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American Paper Institute, Inc.

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Cavaney,
Red
(Powers, Jody)

September 13, 1983

The Honorable James W. Cicconi
Special Assistant to the President and
Special Assistant to the Chief of Staff
The White House
Washington, D.C. 20500

Dear Mr. Cicconi:

Red Cavaney asked that I forward the attached paper to you. It is to replace the one he gave you this morning on Emissions Cap Impact, Union Camp Mill - Eastover, S.C., which had many errors due to a time constraint in getting the paper prepared.

If you should need anything further, please do not hesitate to call.

Sincerely,

Jody Powers
Executive Assistant

RC/jdp
Attachment

Cavaney, Red
(Powers, Jody)

AMERICAN PAPER INSTITUTE MEMORANDUM

EMISSIONS CAP IMPACT

UNION CAMP MILL- EASTOVER, SC

BACKGROUND

Union Camp is constructing in Eastover, South Carolina a (paper and pulp) mill which will commence production in September, 1984. Construction began in 1982. As a new source located in an attainment area for purposes of the Clean Air Act, the Eastover mill must meet New Source Performance Standards ("NSPS") and Prevention of Significant Deterioration ("PSD") requirements, including Best Available Control Technology ("BACT"). Thus, the Eastover facility will meet strict air emission limitations.

Earlier this year, Senator Stafford and Mitchell introduced acid rain legislation (S.769 and S.145 respectively) which would cap emissions of sulfur dioxide and nitrogen oxide, using actual emissions from 1980 as the cap. Any facility not operating in 1980 would be required to obtain "simultaneous (immediate) emission offsets" prior to commencing operation.

THE ISSUE

Unless new sources are exempted from the emissions cap or unless a new baseline is adopted, clean, efficient mills like Eastover may not be able to commence operations because SO₂ and NO_x offsets are not available or not affordable.

DISCUSSION

The Mitchell and Stafford bills, as now drafted, would severely inhibit economic growth in many states and would very possibly prevent Union Camp's Eastover mill from ever commencing operation. It is not at all clear that the necessary SO₂ and NO_x offsets are available, and offsets are the only alternative under the legislative proposals, since it is impossible to obtain zero emissions from scrubbing or fuel switching. In addition, under this legislation, the offsets are required to be made prior to commencing operation. Thus, Union Camp's investment of \$600 million in the Eastover facility will be jeopardized by these pieces of legislation. Even assuming that Union Camp obtained part of the SO₂ and NO_x offsets needed for Eastover, the company would then be required to install expensive and unproven additional control technology (beyond BACT) in order to reduce emissions to the required level of offsets. Further, such

actions would be impossible to be accomplished within the time frame ("simultaneous") required by the legislation.

Penalizing, or preventing construction of efficient, clean, new facilities like Eastover hardly constitutes wise legislative policy. Economic growth, especially when accompanied by BACT, should not be sacrificed in order to reduce further emissions. This is particularly true in the case of the Eastover mill, which began construction many months ago.

CONCLUSION

Requiring SO₂ and/or NO_x offsets for the new Eastover mill will delay or prevent operation of the plant, since offsets are probably not available. API urges that new facilities be exempted from the emissions cap and views the "simultaneous emissions offset" requirement is particularly poor legislative policy.



American Paper Institute, Inc.
Government Affairs
1619 Massachusetts Ave., N.W. Wash., DC 20036/(202) 332-1050

Red Cavaney
Vice President

September 8, 1983

The Honorable James W. Cicconi
Special Assistant to the President and
Special Assistant to the Chief of Staff
The White House
Washington, D.C. 20500

Dear Jim:

Attached is a letter from my boss, Louis Laun, to Jim Baker concerning your upcoming deliberations on acid rain.

I would appreciate the chance to visit with you for five to ten minutes to share some specific figures which will help illustrate the magnitude of the negative impact caused by including industrial boilers and an emission cap in the Administration's acid rain control package.

Hope all is well and that a highly successful fall season is dawning. Thanks.

Warmest regards,

RC/jdp
Attachment

ADC
PI call and
invite him for
lunch in the mess
next Wed =
if he can't do
then sched for
some time
during day
Thank you

Cavaney,
Red

Cavaney, Red



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Office of the president

September 8, 1983

The Honorable James A. Baker III
Chief of Staff
and Assistant to the President
The White House
Washington, D.C. 20500

Dear Mr. Baker:

I understand that the Cabinet Council on Natural Resources will soon recommend an acid rain control package to the President from among a variety of options. Any solution will be expensive, and we feel that cost-effectiveness should be one of the primary guiding principles in selecting a control program. Consultations with CEQ, EPA, DOE, CEA and OPD have increased industry concerns that the cost ramifications of several options under discussion are not fully understood.

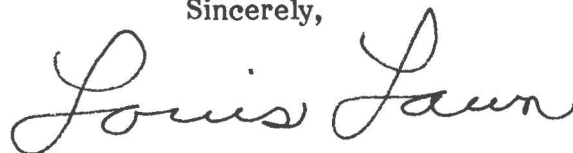
The lowest ratio of expenditures per yield of emission reductions is obtained by concentrating controls on very large utility boilers due to the economies of scale, the relative time and ease of implementation (fewer sources per gross yield), availability of alternative power and the minimization of differential competitive impacts within industrial sectors. Inclusion of industrial boilers and a 1980-based emissions cap in a control program will layer excessive costs and arbitrary expansion barriers on industry at a time when it is critical that we increase our competitiveness in world markets. In addition, costs for industrial boiler retrofits are likely to force the closing of many borderline operations. If a utility boiler program is implemented, industry will doubtless be faced with paying a share of those costs. Our industry's purchases of electricity rank third among the nation's manufacturing industries.

Attached is a study commissioned by our industry which rebuts the perception that controls on industrial boiler sulfur dioxide emissions through the use of "scrubbers" are equally cost-effective with employment of the same control measures for utility boilers. As the attached illustrates, the relative capital cost for scrubber installation rapidly escalates for boilers smaller than 1500 million Btus. Since the bulk of our industrial boilers fall in the 10-500 million Btu range, with the largest planned only in the 900-1100 million Btu range, industrial boilers are clearly at the least cost-effective end of the scale. I might also point out that our study, based largely on actual installed costs, indicates that EPA's estimates for capital costs in this area are 40 to 75% low for industrial-sized boilers with heat inputs from 100 to 400 million Btu.

We also urge that you not include a 1980-based, or other, emissions cap which would clearly inhibit economic growth and job creation by placing new restrictions on new facilities, which are already subject to the strict new source review provisions of the Clean Air Act.

Your assistance in including these concerns in the Administration's acid rain deliberations is greatly appreciated.

