary importance is the EPA's fuel price projections. The Midwest fuel prices are shown below for illustration:

	EPA Scenarios	
	High Coal Penetration (pg. 194)[2] $/MM BTU	**High Oil Penetration** (pg. 190)[2] $/MM BTU
Coal >5.0 LB SO_2/MM BTU	2.50	2.50
Coal <1.2 LB SO_2/MM BTU	3.32	3.32
Resid Oil 3 LB SO_2/MM BTU	6.12	4.94
Resid Oil 0.3 LB SO_2/MM BTU	6.54	6.01
Natural Gas	6.48	5.88

Neither the High Coal nor High Oil Penetration fuel price projections match today's environment.

The High Coal Penetration scenario is the EPA's worst case for SO_2 emissions from new coal-fired boilers. It is the worst case because the assumed differential between coal and natural gas ($3.16 to $3.98/MM BTU), implies a substantial incentive to burn coal. Yet, even under these favorable economic conditions for coal, the EPA projects natural gas will capture 70% of the new boiler market, primarily because of the added penalties of flue gas scrubbing.

Currently, coal/natural gas price differentials are on the order of $1 to $2/MM BTU depending on local gas and coal prices. In today's environment, very few new industrial coal boilers will be built, simply because an adequate fuel price differential, needed to pay for the higher non-fuel costs of coal firing, is lacking.

Thus, although the EPA High Coal Penetration scenario is the basis for impacts shown in this report, it certainly represents a very worst case scenario for new coal fired SO_2 emissions, one that we believe is exaggerated and unrealistic.

[1]U.S. Environmental Protection Agency, Summary of Regulatory Analysis New Source Performance Standards: Industrial—Commercial—Institutional Steam Generating Units of Greater than 100 million BTU/HR Heat Input, (March, 1985); Environmental Protection Agency, *Industrial Boiler SO_2 Cost Report*, EPA-450/3-85-001, (November, 1984).

[2]U.S. Environmental Protection Agency, Summary of Regulatory Analysis New Source Performance Standards (March, 1985).

Chapter 1

Background

Importance of Industrial Steam

The importance of industrial steam is clear: approximately two-thirds of all fuel burned by U.S. industry is consumed to raise steam. Virtually our entire manufacturing base depends on steam to produce its products, either for process use, to drive mechanical equipment (e.g. pumps and fans), for space heating, or for the on-site generation of electricity. Steam's importance to American production and the need for a reliable fuel source to sustain it can hardly be overstated.

Energy Efficiency

Because a manufacturing plant has many uses for steam—process heat, space heat and the generation of electricity—it is able to use the maximum amount of heat present in the steam that can be extracted. This fact, combined with the vigorous energy conservation practiced across U.S. industry since 1973, means that each unit of heat combusted at a manufacturing facility typically contributes twice the useful output achieved in a typical utility generating plant. At utilities, a majority of the potential heat is wasted since there is only one use for it—the production of electricity.

Industrial Energy Conservation and Its Impact on the Industrial Boiler Market

Primarily due to the highly effective energy conservation measures of industry since 1973, total U.S. industrial energy consumption has decreased by 7.5% from 1972 to 1984, according to the Energy Information Administration.[3] Concurrently with this decrease in energy consumption, according to the recent "Joint Report of the Special Envoys on Acid Rain", a 46% reduction in SO_2 emissions from all industrial sources was achieved over this same time span. This reduction was a result of the following factors: energy conservation, reduction in heavy industrial capacity such as non-ferrous smelters, declining industrial boiler population, the replacement nature of the new boiler market (new boilers tend to replace old ones, not add new capacity) and the implementation of more stringent state and local emission standards.

Much of U.S. industry has excess steam-generating capacity, and will add new units largely on a replacement basis. These new boilers will retire existing units, the net effect being a flat or declining U.S. boiler inventory in the foreseeable future.[4]

The result is that most new boiler installations are a discretionary use of scarce capital—and will receive management approval only when they represent sound economic investments. These replacement units will generally be less polluting than the units replaced, with a resultant automatic emissions reduction. This fact is confirmed by the aforementioned survey which shows that, of the installations able to report emissions data from the new and replaced sources, 29 new boilers took the place of 54 old units, with a *resultant annual decrease in SO_2 emis-*

[3]U.S. Department of Commerce, "*1986 Outlook: Prospects for over 350 Manufacturing and Service Industries*," (1986).

[4]A survey conducted by the Council of Industrial Boiler Owners in September, 1984, confirms this trend, showing that more than 80% of new boiler projects will replace older units (See Appendix C).

sions of 9,526 tons. Thus, it is important that environmental regulation not impede this process.

Differences Between Industrial and Utility Boilers

A utility boiler and an industrial boiler are significantly different. Yet, because both generate steam, regulators have tended to treat them alike. The regulations implementing the percent reduction requirement of the current Clean Air Act are an example of such identical treatment.

Today's typical utility unit produces 3.5 million pounds of steam an hour. By contrast, the average industrial boiler generates only about 100,000 pounds per hour. Thus, the average new industrial boiler is a dwarf compared to the giant utility boiler.

Second, while a utility boiler has but one purpose—to generate steam at a relatively steady rate to drive turbines that produce electricity—industrial boilers serve a variety of markedly different purposes in various industries. Furthermore, while utilities burn fossil fuels almost exclusively, industrials frequently burn a wide variety of process-generated wastes.

Industrial boiler design, therefore, varies greatly depending upon the fuels burned, the application of steam in a particular plant, and the daily and seasonal load variations. Even at a single industrial installation the application of steam can change drastically, from day to day, hour to hour, and even sometimes minute to minute depending upon the momentary production activity and its demand for steam. These considerations, the need to maintain production, and to use the least costly fuel, mean that industrial users require of their steam plants a degree of flexibility and reliability not required by a utility, whose output is assured by connection to other plants and systems in an electrical grid. Thus, environmental regulation of industrial boilers must be based on these different conditions rather than treating these boilers like utility units.

Chapter 2:

EPA's Industrial Boiler NSPS Proposal

Synopsis of Draft EPA NSPS for Coal-fired Industrial Boilers

Following passage of the 1977 Clean Air Act, EPA divided its standards-setting process into two parts, applying the percentage reduction requirement to *utility* boilers with an input >250 MM BTU/hr, and letting stand the simple 1.2# SO_2/million BTU input emissions cap for *industrial* boilers with an input >250 MM BTU/hr.

On June 19, 1984, EPA proposed NSPS for emissions of particulate matter (PM) and nitrogen oxides (NO_x) for all commercial, institutional and industrial boilers with a heat input greater than 100 million BTU/hour.[5] The corresponding standard for sulfur dioxide (SO_2) is not yet proposed; however, various industrial representatives have been informed by EPA staff that both percentage reduction and emission limits for industrial boilers are required under the Clean Air Act. EPA now proposes that the standard be amended to cover boilers from 100-250 MM BTU/HR heat input and that, rather than a simple emissions cap, these smaller boilers also be required to implement the percentage reduction requirements of the law. This would result in the application of flue gas desulfurization (scrubbing) to all industrial units greater than 100 MM BTU.

The following table reflects the proposed standards for PM and NO_x and the "pre-proposed or draft" SO_2 standards for coal-fired industrial boilers.

[5] *Federal Register*, June 19, 1984, (pp. 25102-25157).

	Proposed NSPS for Industrial Boilers (#MM BTU Heat Input)		Reported Recommendation to be Proposed June 1, 1986
Fuel	**PM[6]**	**NO_x**	**SO_2**
Coal	0.05	0.5 to 0.7[7]	1.2 and 90%
Oil	0.10	0.10 to 0.4[8]	0.8 and 90%
Nat. Gas	—	0.10	—

Background

Section 111 of the 1977 Clean Air Act defines standards of performance for new sources. The Act provides for emission standards:

> (i) establishing allowable emission limitations for such category of sources, and
> (ii) requiring the achievement of a percentage reduction in the emissions from such category of sources from the emissions which would have resulted from the use of fuels which are not subject to treatment prior to combustion.
> [Sec. 111(a)(1)(A)]

The language clearly establishes congressional intent to achieve balance by requiring that standards reflect:

> the best system of continuous emission reduction which (*taking into consideration the cost of achieving such emission reduction,* and any non-air quality health and environmental impact and *energy* requirements) the Administrator determines *has been adequately demonstrated for that category of sources.* (Emphasis Added.)
> [Sec. 111(a)(1)(C)]

This intent was confirmed in *Sierra Club v. Costle*, 657 F.2d 298, 330 (D.C. Cir. 1981), where the Circuit Court explained that:

[6] *Federal Register*, June 19, 1984, (pp. 25102-25157).
[7] Varies according to combustion type and unit size.
[8] Varies with type oil and nitrogen content.

> section 111 most reasonably seems to require that EPA identify the emission levels that are 'achievable' with 'adequately demonstrated technology.' After EPA makes this determination, it must exercise its discretion to choose an achievable emission level which represents the *best balance of economic, environmental, and energy considerations* . . . (Emphasis Added)

To fulfill the requirements of the law and its implementing regulations, NSPS must be based on the following factors:

1. Cost-effectiveness
2. Achievability
3. Highly reliable control technologies[9]
4. Adequately demonstrated control technologies.

These are not merely "desirable" aspects of sound regulation, they are critical factors required by the plain language of the law.

For more information on the legal aspects see Appendix A.

Economic Analysis of EPA's draft NSPS for SO_2 Emissions Control for Coal-Fired Industrial Boilers[10]

DEFICIENCIES IN COST ESTIMATES; DISPROPORTIONATE COSTS IMPOSED BY DRAFT NSPS

EPA's March 1985 regulatory analysis considered costs of two approaches to reduce SO_2 emissions from coal-fired steam generating units: the combustion of low sulfur coals, and the use of flue gas desulfurization (FGD) systems.[11] (A more detailed discussion of commercial flue gas scrubbing technology is provided in Appendix B-1). EPA's cost analyses show that a 90% SO_2 mandatory reduction for a 100 million BTU/hr boiler would increase annualized costs over burning low sulfur coal by 26% of the fuel costs or $0.87/MM BTU.

For boilers of approximately 400 million BTU/HR heat input, the annualized cost increase over use of low sulfur coal is 18% of the total fuel cost or $0.60/MM BTU.[12] These costs illustrate how economies of scale disproportionately increase costs for the small industrial boiler owner. Further, the small coal user is liable to incur additional cost penalties, particularly if the coal is shipped long distances, due to an inability to obtain volume discounts for coal transportation costs. This kind of cost penalty is not reflected in the EPA costs.

To check the costs of scrubbing reported by the EPA, we conducted a survey of six architect-engineer firms experienced in the design and construction of industrial power plants, as well as several boiler operators. Four of the nine data sets received covered industrial projects; four represented studies based on analyses of past projects and bids; and one was on a dry FGD system which has been operating since 1983. All but one of the cases reported used dry scrubbing.[13] See Appendix B-2.

The cost increase for scrubbing, reported in $/MM BTU, appears to agree very well with EPA data. However, the EPA costs for scrubbing are based on wet systems, whereas the data shown in Appendix B-2, are mostly dry systems. Studies of utility scrubbers have shown that the total annualized costs for dry scrubbers are usually about 10-30% lower than wet scrubbers, when compared on an equal basis.[14]

Another recent survey showed that of 107 industrial coal-fired boilers installed in the last five years, only five had scrubbers, and these were the dry type.[15] This shows the heavy preference of industry for compliance coal.

FUEL-SWITCHING

Figure 1 shows the degree of natural gas penetration into this traditional coal market that can be expected as the EPA recommendation of flue gas desulfurization with a 90% SO_2 reduction and a 1.2 lbs. SO_2/MM BTU emissions limit is applied to various sized industrial boilers. An explanation of the EPA alternatives is given in Table 1. As shown in Figure 1, it becomes quite

[9]Industry routinely expects a forced outage rate of less than 2%.

[10]For an analysis of the current industrial coal market and the outlooks to year 2000, see National Coal Association, "Coal 2000: A Forecast for U.S. Coal", (1986) pp. 40-45.

[11]U.S. Environmental Protection Agency, "Summary of Regulatory Analysis New Source Performance Standards: Industrial-Commercial-Institutional Steam Generating Units of Greater than 100 Million BTU/Hr. Heat Input," (March, 1985).

[12]*Industrial Boiler SO_2 Cost Report*, EPA-450/3-85-001, (November, 1984).

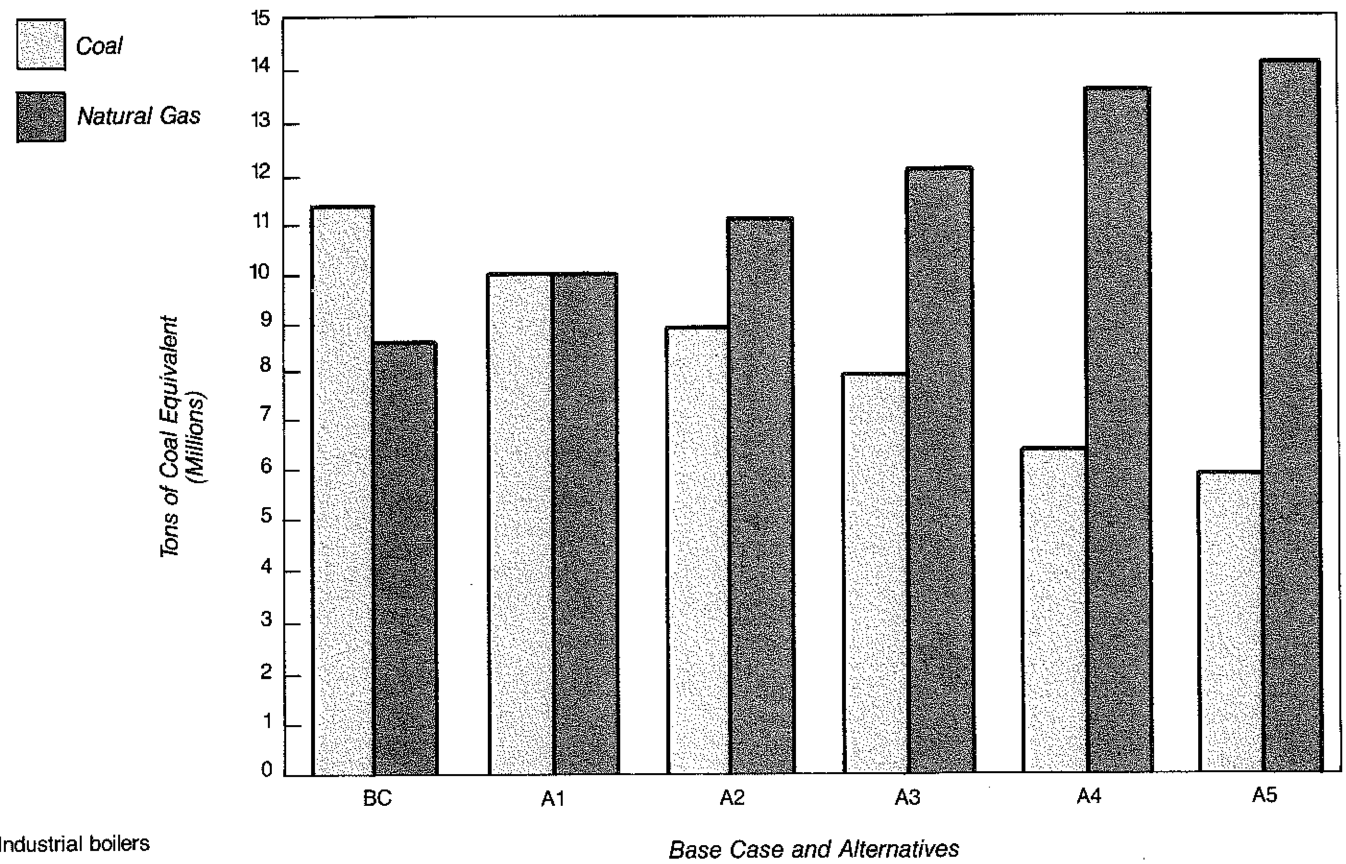
[13]It is important to note that, where removal efficiency was cited, it was 70%.

[14]EPRI CS-3322, *Evaluation and Status of Flue Gas Desulfurization Systems*, (January, 1984), pp. 3-34, 70, 203, 4-37.

[15]See Appendix C for a list of these installations.

FIGURE 1

Comparison of Natural Gas vs. Coal Use*
Under EPA'S Proposed Alternatives



*Industrial boilers

SOURCE:
EPA Development Document, March, 1985, p. 206. Graphic display created by work group.

TABLE 1*

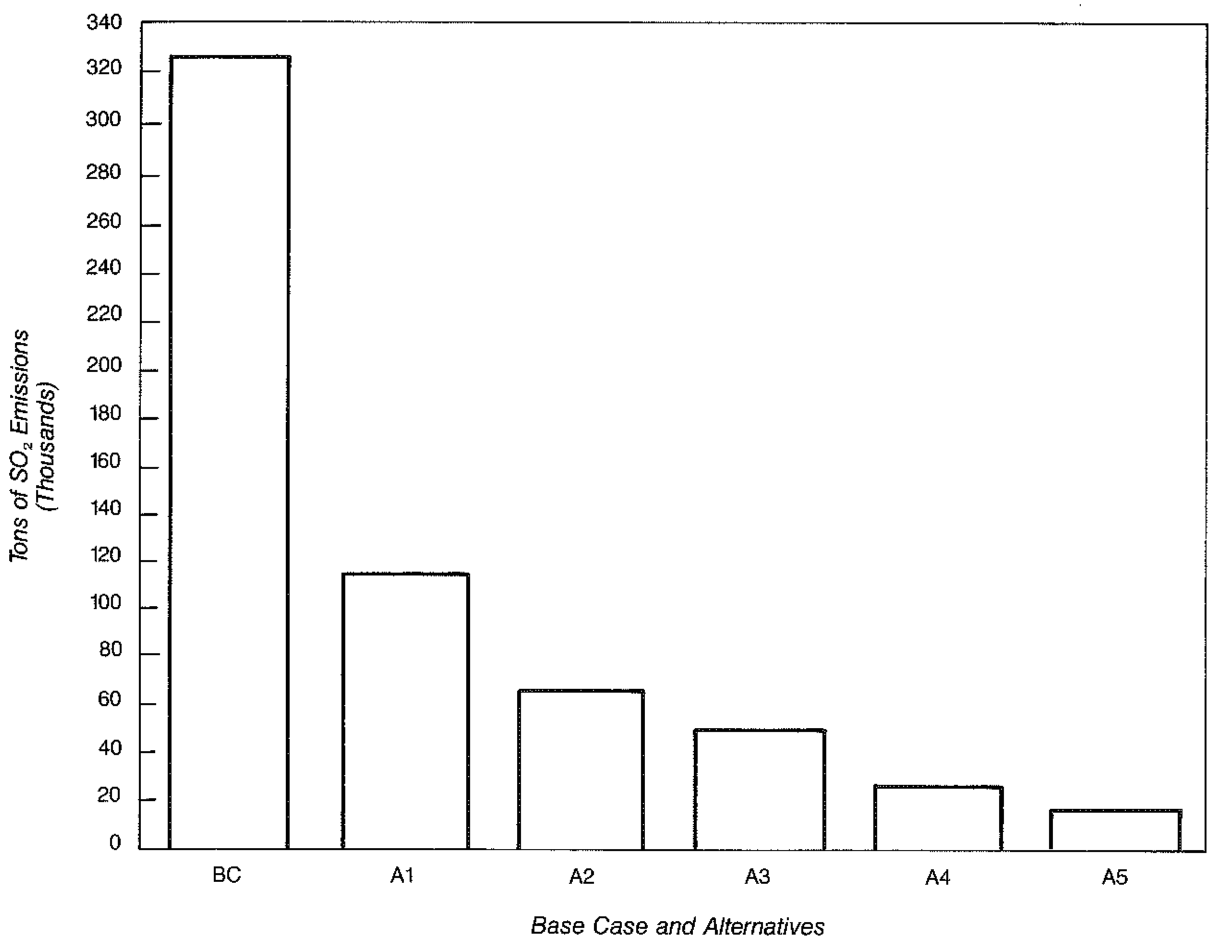
Regulatory Alternatives — Fossil Fuel-Fired Steam Generating Units

REGULATORY ALTERNATIVE[a]	STEAM GENERATING UNIT SIZE (MILLION BTU/HR) 100-150	150-200	200-250	>250
HIGH COAL PENETRATION				
Alternative 1	1.2	1.2	1.2	1.2
Alternative 2	1.2	1.2	1.2	90% Reduction
Alternative 3	1.2	1.2	90% Reduction	90% Reduction
Alternative 4	1.2	90% Reduction	90% Reduction	90% Reduction
Alternative 5	90% Reduction	90% Reduction	90% Reduction	90% Reduction

[a]Control levels shown for each regulatory alternative are SO_2 emission limits in lb SO_2/million Btu for a required percent reduction in SO_2 emissions.
*As per Table 49 (p. 205) EPA Development Document.

FIGURE 2

Comparison of SO_2 Emissions: New Industrial Boilers Under EPA'S Proposed Alternatives



Data Source: EPA Development Document

obvious that the use of natural gas increases as the EPA proposed standard (Alternative 5) is applied to smaller and smaller units. This figure shows in graphic form the data presented in Table 50 (p. 206) of the EPA Development Document of March, 1985. As a matter of fact, under Alternative 5, where the FGD/90% reduction standard is applied to all units, the use of natural gas increases dramatically to 70% of the EPA projection of the 1990 energy market, or an equivalent of 14.1 million tons of coal.

Figure 2 shows quite clearly that a significant SO_2 emissions reduction (65%) occurs with the application of a simple 1.2 lbs. SO_2/MM BTU limit applied across the board under EPA Alternative 1. Incremental reductions in SO_2 with controls more stringent than Alternative 1 occur more as a result of wholesale fuel-switching to natural gas, as demonstrated in Figure 1, rather than the use of the proposed technology. Thus, these emissions are not reduced by use of the proposed control options, but by substituting natural gas for coal.

As mentioned previously, the EPA draft proposal for this sector requires an emission limit of 1.2 lbs. SO_2/MM BTU for all boiler units of 100

MM BTU/HR heat input and larger, accompanied by 90% removal. We have shown through EPA's own analysis that such an approach is not cost effective and that a significant portion of the SO_2 reduction would be achieved not through emission control, but through the utilization of natural gas to avoid these excessive SO_2 control costs.

Further, we also believe that the application of the 1.2 lbs. SO_2 standard to smaller units (i.e. those boilers less than 250 MM BTU/HR heat input) is not justified on the basis of the volume of SO_2 emitted by this group, and the disproportionate share of costs they would bear. Sales figures (1985) of the American Boiler Manufacturers Association show that only 18% of the aggregate capacity of new boilers in this sector is expected to be supplied by smaller units; the remaining 82% of capacity is projected to be supplied by larger units (See Appendix D) which are already subject to the current 1.2 lbs. SO_2 emission limit. It is our belief that a higher standard—such as, for illustration, 1.6 lbs. SO_2/MM BTU—could be applied to smaller units with no serious loss in SO_2 removal. For example: Figure 2 shows that a 65% reduction in SO_2 is achieved when the EPA limit of 1.2 lbs. SO_2 is applied across the board to all units (Alternative 1). When a limit of, e.g., 1.6 lbs. SO_2 is substituted for the EPA proposal of 1.2 lbs. SO_2 for smaller units and the more accurate capacity ratio of smaller to larger units is applied to the projected emissions from this sector, a reduction of 63% is still achieved when compared to the EPA base case. The difference between the EPA recommendation of 1.2 lbs. SO_2 and the substitution in the range of 1.6 lbs. SO_2 for smaller units is a mere 3,000 tons SO_2/YR, less than 1% of the 326,000 TPY projected by EPA for this sector in 1990.

This slight increase in SO_2 emissions would produce significant benefits to smaller users of coal. Coals meeting higher limits are more widely available, thus producing a positive transportation cost effect as well as lower costs per ton of coal.

When one considers the national 23 *million* ton SO_2 emissions from all U.S. sources in 1984, the emissions difference between the illustration and EPA's proposed standard for this category of new sources represents less than 1% of the total annual domestic SO_2 emissions (actually 0.75%)—but it would be achieved at considerably lower costs per ton of SO_2 removed than EPA's proposed standards.[16] As a matter of fact, according to EPA's own estimates, these costs range from \$300 to \$400/ton of SO_2 removed under this alternative compared to \$510 to \$840/ton removed under the EPA's proposed standards. Although the costs under the EPA proposal are nearly twice those of the illustrated alternative, they do not reflect problems associated with sludge disposal, reliability of technology, and the security of reliable sources of energy.

To summarize, the small amount of theoretically additional SO_2 captured through the proposed EPA regulations does not justify the drastic measures proposed for this category of new sources. Furthermore, EPA's calculations do not take into account the fact that a preponderant majority of new boilers installed will retire dirtier units, thus resulting in an *overall emissions reduction regardless of the standard.*

[16] *National Air Quality and Emissions Trends Report*, (April, 1986), pp. 3-16.

Chapter 3

Need to Encourage Innovative Fuels and Technologies; e.g. Fluidized Bed Boilers

New source performance standards should stimulate, rather than dampen, industry's drive to develop and demonstrate new, innovative technologies and fuels, so as to reduce emissions and, at the same time, advance the nation's energy goals in a cost-effective manner. Such action was clearly recognized by the Circuit Court in *Sierra Club v. Costle, Supra*:

> We have no reason to believe that Congress meant to foreclose in Section 111(a) any consideration by EPA of the stimulation of technologies that promise significant *cost, energy*, non-air health and *environmental benefits*. . . Rather, when balancing the enumerated factors to determine the basic standard, it is appropriate to consider which level of required *control will encourage or preclude development of a technology that promises significant advantages with respect to those concerns*. (Emphasis Added.)

It is important that Federal standards regulating the emissions from boilers using such technologies not be proposed until valid EPA test data from a representative group of such installations across U.S. industry have been tabulated and reviewed. Only at this point can the appropriate emission levels be set. Premature proposal of such standards, on the other hand, would inhibit and retard their development and commercial demonstration. Such slowing down would occur because (1) it would pose an additional element of risk to the would-be buyer of such technologies, in an area in which most industrial users shun high-risk investment; and (2) it would reduce sales and consequently the funds available for continued research and commercial development.

An example of this is the fluidized bed boiler, which is rapidly gaining a foothold in several energy-intensive industries. If fully developed, this technology offers the promise of a relatively less expensive, low-polluting power source facilitating use of a low-cost abundant domestic fuel. However, little commercial U.S. operating information is available upon which to base fair and reasonable NSPS regulations for fluidized bed combustors (FBC). As the EPA's own Development Document, (March 1985), pg. 20, states:

> "Of the 80 existing or planned FBC systems in the United States, 16 are designed to burn coal and nine are designed to burn coal along with other fuels. None burn oil. After excluding those FBC systems that are research and development units or that are currently under construction, the remaining of operating FBC systems burning coal is eight. Of these eight, only four FBC systems are using limestone for SO_2 control. In addition, these four FBC systems are concentrated in a very narrow range of steam generating unit size from 7 to 16 MW (24 to 54 million BTU/HR) heat input capacity and operate with an even narrower range of coal sulfur content from 520 to 540 ng SO_2/J (1.2 to 1.3 LB SO_2/million Btu)."

This operating record—just for operating units—is an insufficient basis for a sweeping set of NSPS regulations that would apply to a variety of boiler/combustor types and vendors and a large range of sizes. And these four boilers are smaller than the minimum size which would be affected by the draft industrial NSPS regulations.

Yet EPA's proposal may already include some of these planned installations as "affected facilities". This action could seriously impede the full demonstration and acceptance of this technology, further delaying or perhaps stifling an efficient, economical, environmentally-sound coal-burning power source.

Chapter 4

Other Considerations

Importance of Coal to National Security

The 1973 Arab Oil embargo changed America's thinking about energy in dramatic ways. Two events—the tripling of OPEC oil prices after the embargo and the subsequent increase in oil prices as hostilities broke out in Iran—put America on notice that it was excessively dependent upon energy from an extremely volatile region of the world.

No single domestic energy resource has contributed more than coal toward assuring America adequate supplies of reasonably priced energy over the past decade. With reserves sufficient to power the nation for several hundred years, coal provided an abundant and inexpensive domestic solution to the energy crisis. As other energy sources rose in price and became less available, coal was there to fill the gap.

To some people, the energy crisis appears to be over. However, the shortages and rising costs of energy could occur again unless actions taken to reverse the trends continue. Most of the industrialized nations of the free world remain excessively dependent on insecure sources for a large part of their energy. The implications of this excessive reliance are relatively clear. The nation is extremely vulnerable to economic and social disruption in the event of a major and abrupt interruption in the flow of petroleum from the Mideast—especially to Japan, Western Europe and the U.S. itself. These economies continue to experience a large outflow of wealth to pay for imported oil.

As proposed, the draft NSPS regulations discourage the use of coal in favor of oil and gas, pushing industry once again towards reliance on energy sources which remain insecure even today. The war in Iran continues. The Mideast remains a volatile part of the world. This regulation ignores the lessons of the recent past. Today it is even more important that this nation remain on a path to true energy independence.

The Need to Protect U.S. Industry's Competitive Position in International Markets

To remain competitive in international markets—or to regain position—industrial steam users must be assured a reliable supply of competitive fossil fuels. This essential fuel flexibility will not be possible with an excessively stringent emissions standard for new coal-firing units since this will force most current and potential coal users to burn other fossil fuels. This is a vicious cycle, of course, because fuel switching will in turn drastically dampen coal production for industrial use. In today's market, this may not appear to be a concern; however, over the long term, this would have unquantified but substantial impacts on balance of payments and domestic employment.

Industrial Projects: Delay or Abandonment

Under Section 111 of the Clean Air Act, new source performance standards are effective as of the date of *proposal*, not as of final promulgation. This means that sources must comply with the standard as proposed if construction commences after the date of *proposal*—regardless of changes that might be made in the ultimate standard between proposal and promulgation. This creates a high degree of inherent uncertainty in the industrial boiler planning process. When this factor is combined with the mandating of flue gas SO_2 scrubbing, this uncertainty will be converted into costly project delay and, in many cases, abandonment, an unfortunate and expensive result.

Chapter 5

Comparison of Various Control Strategies

A broad range of control level strategies has been considered; the following three describe the range:

1. Emissions limit/percent reduction (EPA) recommendation)
   - Level: ≥ 100 MM BTU/HR: 1.2 lbs. per MM BTU; 90% reduction
   - Method: Wet FGD
   - Cost: $0.80[17] - 2.52/MM BTU[18]
   - Impact: Because there have been no wet FGD systems installed by industry during the past five years and because of their exorbitant costs, this would discourage expansion of coal use in new industrial boilers.
2. Emissions limit/percent reduction
   - Level: ≥ 100 MM BTU/HR: 1.2 lbs. per MM BTU; 70% reduction
   - Method: Dry FGD
   - Cost: $0.73/MM BTU
   - Impact: Because of cost considerations and the availability of competitive alternative fuels, this would discourage all but a very small number of new coal-fired industrial projects
3. Emissions limit
   - Level: >250 MM BTU/HR: 1.2 lbs. per MM BTU, and 100-250 MM BTU/HR: 1.6 lbs. per MM BTU
   - Methods: Options include one or more of the following: low-sulfur coal, coal beneficiation, fluidized bed combustion, dry sorbent injection and alternative emission reduction techniques.
   - Costs: $0.05-.50/MM BTU
   - Impact: Because this would allow each industrial coal user to select the most cost-effective control method for his specific case, more new coal-fired industrial projects would be constructed than in either of the above alternatives.

This option is supported by data from the Energy Information Administration (EIA)[19] and EPA[20] itself. In its most recent annual coal production report, EIA finds that the average sulfur content of the coal used by industry was 1.6%, by weight, which is equivalent to an average aggregate SO_2 emissions level from existing and newer sources of 2.8 lbs. SO_2 emission per million BTU. Retention of the current 1.2 lbs. limit for large new boilers (>250 million BTU input) and a 1.6 lbs. SO_2 per MM BTU emission limit for smaller new boilers (100-250 million) would produce a resultant reduction in incremental SO_2 emissions approaching 50%.

Second, an analysis done by EPA's contractor in September, 1983, shows that the average SO_2 emissions limit of the nation's 244 air quality control regions is 3.5 lbs. per million BTU input for a model coal-fired boiler of 200 million BTU input capacity. The 1.2/1.6 lbs. combination emissions limitation, again, would result in a 50+% mean reduction for new boilers, from the current national average.

[17] Assumed at least 10% more expensive then dry scrubbers, based on utility data.

[18] This is based on data submitted by General Motors at one of its locations.

[19] EIA, *Coal Production 1984,* Table C4, "Average Sulfur Content of Coal Shipments from Mines by Consumer: 1983," pp. 113.

[20] Correspondence from Karl F. Held, Project Manager, Energy and Environmental Analysis, Inc., to William B. Marx, President, CIBO, (September 19, 1983), [See Appendix F].

Chapter 6

Conclusions

Based on this study, the following conclusions were drawn:

- The draft regulations would increase the cost of steam from new coal-fired industrial boilers by at least $0.70/MM BTU or roughly $17/ton with existing flue gas desulfurization technologies. These additional costs would cause a significant shift from coal to natural gas use. By 1990, it is expected that 70% of the industrial boiler capacity would be gas fired, displacing about 5.6 million tons/year of potential coal sales if the draft EPA rules are instituted.
- New technologies, such as fluidized bed combustion, although promising, lack sufficient operating data upon which to base New Source Performance Standard regulations.
- The total emissions from new industrial boilers will be relatively insignificant for two reasons:
  - —Under a worst-case EPA scenario, the total potential emissions from all new industrial boilers above 100 MM BTU/HR, if left completely unregulated, would amount to less than 1.5% of the total U.S. SO_2 emissions.
  - —Industrial boiler emissions have declined and are expected to continue to decline regardless of any additional federally implemented New Source Performance Standards. Between 1973 and 1983, all U.S. industrial SO_2 emissions have decreased 46%[21]. This reduction is a result of energy conservation (energy use declined 7.5% between 1972 and 1984), reductions in smelters and other heavy industrial capacity, declining industrial boiler population, the replacement nature of the new boiler market (new boilers tend to replace old ones) and existing state and local emission standards.[22]
- The boiler population segment between 100 and 250 MM BTU/HR deserves special consideration because:
  a. Only 18% of the aggregate capacity of new industrial boilers falls in this size range.
  b. SO_2 emissions from this segment will contribute at the most 0.3% of the total U.S. emissions.
  c. Capital related costs incurred by this segment are disproportionally higher than the larger boilers due to a lack of an economy of scale.
  d. Coal transportation costs are liable to be higher because overall coal consumption is lower and therefore volume shipping savings enjoyed by larger users are foregone.

[21] Drew Lewis and William Davis, *Joint Report of the Special Envoys on Acid Rain*, (January, 1986).

[22] U.S. Department of Commerce, *1986 Outlook: Prospects for over 350 Manufacturing and Service Industries*, (1986).

Chapter 7

Recommendations

The National Coal Council recognizes that the EPA is legally compelled to develop standards for new industrial boilers. Therefore, it is recommended that:

1. The Secretary of Energy should support the existing 1.2 LB SO_2/MM BTU maximum emission regulation for new industrial boilers with a heat input of 250 MM BTU/HR or greater.
2. The Secretary of Energy should *not* support the draft EPA regulations for industrial boilers of 100 MM BTU/HR or greater, which includes a mandatory 90% SO_2 reduction.
3. The Secretary of Energy should support a reasonable SO_2 emission standard for new boilers above 100 MM BTU/HR heat input. Between 100-250 MM BTU/HR, the limitation should be established at the point which minimizes both delivered coal costs for the small industrial boiler and overall SO_2 emissions. The level should be *no lower* than 1.2 LB SO_2/MM BTU; 1.6 LB is used for illustration purposes in the report. The exact limitation should be based on a study of the geographic availability of coals with various sulfur contents and associated impacts on delivered coal costs and overall emissions.
4. The Secretary of Energy should ensure that NSPS regulations for new technologies be based upon careful studies of actual commercial units in the applicable size ranges. This is consistent with recommendations made by The National Coal Council Report on Clean Coal Technology (June, 1986).

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Appendices

Appendix A

Other Legal Provisions

With regard to the "adequately demonstrated" requirement, in *Essex Chemical Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973), the court defined the term "adequately demonstrated" as used in Section 111. The court stated:

> An adequately demonstrated system is one which has been shown to be *reasonably reliable, reasonably efficient*, and which can reasonably be expected to serve the interests of pollution control *without becoming exorbitantly costly* in an economic or environmental way. (Emphasis Added.)

In *National Lime Assn. v. EPA*, the same court said:

> *to be achievable, . . . a uniform standard must be capable of being met under most adverse conditions which can reasonably be expected to recur* and which are not or cannot be taken into account in determining the 'costs' of compliance. (Emphasis Added.) 416 F.2d 431n.46 (D.C. Cir. 1980)

With regard to achievability, in *Sierra Club v. Costle, supra*, at 377, the Circuit Court reaffirmed that the Agency must ensure that NSPS can be met under the full range of conditions likely to occur:

> In order for EPA to demonstrate the achievability of the standard . . . it must: (1) identify variable conditions that might contribute to the amount of expected emissions, and
> (2) establish that the test data relied on by the agency are *representative of potential industry performance*, given the range of variables that affect the achievability of the standard. (Emphasis Added.)

In order to recognize the basic differences between utility and industrial boiler design and operation and their positions in the respective business sectors they serve, EPA must make use of the distinguishing authorities of Sec. 111, Standards of Performance for New Stationary Sources, which clearly confers upon the Administrator the authority to make the necessary distinctions in such cases:

> "(2) The Administrator may *distinguish among classes, types, and sizes* within categories of new sources for the purpose of establishing such standards." (Emphasis Added.)
>
> [(b)(1)(B)(2)]
>
> ". . .nothing in this section shall be construed to require, or to authorize a modified source to install and operate *any particular* technological system of continuous emission reduction" to comply with any new source standard of performance. (Emphasis Added.)
>
> [(b)(1)(B)(5)]

Appendix B

Scrubber Technologies and Costs

APPENDIX B-1 Advent of Commercial Scrubbing Technology

To achieve aggressive levels of sulfur dioxide control, sophisticated gas treatment technology had to be developed. Flue gas desulfurization (FGD) is the most common technique employed to date for removing sulfur dioxide (SO_2) from flue gases. All FGD systems are based on acid/base chemistry to capture sulfur. Usually a base compound, e.g. lime or limestone, is slurried in water which is then brought into contact with the acidic SO_2 in the flue gas. The acids and bases react, forming salts such as calcium sulfite or calcium sulfate.

Six basic types of scrubbers have achieved commercial status: wet lime/limestone, lime spray dryers (dry), dual alkali, sodium sulfite, magnesium oxide and aqueous sodium carbonate.[23] By far the most common is the wet lime/limestone—89 of the 119 operating utility systems were of this type in 1984.[24] Wet systems can achieve 90% desulfurization. However, these systems yield a sludge which either requires special disposal or further chemical processing.

Dry scrubbers, which are generally less expensive than wet systems, are gaining acceptance. Dry scrubbers (spray dryers) atomize a lime slurry in a special flue gas contacting vessel. The hot flue gas dries and reacts with the lime to form a dry, stable and innocuous solid waste. These systems can achieve 70%—85% desulfurization but are limited by the humidity (approach to saturation) and sulfur content of the flue gas, residence time in the contacting vessel and downstream systems, and the reactivity of the lime. Most commercial dry FGD systems are used in Western power plants burning low-sulfur coal. The TVA has found dry FGD systems are more cost-effective than wet systems and is actively developing dry FGD's for retrofit applications on high-sulfur eastern coals.[25] A 160 MW dry FGD commercial demonstration is being planned by TVA for start-up in 1990.