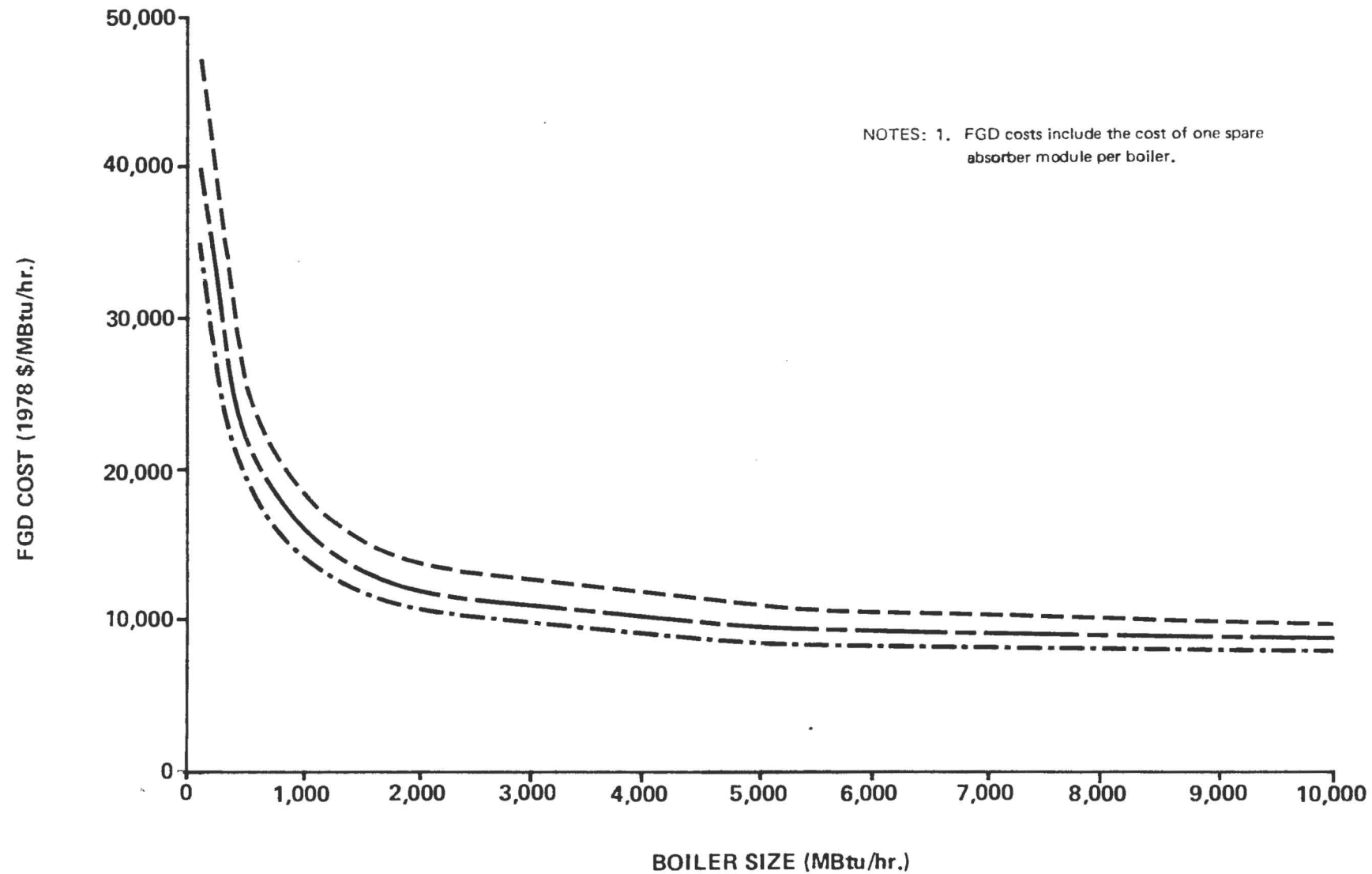
Sincerely,

A handwritten signature in cursive script that reads "Louis Laun". The signature is fluid and elegant, with a large initial "L" and a long, sweeping tail on the "n".

Louis Laun

LFL/jrs

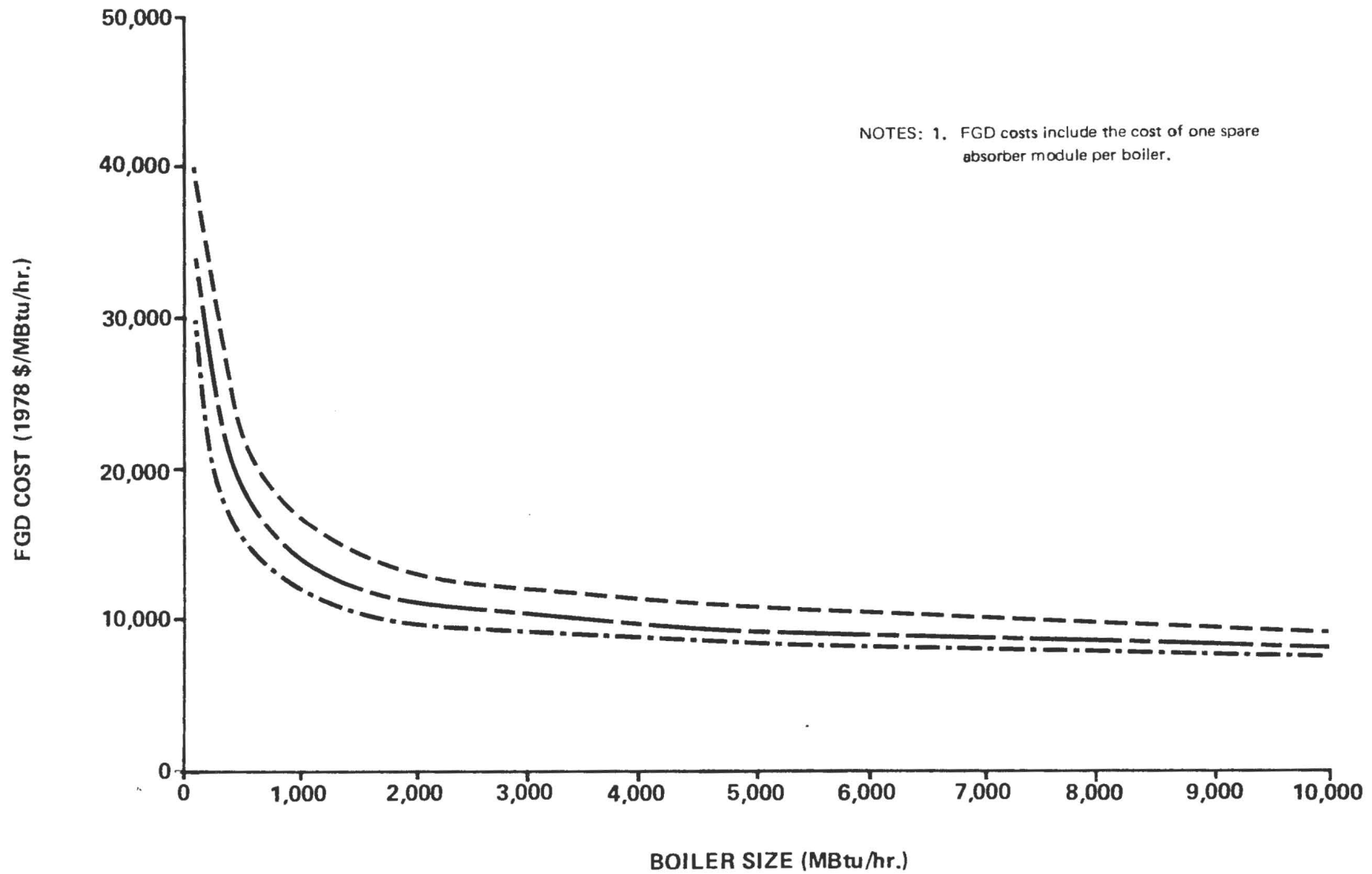
Attachment



--- 3.5% SULFUR
- - - 2.0% SULFUR
- . - . 1.0% SULFUR

Burns & McDonnell
ENGINEERS - ARCHITECTS - CONSULTANTS

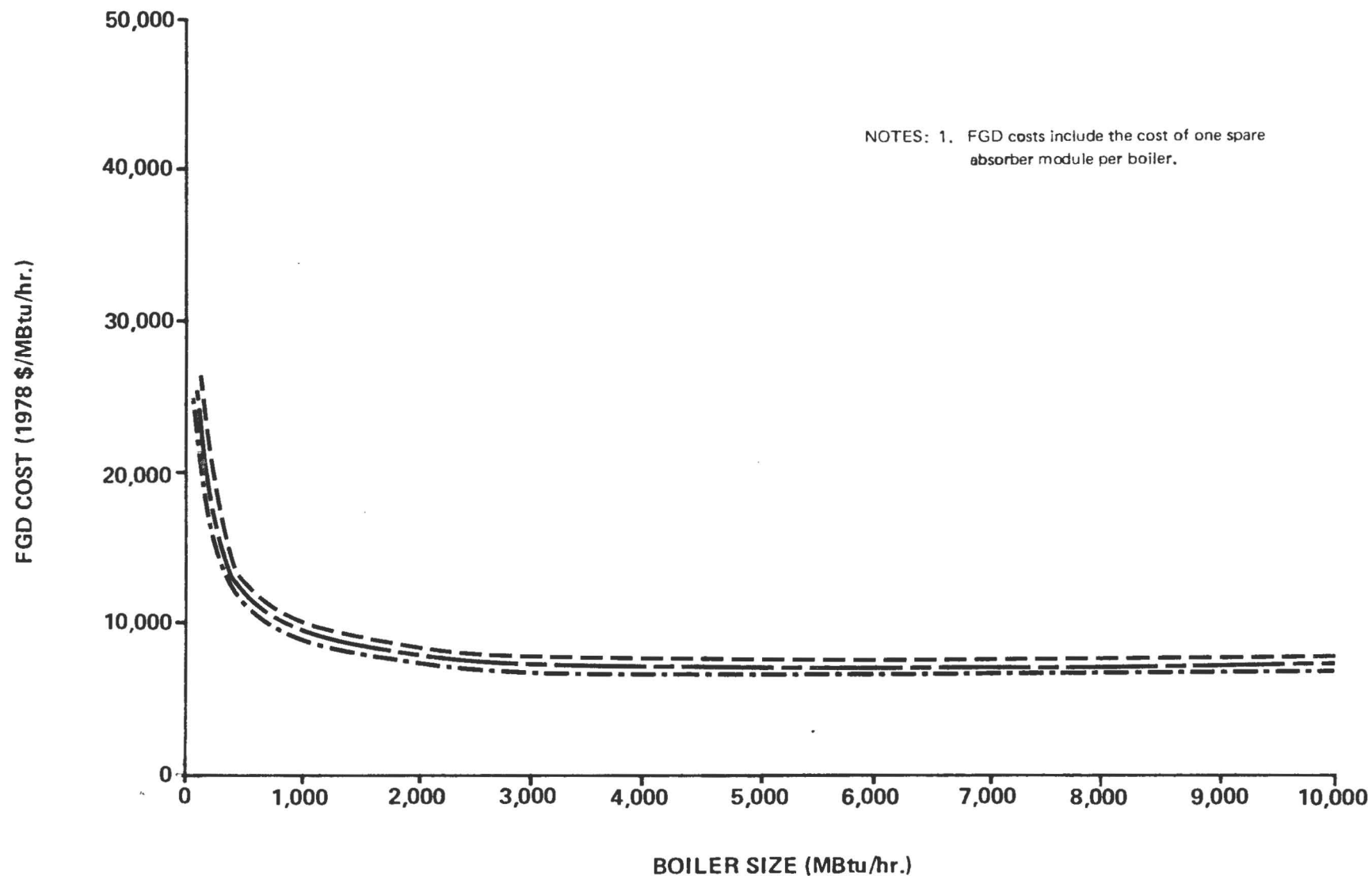
Figure 1A
LIMESTONE FGD UNIT COSTS
AT 90% SO₂ REMOVAL