[23]Energy Research Advisory Board (ERAB), *Clean Coal Use Technologies*, Vol. II, (June, 1985).

[24]National Coal Association, *Steam-electric Plant Factors*, 1985 ed.

[25]R. F. Robards, et al., "High Sulfur Spray Dryer Evaluations," (Cincinnati, OH: 9th Symposium on Flue-Gas Desulfurization, June 4-7, 1985).

APPENDIX B-2 Summary of Scrubbing Cost Survey

Dry FGD Cases[26]

Case	Boiler Size (#/hr × 10³)	Boiler Efficiency %	Boiler Input (MM BTU)	Capacity Factor %	Fuel Cost[27]	FGD Cost[27]	Percent FGD/Fuel	Year
A	150	82	183	90	1.25	0.65	+52	1986
B	200	86	233	85	2.00	0.65	+33	1985
C	180	86	209	80	1.75	0.64	+37	1984
D	150	80	188	70	2.02	0.67	+33	1985
E	150	88	170	70	1.69	1.00	+59	1985
F	120	83	145	60	1.50	1.05	+70	1985
G	170	80	215	70	1.75	0.48	+27	1984
H[28]	250	—	—	—	—	0.71	—	1986
I[29]				(AVERAGE)		0.73		

[26]Includes all operating costs charged to the FGD system and annualized FGD capital costs (See Appendix B-3, Case C history reference).

[27]In current dollars per million BTU input.

[28]Note: *This is an actual operating installation;* (See Appendix B-3 for details).

[29]The ninth case referred to on a previous page involved a wet system at a General Motors site, where a wet FGD system serves 4 boilers with an aggregate input of 384 MM BTU/hr., shows an FGD cost of $2.52 per million BTU input, which more than doubles the price of the coal burned.

APPENDIX B-3 Case A (Dry)

OLD BEN COAL COMPANY

333 West Vine Street • Lexington, Kentucky 40507 • (606)253-3300 • Telex: 910-997-0495

March 18, 1986

William B. Marx
CIBO
5795-B Burke Center Parkway
Burke, Virginia 22015

Dear Bill:

I have checked our in-house files for comparisons between oil, gas and coal fired industrial boiler economics. Unfortunately, there was not as much there as I originally thought. We have no data on industrial pulverized coal or stoker boilers with FGD systems. A rule of thumb (Coffin, B.D., Power, October, 1984) estimates dry scrubber capital costs at $5-10/LB of steam for boilers above 200,000 LB/HR. Coffin also provides cost curves for various kinds of steam plants. I have attached this article from Power for your review.

The one in-house study we have compares a gas fired boiler to a circulating fluid bed combustor (CFB). An economic summary is shown in Table I. As you would expect, capital related costs dominate (shown below) the cost differentials, making gas more economical up to about $4.05/MMBTU.

	CFB		GAS	
	$/MLB	%	$/MLB	%
Fuel Costs	1.81	27.5	3.92	69.5
Non-Capital Related O.C.				
Capital Related O.C.	0.94	14.3	0.24	4.3
Total Operating Costs	4.01		4.99	
Capital Charge	2.57	39.1	0.65	11.5
TOTAL COSTS	6.58	100.0	5.64	100.0

On a pure operating cost basis, coal is more economical than gas down to $2.60/MMBTU. Thus, those who now have coal facilities will most likely continue to run them unless gas or oil falls below $2.60/MMBTU (about $16/BBL of resid, delivered). However, there is no incentive for anyone to build new coal fired facilities unless oil ang gas prices climb about $4.00/MMBTU. This breakeven price for fuel could be lowered of capital costs for coal are reduced or if special government incentives, such as an investment tax credit, are enacted.

To get a feel for the impact of adding an FGD to a stoker boiler, I simply used the capital costs shown in the 1984 Coffin Power article for a stoker, with and without an FGD. FGD costs were assumed to be $15/LB of steam. Compliance coal for the no. FGD stoker was assumed to be $1.80/MMBTU and $1.70/MMBTU for the stoker with the FGD. Ash disposal costs were kept the same as the CFB case. Chemical and power costs were increased by 15% for the FGD case vs. the non-FGD case. The FGD used lime at $50/ton at Ca/S of 1.2. All other costs were kept the same. With these assumptions, the FGD adds about $0.50/MLB to the total costs of steam generation. In addition, these data show that a new compliance coal stoker (<1.2 #SO_2/MMBTU) should be able to remain competitive with gas or oil down to $2.85/MMBTU. Enacting any kind of percent sulfur capture law will quickly make stoker firing uneconomic in today's environment.

continued

Appendix B-3 Case A (Dry) continued

The above costs are rather approximate, with little back-up data. It would be preferable to use publicly available cost estimates or other sources with more detail. However, if none are available, these figures illustrate the basic economics of steam production and the impacts of further sulfur regulations.

Please advise if I can be of further assistance.

Sincerely,

E. T. Robinson
Technical Advisor

ETR/dyf:MARX

TABLE I
Comparison of Gas Fired and CFB Boiler Costs

	CFB		GAS	
BOILER SIZE MLB/HR	150		150	
CAPITAL COSTS $MM	20.28		5.15	
CAPITAL COSTS $/LB OF STEAM	135		34	
OPERATING FACTOR %	90		90	
OPERATING COSTS	$MM/YR	$/MLB	$MM/YR	$/MLB
FUEL				
COAL@$1.25/MMBTU	1.74	1.47	0.00	0.00
GAS@$3.25/MMBTU	0.00	0.00	4.63	3.92
LIMESTONE @ $17/T	0.15	0.13	0.00	0.00
ASH @ $15/T	0.25	0.21	0.00	0.00
TOTAL FUEL COSTS	2.14	1.81	4.63	3.92
O & M				
MANPOWER	0.49	0.41	0.28	0.24
CHEMICALS,POWER,SUPPLIES	1.00	0.85	0.70	0.59
TAXES &INSURANCE @ 3%/YR	0.61	0.51	0.15	0.13
MAINTENANCE @ 2.5%/YR	0.51	0.43	0.13	0.11
TOTAL O & M	2.61	2.20	1.26	1.07
TOTAL OPERATING COSTS	4.75	4.01	5.89	4.98
CAPITAL CHARGE @ 15%	3.04	2.57	0.77	0.65
TOTAL COSTS	7.79	6.59	6.67	5.64

TABLE II
Comparison of Gas Fired, Stoker and CFB Boiler Costs

COST BASIS	OLD BEN CFB		COFEIN STOKER, FGD		COFEIN STOKER,NO FGD		OLD BEN GAS	
BOILER SIZE MLB/HR	150		150		150		150	
CAPITAL COSTS $MM	20.28		12.75		10.5		5.15	
CAPITAL COSTS $/LB OF STEAM	135		85		70		34	
OPERATING FACTOR %	90		90		90		90	
OPERATING COSTS	$MM/YR	$/MLB	$MM/YR	$/MLB	$MM/YR	$/MLB	$MM/YR	$/MLB
FUEL								
COAL@$1.25,1.80/MMBTU	1.74	1.47	2.37	2.00	2.50	2.12	0.00	0.00
GAS@$3.25/MMBTU	0.00	0.00	0.00	0.00	0.00	0.00	4.63	3.92
LIMESTONE @ $17/T,LIME @ $50/T	0.15	0.13	0.20	0.17	0.00	0.00	0.00	0.00
ASH @ $15/T	0.25	0.21	0.22	0.19	0.10	0.09	0.00	0.00
TOTAL FUEL COSTS	2.14	1.81	3.79	2.36	2.61	2.21	4.63	3.92
O & M								
MANPOWER	0.49	0.41	0.49	0.41	0.49	0.41	0.28	0.24
CHEMICALS,POWER,SUPPLIES	1.00	0.85	0.98	0.83	0.85	0.72	0.70	0.59
TAXES &INSURANCE @ 3%/YR	0.61	0.51	0.38	0.32	0.32	0.27	0.15	0.13
MAINTENANCE @ 2.5%/YR	0.51	0.43	0.32	0.27	0.26	0.22	0.13	0.11
TOTAL O & M	2.61	2.20	2.17	1.84	1.92	1.62	1.26	1.07
TOTAL OPERATING COSTS	4.75	4.01	4.96	4.19	4.53	3.83	5.89	4.98
CAPITAL CHARGE @ 15%	3.04	2.57	1.91	1.62	1.58	1.33	0.77	0.65
TOTAL COSTS	7.79	6.59	6.87	5.81	6.10	5.16	6.67	5.64
BREAKEVEN GAS PRICE $/MMBTU		4.04		3.39		2.85		3.25

APPENDIX B-3 Case B (Dry)

P R O C E E D I N G S

FIRST ANNUAL FLUIDIZED BED CONFERENCE

SPONSORED BY THE TECHNICAL COMMITTEE

DEC. 3–4, 1985

COUNCIL OF INDUSTRIAL BOILER OWNERS

WASHINGTON-PLAZA HOTEL • WASHINGTON, D.C. • WILLIAM B. MARX, PRESIDENT

A COMPARISON OF CIRCULATING FLUID BED, BUBBLING FLUID BED, PULVERIZED COAL AND SPREADER STOKER POWER PLANTS

Ronald C. Lutwen, President

Thomas J. Fitzpatrick, Engineer

SOLID FUEL TECHNOLOGY, INC.

A COMPARISON OF FLUID BED SPREADER STOKER AND PULVERIZED COAL FIRED UNITS

In this paper a comparison is made of technical and economic aspects of burning coal in fluid bed, spreader stoker and pulverized coal fired boilers. Operating characteristics are reviewed for each of the combustion processes for a 200,000 lbs. per hour unit under like operating conditions.

COMBUSTION PROCESSES:

Of the several types of stokers available for coal combustion, a type commonly used is the spreader stoker. It is equipped with a set of rotating feeders located at the boiler front which continuously throw coal toward the rear where it is spread across the entire furnace width onto a traveling grate. Some of the coal burns in suspension, while the remainder falls and is burned on the grate. The grate generally travels from the back of the furnace to the front, the coal being burned in a layer having a thickness in the range of 2-1/2 to 5 inches. Combustion is completed at the front and ash is continuously discharged over the front end of the traveling grate into the ash pit. The grate speed can be varied to accommodate variations in fuel characteristics, while the rate of feed may be varied to unit load range.

In a pulverized coal (PC) fired boiler, coal is generally routed from overhead coal bunkers through feeders into the pulverizers. The pulverizers grind the coal to fine consistency, the size of which can be controlled, typically so that 65-75% can pass through a 200 mesh screen. Hot primary air is used to dry the coal in the pulverizer and convey it to the burner where it is emitted into the furnace to burn totally in suspension. The coal/air mixture burns much the same as oil or gas.

In the fluidized bed combustion process, air is blown up through a bed consisting of coal and either limestone, sand, or other inert bed material. Combustion takes place in a turbulent mixing of the particles created by the gas flow through the bed. It is this turbulent mixing which gives the appearance of a boiling fluid.

There are two (2) general types of fluid beds, - bubbling (BFB) and circulating (CFB). In the bubbling bed, the gas velocity is controlled to minimize the entrainment of particles in the gas stream. The hot gases exit the bubbling bed directly into the furnace or heat recovery area. The circulating bed can use higher air velocities which has the effect of entraining the hot particles into the gas stream. From the circulating bed, the particle laden gases pass through the furnace and into cyclones or other mechanical separators. The particles are collected in the separators, and returned to the bed for completion of combustion, with the gases passing to further heat recovery and to the stack.

OPERATING CHARACTERISTICS:

Coal Sizing and Preparation Requirements:

Coal size requirements differ greatly depending on the combustion process. The coal typically specified by the spreader stoker vendor has a maximum size, and a limit on the amount of fines. Exceeding the limits imposed by the manufacturer increases the possibility of carryover and increased levels of unburned combustibles. Most pulverized coal specifications require a top size , with no restrictions on fines. Fluid bed coal requirements generally have a top size limit, and generally do not limit fines unless the BFB has overbed feed.

The following table summarizes typical requirements for coal sizing:

Typical Coal Sizing

	Stoker	PC	BFB	CFB
Maximum size:				
Limit	1-1/4"	1-1/4"	1/8 to 3/8"	1/2" to 3/4"
Typical Spec.	3/4 to 1"	1-1/4"	1/8"	1/2"
Fines limits:	<20%<1/4" <6%<40 Mesh	None	None	None

Of the three combustion systems, the pulverized unit requires the least coal preparation, generally accepting run-of-mine coal at the site with a minor amount of crushing to reduce top sizing to permit entrance to the pulverizer. The circulating fluid bed unit requires the next level of preparation, usually requiring reduction in sizing to one half to three quarter inch. The bubbling fluid bed requires reduction to as little as 3/8". The sizing can sometimes be accomplished by on site crushing, but may require special equipment (rough pulverizing). Dryers are typically required for bubbling bed units. The stoker fired unit is concerned with both top sizing and the amount of fines. Double screened and washed coal, so called "stoker coal", is offered by coal suppliers but at a premium cost. In the past, this extreme was resorted to in applications to reduce dust loading to mechanical collectors. With almost universal use of baghouses and precipitators for improved fly ash collection, there are stoker units in operation using minor preparation, such as run-of-mine run through an on site crusher, with little or no differential in cost over coal used for the other combustion processes. Justification for washing should be an economic one applying to all combustion processes.

Coal Characteristics:

All of the combustion processes under consideration are reasonably tolerant to a wide range of coals. However, there are individual characteristics for each. The stoker unit will burn a wide range of coals, from lignite to bituminous, without regard to swelling indices and hardness, and with low regard for fouling. Since the feeders are volumetric, capacity is affected by coal BTU value, and slagging may occur if the coal is outside design limits for the unit. Pulverized coal fired units are sensitive to several design criteria, such as hardness, slagging, fouling, and moisture. PC units must be designed for the specific coal to be used. Except for the requirement for predrying, and the sizing of crushers for some bubbling bed types, the fluid bed units will burn almost any type of coal, including very low grade types, having high sulfur content. For all units, reduction in BTU content will affect unit capacity.

Boiler Efficiency:

In determining the boiler efficiency of each type of unit, there are a number of factors to consider. The three (3) main factors are unburned combustibles, excess air and exit flue gas temperature. PC and fluid beds can generally be designed for lower excess air for satisfactory operation than can the stoker units. Excess air varies from full load to minimum load. Unburned combustible will vary on a stoker depending on the level of ash reinjection. The levels as stated by the manufacturer are in accordance with a mandatory trade standard. The unburned combustible for stokers, and for PC units are well established and can be predicted for a particular design condition. There is little history for FBC units to corroborate stated values in relation to actual values for unburned combustibles. Early units had up to 10% unburned carbon.

Flue gas temperatures can be similar for all types of units since this depends on the selection of heat traps. Flue gas temperatures can be in the range of 300 to 350 degrees F.

The net effect of these characteristics is that PC units generally have the highest efficiency; FBC and stokers typically have stated efficiencies in the same general range. From historical data, the actual day to day average operating efficiencies are often less than the stated values.

The table below summarizes typical values for excess air, unburned combustible (UC), and efficiency:

Comparative Performance Values

	Stoker	PC	BFB	CFB
Excess Air, %:				
100% Rating	30	20	20	20
50% Rating	50	35	40	40
Min. load	60	40	45	45
Unburned Combustible, %:				
Range	2 to 7	.5 to .8	2 to 10	2 to 4
Typical	4	.5	4 - 8	3 - 4
Unit Efficiency, %:				
Range	80-85	86-88	<80-83	82-85
Typical Stated	84	87	82	84
Expected Operating	82	86	80	84

Turndown:

An important aspect of operation is turndown, or the ability to follow changes in load. Stokers and PC units have a demonstrated history of turndown ratios which should be repeatable. Stoker load is changed by varying the amount of fuel and air, and is limited by the ability to have a stable, on-smoking fuel bed. Load is changed on PC units by varying fuel and air feed, and is limited by stable flame, related to conveying velocities in the coal pipes. As stable lower limit is reached on two pulverizers, one pulverizer can be removed from service and load further reduced using one pulverizer. This may require the use of auxiliary fuel.

Bubbling fluid beds change loads by reducing the amount of bed material, or bed height, or removing beds from service. Early fluid bed units had problems in reaching satisfactory turndown levels, both from the standpoint of load reduction and the ability to make the reduction in a suitable time period. Substantial progress is indicated as fluid beds are now being offered in the market with stated turndown ratios. Some bubbling beds are still offered with load response of as poor as 10% per hour.

The following table summarizes response to load for the combustion processes:

Turndown Ratio and Load Response

	Stoker	PC	BFB	CFB
Typical turndown	3:1	5:1	3:1	3:1
Load response %	10-15%	20-25%	10%	10%
Time Unit	min	min	hour	min

(Some BFB units are offered with better load responses)

Auxiliary Power Requirements:

Power requirements for the three (3) types of units will vary widely. The fluid bed units will have the highest horsepower requirements due to high pressure forced draft fans needed to fluidize the bed and for the power used for moving the gases through the cyclones. The pulverized coal unit will be high in comparison to a stoker unit but will be less than a fluid bed unit. The additional power requirements of the pulverized unit compared to the stoker are consumed in grinding and conveying the coal.

Capacity Ranges:

Pulverized units have been designed for steaming capacities as low as 60,000 lbs. per hour for small industrial units to over 10 million lbs. per hour for utility applications. Stoker fired units are supplied primarily to the industrial market in size ranges from 10,000 to 400,000 lbs. per hour. The selection of PC units for the lower limit of sizes is dictated generally by project specific economics. Fluid bed units have been supplied in the U.S. with steaming capabilities as high as 300,000 lbs. per hour and they are now being offered at capacities of over 1 million lbs. per hour. When the fluid bed demonstrates a competitive position and more experience is gained, the size of fluid bed units supplied in the U.S. market is expected to increase.

Other Considerations:

One of the early difficulties experienced with fluidized bed units was with coal feeding systems. Attempts have been made feed under the bed and over the bed using spreader stoker feeders. Each manufacturer has developed unique feeding system which are currently being offered as solutions to the feeding problems. A history of successful operation is needed to demonstrate performance.

Control systems for stokers have generally been much simpler than either the pulverized or fluid bed units. Stoker control systems are becoming more complex with the addition of O_2 trim and combustibles analyzers designed to improve efficiency. This refinement may be rewarded by higher efficiencies. Operation of a stoker requires that continuous attention be paid to the combustion process to ensure high efficiency and prevent malfunction. However, the forgiving nature of the stoker unit permits operation with relatively unsophisticated operators. Controls for a pulverized unit typically includes automatic burner management systems in addition to combustion controls which are generally of a higher degree of sophistication. These systems monitor both ignition and main fuel, and are usually designed for both automatic start-up and shut-down. Fluid bed units also require relatively complex controls. Much of the fluid bed controls are concerned with maintaining bed temperature, and controlling load following. Operating bed temperature is critical and must be kept lower than the ash fusion point of approximately 2000 F, in order to avoid bed operation problems.

AUXILIARY SYSTEMS AND EQUIPMENT:

Many of the auxiliary systems and much of the equipment required for a power plant installation are independent of the type of combustion process. Included in this category are the turbine-generator unit, condenser, condenser circulating water system, cooling tower, feedwater heaters, boiler feed pumps, and feedwater treatment. The price differentials for these items are of minor significance in comparative cost analysis, and are not included in this paper.

The boiler designer generally has two (2) methods for reducing stack temperature - the use of an air preheater or an economizer. The heat trap selection will depend on the coal burned, the combustion process employed, temperature of incoming feedwater, allowable flue gas temperature and outlet furnace temperature. In stoker firing the incoming air temperature is limited because of grate metal temperature limits to a maximum value in the range of 350 F. Most stoker installations, therefore, have only an economizer. However, some installations use both. In a pulverized coal fired installation, the process must be designed so as to dry the coal and provide a controlled temperature of the coal/air mixture to the furnace. Use of air preheaters are thus mandated in such installations; economizers may be used in conjunction, depending on other factors. The selection of heat recovery is specific to each process, and in this paper are considered in the overall pricing with no specific differentials applied.

Systems and equipment which are influenced by the combustion process include building size, ash handling, coal handling, fans, instruments and controls, electrical equipment, piping, and wiring. In changing the combustion process, some of these systems will vary in physical extent while others differ in basic design. In either case, the total installed cost differentials between combustion processes can be significant. The cost differences pointed out in this report should not be interpreted as being universally applicable, but rather typical of some installations. Physical limitations and inherent process requirements may exist which would alter the differentials that are described in this paper.

The building volume required for the pulverized coal unit is larger than that needed for a stoker fired unit of equivalent rating because of the inherent furnace design requirements, and space required for the pulverizers. The fluid bed unit may require a building of even larger size due to the bed material reinjection and handling system.

The stoker fired unit generally requires the least sophistication in instrument and controls systems, coal handling, and coal feed system. Consequently, they require the least amount of wiring and equipment. The fluid bed will generally require the most extensive electrical system.

The ash system for all of the processes can be very similar in type. The fluid bed system must be designed for a larger capacity in order to handle the higher quantities resulting from the spent bed material.

AIR POLLUTION:

The three (3) primary air pollutants resulting from the combustion of coal are sulfur oxides, nitrogen oxides, and particulates. The various methods of control for each of these pollutants are addressed in this section.

Flue Gas Desulfurization:

Neither the stoker fired boiler nor the pulverized unit can be designed presently for reducing the amount of sulfur oxide exiting the boiler. Control of sulfur oxide from these units requires the use of a removal system located downstream of the boiler. Removal has historically been with some type of gas scrubber. There are two (2) general types of scrubbers - throw away systems and by-product systems. The three (3) prevalent types of systems being used today are - dry scrubbing, lime/limestone and dual alkali. All three (3) are throw away systems. There are a number of byproduct systems which may be attractive for large units or in specific applications.

The lime and limestone systems use a slurry of calcium oxide and calcium carbonate respectively to absorb SO2 in a wet absorption tower. The products of this reaction include calcium sulfite, calcium sulfte and unreacted lime. The product slurry is then precipitated in a settling tank and disposed of as a sludge. The tank overflow is recycled and a small slip stream is disposed of.

In the dual alkali system, the absorption of SO2 and formation of waste products occur in different systems. A sodium based alkali solution is used to absorb the SO2. The effluent from the absorber is sent to a reactor tank where it is reacted with slaked lime for regeneration of the sodium scrubbing medium. Insoluble calcium salts are formed in the reactor tank. The slurry stream, containing the insoluble calcium sulfite/sulfate solids, is sent to a thickener where the solids are concentrated for disposal. For the lime, limestone, and dual alkali systems, the wastes can be oxidized to calcium sulfate, which is suitable for disposal in land fills.

In the dry scrubbing system, the flue gas is intimately mixed with a slurry of reagent such as lime. In the presence of lime, moisture and fly ash, a high percentage of the gaseous SO2 is converted into calcium sulfite and calcium sulfate. The resultant mixture of reaction solids and fly ash can be collected in a dry state by either an electrostatic precipitator or baghouse.

For this comparison, dry scrubbing has been used.

In Bed Desulfurization:

The development of the fluid bed provides a system which allows for SO2 reduction during the combustion process. Early development showed that using limestone as the bed material greatly reduced sulfur emissions. Two (2) reactions occur in the process. The lime and oxygen react to form calcium oxide.

This calcium oxide then reacts with the sulfur dioxide to form calcium sulfate. A combustion temperature of 1500 F to 1600 F provides for the greatest efficiency of sulfur capture.

NOx Control:

Because of the low bed temperature, nitrogen oxide emissions from the fluid bed unit are low in comparison to pulverized units. Fluid bed units are represented to be capable of nitrogen oxide emissions as low as .5 lbs. per million BTU, although there is little commercial operating history. Pulverized units have demonstrated they can reach nitrogen oxide emissions levels of .7 lbs. per million BTU using low NOX burners. NOX emissions from stoker units are typically in the same rage.

Particulate Control:

Compliance with almost all air pollution agency regulations require the use of either electrostatic precipitators or baghouses for the types of firing under consideration. Determination of the range of coals to be utilized in the boiler must be completed before an intelligent decision can be made concerning which system should be installed for best overall cost, maintenance and system flexibility.

For the purposes of this comparison, all units are assumed to be equipped with baghouses.

CAPITAL COST COMPARISONS:

Much of the literature on the subject of cost comparison of fluid beds with other systems mentions the inherent small size of the fluid bed heat exchange process and concludes that fluid bed is low in cost when compared with conventional boilers. This presumes mass production and marketing of the product. In order to determine actual comparative costs, manufacturers' prices for units of the three types, (stoker, PC, FBC), have been solicited and are compared.

Since there is a divergence of prices on each type in the competitive market place, it is inconclusive to establish the exact price for each as a concrete number. Prices have been compared on boilers of the different types for identical function and as nearly as possible, on the same extent, type and quality of ancillary equipment.

Prices were in the following ranges for the boiler on a bunker to stack outlet, erected basis, exclusive of civil works, and other balance of plant costs:

Capital Cost Comparisons

NO SULFUR REMOVAL

	Low	High	Median	Average
Circ. Fl. Bed	9,590,000	13,090,000	11,340,000	11,520,000
Bub. Fl. Bed	7,590,000	9,340,000	8,465,000	8,503,000
Stoker Fired	4,460,000	7,860,000	6,160,000	6,350,000
Pulverized Coal	6,040,000	8,115,000	7,077,500	7,098,750

WITH SULFUR REMOVAL

	Low	High	Median	Average
Circ. Fl. Bed	9,590,000	13,090,000	11,340,000	11,520,000
Bub. Fl. Bed	7,590,000	9,340,000	8,465,000	8,503,000
Stoker Fired	5,760,000	9,860,000	7,810,000	8,050,000
Pulverized Coal	7,340,000	10,115,000	8,727,500	8,798,750

The prices tabulated on the previous page are for the boiler only. Adjustments were made to these prices to account for comparative total cost in place, including balance of plant. This information is summarized below:

Comparative Installed Costs

NO SULFUR REMOVAL

	Stoker	PC	BFB	CFB
Boiler, in place	-5,500,000	-4,700,000	-3,000,000	Base
Building costs	-120,000	-40,000	0	Base
Materials handling	-100,000	-100,000	100,000	Base
Controls and Instruments	-100,000	-25,000	0	Base
Piping and Mech. Work	-50,000	-15,000	0	Base
Wiring and Elect. Work	-30,000	-5,000	0	Base
Comparative Cost	-5,900,000	-4,885,000	-2,900,000	Base

WITH SULFUR REMOVAL

	Stoker	PC	FB	CFB
Boiler, in place	-3,700,000	-2,900,000	-3,000,000	Base
Building costs	-80,000	0	0	Base
Materials handling	-120,000	-120,000	100,000	Base
Controls and instruments	-25,000	50,000	0	Base
Piping and Mech. Work	0	35,000	0	Base
Wiring and Elect. Work	0	25,000	0	Base
Comparative Cost	-3,925,000	-2,910,000	-2,900,000	Base

OPERATING COST COMPARISON:

There are differences in the cost of operation between the three types of boilers. The principal factors are:

- Effect of combustion efficiency
- Degree of coal preparation
- Amount of operations labor
- Maintenance requirements
- Comparative auxiliary power
- Bed materials or reagent
- Disposal costs

OPERATING DATA AND COST FACTORS:

Various data and factors used in calculating costs and in comparative analysis follow:

Operating Data and Cost Factors

Steam Conditions:	800 psig, 850F
Feedwater Temp.	300 F
Load:	75% fixed, 50 weeks per year 25% variable Peak 200,000 lbs/hr. Winter average 180,000 lbs/hr. Summer average 160,000 lbs/hr. Annual Average 170,000 lbs/hr.
High Sulfur Coal 3%	12,000 BTU/lb, 9.9% Ash, $48/ton
Low Sulfur Coal (1%	12,445 BTU/lb, 9.9% Ash, $50/ton
Limestone	$15/ton, 85% pure
Lime	$56/ton, 90% pure
Inert bed material	$2/ton (sand)
Ash and sludge disposal	$6/ton
Electrical Power	$.05/kwh

Other pricing and operating costs from various estimating data bases.

An attempt has been made to quantify the differences for the three types of firing for two modes of operation, with and without flue gas desulfurization. Representative values for these differences are summarized on the next page.

Operating Cost Comparisons

NO SULFUR REMOVAL

		Stoker	PC	BFB	CFB
Cost of unprepared fuel, $/ton		50	50	50	50
Cost of fuel prep., $/ton	A	0	0	0	0
	B	6	0	4	0
	C	12	0	4	0
Cost of fuel as used, $/ton	A	50	50	50	50
	B	56	50	54	50
	C	62	50	54	50
Efficiency, %		82	86	80	84
Annual fuel cost, $	A	107,140	-107,140	212,860	Base
	B	617,980	-107,140	561,910	Base
	C	1,128,800	-107,140	561,910	Base
Operations labor, $		-35,000	-35,000	0	Base
Maintenance					
Fuel burning system, $		-25,000	- 9,000	- 5,000	Base
Materials handling, $		-10,000	-10,000	0	Base
Furnace, $		-15,000	-15,000	-10,000	Base
Auxiliary Power, $		-186,890	-89,060	93,290	Base
Bed Material, $		- 46,500	-46,500	0	Base
Ash disposal, $		-139,590	-142,130	0	Base
Total Comp. cost, $/yr	A	-350,840	-453,830	291,150	Base
	B	160,000	-453,830	640,200	Base
	C	670,820	-453,830	640,200	Base

WITH SULFUR REMOVAL

		Stoker	PC	BFB	CFB
Cost of fuel as used, $/ton	A	48	48	48	48
	B	54	48	52	48
	C	60	48	52	48
Efficiency, %		82	86	80	84
Annual fuel cost, $	A	98,600	- 98,600	211,800	Base
	B	628,360	- 98,600	573,800	Base
	C	1,158,120	- 98,600	573,800	Base
Operations labor, $/yr		-70,000	-70,000	0	Base
Maintenance:, $/yr					
Fuel burning system		-20,000	-4,000	5,000	Base
Scrubber		10,000	10,000	0	Base
Lime/limestone handling		-5,000	-5,000	0	Base
Furnace		-5,000	-5,000	-10,000	Base
Auxiliary Power, $/yr		-148,060	-49,660	93,290	Base
Lime/limestone, $/yr		-58,470	-76,270	0	Base
Ash and Sludge Disposal, $/yr		-135,900	-145,840	0	Base
Bed Material, $		- 46,500	- 46,500	0	Base
Total Comparative Cost	A	-380,330	-490,870	300,090	Base
	B	149,430	-490,870	662,090	Base
	C	679,190	-490,870	662,090	Base

ECONOMIC COMPARISON:

The above capital and operating cost information is summarized in the following tables into a comparison of total costs associated with owning and operating the three types of coal combustion equipment.

Comparative Cost of Ownership

NO SULFUR REMOVAL

		Stoker	PC	BFB	CFB
Incremental Investment		-5,900,000	-4,885,000	-2,900,000	Base
Annualized Capital Cost (12% of Increment. Investment)		-708,000	-586,200	-348,000	Base
Comp. Operating Cost	A	-350,840	-453,830	291,150	Base
	B	160,000	-453,830	640,200	Base
	C	670,820	-453,830	640,200	Base
Comp. Total Owner Cost	A	-1,058,840	-1,040,030	- 56,850	Base
	B	-548,000	-1,040,030	292,200	Base
	C	-37,180	-1,040,030	292,200	Base

WITH SULFUR REMOVAL

		Stoker	PC	BFB	CFB
Incremental Investment		-3,925,000	-2,910,000	-2,900,000	Base
Annualized capital costs (12% of Incremental Investment)		-471,000	-349,200	-348,000	Base
Comp. Operating Cost	A	-380,330	-490,870	300,000	Base
	B	149,430	-490,870	662,090	Base
	C	679,190	-490,870	662,090	Base
Comp. Total Owner Cost	A	-851,330	-840,070	-47,910	Base
	B	-321,570	-840,070	314,090	Base
	C	208,190	-840,070	314,090	Base

SUMMARY

A. No Sulfur Removal:

1. If sulfur removal is not required and the same fuel will be burned on all units the spreader stoker and PC units are the most economical units to install and operate.

2. The spreader stoker unit is even with PC until a penalty is applied for stoker sized coal. If the penalty gets to $12/ton then the CFB even becomes more economical.

3. If there is any fuel preparation penalty on the BFB the CFB becomes more economical.

B. With Sulfur Removal:

1. With sulfur removal the spreader stoker and PC units again prove more economical to install and operate than BFB and CFB.

2. The spreader stoker unit is even with PC until a penalty is applied for stoker sized coal. If the penalty gets to approximately $10/ton then the CFB even becomes more economical.

3. If there is any fuel preparation penalty on the BFB the CFB becomes more economical.

C. Advantages and Disadvantages of Conventional and Fluid Bed Units:

Stoker Fired Units:

Advantages

Low capital cost
Reliability-availability
Good load response
Simplicity of operation
Do not require auxiliary fuels
Will burn a wide rane of coals
Low maintenance costs
Low fouling
Low auxiliary horsepower
Demonstrated technology

Disadvantages

Some operator attendance required
Sensitive to coal sizing and segregation
Grate outage is unit outage
Requires auxiliary equipment for sulfur removal

Comments:

With proper particulate control equipment and reinjection, the unit can operate at 2% carbon loss and 85% efficiency, using crushed run-of-mine coal.

Pulverized Coal Units:

Advantages

- Minimum operator attendance
- High predictable efficiency consistently
- Excellent load response
- Burns wide range of fuels
- Minimum fuel preparation
- Can burn fuels in combination
- Excellent turndown
- High availability and reliability
- Demonstrated technology

Disadvantages

- Requires auxiliary fuels
- Maintenance on fuel burning equipment relatively high
- Susceptible to slagging and fouling
- Relatively high auxiliary horsepower
- Must be protected against furnace explosions
- Requires auxiliary equipment for SO2 reduction

Bubbling Fluid Bed:

Advantages

- Will burn a wide range of coals
- Inherent SO2 removal in process
- Low NOX emissions

Disadvantages

- Poor load response
- Low turndown ratio
- High unburned combustible
- High capital cost
- High auxiliary horsepower
- High operating cost
- Poor availability
- Short history of experience
- High maintenance and operating costs
- Fuel must be prepared if inbed feed
- Fines must be limited if overbed feed

Circulating Fluid Bed:

Advantages

- Will burn a wide range of coals and other fuels
- SO2 removal inherent in process
- Acceptable turndown ratio and load response
- Low NOx emissions

Disadvantages

- High capital cost
- High auxiliary horsepower
- High operating and maintenance costs
- Availability uncertain
- Technology relatively new

D. Sensitivity Analysis:

There are various key numbers that when altered will greatly affect the overall economic analysis. They are:

1. Capital costs

   Presently the pricing we have received and developed ourselves shows that CFB and BFB units as quite a bit more costly than PC and spreader stoker units. As the fluid bed manufacturers react to the market place their pricing will approach PC and spreader stoker pricing, when sulfur removal is required.

2. Fuel pricing

   The fluid beds are capable of burning a much wider range of fuels than the PC and stoker units can.

   This could create a lower price for the fuels that will be burned in a fluid bed unit. For the analysis in this paper approximately 60,000 tons of coal were burned each year. If by using a fluid bed a fuel could be purchased that was $10 less a ton the impact on operating costs is $600,000 per year.

   Also with fuel pricing the cost of special preparation has a major impact on the evaluation. Many stoker people argue that there is no longer a need for special sizing, but many users continue to buy double screened coal.

CONCLUSIONS:

Based on economic comparisons, with or without SO_2 reduction, and assuming no premium for coal preparation, the spreader stoker and PC units are essentially of equal attractiveness, and a much better selection than either type of fluid bed indicated. Annual savings approximately $1.0 million (with no sulfur reduction) and approximately $850,000 (with sulfur reduction), through the use of the conventional firing methods. These comparisons are using current pricing data bases. It is expected that the fluid bed units will be more competitive in pricing after additional experience is gained, and technology risk is removed from pricing.

The only economic justification for selection of the fluid bed would be if a high premium was expected to be paid for coal preparation cost or a less expensive fuel could be burned.

The stoker or PC units with scrubbers at this time appear to be better selections than fluid bed for SO_2 reduction. The conventional units have a long history of successful operation. Additional experience is needed with the fluid bed units on SO_2 removal.

For the units sizes considered in this paper, selection of the circulating fluid bed over the bubbling bed is indicated because of the better performance characteristics. The economic attraction is modest. There are specialized bubbling fluid bed units that may be superior to circulating fluid beds being offered, particularly in the smaller sizes.

The advantages, disadvantages and economics will differ for each application. The ultimate users should evaluate their own situations and determine which combustion method should be used. The only real way to make an exact determination is to solicit firm priced competitive bids with required performance guarantees.

APPENDIX B-3 Case C (Dry)

Preliminary Design
for the
Replacement Of Boilers 1 & 2

44 for

Iowa State University
Physical Plant

Ames, Iowa

August 1984

83-005-1-005

IOWA STATE UNIVERSITY ★ OF SCIENCE AND TECHNOLOGY ★
SCIENCE with PRACTICE

Burns & McDonnell
ENGINEERS - ARCHITECTS - CONSULTANTS

APPENDIX B-3 Case D (Dry)

P R O C E E D I N G S

FIRST ANNUAL FLUIDIZED BED CONFERENCE

SPONSORED BY THE TECHNICAL COMMITTEE

DEC. 3–4, 1985

COUNCIL OF INDUSTRIAL BOILER OWNERS

WASHINGTON-PLAZA HOTEL • WASHINGTON, D.C. • WILLIAM B. MARX, PRESIDENT

APPENDIX B-3 Case E (Dry)

ECONOMICS OF FLUID BED, PULVERIZED COAL
AND SPREADER STOKER STEAM GENERATORS

by

R. A. MALONE
BLACK & VEATCH
ENGINEERS-ARCHITECTS

PRESENTED TO

COUNCIL OF INDUSTRIAL BOILER OWNERS
FLUIDIZED BED SEMINAR

DECEMBER 3-4, 1985

APPENDIX B-3 Case F (Dry)

UNIVERSITY OF MISSOURI

Facilities Management & Planning

Final Phase II Report

RECOMMENDATIONS FOR IMPROVEMENTS
COGENERATION POWER PLANT AND
DISTRIBUTION FACILITIES

at the
University of Missouri – Columbia

July 23, 1985

BIBB and Associates Inc.
Engineers and Consultants

6901 W 63RD ST., CLOVERLEAF 2, SUITE 106
OVERLAND PARK, KANSAS 66202 913-236-7200
P.O. BOX 37, SHAWNEE MISSION, KANSAS 66201

APPENDIX B-3 Case G (Dry)

48

THE HUBINGER COMPANY

Keokuk, Iowa

Part B Study for

COAL-FIRED BOILER AND ELECTRIC COGENERATION SYSTEM

May 31, 1984

BIBB and Associates Inc.
Engineers and Consultants

6901 W 63RD ST CLOVERLEAF 2 SUITE 106
OVERLAND PARK KANSAS 66202 913-236-7200

P O BOX 37 SHAWNEE MISSION KANSAS 66201

APPENDIX B-3 Case H (Dry)