--- 3.5% SULFUR
--- 2.0% SULFUR
-.- 1.0% SULFUR

Burns & McDonnell
ENGINEERS - ARCHITECTS - CONSULTANTS

Figure 4A
DUAL ALKALI FGD UNIT COSTS
AT 90% SO₂ REMOVAL



--- 3.5% SULFUR
--- 2.0% SULFUR
-.- 1.0% SULFUR

Burns & McDonnell
ENGINEERS - ARCHITECTS - CONSULTANTS

Figure 7A
SPRAY DRYER FGD UNIT COSTS
AT 90% SO₂ REMOVAL

ncasi

special report

NATIONAL COUNCIL OF THE PAPER INDUSTRY FOR AIR AND STREAM IMPROVEMENT, INC., 260 MADISON AVENUE, NEW YORK, N.Y. 10016

REPORT ON THE DEVELOPMENT OF FLUE GAS DESULFURIZATION
SYSTEM CAPITAL COSTS FOR VARIOUS-SIZED UNITS

SPECIAL REPORT NO. 83-06

JULY 1983



NATIONAL COUNCIL OF THE PAPER INDUSTRY FOR AIR AND STREAM IMPROVEMENT, INC.
260 MADISON AVE. NEW YORK, N.Y. 10016 (212) 532-9000

Russell O. Blosser
Technical Director
(212) 532 9001

July 15, 1983

SPECIAL REPORT 83-06

REPORT ON THE DEVELOPMENT OF FLUE GAS DESULFURIZATION
SYSTEM CAPITAL COSTS FOR VARIOUS-SIZED UNITS

In the review of background information generated by EPA for use in developing New Source Performance Standards for industrial boilers, the National Council staff detected what appeared to be a discrepancy between capital construction costs for industrial sized boiler flue gas desulfurization systems in an EPA contractor report and those appearing in other published information on the costs for similar systems on utility sized boilers.

To determine if the staff analysis was a proper one, Burns and McDonnell, a consulting firm with extensive flue gas desulfurization system design and capital cost experience for both industrial and utility sized boilers, was contracted to assemble flue gas desulfurization system costs for an array of boiler sizes.

The attached special report was prepared directly from the Burns and McDonnell report with supplemental elaboration by NCASI staff. Dr. John Pinkerton, our Air Quality Program Manager, who managed this project, which was co-funded by NCASI, the American Paper Institute and the National Forest Products Association, also provided the staff elaboration on the original report.

The capital costs developed in this report for various flue gas desulfurization systems are based on actual installed costs wherever possible and on detailed engineering estimates otherwise. These capital costs have been compared to flue gas desulfurization capital cost estimates prepared by an EPA contractor. For similar flue gas desulfurization systems with equivalent SO₂ removal capabilities, it was found that the EPA estimates are 40 to 75% lower than the capital costs developed in this report for industrial sized boilers with heat inputs from 100 to 400 x 10⁶ Btu/hr.

This report did not develop information on operation and maintenance costs. However, NCASI staff review of operating and maintenance costs reported in EPA documents for flue gas desulfurization systems on industrial and utility boilers reveals that those for utility boilers are about one half those for industrial boilers. While it is not possible to identify the more realistic of the two estimates, it is suggested that total flue gas desulfurization costs shown in the EPA report, which was the subject of this study, should be subject to careful review.

Your comments and inquiries are invited on matters covered in this report and should be directed to Dr. John E. Pinkerton or myself at the telephone or address above.

Yours very truly,

A handwritten signature in dark ink, appearing to read "Russell O. Blosser", written in a cursive style.

Russell O. Blosser
Technical Director

ROB:gs
Attach.

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REPORT ON THE DEVELOPMENT OF FLUE
GAS DESULFURIZATION SYSTEM
CAPITAL COSTS FOR VARIOUS-SIZED UNITS

I FOREWORD

The Environmental Protection Agency has during the past two or more years been assembling background information for use in the development of New Source Performance Standards for SO₂ emission control for industrial boilers. In the review of the cost data in this background information, the National Council staff observed what appeared to be a major discrepancy between construction cost estimates for flue gas desulfurization systems for industrial boilers in a contractor report prepared for EPA for use in development of NSPS, and published information on the capital costs for flue gas desulfurization systems in the larger utility boilers. In summary, the unit construction costs for industrial boiler flue gas desulfurization systems were consistently less on a common unit costing basis, than for utility boilers. Such a situation runs counter to well known engineering cost principles in that the economy of scale factor was absent.

To determine if the staff analysis was a proper one, Burns & McDonnell, a consulting firm with extensive flue gas desulfurization system design and capital cost experience for both industrial and utility sized boilers were contracted to assemble flue gas desulfurization system costs for an array of boiler sizes.

The following NCASI special report was prepared directly from the Burns & McDonnell report. The foreword and Part F in Section V were prepared by the NCASI staff. In those cases where explanatory editing was carried out within the report by the NCASI staff, this editing is underlined for identification. The capital costs developed in this report for various flue gas desulfurization (FGD) systems are based on actual installed costs wherever possible and on detailed engineering estimates otherwise. These capital costs have been compared to flue gas desulfurization capital cost estimates prepared by an EPA contractor. For similar FGD systems with equivalent SO₂ removal capabilities, it was found that the EPA estimates are 40 to 75% lower than the capital costs developed in this report for boilers with heat inputs from 100 to 400 x 10⁶ Btu/hr. Although apparently the EPA estimates did not include (a) redundant equipment to insure that adequate SO₂ removal would be accomplished at all times, and (b) interest charges during construction, these two factors alone cannot account for all of the differences between the two sets of cost figures. Detailed examination of additional reasons for these significant differences was beyond the scope of this study.

The cost of flue gas desulfurization consists of two major components, (a) the capital cost associated with the engineering design, equipment purchase, and installation of the FGD system, and (b) the expenses associated with the operation and maintenance of the FGD system. This report focuses solely on the installed capital cost component because it can be quantified in a reasonable straightforward manner compared to operating and maintenance costs. Calculation of installed capital costs does not require assumptions regarding (a) levels of maintenance, (b) frequency of equipment replacement, (c) chemical usage and price, (d) operating manpower, (e) waste disposal, (f) power costs for system operation, (g) stack gas reheat cost, or (h) capacity utilization, all of which are needed to arrive at an estimate of annual operating and maintenance costs.

The EPA contractor's report does include estimates of annual operating and maintenance expenses for FGD systems on industrial sized boilers ranging from 30 to 400 x 10⁶ Btu/hr. Given the observed significant differences in capital costs between the EPA report and this report, it is logical to inquire if the EPA operating and maintenance cost estimates are reasonable. A cursory comparison of a dual alkali FGD system (90% removal efficiency on a 3.5% sulfur coal) operating and maintenance cost for the electric utility industry cited in another EPA contractor document (EPA-450/2-78-007a, Electric Utility Steam Generating Units - Background Information for Proposed SO₂ Emission Standards) with those for a similar industrial boiler flue gas desulfurization dual alkali system estimated in the EPA/Radian document indicates that the industrial boiler FGD operating and maintenance cost estimate is only one-half of that for an equivalent sized utility system (\$0.50/10⁶ Btu, mid-1978 dollars for a 250 x 10⁶ Btu/hr boiler running at 60% capacity). Because of the many assumptions necessary to obtain an operating and maintenance cost estimate, it is not possible to identify the more realistic of the two estimates. This example comparison merely indicates that the operating and maintenance costs given in the EPA document for industrial boilers are open to question, and that any estimates for total flue gas desulfurization costs based on the EPA document should be subject to careful review.

II INTRODUCTION

A. Purpose of the Report

The purpose of this report is to (a) present flue gas desulfurization (FGD) system cost curves for three FGD processes

over a range of boiler sizes from 100 to 10,000 MBtu/hr, (in this report, 1 MBtu = 10⁶ Btu), and (b) compare these costs with similar costs presented in a recent EPA report (EPA-450/3-82-021, August 1982). The comparison of the costs presented in the two reports includes a discussion of the cost differences and the possible reasons for the observed differences.

The cost curves presented in this report represent adjusted cost data obtained from actual FGD installations and are based on specific design criteria developed especially for this study. The design criteria and the methodology utilized in developing these FGD system cost curves are summarized for the purpose of providing an accurate picture of the actual costs of FGD systems. The FGD system cost curves also show the economy-of-scale relationship between FGD costs and boiler size.

B. Organization of the Report

The report includes a Summary and Conclusions Section which follows the main body of the report. The body of the report is organized into three parts as outlined below.

Section III describes the three types of FGD systems, limestone, dual alkali and spray dryers, examined in this report. The descriptions are intended to give the reader an overview of the types of FGD processes including special characteristics and equipment requirements for each type of FGD system.