Received in CIBO office
on 4/7/86. MBM

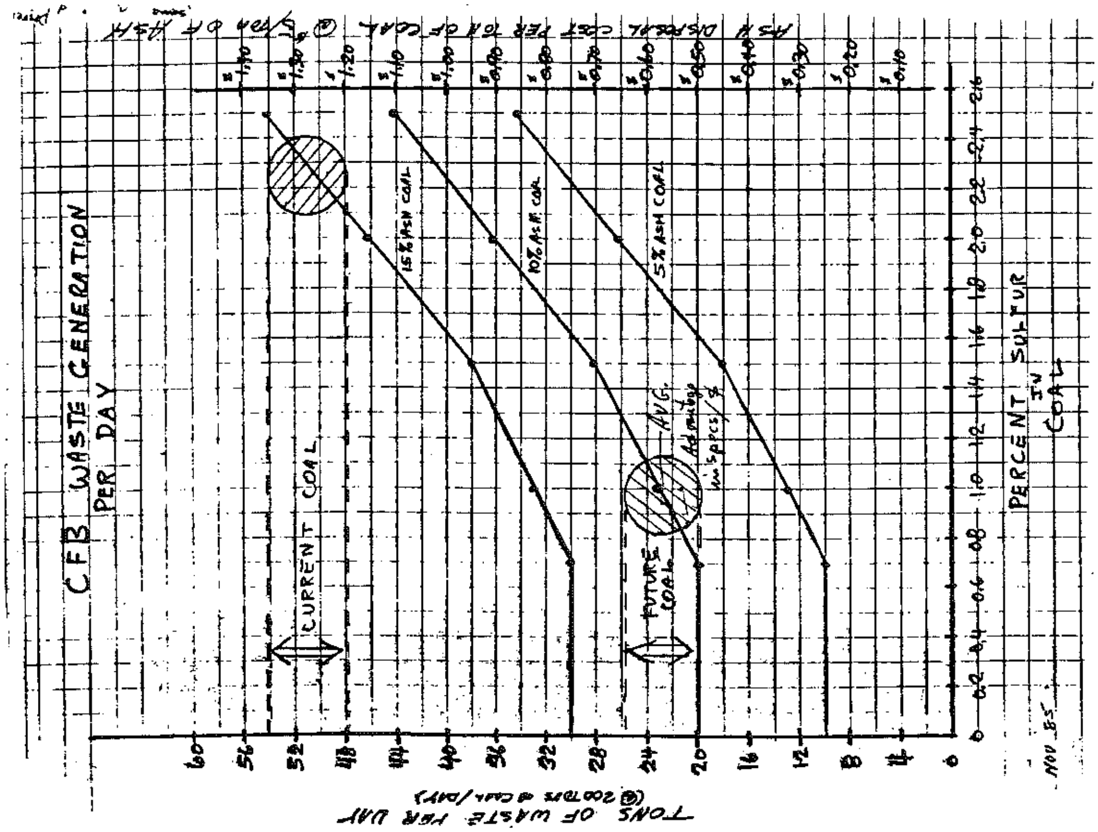
WALLY BRADLEY

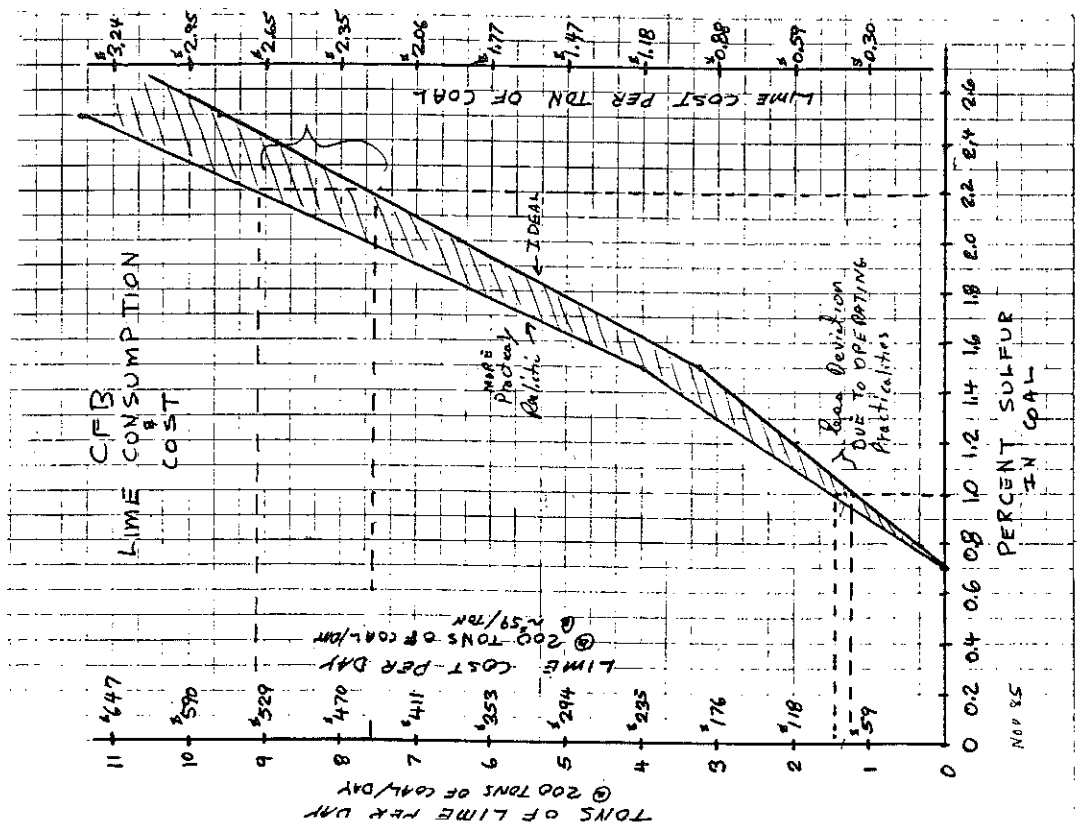
Attached is the data on our sulfur scrubbing cost at Austell Box Board. The Term "Current Coal" refers to a 2.2-2.4% sulfur, 12,000 BTU/LB, 15% ash Coal. The term future refers to a 1% sulfur, 10% ash, 12,500 BTU/LB Coal.

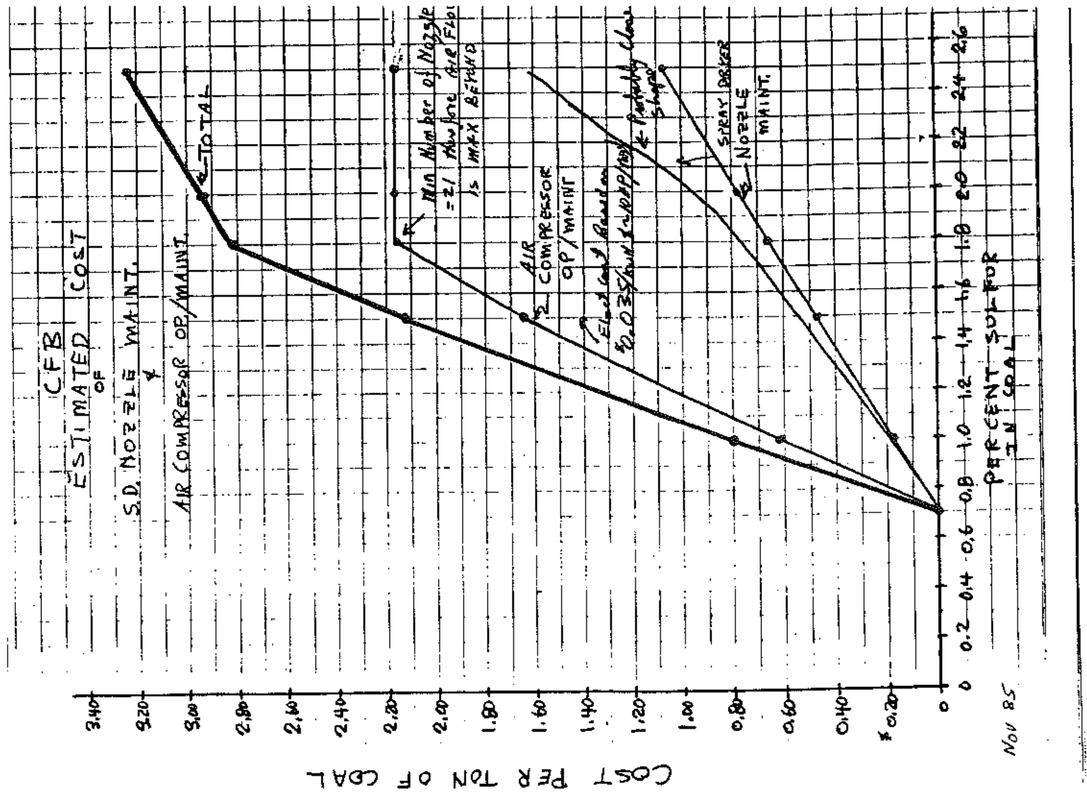
I trust this data will be of some help in your project. Please give me a call if I can answer any specific questions that arise

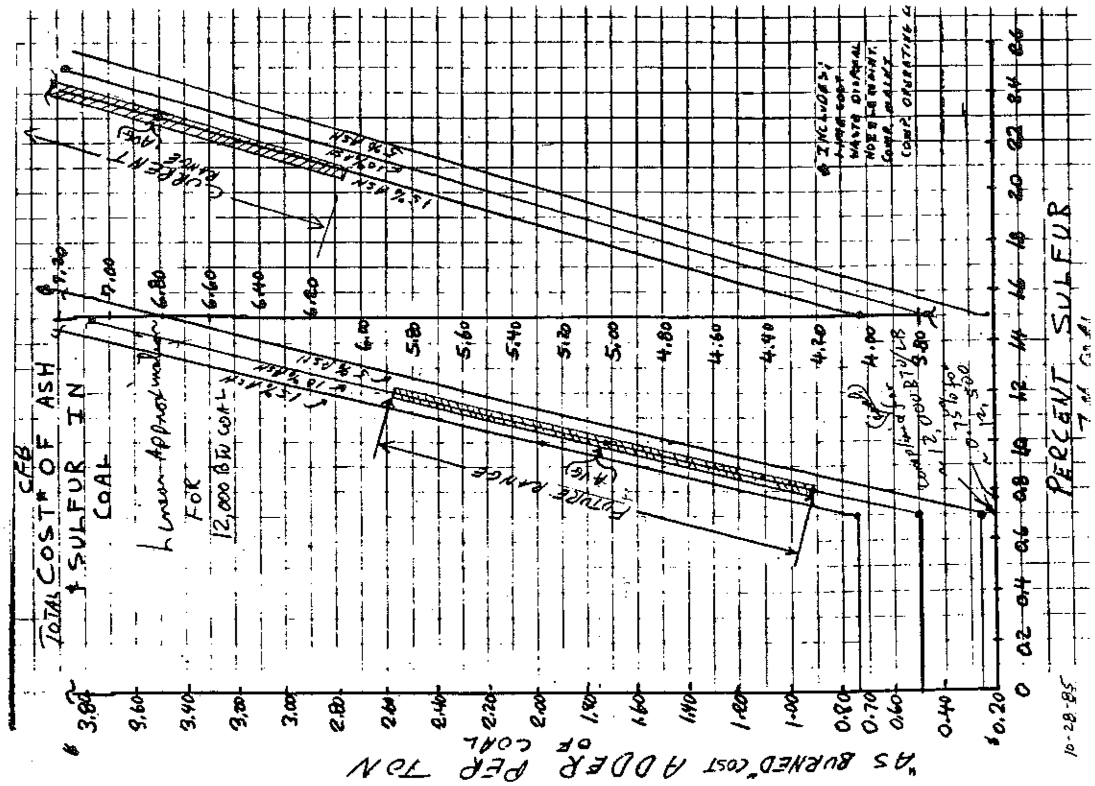
Sincerely
Wallace H Bradley

NOTE:
In a telephone conversation with Mr. Bradley 4/4 I was told the capital costs for FGD and fabric filter was $2.3 million; allowing $300,000 for the fabric filter, leaves an FGD capital cost of $2 million. MBM


CFB WASTE GENERATION PER DAY
TONS OF WASTE PER DAY
(@ 200 TONS of COAL/DAY)
PERCENT SULFUR IN COAL
ASH DISPOSAL COST PER TON OF COAL @ $/TON OF ASH
15% ASH COAL
10% ASH COAL
5% ASH COAL
CURRENT COAL
FUTURE COAL
NOV 85


CFB LIME CONSUMPTION & COST
TONS OF LIME PER DAY
@ 200 TONS OF COAL/DAY
LIME COST PER DAY
LIME COST PER TON OF COAL
PERCENT SULFUR IN COAL
IDEAL
DUE TO OPERATING Practicalities
NOV 85


CFB
ESTIMATED COST
OF
S.D. NOZZLE MAINT.
+
AIR COMPRESSOR OP/MAINT.
TOTAL
AIR COMPRESSOR OP/MAINT.
SPRAY DRYER NOZZLE MAINT.
PERCENT SULFUR IN COAL
COST PER TON OF COAL
NOV 85


CFB
TOTAL COST* OF ASH & SULFUR IN COAL
Linear Approximation FOR 12,000 BTU COAL
CURRENT RANGE
FUTURE RANGE
PERCENT SULFUR
"AS BURNED" COST ADDER PER TON OF COAL
10-28-85

Appendix C

Letter to Fred L. Porter from William B. Marx

COUNCIL OF INDUSTRIAL BOILER OWNERS

PRESIDENT
William B. Marx

July 30, 1985

Mr. Fred L. Porter
Standards Development Branch
Emission Standards and
Engineering Division
United States Environmental
Protection Agency
Office of Air Quality Planning and
Standards
Research Triangle Park
North Carolina 27711

Dear Fred:

In response to your letter of June 18, 1985 on the CIBO boiler survey, enclosed please find the following documents:

1. Boiler "Expansion-Replacement"Survey, 27 case histories;
2. Boiler "Expansion-Replacement" Survey, summary sheet;
3. New Appendix A, showing revised aggregate boiler capacity and input values.

Appendix A is made up from the replacement cases which were able to report comparative SO_2 emissions. Due to a calculation error, the aggregate net boiler capacity and input values swing from a small decrease to a small increase. The net boiler population reduction and reduction in aggregate SO_2 emissions, however, remain unchanged.

Finally, we are transmitting a report on agricultural wastes, "A Case History of Particulate Emissions from Agricultural Waste Fuel", by Gary Q. Johnson of Procter & Gamble, which the Agency will wish to review and have placed in the docket.

Please call with any questions you may have.

Sincerely,

Bill Marx

William B. Marx

WBA:ar
attachments

CC: C. L. Elkins
J. M. Campbell
M. Shelby

11222 Silverleaf Drive, Fairfax Station, Virginia 22039 • (703) 250-9042

Appendix A

COUNCIL OF INDUSTRIAL BOILER OWNERS

BOILER REPLACEMENT SURVEY

The information tabulated below is derived from a CIBO survey conducted in September 1984, to determine the replacement/expansion ratio of new boiler installations. The information covers: a) installations finished or in process back to 1979; b) installations not yet completed but for which funds have been appropriated; c) future installations projected to 1988.

The responses show a 4:1 replacement/expansion ratio; i.e., approximately 80% of new boilers are for replacement purposes. The fuels of the replaced and new boilers, and the number of boilers involved, are as follows:

	From	To
Fuel "Conversions"	40 Oil	Coal 22
	43 Coal	Coal 21
	7 Oil	Wood 3
	6 Oil	Gas 2
	5 Wood	Wood 2
	11 Coal	Wood 11
	5 Gas	Coal 1
Totals	117	62

Thus, 117 boilers are being replaced by 62 new units, a decrease of 55 boilers. Over 95% of the boilers that are being retired fire fuels other than natural gas.

The data from the 9 companies providing emissions data show that the replacement process, by itself, will result in a decrease in SO_2 emissions, independent of any NSPS:

	Replaced	New	Net Result (Decrease)
No. of Boilers	54	29	(25)
Aggregate Capacity lbs/hr X 1000	7,080	7,630	550
Aggregate Input MMBTU/hr	8,300	8,870	570
Total SO_2 Emissions, tons/yr	36,382	26,856	(9,526)

July 1985

BOILER EXPANSION-REPLACEMENT SURVEY

	EXPANSION		REPLACEMENT	
Case #	Units	Capacity*	Units	Capacity*
1.			1	350
2.			1	250
3.	2	150		
	1	100		
4.			1	88
5.			1	770
6.			1	180
			1	300
			4	500
			4	125
7.	0	0	-	-
8.			2	75
			1	150
9.	9	150	15	240
	2	300	1	300
	4	60	13	200
10.			1	450
11.			2	185
12.			2	125
			4	80
			1	100
13.			1	675
14.			2	100
			2	150
			2	250
15.			2	120
			1	150
			1	100
16.			1	150
17.			1	200
18.			2	220
19.			1	110
20.	1	30	16	1626**
21.			2	120
22.	4	210	1	258
			2	125
23.	1	420	1	275
			1	500
24.			2	232
			1	144
			1	199
			1	185
			1	100
			2	90
25.	2	600	1	600
26.	2	500	2	400
			5	500
			1	600
27.			3	600
Totals	28	6080	117	26,514
Grand Total			143	32,594

* In thousands of pounds per hour of boiler steaming capacity each.

** This is aggregate capacity of 16 units.

BOILER "EXPANSION-REPLACEMENT" SURVEY *

New Boilers			Boiler(s) Replaced (If Applicable)		
Number and Capacity[1]	Fuel[2]	SO_2, PM and NOx Emissions[3]	Number and Capacity[1]	Fuel	SO_2, PM and NOx Emissions[3]
A. INSTALLATIONS FINISHED OR IN PROCESS (BACK TO 1979)					
1-350,000 #/HR	Bark/Coal/Oil	.7 .7 .7	100,000 #/HR	#6 Oil	.7 .7
			4 35,000 #/HR	#6 Oil	
			75,000 #/HR	#6 Oil/Bark	
			60,000 #/HR	#6 Oil/Bark	
B. INSTALLATIONS FUNDED					
C. INSTALLATIONS PROJECTED (To 1988)					

* (With a boiler capacity > 80,000 lbs./hr. i.e. input 100 MMB)
1. In thousands of pounds/hr. steam
2. Include mixtures, denoting individual fuels
3. Tons per year of each pollutant

26 2-Digit SIC

2.

BOILER "EXPANSION-REPLACEMENT" SURVEY *

New Boilers			Boiler(s) Replaced (If Applicable)		
Number and Capacity[1]	Fuel[2]	SO_2, PM and NOx Emissions[3]	Number and Capacity[1]	Fuel	SO_2, PM and NOx Emissions[3]
A. INSTALLATIONS FINISHED OR IN PROCESS (BACK TO 1979)					
1-250 KLBS/HR	PC		1-20 KLB/HR	N. Gas	
			1-60 KLB/HR	N. Gas	
			1-30 KLB/HR	N. Gas	
			1-80 KLB/HR	N. Gas	
			1-19 KLB/HR	N. Gas	
B. INSTALLATIONS FUNDED					
C. INSTALLATIONS PROJECTED (To 1988)					

* (With a boiler capacity > 80,000 lbs./hr. i.e. input 100 MMB)
1. In thousands of pounds/hr. steam
2. Include mixtures, denoting individual fuels
3. Tons per year of each pollutant

26 2-Digit SIC

3.

BOILER "EXPANSION-REPLACEMENT" SURVEY *

New Boilers			Boiler(s) Replaced (If Applicable)		
Number and Capacity[1]	Fuel[2]	SO_2, PM and NOx Emissions[3]	Number and Capacity[1]	Fuel	SO_2, PM and NOx Emissions[3]
A. INSTALLATIONS FINISHED OR IN PROCESS (BACK TO 1979)					
1979 1-150,000 lbs/HR	Coal	0.25lb/1MM BTUS (PM)		None	
1983 1-100,000 lb/HR	Coal	0.16lb/1MM BTUS (PM)			
1980 1-150,000 lb/HR	Wood				
B. INSTALLATIONS FUNDED					
-None-				-None-	
C. INSTALLATIONS PROJECTED (To 1988)					
-None-				-None-	

* (With a boiler capacity > 80,000 lbs./hr. i.e. input 100 MMB)
1. In thousands of pounds/hr. steam
2. Include mixtures, denoting individual fuels
3. Tons per year of each pollutant

22 2-Digit SIC

4.

BOILER "EXPANSION-REPLACEMENT" SURVEY * **

New Boilers			Boiler(s) Replaced (If Applicable)		
Number and Capacity[1]	Fuel[2]	SO_2, PM and NOx Emissions[3]	Number and Capacity[1]	Fuel	SO_2, PM and NOx Emissions[3]
A. INSTALLATIONS FINISHED OR IN PROCESS (BACK TO 1979)					
B. INSTALLATIONS FUNDED (to start-up in 1985)					
1-88,000 #/HR (105 Btu/hr)	Coal		1-20,000 #/HR	Oil, Gas	
			1-100,000 #/HR	Oil, Gas	
C. INSTALLATIONS PROJECTED (To 1988)					

* (With a boiler capacity > 80,000 lbs./hr. i.e. input 100 MMB)
1. In thousands of pounds/hr. steam
2. Include mixtures, denoting individual fuels
3. Tons per year of each pollutant

20 2-Digit SIC

** Telephone Report

5.

BOILER "EXPANSION-REPLACEMENT" SURVEY *

New Boilers			Boiler(s) Replaced (If Applicable)		
Number and Capacity[1]	Fuel[2]	SO_2 PM and NOx Emissions[3]	Number and Capacity[1]	Fuel	SO_2 PM and NOx Emissions[3]
A. INSTALLATIONS FINISHED OR IN PROCESS (BACK TO 1979)					
1 - 390,000 #/HR	Coal if 100% Coal & Wood- if 100% WW waste	2463 (1232) 228 1596 0 270 1961	None		
1 - 770,000 #/HR	Pulv. Coal	4329 359 2165	1-145,000 #/HR 1-115,300 #/HR	#6 Oil #6 Oil	2094 76 296 1665 60 234

B. INSTALLATIONS FUNDED

None

C. INSTALLATIONS PROJECTED (To 1988)

None

* (With a boiler capacity > 80,000 lbs./hr. i.e. input 100 MMB)
1. In thousands of pounds/hr. steam
2. Include mixtures, denoting individual fuels
3. Tons per year of each pollutant

26 2-Digit SIC

6.

Boiler "Expansion-Replacement" Survey

New Boilers					Boilers Replaced				
No. and Capacity (1)	Fuel	SO_2	PM	NO_x	No. and Capacity (1)	Fuel	SO_2	PM	NO_x
A. Installations Finished									
1-Gas turbine/HRSG 36 MW, 180,000 lb/hr steam	Gas	0	15	342	2-300,000 lb/hr.stm.	Gas/ Oil	328	39	493
B. Installations Funded									
1-Gas turbine/HRSG 45 MW, 300,000 lb/hr steam	Gas	0	5	719	2-300,000 lb/hr.stm.	Gas/ Oil	28	8	406
C. Projected Installations									
Gas turbine/HRSG 95 MW/500,000 lb/hr. steam (4 units)	Coal/ Wood	1020	124	928	2-550,000 lb/hr. stm.	Gas/ Oil	1421	113	891
Gas turbine/HRSG 95 MW/125,000 lb/hr. steam (4 units)	Coal/ Wood	680	186	928	2-wood 6-oil/gas 1,030,000 lb/hr. stm.	Gas/ Oil Wood	1613	422	1642

(1) Total capacity lbs/hr steam

SIC 26

7.

BOILER "EXPANSION-REPLACEMENT" SURVEY *

New Boilers			Boiler(s) Replaced (If Applicable)		
Number and Capacity[1]	Fuel[2]	SO_2 PM and NOx Emissions[3]	Number and Capacity[1]	Fuel	SO_2 PM and NOx Emissions[3]
A. INSTALLATIONS FINISHED OR IN PROCESS (BACK TO 1979)					
>80,000 #/HR	None				

B. INSTALLATIONS FUNDED

>80,000 #/HR None

C. INSTALLATIONS PROJECTED (To 1988)

Unknown. Possible conversion to coal/liquid slurry for 1-2 Boilers in this size range. Dependent upon available technology.

* (With a boiler capacity > 80,000 lbs./hr. i.e. input 100 MMB)
1. In thousands of pounds/hr. steam
2. Include mixtures, denoting individual fuels
3. Tons per year of each pollutant

20, 30, 36 2-Digit SIC

8.

BOILER "EXPANSION-REPLACEMENT" SURVEY *

New Boilers			Boiler(s) Replaced (If Applicable)		
Number and Capacity[1]	Fuel[2]	SO_2 PM and NOx Emissions[3]	Number and Capacity[1]	Fuel	SO_2 PM and NOx Emissions[3]
A. INSTALLATIONS FINISHED OR IN PROCESS (BACK TO 1979)					
2-75,000 #/HR	Coal (.8 Sulphur)	NO_x - .42 lbs/10^6 BTU Part. - .058 lbs/10^6 BTU	2-42,000#/HR	Oil/Gas 1 1/2-2% Sulphur	No Test Data
B. INSTALLATIONS FUNDED					
C. INSTALLATIONS PROJECTED (To 1988)					
Start Up Jan Or Feb 1985 1-150,000 #/HR	Coal (.8 Sulphur)		3-100,00 #/HR	Oil/Gas 1 1/2-2 1/2% Sulphur	No Test Data

* (With a boiler capacity > 80,000 lbs./hr. i.e. input 100 MMB)
1. In thousands of pounds/hr. steam
2. Include mixtures, denoting individual fuels
3. Tons per year of each pollutant

22 2-Digit SIC

9.

BOILER "EXPANSION-REPLACEMENT" SURVEY *

New Boilers			Boiler(s) Replaced (If Applicable)		
Number and Capacity [1]	Fuel [2]	SO_2 PM and NOx Emissions [3]	Number and Capacity [1]	Fuel	SO_2 PM and NOx Emissions [3]
A. INSTALLATIONS FINISHED OR IN PROCESS (BACK TO 1979)					
9-150,000	Coal				
2-300,000	Coal				
4- 60,000	Coal				
15-240,000	Coal		13-240,000	Coal	
1-300,000	Coal		2-240,000	Oil, Gas	
13-200,000	Coal		1-300,000	Coal	
			13-200,000	Coal	
B. INSTALLATIONS FUNDED					
C. INSTALLATIONS PROJECTED (To 1988)					

* (With a boiler capacity > 80,000 lbs./hr. i.e. input 100 MMB)
1. In thousands of pounds/hr. steam
2. Include mixtures, denoting individual fuels
3. Tons per year of each pollutant

37 2-Digit SIC

10.

BOILER "EXPANSION-REPLACEMENT" SURVEY *

New Boilers			Boiler(s) Replaced (If Applicable)		
Number and Capacity [1]	Fuel [2]	SO_2 PM and NOx Emissions [3]	Number and Capacity [1]	Fuel	SO_2 PM and NOx Emissions [3]
A. INSTALLATIONS FINISHED OR IN PROCESS (BACK TO 1979)					
No. 1 Coal Boiler 450,000 pph	Bituminous Coal	SO_2 = 3041 PM^2 = 253 NO_x = 1776	No. 1 Power Boiler 60,000 No. 2 Power Boiler 100,000 pph No. 3 Power Boiler 300,000 pph No. 4 Power Boiler 125,000 pph	No. 6 Fuel Oil	SO_2 = 8990 PM^2 = 1339 NO_x = 950
B. INSTALLATIONS FUNDED					
C. INSTALLATIONS PROJECTED (To 1988)					

* (With a boiler capacity > 80,000 lbs./hr. i.e. input 100 MMB)
1. In thousands of pounds/hr. steam
2. Include mixtures, denoting individual fuels
3. Tons per year of each pollutant

26 2-Digit SIC

11.

BOILER "EXPANSION-REPLACEMENT" SURVEY *

New Boilers			Boiler(s) Replaced (If Applicable)		
Number and Capacity [1]	Fuel [2]	SO_2 PM and NOx Emissions [3]	Number and Capacity [1]	Fuel	SO_2 PM and NOx Emissions [3]
A. INSTALLATIONS FINISHED OR IN PROCESS (BACK TO 1979)					
			2-185 MPPH	Pulv Coal	PM ~80TPY/Blr @ .1 lb/MM Btu ~17 TPY/Blr @ Actual Emission Rate NOx ~580TPY/Blr @ .7 lb/MM Btu
B. INSTALLATIONS FUNDED					
			2-100 MPPH (Used Boilers)	No.6 Oil	NOx 276 TPY Total Permitted
C. INSTALLATIONS PROJECTED (To 1988)					

* (With a boiler capacity > 80,000 lbs./hr. i.e. input 100 MMB)
1. In thousands of pounds/hr. steam
2. Include mixtures, denoting individual fuels
3. Tons per year of each pollutant

28 2-Digit SIC

12.

BOILER "EXPANSION-REPLACEMENT" SURVEY *

New Boilers			Boiler(s) Replaced (If Applicable)		
Number and Capacity [1]	Fuel [2]	SO_2 PM and NOx Emissions [3]	Number and Capacity [1]	Fuel	SO_2 PM and NOx Emissions [3]
A. INSTALLATIONS FINISHED OR IN PROCESS (BACK TO 1979)					
None			None		
B. INSTALLATIONS FUNDED					
None			None		
C. INSTALLATIONS PROJECTED (To 1988)					
(2)-125	Wood	PM = 100 each (.1 #/ MMB) NOx= 1000 each (1.04 #/ MMB)	(4) - 80	Wood/N.G.	PM = 180 each (.3#/MMB) NOx= 600 each (1.04#/MMB)
			(1) - 100	No. 6/N.G.	PM = 90 (.17 #/MMB) NOx= 135 (.25#/MMB)

* (With a boiler capacity > 80,000 lbs./hr. i.e. input 100 MMB)
1. In thousands of pounds/hr. steam
2. Include mixtures, denoting individual fuels
3. Tons per year of each pollutant

28 2-Digit SIC

13.

BOILER "EXPANSION-REPLACEMENT" SURVEY *

New Boilers			Boiler(s) Replaced (If Applicable)		
Number and Capacity [1]	Fuel [2]	SO_2 PM and NOx Emissions [3]	Number and Capacity [1]	Fuel	SO_2 PM and NOx Emissions [3]
A. INSTALLATIONS FINISHED OR IN PROCESS (BACK TO 1979)					
None					
B. INSTALLATIONS FUNDED					
None					
C. INSTALLATIONS PROJECTED (To 1988)					
1 - 675,000 lb/hr.	Petroleum Coke	Part. 50(1) NO_x 2500(1)	3 - 325,000 16/hr.	Nat. Gas	Part 987 NO_x 71

* (With a boiler capacity > 80,000 lbs./hr. i.e. input 100 MMB)
1. In thousands of pounds/hr. steam
2. Include mixtures, denoting individual fuels
3. Tons per year of each pollutant

28 2-Digit SIC

(1) Based on Preliminary design data

14.

BOILER "EXPANSION-REPLACEMENT" SURVEY *

	New Boilers			Boiler(s) Replaced (If Applicable)		
	Number and Capacity [1]	Fuel [2]	SO_2 PM and NOx Emissions [3]	Number and Capacity [1]	Fuel	SO_2 PM and NOx Emissions [3]
	A. INSTALLATIONS FINISHED OR IN PROCESS (BACK TO 1979)					
A	2 x 100,000 (250 MMB)	Bituminous Coal	1806-33-468	2 x 35,000 1 x 54,000 1 x 100,000	Bitminous Bituminous 3.4% S #6 Oil	2524-311-705
	B. INSTALLATIONS FUNDED					
	C. INSTALLATIONS PROJECTED (To 1988)					
B	2 x 150,000 (SCB)	Anthracite Culm	514-51-514	2-100,000 2-60,000 1-70,000	Sub Bituminous Coal	1428-127-NA
B	2 x 250,000 (SCB)	Coal	420-74-750	1-90,000 1-104,000 1-110,000	0.3% S #6 Oil Natural Gas	459-142-538

* (With a boiler capacity > 80,000 lbs./hr. i.e. input 100 MMB)
1. In thousands of pounds/hr. steam
2. Include mixtures, denoting individual fuels
3. Tons per year of each pollutant

28 2-Digit SIC

A - Replacement in kind - no additional process steam requirement.

B - Replacement in kind, but with net additional steam produced for cogeneration condensing turbine. No additional process steam requirement.

15.

BOILER "EXPANSION-REPLACEMENT" SURVEY *

New Boilers			Boiler(s) Replaced (If Applicable)		
Number and Capacity [1]	Fuel [2]	SO_2 PM and NOx Emissions [3]	Number and Capacity [1]	Fuel	SO_2 PM and NOx Emissions [3]
A. INSTALLATIONS FINISHED OR IN PROCESS (BACK TO 1979)					
1-120,000 Stoker	Coal	PM 19 ton/yr. NO_x 378 ton/yr.			
1-150,000 Stoker	Coal	21 ton/yr. 412 ton/yr.			
B. INSTALLATIONS FUNDED					
C. INSTALLATIONS PROJECTED (To 1988)					
1-120,000 Stoker	Coal	PM 19 ton/yr. NO_x 378 ton/yr.			
1-100,000 Stoker	Coal	------- -------			

* (With a boiler capacity > 80,000 lbs./hr. i.e. input 100 MMB)
1. In thousands of pounds/hr. steam
2. Include mixtures, denoting individual fuels
3. Tons per year of each pollutant

28 2-Digit SIC

16.

BOILER "EXPANSION-REPLACEMENT" SURVEY *

New Boilers			Boiler(s) Replaced (If Applicable)		
Number and Capacity [1]	Fuel [2]	SO_2 PM and NOx Emissions [3]	Number and Capacity [1]	Fuel	SO_2 PM and NOx Emissions [3]
A. INSTALLATIONS FINISHED OR IN PROCESS (BACK TO 1979)					
1-150	Coal	440 1 464	1	#6 Oil	440 60 498
B. INSTALLATIONS FUNDED					
C. INSTALLATIONS PROJECTED (To 1988)					

* (With a boiler capacity > 80,000 lbs./hr. i.e. input 100 MMB)
1. In thousands of pounds/hr. steam
2. Include mixtures, denoting individual fuels
3. Tons per year of each pollutant

32 2-Digit SIC *Conversion

17.

BOILER "EXPANSION-REPLACEMENT" SURVEY *

New Boilers			Boiler(s) Replaced (If Applicable)		
Number and Capacity [1]	Fuel [2]	SO_2 PM and NOx Emissions [3]	Number and Capacity [1]	Fuel	SO_2 PM and NOx Emissions [3]

A. INSTALLATIONS FINISHED OR IN PROCESS (BACK TO 1979)

B. INSTALLATIONS FUNDED

C. INSTALLATIONS PROJECTED (To 1988)

One (1) 200,000 #/HR Oil & Gas Fired Package Boiler to replace four (4) old G & O Fired Package Boilers aggregating 360,000 #/HR.

* (With a boiler capacity > 80,000 lbs./hr. i.e. input 100 MMB)
1. In thousands of pounds/hr. steam
2. Include mixtures, denoting individual fuels
3. Tons per year of each pollutant

28 2-Digit SIC

18.

BOILER "EXPANSION-REPLACEMENT" SURVEY *

New Boilers			Boiler(s) Replaced (If Applicable)		
Number and Capacity [1]	Fuel [2]	SO_2 PM and NOx Emissions [3]	Number and Capacity [1]	Fuel	SO_2 PM and NOx Emissions [3]
A. INSTALLATIONS FINISHED OR IN PROCESS (BACK TO 1979)					
2- 220,000 PPH each.	Pulverized Coal Gas Ignitors	6490 T/Yr. SO_2 .7 lbs./MMBTU NO_x	*5 - 75,000 PPH each	Stoker Coal	6490 T/Yr. SO_2 NO_x NA

B. INSTALLATIONS FUNDED

C. INSTALLATIONS PROJECTED (To 1988)

* (With a boiler capacity > 80,000 lbs./hr. i.e. input 100 MMB)
1. In thousands of pounds/hr. steam
2. Include mixtures, denoting individual fuels
3. Tons per year of each pollutant

26 2-Digit SIC

* Max permitted

19.

BOILER "EXPANSION-REPLACEMENT" SURVEY * **

New Boilers			Boiler(s) Replaced (If Applicable)		
Number and Capacity [1]	Fuel [2]	SO_2 PM and NOx Emissions [3]	Number and Capacity [1]	Fuel	SO_2 PM and NOx Emissions [3]
A. INSTALLATIONS FINISHED OR IN PROCESS (BACK TO 1979)					
1 - 110,000 #/hr	Coal		3 - 60,000 #/hr	Oil,Gas	

B. INSTALLATIONS FUNDED

C. INSTALLATIONS PROJECTED (To 1988)

* (With a boiler capacity > 80,000 lbs./hr. i.e. input 100 MMB)
1. In thousands of pounds/hr. steam
2. Include mixtures, denoting individual fuels
3. Tons per year of each pollutant

28 2-Digit SIC

** Telephone Report

20.

Boiler Survey - Site	Capacity M lb.hr	New Replacement	Startup Date	Fuel	Fuel Replaced
	140	Replacement	3-81	Waste wood	Natural Gas
	30	New	11-81	Sawdust	None
	28	Replacement	2-82	Ind waste	Coal
	38	Replacement	2-82	Waste heat (nat gas)	Natural Gas
	80	Replacement	12-82	Waste wood	Natural Gas
	30	Replacement	6-83	Office trash	Natural Gas
	140	Repl/Cogen (70/70)	7-83	Waste wood	Natural Gas
	240	Replacement	7-83	Waste wood	Nat gas/# 6 F.D.
	80	Replacement	11-83	Waste heat (Nat gas)	Natural Gas
	70	Replacement	6-85	Waste heat (Nat gas)	Natural Gas
Subtotal New	30	3.21%			
Subtotal Repl.	836	89.32%			
Subtotal Cogen.	70	7.47%			
TOTAL	936	100.00%			
Future Projects					
	100	Replacement		Waste wood	Natural Gas
	80	Replacement		Waste heat (nat gas)	?
	100	Replacement		Coal	Coal
	100	Replacement		Waste wood	?
	170	Repl/Cogen(20/150)		Waste heat (nat gas)	Natural Gas
	170	Repl/Cogen(50/120)		Waste heat (nat gas)	Natural Gas
Subtotal New	0	0.00%			
	450	62.50%			
	270	37.50%			
TOTAL	720	100.00%			
TOTALS - PERCENT (since 1/1/80) and PROJECTED					
Subtotal New	30	1.81%			
Subtotal Repl.	1286	77.66%			
Subtotal Cogen.	340	20.53% (Replaces utility capacity)			
TOTAL	1656	100.00%			

21.

BOILER "EXPANSION-REPLACEMENT" SURVEY *

New Boilers			Boiler(s) Replaced (If Applicable)		
Number and Capacity[1]	Fuel[2]	SO_2 PM and NOx Emissions[3]	Number and Capacity[1]	Fuel	SO_2 PM and NOx Emissions[3]
A. INSTALLATIONS FINISHED OR IN PROCESS (BACK TO 1979)					
(2) 120,000	Coal	SO_2 - 1141 PM - 61 NO_x - 582	*(3) 150,000 (one unit wax complete) (Spare)	No. 6 Fuel	SO_2 - 2110 PM - 148 NO_x - 596

B. INSTALLATIONS FUNDED

None

C. INSTALLATIONS PROJECTED (To 1988)

* (With a boiler capacity > 80,000 lbs./hr. i.e. input 100 MMB)
1. In thousands of pounds/hr. steam
2. Include mixtures, denoting individual fuels
3. Tons per year of each pollutant

29 2-Digit SIC

22.

BOILER "EXPANSION-REPLACEMENT" SURVEY *

New Boilers			Boiler(s) Replaced (If Applicable)		
Number and Capacity[1]	Fuel[2]	SO_2 PM and NOx Emissions[3]	Number and Capacity[1]	Fuel	SO_2 PM and NOx Emissions[3]

A. INSTALLATIONS FINISHED OR IN PROCESS (BACK TO 1979)

*1-306X10^{12} BTU/hr Coal PM=11.6 Ton/Year Actual (40 Ton/year allowable)
(N.G. Ignit.)NOx = 280 Ton/year actual (280 ton/year allowable)
4-248X10^6 BTU/hr[each] Coal PM=100 Ton/year Projected Actual(Allowable = 155 Ton/year)
(Propane Ig) NOx=1540 Ton/year Projected Actual (Allowable 2311 Ton/year)

B. INSTALLATIONS FUNDED

None

C. INSTALLATIONS PROJECTED (To 1988)

2-150X10^6 BTU/hr[each] Coal PM = 20 Ton/year Project Actual (Allowable = 40 Ton/year)
(N.G. Ignit.)NOx=273 Ton/year Projected Actual (Allowable = 546 Ton/year)

* (With a boiler capacity > 80,000 lbs./hr. i.e. input 100 MMB)
1. In thousands of pounds/hr. steam
2. Include mixtures, denoting individual fuels
3. Tons per year of each pollutant

21 2-Digit SIC

*This is a new boiler addition and not a replacement; however, it was installed primarily to replace existing boiler capacity while four older boilers are taken out of service sequentially for rebuilding.