Section IV defines the FGD design criteria necessary to develop consistent cost data over the wide range of boiler sizes examined in this report. General design criteria which apply to all three FGD processes include site conditions, fuel analysis, boiler specification, SO₂ removal efficiency and general equipment requirements. The specific design criteria for each individual FGD process includes the basic equipment requirements and design criteria for that equipment.

Section V describes the methodology used in developing FGD system costs and presents the FGD cost curves. This section includes descriptions of (a) the sources for the actual FGD cost data, (b) the methods by which FGD cost data were checked for completeness and adjusted where necessary, and (c) how the data were escalated or de-escalated to mid-1978 dollar values. The Methodology Section also describes the cost adjustments that were made to actual FGD cost data to account for various fuel sulfur contents and sulfur dioxide removal efficiencies.

The FGD system capital cost curves and a discussion of the economy-of-scale relationships for industrial and utility boiler

applications are presented at the end of this section. The FGD capital cost curves summarize costs in terms of mid-1978 dollars per MBtu/hr versus boiler size (MBtu/hr).

III FLUE GAS DESULFURIZATION SYSTEM DESCRIPTIONS

A. Background and General Descriptions

Three flue gas desulfurization (FGD) systems are examined in this report, they are limestone and dual alkali (both wet FGD systems), and lime spray dryers. Each of these FGD processes works on the principle of absorption, whereby the SO_2 in the combustion gas is transferred from the gas phase into an alkali solution or slurry.

In wet limestone FGD systems, the absorbent is water containing a suspended, only slightly soluble alkali. Therefore, the wet limestone process is classified as a slurry system. Alkali slurries are not easy to handle because they are abrasive and the suspended solids tend to settle out. The products of the absorption process also have limited solubility and may precipitate forming scale on the equipment. On the other hand, since the products are relatively insoluble, waste disposal is a matter of physical separation of the solids and the water.

The dual alkali FGD system is a clear liquor process which uses a highly soluble alkali absorbent and forms soluble salts as reaction products. The clear liquor is easy to handle and does not settle out of solutions which greatly simplifies the type of absorption equipment. However, since the products of the absorption process are soluble salts, the waste disposal process includes an extra step to produce an insoluble waste product that can be physically separated.

The dry FGD system also utilizes water in preparing an alkali solution or slurry. However, the amount of water injected into the absorber is carefully controlled so that the gas does not become saturated, allowing moisture condensation. The dry waste product can be handled more easily by a less complicated waste disposal system.

B. Wet Limestone Flue Gas Desulfurization System Description

In the limestone FGD process, a limestone slurry is sprayed, usually countercurrent to the gas flow to provide contact between the slurry and the SO_2 in the gas. Once the SO_2 is absorbed in the liquor, a number of chemical reactions take

place, resulting in the formation of calcium sulfite and sulfate. Because this process is nonregenerable, a portion of the spent slurry is constantly purged from the process and additional limestone is added.

Since the limestone system is a one-step throwaway process, the process chemistry is much simpler than the dual alkali system described later. The low solubility of calcium carbonate in water, however, requires that the absorbing liquor be a slurry of suspended limestone particles. This slurry is not easy to handle because it is abrasive and solids will settle out forming deposits unless constantly kept moving. The control of the process chemistry is also critical because the reaction products are also only slightly soluble and also tend to settle.

Because the limestone system is a slurry process, the absorption equipment is both large and complex. The absorption equipment consists of spray tower with a high liquid flow rate or various designs of internal packing, plates, or venturi arrangements to maximize the gas-liquid interfacial area. The open spray tower design is most common because of lower cost and lack of surfaces which might plug or scale. Special attention is required at the wet/dry interface and mist eliminators are needed to avoid scaling and plugging. Slurry pH and density must be fully regulated to optimize both SO₂ removal efficiency and limestone utilization, but also to prevent scaling and plugging.

Makeup slurry for the system is usually prepared by wet grinding pebble-sized limestone rock. The wet grinding equipment consists of a wet ball mill and a classifier arrangement to produce a slurry as fine as 85 percent through 325 mesh (approximate).

A throwaway waste product is produced by the limestone system. The dewatering process typically includes a thickener (hydroclones have also been used) to concentrate the solids followed by a vacuum filter or centrifuge to dewater the solids. The FGD waste product is then mixed with boiler fly ash as collected by a precipitator or baghouse, to provide a stabilized sludge that can be transported via truck or conveyor to a disposal area.

C. Dual Alkali Flue Gas Desulfurization System Description

The dual alkali process uses highly soluble sodium (NH₄, Mg or Al can also be used) absorption solution followed by the addition of lime or limestone to precipitate the sulfite and bisulfite reaction waste products and regenerate the absorption

solution. The absorption phase of the process utilizes an aqueous alkaline solution to absorb the SO_2 forming soluble sulfite and bisulfite ions. A slipstream of the recirculating absorbent solution is treated with lime or limestone to form a calcium base precipitate from the soluble sodium sulfite and bisulfite waste products. The regenerated solution is then returned to the absorption loop.

Dewatering of the reacted slurry is required to separate the calcium base precipitate from the absorbent liquor and recover the soluble alkali liquor. The main components of the dewatering system are the thickener and rotary vacuum filters. Slurry from the reactor tank where lime or limestone slurry is mixed with liquor, is fed to the thickener. Clarified liquor overflows to the thickener hold tank prior to return to the system for pH control. The thickener underflow slurry is pumped to the filter system where solids separation is completed. The filter cake is washed with fresh water to recover the soluble alkali absorbent. The filter cake may then be transported directly to a disposal area.

D. Dry Lime Flue Gas Desulfurization System Description (Spray Dryer)

In the spray dryer system, an alkali reactant, in the form of solution or slurry, is pumped to the atomizers of the spray dryer absorber module. The atomizers are used to create a dispersed spray of fine droplets which are intimately mixed with the incoming flue gas. The SO_2 contained in the flue gas is absorbed on the surface of the droplets and the alkali material reacts with the gas to form sulfites and sulfates. The droplets simultaneously undergo drying and a portion of the spent solids is collected in the base of the drying chamber. The remainder of the solids is collected together with fly ash still entrained in the flue gas by a fabric filter or electrostatic precipitator.

The operation of the spray dryer absorber system is controlled by four process mechanisms. The first is the atomization of the absorbent which is related to the required surface area of the spray droplets necessary for proper drying. Intimate contact between the spray droplets and flue gas is also necessary for high SO_2 absorption rates. Similarly, proper gas dispersion is required for mixing and also for the prevention of moist or wet lumps in the drying chamber. Finally, the gas residence time, and thus the chamber size, must be sufficient to permit maximum SO_2 absorption.

Spray dryer systems utilize solids recycle to improve system stoichiometry (mole reactant per mole of SO_2 at the absorber inlet). The process of solids recycle involves mixing

a portion of the waste solids with the alkali slurry. Recycling improves reactant utilization and takes advantage of any alkalinity in the fly ash. Dry waste products of calcium sulfites/sulfates and fly ash can be conveyed or pneumatically transferred to a temporary storage silo to await transportation to a disposal site.

IV COST DEVELOPMENT DESIGN CRITERIA

A. Purpose

Flue gas desulfurization (FGD) system capital costs are affected by factors such as fuel analysis, sulfur removal efficiency, gas volume, equipment included and in-service date. In order to provide FGD costs for various boiler sizes, the above factors are held constant by developing design criteria for boilers, fuel, operating conditions and FGD systems. The design criteria are applied to actual FGD system costs to provide a consistent set of FGD system cost curves. This section includes descriptions of the general design criteria applied to all FGD systems and specific design criteria applied to each type of FGD system. The specific design criteria includes a detailed summary of the equipment and design assumptions incorporated into each of the three FGD systems examined in this study.

B. General Design Criteria

The general design criteria listed apply to all three FGD systems. All FGD system costs are for new boiler installations, because of the difficulty of estimating site specific retrofit requirements. Equipment costs for support systems such as electrical power, instrument air and make-up water are proportioned according to requirements by the FGD system.

The predominant design criteria influencing FGD system price is the design gas volume and sulfur dioxide mass flow rate. The design gas volume is affected primarily by coal analysis, amount of combustion air, gas temperature and site elevation. Plant site elevation for this study is 500 feet above sea level. Unlike site elevation, the other factors affecting gas volume and sulfur dioxide concentration cannot be held constant but will vary within a known range of values. Good engineering practice dictates that the design gas volume reflect this range of variation, therefore, the design gas volumes for each case are increased by 10 percent.

The fuel selected for this study is bituminous coal. An ultimate analysis for a bituminous coal was developed and used in all combustion calculations. In order to perform combustion calculations, the ultimate analysis for each sulfur content must add up to 100 percent. Ash was chosen as the constituent to vary since it has no effect on the volume of combustion gas produced. A normal bituminous ash analysis would be expected to vary within a range large enough to compensate for the 1.0 to 3.5 percent sulfur range indicated. The ultimate analyses (typical of Missouri, Ohio, Illinois, and Kansas bituminous) are shown in Table 1.