23.

BOILER "EXPANSION-REPLACEMENT" SURVEY *

New Boilers			Boiler(s) Replaced (If Applicable)		
Number and Capacity[1]	Fuel[2]	SO_2 PM and NOx Emissions[3]	Number and Capacity[1]	Fuel	SO_2 PM and NOx Emissions[3]
ON LINE 1982 (NOTE: 70% REPLACEMENT CAPACITY)					
275,000 #/HR	Coal Wood Sludge	PM-70 T/Yr SO_2-1100 T/Yr. NOx-1100 T/Yr.	90,000 #/HR 60,000 #/HR	Coal/Gas Cool/Sludge Bark	SO_2 -80 PM -20 T/Yr. NOx 260
420,000 #/HR	Coal Wood	PM - ? SO_2 - 2870 NOx - 1670			
NOTE: Added load; old boiler burned gas.					
ON LINE 1985					
500,000 #/HR	Coal Wood Sludge	PM - ? SO_2-935 T/Yr. NOx-2125 T/HR	250,000 #/HR 170,000 #/Hr 170,000 #/HR	Oil	SO_2-4952 T/Yr. NOx-935 T/Yr.

* (With a boiler capacity > 80,000 lbs./hr. i.e. input 100 MMB)
1. In thousands of pounds/hr. steam
2. Include mixtures, denoting individual fuels
3. Tons per year of each pollutant

26 2-Digit SIC

24.

BOILER "EXPANSION-REPLACEMENT" SURVEY *

New Boilers				Boiler(s) Replaced (If Applicable)			
Number and Capacity[1] (a)	Fuel[2]	SO_2 PM and NOx Emissions[3] (c)		Number and Capacity[1]	Fuel (b)	SO_2 PM and NOx Emissions[3] (c)	
A. INSTALLATIONS FINISHED OR IN PROCESS (BACK TO 1979)							
2/232 Klb/hr ea 1/144 Klb/hr	Coal #6 Oil	127 24	890 110	1/199 Klb/Hr 1/185 Klb/Hr 1/100 Klb/Hr	Coal Coal Coal	110 50 35	765 710 350
B. INSTALLATIONS FUNDED							
C. INSTALLATIONS PROJECTED (To 1988)							
				2/90 Klb/Hr ea.	Coal	20	345

* (With a boiler capacity > 80,000 lbs./hr. i.e. input 100 MMB)
1. In thousands of pounds/hr. steam
2. Include mixtures, denoting individual fuels
3. Tons per year of each pollutant

20 2-Digit SIC

a) These are not the manufacturer guarantees, but the permitted maximum assuming 1250 BTU/lb steam
b) Replacements are coal in place of natural gas or residual oil
c) Emissions are the maximum legal allowables, not actuals, for each unit.

25.

BOILER "EXPANSION-REPLACEMENT" SURVEY *

New Boilers			Boiler(s) Replaced (If Applicable)		
Number and Capacity[1]	Fuel[2]	SO_2 PM and NOx Emissions[3]	Number and Capacity[1]	Fuel	SO_2 PM and NOx Emissions[3]
A. INSTALLATIONS FINISHED OR IN PROCESS (BACK TO 1979)					
(1) 600,000 lb/HR	Coal	SO_2-3,750 T.P.Y. PM - 60 T.P.Y. NOx- 2,050 T.P.Y.	(6) 600,000 lb/HR	Coal	SO_2 - . 5250 T.P.Y. PM - 262 T.P.Y. NOx - No Data Available
B. INSTALLATIONS FUNDED					
None					
C. INSTALLATIONS PROJECTED (To 1988)					
None					

* (With a boiler capacity > 80,000 lbs./hr. i.e. input 100 MMB)
1. In thousands of pounds/hr. steam
2. Include mixtures, denoting individual fuels
3. Tons per year of each pollutant

28 2-Digit SIC

Note: The six boilers were not dismantled, but rather placed in standby status until load increases dictate they be placed in service.

26a.

CIBO NSPS BOILER "EXPANSION-REPLACEMENT" SURVEY*

New Boilers					Replaced Boilers[4]
Name	Capacity[1]	Fuel[2]	Emissions[3] PM	NO_x	
A. INSTALLATIONS FINISHED OR IN PROCESS (BACK TO 1979)					
	400- 500 500 500	wood coal oil combination	25[l] 37[l] 30[m] 39[l]	700[g] 1288[h] 770[i] 890[j]	Replaced oil firing in several boilers of approx. 400,000 pph avg. rate. Shutdown 1 or 2 old boilers.
	400	future peat	40[m]	2240[k]	Reduced load on others in standby status.
	500 500	coal oil (standby)			Fuel conversion on existing boiler to replace 500,000 pph on oil.
	500 600 600 500	wood coal oil combination	127[b] 130[c] 105[e] 127[a]	273[b] 2155[d] 1050[f] 273[a]	New plant.

Notes:
*(For boiler capacity >80,000 lbs/hr, i.e. heat input >100 million Btu/hr)
[1]For multi-fuel boilers steam rate in thousands of lbs/hr for each fuel.
[2]Include mixtures, denoting individual fuels.
[3]Tons per year of each pollutant.
[4]Comments in lieu of data.

[a]Actual based on 8760 hours.
[b]Assumed same as combination.
[c]Expected based on electroscrubber performance measured for wood/coal firing.
[d]Assume 820 x 10^6 Btu/hr heat input and 0.6# $NO_x/10^6$ Btu and 8760 hr/yr operation.
[e]Assumes 800 x 10^6 Btu/hr input and 0.03#/10^6 Btu for 8760 hrs.
[f]Assume 0.3#/10^6 Btu.
[g]Measured at 0.25#/10^6 Btu.
[h]Measured at 0.44#/10^6 Btu.
[i]Measured at 0.27#/10^6 Btu.
[j]Measured avg. of 0.26#/10^6 Btu.
[k]Estimated at 0.80#/10^6 Btu.
[l]Actual test data.
[m]Estimate.

26b.

New Boilers					Replaced Boilers
Name	Capacity	Fuel	Emissions PM	NO_x	
B. INSTALLATIONS FUNDED					
None.					
C. INSTALLATIONS PROJECTED (TO 1988)					
	600	coal or coal/wood (with gas/oil standby)	480[a]	3360[b]	Replaces #1 Power Boiler rated 700,000 pph on gas/oil.
	500	black liquor	365[c]	615[d]	New plant
	300	red liquor	240[a]	1680[b]	Replaces oil in one or more existing boilers and burns liquor now wasted.

[a]Assume 0.1#/10^6 Btu.
[b]Assume 0.7#/10^6 Btu.
[c]Assume 0.044 gr/sdcf @ 8% O_2.
[d]Assume 70 ppm NO_x and 800 x 10^6 Btu/hr.

SIC 26

27.

BOILER "EXPANSION-REPLACEMENT" SURVEY *

New Boilers			Boiler(s) Replaced (If Applicable)		
Number and Capacity[1]	Fuel[2]	SO_2 PM and NOx Emissions[3]	Number and Capacity[1]	Fuel	SO_2 PM and NOx Emissions[3]
A. INSTALLATIONS FINISHED OR IN PROCESS (BACK TO 1979)					
3-600	Waste	SO_2 3578 NOx 1960	7-145	Oil, Gas	SO_2 - 3000 NOx - 3200
B. INSTALLATIONS FUNDED					
C. INSTALLATIONS PROJECTED (To 1988)					

* (With a boiler capacity > 80,000 lbs./hr. i.e. input 100 MMB)
1. In thousands of pounds/hr. steam
2. Include mixtures, denoting individual fuels
3. Tons per year of each pollutant

29 2-Digit SIC

APPENDIX C

Appendix D

Letter to William B. Marx from R.N. Mosher

ABMA

american boiler manufacturers association

April 11, 1986

Mr. William Marx
Council Of Industrial Boiler Owners
5795 Burke Center Parkway
Burke, VA 22015

Dear Bill:

In response to your recent inquiry regarding the number of domestic coal fired boilers purchased and reported to ABMA for 1985, we confirm the following:

- Between 100 and 250 million BTU - 7 units totaling 960,000 PPH.
- Greater than 250 million BTU - 10 units totaling 3,632,000 BTU.

We trust this ABMA data will be useful in the National Coal Council report.

Best regards,

Russell N. Mosher
assistant executive director

RNM/pam

suite 160
950 north glebe road
arlington, virginia 22203
703/522-7350

Appendix E

Letter to William B. Marx from Joseph B. Landwehr

Burns & McDonnell
ENGINEERS - ARCHITECTS - CONSULTANTS

February 6, 1986

Mr. William B. Marx, President
Council of Industrial Boiler Owners
11222 Silverleaf Dr.
Fairfax Station VA 22039

Dry FGD Systems

Dear Bill:

Please find enclosed one photocopy each of the 21 visual aids which I used for my presentation at the Technical Committee Meeting on February 4, 1986. If I can be of any further assistance, please do not hesitate to call.

Sincerely,

Joe Landwehr

Joseph B. Landwehr, P.E.

JBL/gs

Enclosure

4800 EAST 63rd STREET, P.O. BOX 173, KANSAS CITY, MISSOURI 64141 • TEL: 816-333-4375 TWX: 910-771-3059

ATTACHMENT

DRY FLUE GAS DESULFURIZATION SYSTEMS ON INDUSTRIAL BOILERS

By

Joseph B. Landwehr, P.E.

Burns & McDonnell
ENGINEERS – ARCHITECTS – CONSULTANTS

3. CONTAINER CORPORATION OF AMERICA
   PHILADELPHIA, PENNSYLVANIA
   P.C. BOILER: 170,000 lb/hr
   COAL: 1.0 - 2.0% SULFUR
   FGD: ECOLAIRE
   1 ROTARY ATOMIZER
   94,000 ACFM
   RECYCLE NOT USED
   START-UP 1981
   90+ % SO_2 REMOVAL
   BAGHOUSE: ECOLAIRE
   8 COMPARTMENT PULSE-JET

5. AUSTELL BOX BOARD CORP.
   AUSTELL, GEORGIA
   P.C. BOILER: 250,000 lb/hr
   COAL: 1.5 TO 2.5% SULFUR
   FGD: WHEELABRATOR-FRYE
   21 DUAL-FLUID NOZZLE ATOMIZATION
   110,000 ACFM INLET GAS FLOW
   START-UP 1983
   80+ % SO_2 REMOVAL
   BAGHOUSE: WHEELABRATOR-FRYE
   6 COMPARTMENT PULSE-JET

6. BUICK MOTOR DIVISION
   GENERAL MOTORS CORP.
   FLINT, MICHIGAN
   P.C. BOILER: 400,000 lb/hr
   COAL: 1.0 to 3.0% SULFUR
   FGD: NIRO/JOY
   1 ROTARY ATOMIZER
   172,000 ACFM INLET GAS FLOW
   FLYASH RECYCLE
   START-UP 1983
   80+ % SO_2 REMOVAL
   BAGHOUSE: WESTERN PRECIPITATION-JOY
   6 COMPARTMENT REVERSE AIR

9. **NORTH AMERICAN ROCKWELL**
   COLUMBUS, OHIO
   P.C. BOILER: 225,000 lb/hr
   COAL: 1.0 to 3.5% SULFUR
   FGD: FLAKT
   1 ROTARY ATOMIZER
   102,000 ACFM INLET GAS FLOW
   START-UP 1985
   75 + % SO_2 REMOVAL (DESIGN)
   BAGHOUSE: FLAKT
   8 COMPARTMENT REVERSE AIR

12. **A.E. STALEY**
   MORRISVILLE, PENNSYLVANIA
   P.C. BOILER: 210,000 lb/hr
   COAL: 1.5% SULFUR
   FGD: KOCH/MIKROPUL
   9 DUAL-FLUID NOZZLES
   78,000 ACFM INLET GAS FLOW
   START-UP 1985
   85 + % SO_2 REMOVAL (DESIGN)
   BAGHOUSE: MIKROPUL
   8 COMPARTMENT PULSE-JET

Appendix F

Letter to William B. Marx from Karl F. Held

ENERGY AND ENVIRONMENTAL ANALYSIS, INC.
1111 North 19th Street
Arlington, Virginia 22209
(703) 528-1900

September 19, 1983

Mr. William B. Marx
President
Council of Industrial Boiler Owners
11222 Silverleaf Drive
Fairfax Station, Virginia 22039

Dear Bill,

Please find attached information on SO_2 emission regulations for coal- and oil-fired industrial boilers, as requested by phone today through Al Wehe (EPA/OAQPS). The emission regulations are based on State Implementation Plans (SIP's) and represent the SO_2 limits in each air quality control region (AQCR) for two boiler sizes: 75 MMBtu/hour and 200 MMBtu/hour thermal heat input. I hope that this provides you with some idea of the range of industrial boiler emission regulations across AQCR and boiler size.

If you have any questions, please do not hesitate to call.

Sincerely,

Karl F. Held

Karl F. Held
Project Manager

KFH:mk

Attachment

cc: Al Wehe (EPA)

Economics / Engineering

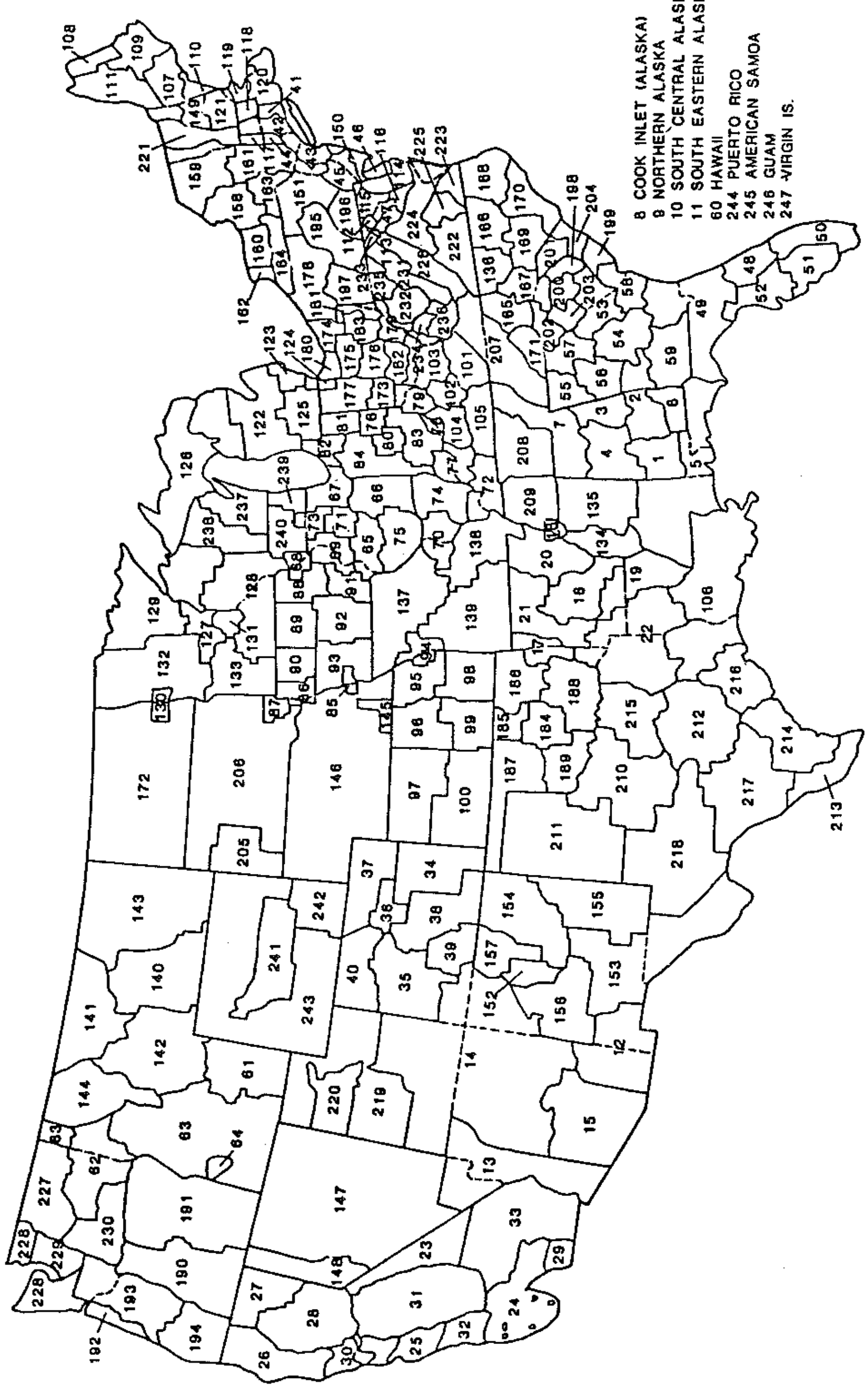


Figure 2.3-2. Air Quality Control Regions

SO2 SIPS FOR COAL FOR SIZES:

AQCR	75.	200.
1	400	400
2	400	400
3	400	400
4	400	400
5	230	230
6	400	400
7	420	420
8	170	170
9	170	170
10	170	170
11	170	170
12	65	65
13	140	140
14	110	110
15	100	100
16	950	950
17	120	120
18	950	950
19	580	580
20	950	950
21	950	950
22	440	440
23	680	680
24	55	55
25	100	100
26	340	340
27	680	680
28	270	100
29	50	50
30	100	100
31	270	100
32	100	100
33	270	100
34	120	120
35	120	120
36	120	120
37	120	120
38	120	120
39	120	120
40	120	120
41	110	110
42	110	160
43	85	85
44	110	110
45	85	85
46	950	950
47	160	160
48	620	620
49	580	600
50	620	620
51	620	620
52	620	620
53	360	400
54	420	500
55	420	480
56	420	500
57	420	500
58	420	480
59	420	500
60	400	400

SO2 SIPS FOR COAL FOR SIZES:

AQCR	75.	200.
62	210	210
63	200	200
64	200	200
65	270	270
66	180	180
67	270	270
68	580	580
69	520	520
70	440	440
71	180	180
72	180	170
73	180	180
74	180	180
75	180	180
76	400	300
77	380	340
78	270	210
79	300	300
80	400	300
81	600	600
82	540	540
83	600	600
84	600	600
85	260	260
86	540	540
87	300	300
88	600	600
89	600	600
90	600	600
91	600	600
92	600	600
93	600	600
94	800	800
95	950	950
96	950	950
97	950	950
98	950	950
99	950	950
100	950	950
101	200	130
102	200	130
103	300	290
104	200	130
105	200	130
106	520	520
107	420	420
108	420	420
109	420	420
110	170	170
111	420	420
112	120	360
113	120	340
114	120	360
115	170	170
116	120	360
117	240	240
118	110	240
119	55	55
120	110	180
121	280	280

SO2 SIPS FOR COAL FOR SIZES:

AQCR	75.	200.
123	170	170
124	240	240
125	240	240
126	240	240
127	400	400
128	400	400
129	400	400
130	320	320
131	300	300
132	400	400
133	400	400
134	240	240
135	240	240
136	230	230
137	800	800
138	800	800
139	800	800
140	200	200
141	200	200
142	200	200
143	200	200
144	200	200
145	250	250
146	250	250
147	140	140
148	140	140
149	300	300
150	30	30
151	380	380
152	55	55
153	270	270
154	55	55
155	55	55
156	55	55
157	55	55
158	380	380
159	360	360
160	380	380
161	380	380
162	280	280
163	380	380
164	380	380
165	230	230
166	230	230
167	260	260
168	230	230
169	230	230
170	230	230
171	230	230
172	300	300
173	300	300
174	620	620
175	500	500
176	400	400
177	320	320
178	520	520
179	340	340
180	540	540
181	340	340
182	440	440

SO2 SIPS FOR COAL FOR SIZES:

AQCR	75.	200.
184	120	120
185	120	120
186	120	120
187	120	120
188	120	120
189	120	120
190	200	160
191	200	160
192	200	160
193	210	170
194	200	160
195	400	400
196	400	400
197	90	80
198	360	360
199	230	230
200	360	360
201	360	360
202	360	360
203	360	360
204	360	360
205	300	300
206	300	300
207	480	480
208	500	500
209	500	500
210	300	300
211	300	300
212	300	300
213	300	300
214	300	300
215	300	300
216	300	300
217	300	300
218	300	300
219	200	200
220	200	200
221	340	340
222	260	260
223	260	260
224	260	260
225	260	260
226	260	260
227	230	230
228	230	230
229	230	230
230	230	230
231	320	320
232	320	320
233	320	320
234	160	160
235	320	320
236	320	320
237	950	950
238	950	950
239	950	950
240	950	950
241	950	950
242	950	950
243	950	950

SO_2 Emission Regulations for Coal-fired Industrial Boiler
(in Lbs. SO_2/ 10^8 Btu's)

KEY:

Column 1: Air Quality Control Region

Column 2: SO_2 SIP's for 75 MMBtu/hour boiler.