TABLE 1
ULTIMATE ANALYSIS FOR A BITUMINOUS COAL
(percent by weight)

	<u>Low Sulfur</u>	<u>Medium Sulfur</u>	<u>High Sulfur</u>
Carbon	70.0%	70.0%	70.0%
Hydrogen	4.0%	4.0%	4.0%
Nitrogen	1.0%	1.0%	1.0%
Sulfur	1.0%	2.0%	3.5%
Water	7.0%	7.0%	7.0%
Ash	9.0%	8.0%	6.5%
Oxygen	8.0%	8.0%	8.0%
Higher Heating Value	12,000 Btu/lb	12,000 Btu/lb	12,000 Btu/lb

Boiler-related parameters affecting gas volume are combustion air requirements, leakage and gas temperature. Boilers with a thermal input rate greater than 250 MBtu/hr are pulverized coal boilers. Spreader stoker boilers are used below 250 MBtu/hr. The larger pulverized coal boilers require 125 percent total air for combustion and an air heater. Air heater leakage is assumed to be 15 percent. The spreader stoker boilers require 130 percent total air and are not equipped with an air heater because the economizer can serve that function. For all boilers, the gas outlet temperature (absorber inlet design gas temperature) is 350 degrees F.

Structural design and freeze protection are also affected by site-related parameters. Structural design is based on an assumed plant site located in a Seismic Zone 1 thereby eliminating the need for specially designed (e.g. earthquake) foundations and structures. Freeze protection is accomplished by providing metal wall panel enclosures. Enclosures offer the advantages of protected maintenance and work areas at a long-term

cost equal to or less than the costs of heat tracing and insulation.

All FGD systems include ductwork, complete with turning vanes, internal stiffeners and insulation and lagging, to direct combustion gases to and from the absorber modules. Included in the limestone and dual alkali FGD costs is the ductwork from the particulate control device outlet (excluding transitional ductwork required to reduce cross-sectional area or connecting two or more particulate control devices) to the absorber inlet. Also included are bypass ductwork and ductwork from the absorber outlet to the stack. The spray dryer FGD cost includes a similar amount of ductwork except it starts at the air heater outlet and ends at the particulate control device inlet. Structural-steel required to support the ductwork is included in its cost, however, the ductwork is assumed not to be designed to support equipment or structures connected to it such as the stack and air heater.

Capital costs for particulate control devices, such as electrostatic precipitator, baghouse and venturi scrubber, are not included in the FGD system costs. Particulate removal is required for installation regardless of whether or not a FGD system is provided. Because particulate control costs are not included, all three FGD system costs presented in this report can be compared on an equal basis.

C. Flue Gas Desulfurization System Design Criteria

(1) General - Each of the FGD systems described is considered a closed-loop system producing a throwaway waste that can be handled safely and transported to a waste disposal area. All FGD systems include a spare absorber module and a metal wall panel building enclosure. The limestone and dual-alkali FGD systems include ductwork to bypass 100 percent of the gas volume at 70 fps. The spray dryer FGD system includes bypass ductwork for reheat only. Complete bypass capability can be accomplished by directing gas through a nonoperating absorber module.

A spare absorber module is included with each type of FGD system to allow steady-state, full-load operation of the boiler without violation of sulfur dioxide emission standards if one absorber becomes inoperative. The spare module permits maintenance of the inoperative absorber module with the boiler at full load. Although this type of redundancy is not necessarily "standard engineering practice," it is similar to the design philosophy for equipment which is required for full-load operation and which has a potential for frequent removal from service for repairs.

(2) Wet Limestone FGD - The equipment for the wet limestone process is divided into the twelve systems described below.

- (a) Absorption System - This system removes sulfur dioxide from the flue gas by contacting it with a slurry of limestone, calcium sulfite and calcium sulfate. The Absorption System consists of the following equipment: (i) absorbers, (ii) slurry recycle tanks, (iii) recycle tank mixers, (iv) absorber recycle pumps, (v) mist eliminator wash water tanks, (vi) wash water pumps, (vii) dampers, (viii) valves and piping, and (ix) instruments and controls.

The absorbers are countercurrent spray towers designed for a saturated gas velocity of 8 ft/sec and a residence time of 5 sec. Design SO₂ removal efficiency is 90 percent with a liquid to gas (L/G) ratio of 60 gpm/1000 cfm for low sulfur (1 percent) fuel, 70 gpm/1000 cfm for medium sulfur (2 percent) fuel, and 90 gpm/1000 cfm for high sulfur (3.5 percent) fuel. Towers are constructed of carbon steel with rubber lining, except for the wet/dry interface area and outlet ductwork which are a high nickel-chromium alloy. Mist eliminators are pressure-molded, fiberglass-reinforced plastic (FRP), two-stage chevrons.

Sulfur dioxide removal efficiencies of 70 and 50 percent will be accomplished with combustion gas bypass. Utilizing gas bypass to achieve reductions in overall removal efficiency, reduces the size and cost of the entire FGD system by the percentage of gas bypassed.

The bypass ductwork, however, is not reduced in size since it must still bypass 100 percent of the combustion gas volume produced by the boiler.

Slurry recycle tanks are covered, carbon steel tanks with organic, corrosive-resistant linings. A separate tank, sized for a slurry hold time of 10 minutes, is required for each absorber tower.

Absorber recycle pumps are rubber-lined centrifugal pumps; two 100 percent capacity pumps are provided when the design slurry flow rate can be handled by one pump and three 50 percent capacity pumps when two pumps are required to handle the design flow rate. When three or more pumps are required to provide the design slurry flow, spare capacity pumps are not provided. Instead, the total capacity of the pumps is increased to greater than 100 percent of the design slurry flow. Slurry piping is rubber-lined carbon steel.

- (b) Limestone Handling System - This system transports limestone from the rail car or truck unloading point to the ready pile and from the ready pile to storage silos where it is stored until dispensed for production of limestone slurry. The Limestone Handling System includes the following equipment: (i) limestone unloading hopper, (ii) limestone unloading hopper gate valves, (iii) limestone unloading hopper vibrating feeders, (iv) belt conveyors and/or bucket elevators, (v) conveyor galleries, (vi) belt scales, (vii) belt conveyor magnetic separators, (viii) limestone lowering well, (ix) limestone ready pile reclaim hopper, (x) limestone ready pile dischargers, (xi) limestone ready pile vibrating feeders, (xii) limestone storage silo, (xiii) limestone silo bin dischargers, (xiv) limestone storage silo flop gate, (xv) limestone storage silo dust collectors, (xvi) ventilation system, and (xvii) instruments and controls.

Limestone can be stored on site in an uncovered pile for long-term storage; therefore, the limestone storage silo provides three days' storage. The smaller capacity systems utilize a bucket elevator to transfer limestone from long-term storage to the limestone storage silo.

- (c) Limestone Preparation System - This system wet grinds the limestone and delivers the slurry obtained to the Absorption System. The Limestone Slurry System includes the following: (i) limestone weigh feeders, (ii) ball mills, (iii) mill product tanks, (iv) classifiers, (v) mill product pumps, (vi) limestone slurry storage tanks, (vii) limestone slurry transfer pumps, (viii) piping and valves, and (ix) instruments and controls.

It is assumed that this system includes two 100 percent capacity ball mills complete with classifiers to produce a 30 percent suspended solids limestone slurry product with 85 percent of the solids less than 325 mesh. The slurry storage tank provides a two-day limestone slurry storage capacity.

- (d) Oxidation Air System - This system provides low-pressure (18-psig) compressed air to the oxidation tanks to oxidize the suspended solids in the waste slurry from calcium sulfite (CaSO_3) to calcium sulfate (CaSO_4 gypsum). The sulfate crystals settle faster and dewater easier than the sulfite crystals. Also, the sulfate compound produced is a more easily handled waste product. The Oxidation Air

System consists of the following: (i) intake filter silencers, (ii) forced oxidation air compressors (centrifugal), (iii) blowoff silencers, (iv) instruments and controls, and (v) piping and valves.

- (e) Waste Slurry System - This system transfers the overflow from the absorber reactor tanks through the forced oxidation tanks to the thickener. The system also includes the emergency hold tank and a drainage sump. The Waste Slurry System includes the following: (i) waste slurry tank, (ii) waste slurry tank agitator, (iii) waste slurry transfer pumps, (iv) waste slurry sump, (v) waste slurry sump agitator, (vi) waste slurry sump pumps, (vii) oxidizer feed tank, (viii) oxidation tanks, (ix) thickener feed tank, (x) emergency hold tank, (xi) emergency hold tank pumps, (xii) piping and valves, and (xiii) instruments and controls.
- (f) Sludge Dewatering System - This system concentrates and dewateres the suspended solids present in the absorber waste slurry for further processing and final disposal by the Sludge Handling System. Concentration, or thickening, takes place in a round mechanical lift thickener with dewatering occurring in a single-stage vacuum filter. Various building drainage sumps are also included in the Disposal System. The Sludge Dewatering System includes the following: (i) thickener, (ii) thickener underflow pumps, (iii) fabric vacuum filters, (iv) belt conveyors, (v) thickener tunnel, pug mill and sludge dewatering building sump pumps, (vi) pug mill and sludge dewatering building sump mixers, and (vii) instruments and controls.