Column 3: SO_2 SIP's for 200 MMBtu/hou boiler.

"950" denotes no emission regulation.

SO2 SIPS FOR RES. FOR SIZES:

AQCR	75.	200.
1	400	400
2	400	400
3	400	400
4	400	400
5	230	230
6	400	400
7	420	420
8	120	120
9	120	120
10	120	120
11	120	120
12	65	65
13	140	140
14	160	160
15	160	160
16	950	950
17	80	80
18	950	950
19	480	480
20	950	950
21	950	950
22	300	300
23	480	480
24	25	25
25	50	50
26	240	240
27	480	480
28	270	100
29	25	25
30	50	50
31	270	100
32	50	50
33	270	100
34	80	80
35	80	80
36	80	80
37	80	80
38	80	80
39	80	80
40	80	80
41	110	110
42	110	160
43	60	60
44	110	110
45	65	65
46	120	120
47	110	110
48	280	280
49	270	280
50	230	280
51	280	280
52	280	280
53	320	340
54	260	320
55	290	340
56	260	320
57	260	320
58	270	320
59	[illegible]	[illegible]

SO2 SIPS FOR RES. FOR SIZES:

AQCR	75.	200.
62	180	180
63	190	190
64	190	190
65	140	140
66	100	100
67	180	180
68	240	240
69	170	170
70	280	280
71	100	100
72	100	100
73	100	100
74	100	100
75	100	100
76	600	600
77	170	170
78	210	170
79	300	300
80	600	600
81	600	600
82	520	520
83	600	600
84	600	600
85	250	250
86	250	250
87	300	300
88	250	250
89	250	250
90	250	250
91	250	250
92	250	250
93	250	250
94	800	800
95	950	950
96	950	950
97	950	950
98	950	950
99	950	950
100	950	950
101	130	85
102	130	85
103	270	250
104	130	85
105	130	85
106	400	400
107	260	260
108	260	260
109	260	260
110	110	110
111	260	260
112	210	210
113	210	210
114	210	210
115	110	110
116	210	210
117	240	240
118	110	110
119	55	55
120	110	180
121	220	220

SO2 SIPS FOR RES. FOR SIZES:

AQCR	75.	200.
123	75	75
124	160	160
125	120	120
126	120	120
127	200	200
128	200	200
129	200	200
130	230	230
131	160	160
132	200	200
133	200	200
134	240	240
135	240	240
136	230	230
137	800	800
138	800	800
139	800	800
140	200	200
141	200	200
142	200	200
143	200	200
144	200	200
145	250	250
146	250	250
147	140	140
148	140	140
149	210	210
150	210	210
151	380	380
152	35	35
153	95	95
154	35	35
155	35	35
156	35	35
157	35	35
158	210	210
159	210	210
160	210	80
161	210	80
162	180	180
163	210	210
164	210	210
165	230	230
166	230	230
167	260	260
168	230	230
169	230	230
170	230	230
171	230	230
172	300	300
173	300	300
174	620	620
175	500	500
176	400	400
177	160	160
178	190	190
179	280	280
180	540	540
181	270	270
182	160	160

SO2 SIPS FOR RES. FOR SIZES:

AQCR	75.	200.
184	80	80
185	80	80
186	80	80
187	80	80
188	80	80
189	80	80
190	190	140
191	190	140
192	190	140
193	180	140
194	190	140
195	400	400
196	400	400
197	90	80
198	360	360
199	230	230
200	360	360
201	360	360
202	360	360
203	360	360
204	360	360
205	300	300
206	300	300
207	480	480
208	500	500
209	500	500
210	110	110
211	110	110
212	110	110
213	110	110
214	110	110
215	110	110
216	110	110
217	110	110
218	110	110
219	170	170
220	170	170
221	210	210
222	260	260
223	260	260
224	260	260
225	260	260
226	260	260
227	170	170
228	170	170
229	170	170
230	170	170
231	320	320
232	320	320
233	320	320
234	160	160
235	320	320
236	320	320
237	950	950
238	950	950
239	950	950
240	950	950
241	950	950
242	950	950
243	950	950

SO_2 Emission Regulations for
Residual Oil-fired Industrial Boilers

(in Lbs. $SO_2/10^6$ Btu's)

Column 1: Air Quality Control Region

Column 2: SO_2 SIPS for 75 MMBtu/hour industrial boiler.

Column 3: SO_2 SIPS for 200 MMBtu/hour industrial boiler.

"950" denotes no emission regulation.

Appendix G

Comments of the Coal Policy Committee on Industrial Boiler NSPS Draft Report, April 22, 1986

Coal Policy Committee Meeting Notes from April 22, 1986—Notes by K. A. Shaffer

1. Hill—Move technical material to Appendix
   Response: Incorporated in text
2. Weir—Clarify EPA proposals
   Response: Incorporated in text
3. Holsten—Why can't standard be 2.5 lbs. SO_2/MM BTU?
   Response: See reply under Written Comments.

Responses to Written Comments

1. Pittsburgh and Midway Coal Mining Co.—R. M. Holsten
   - Recommends that SO_2 emissions level be raised from 1.6 lbs. to 2.5 lbs. SO_2/MM BTU for small boilers (<250 MM BTU/HR heat input).

   Response:
   The report has been revised to show that the 1.6 lbs. value is used for illustrative purposes only. It makes no specific recommendations for small boilers, but rather suggests that a study be performed by the DOE to determine the geographic availability of coal to the prominent industrial user regions and base a recommendation on that study.
2. AMAX—Wm. R. Wahl
   - Recommends that any references to acid rain impacts be de-emphasized.

   Response:
   We agree. All references to acid rain have been deleted.
3. Consolidation Coal Company—B. R. Brown
   - Comments can be broken down into three parts:
     a. A concern that flue gas scrubbing was listed as the only means to achieve a percent reduction.
     b. Not enough emphasis on other technological means such as fluidized bed combustion.
     c. A concern over the question of reliability of FGD systems when applied to industrial boilers.

Response:

a. The report was written in response to EPA's recommendation for SO_2 emissions standards for industrial boilers. In turn, these standards were based on the EPA Development Document of March, 1985 on industrial boilers. The Development Document expresses costs and makes recommendations on the basis of FGD at a 90% SO_2 removal rate. Thus, our report makes similar references to FGD when discussing cost comparisons and impacts on the coal market.

b. We agree that there are other technological means of achieving a percent reduction. The NSPS report does address other technologies. The revised version of our report gives the section on fluidized bed combustion greater prominence and includes comments in the Executive Summary.

We believe FBC's are the trend of the future. However, there is little long term operating data currently available for industrial coal-fired FBC's from which fair and reasonable NSPS regulations can be developed. For example, the EPA Development Document, p. 20 states:

> *"Of the 80 existing or planned FBC systems in the United States, 16 are designed to burn coal and nine are designed to burn coal along with other fuels. None burn oil. After excluding*

those FBC systems that are research and development units or that are currently under construction, the remaining of operating FBC systems burning coal is eight. Of these eight, only four FBC systems are using limestone for SO_2 control. In addition, these four FBC systems are concentrated in a very narrow range of steam generating unit size from 7 to 16 MW (24 to 54 million Btu/hr) heat input capacity and operate with an even narrower range of coal sulfur content from 520 to 540 ng SO_2/J (1.2 to 1.3 lb SO_2/million Btu)."

We believe this operating record is an insufficient basis for NSPS regulations for a wide range of boiler (FBC) sizes and various boiler (FBC) vendor technologies.

c. *We agree that the current generation of flue gas desulfurization technologies has been proven reliable for the utility sector. The actual reliability data show, according to ERAB statistics, that wet limestone scrubber availability is 73% while wet lime fares better at 84% availability. These figures are adequate for a utility who has access to a grid system to supplement needs with other units when the FGD system is down for repairs or routine maintenance. On the other hand, an industrial boiler must stand alone and does not have the luxury of a grid system to supply energy needs at a moment's notice.*

Even at 84% availability, this is not adequate, in our opinion, as a reliable technology for the industrial user. In addition, the costs of imposing this technology on the industrial sector simply drives the user to natural gas as shown by the EPA study.

4. Kerr-McGee
   a. Analysis is too long and confusing: logic leading to conclusion is unclear.

   Response: *We agree. Attempts have been made to revise the report by placing more of the discussion in the appendices and by rearranging the order of other points to make the report flow better.*

   b. NCC should write an Issue/Option Paper or a sharply drawn Executive Summary.

   Response: *We agree and have improved the Executive Summary.*

   c. Raises a question as to the purpose of EPA's addressing NSPS for industrial boilers.

   Response: *Industrial boilers have been defined as a "major source" by EPA and therefore NSPS regulations are required to control polluting emissions. Also, as a result of a lawsuit by NRDC, which was eventually settled out of court, EPA is required to finalize the standards for industrial boilers by November of 1986.*

   d. Raises the question of the proposed NSPS for industrial boilers and recommends a less stringent standard.

   Response: *EPA NSPS for industrial boilers greater than 250 MM BTU/HR heat input (i.e. 1.2 lbs. SO_2/MM BTU) were based on the 1971 amendments to the Clean Air Act and cannot be made less stringent. However, units smaller than 250 MM BTU/HR heat input are being addressed by EPA for the first time and we agree that a less stringent standard can be imposed with little or no impact on total SO_2 emissions.*

Appendix H

Comments of The National Coal Council on Industrial Boiler NSPS Draft Report, May, 1986

1. D. M. Carlton, Radian Corporation

Comment:

One of the conclusions is that the FBC technology lacks sufficient operating data upon which to base New Source Performance Standards. It is my opinion that there is sufficient operating data to consider this technology in the development of New Source Performance Standards.

Response:

We believe that any New Source Performance Standards should be commensurate with the technology involved. The draft standards we have seen do not differentiate between flue gas scrubbers, fluidized bed boilers, or other new, promising technologies. Any new standards should try to promote the use of the most cost-effective technologies, not discourage their development by imposing blanket regulations that do no recognize technology and operational differences.

We agree that fluidized bed boilers (FBC) should eventually be included with New Source Performance Standards. However, as the EPA noted in their Development Document, there are only four commercial operating FBC systems in the U.S. utilizing limestone for SO_2 control, and all four of these units are less than 100 MM BTU/HR heat input (i.e. 24 to 54 MM BTU/HR).

We believe, and CIBO (Council of Industrial Boiler Owners) concurs, that this is an inadequate basis for regulations. Most industrial FBC's will be considerably larger than 54 MM BTU/HR (at least 3 to 10 times) simply because all coal-fired systems are capital intensive and require larger sizes to capture economies of scale. Since FBC technology is relatively new to the U.S., these larger sizes will mean the system owner will be taking both scale-up and new technology risks. By requiring the owner to meet NSPS standards, which are basically unproven under actual industrial operating conditions at these larger sizes, he will be burdened with yet another uncertainty.

The EPA in establishing NSPS is permitted by law to differentiate on the basis of technology and applications. We believe these standards should be based on actual performance data gathered from industrial units in the appropriate size range. Many of those units are now under construction, and more will be built within the next several years. The EPA should select a representative sampling of these units for study, then base the NSPS on these data.

2. M. S. White, American Electric Power

Comment:

On page 10, a more recent time frame should be used when quoting wet limestone and lime system availabilities. Current designs for wet lime FGD systems would yield availabilities greater than 90%.

Response:

We do not have more recent data on the availability of flue gas desulfurization systems. Variable results are found in the EPA Development Document for industrial boilers as summarized in table on next page:[30]

These data shown in the table are more relevant than ERAB data because they are for industrial boilers.

However, the EPA data only represents about 12 installations (out of over 100). We do not know if these examples are representative of the entire population, or just special cases. In light of the uncertainty regarding

[30]Environmental Protection Agency, 600-7-79-178, *Technology Assessment Report for Industrial Boiler Applications: FGD*, (November, 1979); Draft: "Summary of Regulatory Analysis New Source Performance Standards: Industrial Commercial—Institutional Steam Generating Units," (March, 1985).

FGD	Cumulative Time Period Days	Average Availability %	Time Period Days	Availability Comment
Lime Spray Drying	2712	71.4	?	Very good based on pilot scale
Lime/L.S. Wet Scrubber	815	94.7	?	A problem, but improving
Dual Alkali	41	100.0	?	Very high
Sodium Wet Scrubber	1855	98.2	?	Excellent Scrubber

availability, we have deleted the ERAB reference in question and are seeking performance information from members of CIBO.

3. G. R. Schleede, New England Energy

Comment:

"The practical effects of these new requirements (industrial NSPS which are less stringent than utility NSPS) seem to be that higher emissions from one facility will have to be offset by another facility or facilities in the same area. Thus, less stringent requirements for industrial facilities may well mean tighter emission limitations for utility plants in the area." What effect will this then have on utility coal demand?

Response:

As shown on p. 16 of the report, calculations using a 1.6 lbs. SO_2 limit (used for illustration) for smaller boilers (i.e. <250 MM BTU/HR heat input) yields a mere 3000 TPY SO_2 nationwide over the case where the 1.2 lbs. limit is applied across the board to all boilers in this category of sources (the 1.2# limit already applies to larger boilers). It is our belief that this additional 3000 TPY prorated on a state-by-state basis will have minimal impact on utility emissions.

For example: The total coal market for industrial users in 1984 was 72.8 million TPY and Ohio was the #1 user at 5.8 million TPY (NCA data). Prorating this 3000 TPY to Ohio on the basis of industrial consumption yields a mere 239 tons per year statewide. On the other hand, a typical utility boiler in Ohio probably emits that much SO_2 in a day. *Obviously, the effect of this 3000 TPY becomes even smaller if prorated to other states. Similar calculations for Massachusetts, for example, yields a mere four tons SO_2 per* year.

While Mr. Schleede's point is well taken, we do not believe that less stringent SO_2 emission limits placed on small boilers (i.e. <250 MM BTU) as we propose will present too much difficulty to utilities should they be required to seek offsets.

Appendix I

Letter from B.R. Brown to the Secretary of Energy and the Secretary of Energy's Response to Mr. Brown's Letter

THE NATIONAL COAL COUNCIL
Post Office Box 17370, Arlington, Virginia 22216

December 19, 1985

The Honorable John S. Berrington
The Secretary of Energy
Department of Energy
1000 Independence Avenue, S.W.
Washington, D.C. 20565

Dear Mr. Secretary:

The National Coal Council has been following the activities of the U.S. Environmental Protection Agency in the matter of proposals under study relative to NSPS for industrial boilers. We are encouraged that you have met with representatives of industry, including NCC member Bill Marx, to hear their concerns.

At a recent meeting of the NCC, the members were given an update on the status of the EPA's proposal. There is concern over the potential devastating impact on existing and/or expanded use of coal in the industrial sector. Many believe that the proposed actions will promote the increased use of oil and/or natural gas.

We believe that this proposal may not be in the national interest and, therefore, we wanted to again express our grave concerns. The National Coal Council Coal Policy Committee is following this matter closely. We are ready to provide assistance and advice to you as needed.

Sincerely,

B. R. Brown
Acting Chairman

/ds

An Advisory Committee to the Secretary of Energy

THE SECRETARY OF ENERGY
WASHINGTON, D.C.

January 13, 1986

Dear Mr. Brown:

Thank you for your letter of December 19, 1985, indicating your concern about the Environmental Protection Agency's (EPA) proposed new source performance standards for industrial boilers.

I understand your concern, and would like to make the following suggestion. Since one of the functions of the National Coal Council is to provide advice on federal policies which, directly or indirectly, affect the production, marketing, and use of coal, it seems to me that the proposed EPA standards could be an appropriate topic for a more detailed study by the Council.

I am interested in the views of both the individual Council members and the Council on the specific impact of these standards on the various facets of the coal industry. A comprehensive study characterizing and quantifying the effects of the proposed standards would be most useful as the Department of Energy continues to work with EPA and other agencies of the Administration on these standards.

Please be assured of my interest and support in this matter.

Yours truly,

John S. Herrington

Mr. B. R. Brown
Acting Chairman
The National Coal Council
Post Office Box 17370
Arlington, Virginia 22216

Appendix J

Description of The National Coal Council and The National Coal Council Membership Roster

Background Information on The National Coal Council

Recognizing the valuable contribution of the industry advice provided over the years to the Executive Branch by the National Petroleum Council and the extremely critical importance of the role of coal to America and the world's energy mix for the future, former Secretary of Energy, Don Hodel, with strong support from President Reagan, floated the idea of a similar advisory group for the coal industry in 1984 at the White House conference on Coal. The opportunity for the coal industry to have an objective window into the Executive Branch drew overwhelming support.

In the fall of 1984, the National Coal Council was born with the appointment by Secretary Hodel of the first 23 members. In April of 1985, Secretary of Energy, John Herrington, made the Council fully operational with the appointment of an additional 94 members. Secretary Herrington's action was based on his conviction that such an industry advisory council could make a vital contribution to America's energy security by providing him with information that could help shape policies leading to the increased production and use of coal and, in turn, decreased dependence on other, less abundant, more costly and less secure sources of energy.

The Council is chartered by the Secretary of Energy under the Federal Advisory Committee Act. The purpose of The National Coal Council is solely to advise, inform and make recommendations to the Secretary of Energy with respect to any matter relating to coal or the coal industry that he may request.

The National Coal Council does not engage in any of the usual trade association activities. It specifically does not engage in lobbying efforts.

Matters which the Secretary of Energy would like to have considered by the Council are submitted as a request in the form of a letter outlining the nature and scope of the study. The request is then referred to the Coal Policy Committee which makes a recommendation to the Council. The Council reserves the right to decide whether or not it will consider any matter referred to it.

The first major studies undertaken by The National Coal Council at the request of the Secretary of Energy were concerned with (1) an overview of federal policies affecting coal production, marketing and use, and (2) identification of impediments to coal use and recommended solutions. Under these two topics, the members proceeded to study three subjects:

- Coal Conversion
- Clean Coal Technologies
- Interstate Transmission of Electricity

The Council also can determine topics which it believes significant for study and then seek the approval of the Secretary to proceed, as in the case of the recently completed study on New Source Performance Standards for Industrial Boilers.

Members of The National Coal Council are appointed by the Secretary of Energy and represent all segments of coal interests and geographical disbursement. The National Coal Council is headed by a Chairman and a Vice Chairman who are elected by the Council. The Council is supported entirely by voluntary contributions from its members.

The National Coal Council Membership Roster 1985-1986

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Attorney at Law
McGuire, Woods & Battle

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President/CEO
Knife River Coal Mining Company

Mr. Peterson Zah
Chairman
The Navajo Tribal Council

Appendix K

The National Coal Council Coal Policy Committee Membership Roster and New Source Performance Standards Work Group

Coal Policy Committee Membership Roster 1985-1986

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