It is assumed that this system includes one 100 percent capacity thickener to produce a 30 percent solids underflow. A spare thickener is not required because of the storage capacity available in the emergency hold tanks. Fabric vacuum filters (including one spare) produce a 50 percent solids sludge cake from the thickener underflow.

- (g) Sludge Handling System - This system transforms the sulfur dioxide (SO₂) scrubber sludge and fly ash into a product suitable for final disposal. The Sludge Handling System consists of the following equipment: (i) belt conveyors and scales, (ii) fly ash silo knife gates and rotary feeders, (iii) pug mills, (iv) pug mill dust collectors, and (v) instruments and controls.

It is assumed that this system produces a stable waste material for transportation off site.

- (h) Gas Cleaning and Sludge Dewatering Control System - The Control System automatically controls the gas cleaning equipment and associated fluids as required to maintain flue gas emissions within the gas cleaning system specifications, and disposes of waste products generated by these systems. The Gas Cleaning and Sludge Dewatering Control System is contained in an air-conditioned and heated control room in the FGD enclosure and consists of the following components: (i) gas cleaning control board, (ii) Sludge Handling System control board, (iii) analog controls, (iv) logic controls, (v) control switches, lights, operating stations, recorders and indicators, (vi) analyzers, transmitters, controllers, control drives, valves and alarms, and (vii) events recorder with printer.
 - (j) Reclaimed Water System - This system recycles clarified process water and provides liquid storage capacity within the closed-loop absorber and scrubber sludge dewatering handling system. The Reclaimed Water System includes the following: (i) reclaim water tank, (ii) reclaim water pumps, (iii) valves and piping, and (iv) instruments and controls.
- (3) Auxiliary Systems - The following systems are required for proper operation of the FGD system.
- (a) Makeup Water System - This system provides good quality water for various process and equipment uses in the absorber and sludge dewatering systems which cannot utilize reclaim water. The source of makeup water is the plant service water or cooling water systems. The makeup water system provides water for the following systems and uses: (i) mist eliminator wash, (ii) absorber inlet and outlet isolation damper flush, (iii) solids disposal system, (iv) reclaim water system, (v) pump seal water, (vi) cooling water to various pieces of equipment, (vii) fly ash wetting in the dustless unloader, and (viii) scrubber sludge and fly ash wetting in the pug mills.
 - (b) System Seal Water - This system provides seal water to pumps in the FGD system. The Seal Water System consists of the following equipment: (i) seal water tank, (ii) seal water pumps, (iii) seal water strainer, and (iv) valves and piping.
 - (c) System Instrument Air - This system distributes clean, dry air from the plant compressed air system to operate control

valves, solenoid valves and other instruments in the absorber, reagent preparation and waste handling areas. This system includes: (i) compressed air receiver tank, (ii) air filters, and (iii) piping and valves.

(4) Dual-Alkali FGD - The equipment for the Dual-Alkali FGD System is separated into the ten systems described below.

- (a) Absorption System - This system removes sulfur dioxide from the combustion gas by contacting it with a highly soluble soda ash solution. The Absorption System consists of the following equipment: (i) absorbers, (ii) absorbent solution recycle tanks, (iii) recycle tank mixers, (iv) absorber recycle pumps, (v) mist eliminator wash water tanks, (vi) wash water pumps, (vii) dampers, (viii) valves and piping, (ix) instruments and controls, (x) soda ash silo, (xi) soda ash bin dischargers, and (xii) rotary feeder.

The absorbers will be tray type constructed of lined carbon steel or stainless steel. The absorbers are designed for a liquid to gas (L/G) ratio of 10 gallons per thousand acf saturated at 130 degrees F and a gas velocity of 8 fps through the absorber. The Dual-Alkali System will achieve 90 percent removal with a 10 percent soda ash solution. Removal efficiencies of 70 and 50 percent will be accomplished with combustion gas bypass.

The Dual-Alkali Absorption System will be provided with a soda ash storage silo sized for a 5-day emergency feed rate. The emergency feed rate will occur when the sludge solids wash system is nonoperative. During emergency conditions, approximately 10 percent of the sodium ion is leaving the system in the sludge cake while under normal conditions, (i.e. with solids washings) only about 2 percent of the soluble sodium ion leaves the system. Under normal conditions, the soda ash silo provides 30 days storage.

- (b) Quicklime Handling System - This system unloads pebble quicklime from rail cars and/or trucks, and pressure conveys the product to storage silos. The Quicklime Handling System includes the following: (i) unloading hopper, (ii) unloading filter/receiver, (iii) rotary feeders, (iv) unloader vacuum pumps, (v) unloader pressure blower, (vi) transfer blowers, (vii) quicklime silos, (viii) bin dischargers, (ix) pneumatic conveyor piping, (x) blower filters and silencers, (xi) bin vent filter fans and filters, and (xii) diverter valves, control valves, instruments and controls.

The quicklime handling system silo will provide 30-day on-site storage.

- (c) Regeneration System - This system precipitates the soluble sodium sulfite and bisulfite waste products from the absorption system recirculating loop. The Regeneration System includes the following equipment: (i) quicklime silo, (ii) lime silo bin vibrator, (iii) lime weigh feeder, (iv) lime slaker, (v) silo vent filter fans and filter, (vi) reactor tank, (vii) reactor tank agitator, (viii) emergency hold tank and pumps, (ix) thickener feed pumps, and (x) instruments and controls.

The following assumptions apply:

The Regeneration System will utilize pebble quicklime providing 90 percent lime utilization in the regeneration process at a 10-minute retention time in the reaction tank. The lime preparation system will include two 100 percent capacity slakers and a feed system. The lime preparation feed silo will provide a minimum of 10 days storage. For the smaller units burning low sulfur coals, bulk storage will not be required because the lime preparation feed bin can be sized to hold the 30-day lime requirement.

- (d) Sludge Dewatering System - This system concentrates and dewateres the suspended solids present in the Regeneration System slurry for further processing and final disposal by the Sludge Handling System. Concentration or thickening takes place in a round mechanical lift thickener with dewatering occurring in a single-stage vacuum filter. Various building drainage sumps are also included in the Disposal system. The Sludge Dewatering System includes the following: (i) thickener, (ii) thickener underflow pumps, (iii) fabric vacuum filters with wash system, (iv) belt conveyors, (v) thickener tunnel, pug mill and sludge dewatering building sump pumps, (vi) pug mill and sludge dewatering building sump mixers, (vii) instruments and controls, and (viii) absorbent solution return pumps.

The Sludge Dewatering system will be equipped with a 100 percent capacity thickener producing 30 percent suspended solids. A spare thickener is not required because of the storage available in the emergency hold tanks. Fabric vacuum filters (including one spare) produce a 50 percent solids cake for transportation off site. The fabric vacuum filters are equipped with a filter cake wash system to recover soluble alkali absorbent.

- (e) Sludge Handling System - This system serves the same purpose and includes the same equipment as described for the Wet Limestone FGD system.
 - (f) Gas Cleaning and Sludge Dewatering Control System - This system serves the same purpose and includes the same equipment as described for the Wet Limestone FGD system.
 - (g) Auxiliary Systems - The following systems each serve the same purpose and include the same equipment as described for the Wet Limestone FGD system which includes: (i) makeup water system, (ii) seal water system, and (iii) system instrument air.
- (5) Dry Lime FGD (Spray Dryer) - Equipment for the dry lime FGD is separated into the systems described below.
- (a) Absorption System - This system removes sulfur dioxide from the combustion gas by contacting it with a dispersed spray of fine lime slurry droplets. The absorption system includes the following equipment: (i) absorbers, (ii) reheat ductwork, (iii) slurry feed tank, (iv) slurry feed pumps, (v) slurry atomizers, (vi) dampers, (vii) valves and piping, and (viii) instruments and controls.

The spray dryer system will utilize a liquid to gas ratio of 0.3-gallon per 1,000 scf, have a design gas velocity through the absorber of 3 fps and a 12-second gas residence time. The towers and ductwork are constructed of carbon steel. Reheat via gas bypass ductwork is required to keep the treated gas above its dew point, thereby eliminating the possibility of moisture condensation which would adversely affect the performance of the downstream particulate removal device.

Stoichiometry for the process is based upon a 20 degree F approach temperature to saturation and varies with the SO₂ inlet concentration, percent removal and solids recycled as shown on Table 2. The stoichiometry requirements presented in Table 2 are not intended to be representative of a manufacturer's guaranteed lime stoichiometry. Rather, they represent design values appropriate for use in sizing reagent preparation and related equipment. A minimum stoichiometry requirement of 0.7 mole of lime per mole of SO₂ at the absorber inlet is applied to all cases. Slurry recycle is not employed unless required to achieve the required percent SO₂ removal (high sulfur and 90 percent removal).

TABLE 2

DESIGN STOICHIOMETRY REQUIREMENTS FOR SPRAY DRYER

<u>% S Fuel</u>	<u>SO₂ ppm (Wet)</u>	<u>% SO₂ Removal</u>	<u>Stoichiometry Required</u>
		50	0.7
1%	700 ppm	70	0.9
		90	2.0
		50	0.7
2%	1400 ppm	70	1.0
		90	2.2
		50	0.8
3.5%	2600 ppm	70	1.3
		90	2.0 (R)

(R) - 50 percent recycle of sorbent with lime, assumes no alkalinity fly ash.

- (b) Quicklime Handling System - This system unloads pebble quicklime from rail cars and/or trucks, and pressure conveys the product to storage silos. The Quicklime Handling System includes the following: (i) unloading hopper, (ii) unloading filter/receiver, (iii) rotary feeders, (iv) unloader vacuum pumps, (v) unloader pressure blower, (vi) transfer blowers, (vii) quicklime long-term storage silos, (viii) bin dischargers, (ix) pneumatic conveyor piping, (x) blower filters and silencers, (xi) bin vent filter fans and filters, and (xii) diverter valves, control valves, instruments and controls.

The Quicklime Handling System will provide 30 days' on-site storage.

- (c) Lime Preparation System - The Lime Preparation System provides lime slurry for use in the absorption system. The system includes the following equipment: (i) quicklime silo, (ii) lime silo bin vibrator, (iii) lime weigh feeders, (iv) lime slakers, (v) mill product tanks, (vi) classifiers, (vii) mill product pumps, (viii) lime slurry hold tanks, (ix) lime slurry transfer pumps, (x) piping and valves, and (xi) instruments and controls.

The Lime Preparation System includes a minimum 10-day-capacity lime silo. Packaged lime preparation systems can be utilized for storage capacities less than 5,000 ft³. As was the case for the dual-alkali FGD system, some small units are capable of 30 days storage in the lime preparation feed bin. Two lime slakers (one 100 percent backup) with a 3:4 water to lime ratio produce a 10 percent suspended solids slurry. The lime slurry hold tank is sized for 30-minute retention to allow for lime stabilization.

- (d) Slurry Recycle System - When required, this system recycles approximately 50 percent of the waste product to increase lime utilization. The system includes the following equipment: (i) waste product storage tank, (ii) screw conveyor, (iii) slurry recycle tank, (iv) slurry recycle tank mixers, and (v) slurry recycle pump.
- (e) Gas Cleaning and Waste Handling Control System - The Gas Cleaning and Waste Handling Control System automatically controls the gas cleaning equipment and associated fluids as required to maintain flue gas emissions within the cleaning system specifications, and disposes of waste products generated by these systems. This System consists of the following components: (i) gas cleaning control board, (ii) waste handling system control board, (iii) analog controls, (iv) logic controls, (v) control switches, lights, operating stations, recorders and indicators, (vi) analyzers, transmitters, controllers, control drives, valves and alarms, and (vii) events recorder with printer.
- (f) Waste Handling System - This system transports dry absorber waste from the absorber hopper to a storage silo to await transportation to a disposal area. This system utilizes much of the same equipment required by the ash handling system. The cost of this system reflects the cost of equipment and additional equipment capacity required specifically for the FGD system. Equipment costs include: (i) absorber hopper intake valves, (ii) pneumatic conveyor piping, (iii) diverter valves, and (iv) instruments and controls.

Additional equipment capacity costs include: (i) transfer blower capacity and (ii) storage silo capacity.

- (g) Auxiliary System - These systems each serve the same purpose and include the same equipment as described for the

Wet Limestone FGD system which include: (i) makeup water system, (ii) seal water system, and (iii) system instrument air.

V DEVELOPMENT OF FLUE GAS DESULFURIZATION SYSTEM CAPITAL COSTS

A. Introduction

Flue Gas Desulfurization (FGD) System capital costs were developed for limestone, dual-alkali and spray-drying FGD processes for installation on coal-fired boilers ranging in size from 100 to 10,000 MBtu/hr. For each type of FGD process, two sets of costs were developed: (a) costs for coal sulfur contents of 1.0, 2.0 and 3.5 percent, and (b) sulfur dioxide removal efficiencies of 50, 70 and 90 percent.

The FGD System costs for each set were based on actual installed costs, where available, and on estimated costs developed especially for this study. Both actual and estimated costs were developed to reflect the design criteria outlined in Section IV. Actual cost data were adjusted upward or downward to arrive at costs for the nominal sulfur and removal efficiency percentages identified.

The following sections describe the methodology used in the development of actual costs, cost estimates and cost adjustments.

B. Collection and Development of Actual Cost Data

(1) Actual Cost Data - The FGD system cost curves presented in this report are based primarily on actual cost data for industrial and electric utility applications. The extensive use of actual FGD costs required the ability to (a) identify and separate costs into FGD systems or components and, (b) establish an index year for the costs. These prerequisites were established so that actual costs could be adjusted for the design criteria defined in Section IV and corrected to mid-1978 dollar values. Actual FGD system cost data were obtained from both Burns & McDonnell FGD projects and other sources. Burns & McDonnell FGD projects include eleven limestone FGD systems ranging in size from 750 to 6700 MBtu/hr and two spray dryer systems at 175 and 6700 MBtu/hr. Additional sources of FGD cost data included data from the EPA Utility Flue Gas Desulfurization Information System Data Base and information published by owners and manufacturers concerning actual installed FGD system costs. These sources provided costs for a 200 MBtu/hr spray dryer and dual alkali systems at 200, 1200 (2 systems), and 4,000 MBtu/hr.

(2) Cost Identification - As indicated earlier, the usefulness of actual FGD system costs depends on the availability of a detailed system description and cost breakdown. A detailed system description includes, for example, information concerning the amount of sulfur in the fuel, percent sulfur dioxide removal, gas volume treated, size of the boiler served, percent gas bypass, and in-service date. A detailed cost breakdown includes information concerning not only the costs of equipment and installation but also equipment size, equipment redundancy, and special materials of construction.

The detailed system cost breakdown prepared for this report to use in checking actual cost data for completeness includes the breakdown of direct construction costs and indirect costs.

Direct construction costs include the cost of material and installation for: (i) FGD absorbers, (ii) ductwork and dampers, (iii) reagent preparation equipment, (iv) FGD enclosure and structures, (v) foundation and substructures (vi) sludge dewatering equipment, (vii) process piping and pumps, (viii) power wiring and electrical equipment, (ix) instruments and controls, (x) site preparation, and (xi) painting, paving, cleanup and miscellaneous.

Indirect costs include the costs of: (i) engineering costs, and (ii) interest during construction.

Taxes were not included as an indirect cost of the FGD systems since pollution control equipment is generally tax exempt.

(3) Cost Indexing - Following the identification and breakdown of actual FGD costs into direct construction and indirect costs, all cost data were either escalated or de-escalated according to the date for which the costs were reported. The cost adjustment factors used to correct costs to mid-1978 values appear in Table 3. The cost adjustment factors are derived from the weighted average of several indices. The indices include those commonly used in Burns & McDonnell FGD absorber and related contracts for labor and material escalation, the Handy Whittman Indices for Utility Boiler-Erected Structural Steel and Labor Crafts, and applicable indices for electrical and control wiring and equipment, pumps and piping. The cost adjustment factors were submitted to several FGD suppliers and found to be representative of the actual cost escalation experienced by these suppliers.

TABLE 3
COST ADJUSTMENT FACTORS

<u>Year</u>	<u>CA Factor</u>	<u>Year</u>	<u>CA Factor</u>
Mid-1973	0.57	Mid-1978	1.00
Mid-1974	0.73	Mid-1979	1.09
Mid-1975	0.81	Mid-1980	1.19
Mid-1976	0.85	Mid-1981	1.29
Mid-1977	0.91	Mid-1982	1.37

C. Development and Application of Cost Estimates

Cost estimates were developed primarily to provide continuous cost curves for the FGD systems as defined in Section IV of this report, for boilers ranging from 100 to 10,000 MBtu/hour. Cost estimates were provided for equipment or FGD systems that were excluded according to the detailed system cost breakdowns for actual FGD costs. Cost estimates were also developed for entire FGD systems when no actual FGD cost data was available. All estimated cost data are based on Burns & McDonnell FGD projects, cost data for similar-sized equipment and equipment manufacturer's data or were prepared by Burns & McDonnell's Estimating Department given the design criteria in Section IV for FGD applications. Again, all cost estimates were corrected to mid-1978 dollars before being added to FGD system costs.

D. Flue Gas Desulfurization Capital Cost Adjustments

The final stage in the development of FGD capital costs involved adjustments to provide costs for 1.0, 2.0, and 3.5 percent sulfur and 50, 70, and 90 percent sulfur dioxide removal efficiency at a known boiler size. Adjustments were made for gas volume, percent sulfur and percent SO₂ removal.

(1) Adjustment for Gas Volume - Each of the actual FGD systems examined for this report have absorber modules which were sized to a certain design gas volume as determined on a plant by plant basis. Before using the actual FGD cost data, it is necessary to convert the actual design gas volume into an equivalent boiler size based on the assumed parameters for site elevation, fuel analysis, combustion air, leakage and gas temperature as defined in Section IV. The adjustment for gas volume is accomplished by dividing each FGD design gas volume by a constant correction factor, with the units of actual cubic feet per MBtu.

The reason for this adjustment is that the actual cost data was based on design parameters which do not coincide with the design assumptions of the study.

The adjustment results in an equivalent boiler size in MBtu per hour at which 100 percent of the design gas volume is treated. For FGD systems with two or more absorber modules, but without a spare absorber module at the design gas volume, one of the modules is designated as a spare and the design gas volume reduced accordingly. This adjustment results in an equivalent boiler size that includes a spare FGD module. The cost of this FGD system is then corrected to reflect reduced reagent and sludge handling requirements.

(2) Adjustment for Percent Sulfur - Sulfur content directly affects waste solids production and reagent requirements. Cost adjustments for sulfur contents of 1.0, 2.0, and 3.5 percent sulfur reflect equipment changes in reagent handling, reagent preparation, Absorption System's slurry recycle (L/G requirements), Sludge Dewatering System and Sludge Handling System. Variations in sulfur content also have a slight effect on control systems, piping, and electrical wiring by virtue of equipment requirements. However, these cost changes are judged negligible in comparison to the changes in equipment costs and, therefore, have not been included in the adjustments.

(3) Adjustment for Percent Removal Efficiency - As indicated earlier, the adjustment for gas volumes resulted in the cost for a FGD system that treats 100 percent of the combustion gas with one spare module. From this cost data, adjustments are made to provide costs for FGD systems with 70 percent and 50 percent sulfur dioxide removal efficiencies.

For limestone and dual-alkali FGD systems, lower percent removal efficiencies are accomplished with combustion gas bypass. The amount of combustion gas bypass required for a FGD system with a design SO₂ removal efficiency of 90 percent, as defined by the FGD design criteria in Section IV, is shown in Table 4.

TABLE 4

EQUIVALENT SULFUR DIOXIDE REMOVAL EFFICIENCIES
FOR A KNOWN AMOUNT OF COMBUSTION GAS BYPASS

<u>Equivalent SO₂</u> <u>Removal Efficiency</u>	<u>Combustion Gas</u> <u>Bypass Percentage</u>
90	0
70	22
50	44

The amount of combustion gas bypass indicated in Table 4 gives an indication of the reduction in size of all FGD systems (and costs) except for bypass ductwork and ID fans.

For spray dryer systems, adjustment of the SO₂ removal efficiencies is accomplished by the adjustment of system stoichiometry. Stoichiometry requirements are shown on Table 2. Increasing system stoichiometry increases the cost of all spray dryer systems and equipment except for ductwork, ID fans, and the absorber module. Stoichiometry requirements also indicate the desirability of solids recycle at high sulfur and high removal efficiency. Consequently, spray dryer FGD system costs, at 3.5 percent sulfur and 90 percent removal, include the additional cost of the Slurry Recycle System.

E. Flue Gas Desulfurization Capital System Costs

FGD capital costs are presented in the attached Figures 1, 2, and 3 limestone FGD unit costs, Figures 4, 5, and 6 dual-alkali FGD unit costs, and Figures 7, 8 and 9 spray dryer FGD unit costs. All FGD system capital costs are summarized by cost curves representing mid-1978 dollars per million Btu per hour versus boiler size in million Btu per hour heat input. Presented in this form, the phenomenon known as "economy of scale" is dramatically demonstrated.

In addition to the cost curves, flue gas desulfurization system costs are also summarized in Table 5. Table 5 presents FGD cost percentages broken down for material, installation, engineering and interest during construction at several different boiler sizes. It should be noted that interest during construction is not dependent on unit size but rather is totally dependent on the terms of financing used. Actual cost data provided costs for interest during construction within a range of 20 percent to 30 percent of total FGD costs.

Included in all of the FGD cost percentages summarized in Table 5 is the cost of redundant equipment. Redundant equipment is described in Section IV as equipment for which providing redundancy is not "standard engineering practice," but spare capacity required for continuous full-load operation. This includes the spare absorber module and the spare equipment capacities, as described in Section IV, for the reagent preparation and the sludge dewatering systems. The cost of redundant equipment, as a percentage of total FGD system costs, varies slightly with the size of the system. For example, the cost of redundant equipment for unit sizes of 1,000 MBtu/hr and less vary within the range of 20 percent to 25 percent of the total FGD system costs. For a unit size of 6,000 MBtu/hr the cost of redundant equipment is within the range of 10 percent to 15 percent of the total FGD system cost.

TABLE 5

FGD COMPONENT COSTS AS A PERCENTAGE OF FGD SYSTEM
CAPITAL COSTS AT GIVEN BOILER SIZE

Component	Boiler Size (MBtu/hr)			
	200	2000	4000	6000
Equipment, Material and Structures	37%	41%	45%	45%
Erection, Installation and Contractor Fees	30%	27%	24%	24%
Engineering and Start-up	8%	7%	6%	6%
Interest During Construction	25%	25%	25%	25%

F. Further Comparison to the EPA Capital Cost Estimates

As discussed earlier, the capital cost estimates contained in the EPA document "Costs of Sulfur Dioxide, Particulate Matter, and Nitrogen Oxide Controls on Fossil Fuel Fired Industrial Boilers" are significantly lower than those shown in Figures 1 through 9. In the EPA report, FGD cost estimates are given for dual alkali and spray dryer systems for model boiler sizes of 30, 75, 150 and 400 MBtu/hr. For the dual alkali FGD systems, removal efficiencies of 50 and 90% were considered for coals with sulfur contents of 3.54 and 0.6%. For the spray dryer, costs were only developed for a 50% removal efficiency for a 0.6% sulfur coal.

It is illustrative to graphically compare the EPA cost estimates to those developed in this report for similar FGD systems and removal efficiencies. These comparisons are shown in Figure 10 (dual alkali systems, 90% SO₂ removal), Figure 11 (dual alkali system, 50% SO₂ removal), and Figure 12 (spray dryer, 50% removal). The EPA cost figures were taken from Tables 3-1 and 3-2 in the Radian report for the dual alkali systems which did not include particulate matter control as part of the SO₂ control costs. Spray dryer costs were estimated from Table 3-2 by subtracting the fabric filter cost (to be consistent with the Burns & McDonnell costs) from the combined SO₂ and particulate matter control cost. All costs were normalized to mid-1978 dollars per 10⁶ Btu/hr boiler heat input.

Figures 10 through 12 show the EPA capital cost estimates are lower than those developed by Burns & McDonnell by factors of roughly 2.5 to 4. Although costs for some redundant equipment and interest charges during construction were included in the

Burns & McDonnell cost estimates but apparently not in the EPA values, these two factors are not nearly great enough to account for the large observed differences. While it is beyond the scope of this study to identify why the EPA cost figures are so much lower, it seems likely the Radian cost algorithms do not realistically reflect installed costs of dual alkali and spray dryer FGD systems experiences at a number of actual facilities.

VI SUMMARY AND CONCLUSIONS

A. Summary

(1) This report presents capital costs developed from actual installed cost data for three flue gas desulfurization (FGD) systems, limestone, dual alkali and spray dryer. The costs were developed for the purpose of comparison to similar costs presented in a recent report prepared by the Radian Corporation for the U.S. Environmental Protection Agency titled, Costs of Sulfur Dioxide, Particulate Matter and Nitrogen Oxide Controls on Fossil Fuel-Fired Boilers (EPA-450/3-82-021).

(2) The FGD system costs presented in this report are for bituminous coals with sulfur contents of 1.0, 2.0 and 3.5 percent, and for sulfur dioxide removal efficiencies of 50, 70 and 90 percent over a range of boiler sizes from 100 to 10,000 MBtu/hr. (The cost of redundant equipment is included in the cost estimates. Redundant equipment is defined as spare capacity equipment needed for continuous operation of the FGD system, beyond the equipment judged necessary for "good engineering practice"). To provide consistent cost data over the range of boiler sizes, all costs are corrected to mid-1978 dollars and are based on design criteria developed especially for this study. The design criteria define the process systems and equipment included in the costs for each type of FGD system and allow for adjustment of cost estimates to account for items not included in the costs of actual installed FGD systems.

(3) The costs of particulate control devices for any of the three FGD systems examined are not included in this report. Particulate control devices are required for coal-fired boilers regardless of whether or not a FGD system is provided. Often, as in the case of the Radian report, the cost of a particulate control device is included in the cost of spray dryer FGD systems, because it is considered an integral part of the system. However, particulate removal is equally important for a wet FGD system because of the adverse effect of particulate on absorber performance and maintenance. Because particulate removal is not included, all three FGD system costs are compared on an equal basis.

(4) In general, the cost of particulate control equipment depends on the type of equipment employed and the particulate removal efficiency required. The two most common types of equipment for collecting the relatively small-sized fly ash particles from coal-fired boilers are electrostatic precipitators and bag-houses. Both of these types can be designed for the high removal efficiency which is commonly required to meet state and Federal particulate emission standards. Although the cost of a complete particulate control system depends on the size of the boiler, the type of equipment selected and the degree of conservation exercised by the designer, the cost of a complete particulate control system is estimated to range from 30 to 85 percent of (and in addition to) the cost of the FGD system. This estimate is based on achieving an emission rate of 0.05lb/MBtu which is the particulate emission limitation expected to be proposed for new coal-fired industrial boilers. The exact cost of particulate control equipment depends on the various factors involved and must be determined on a case-by-case basis.

(5) FGD system costs are presented in the form of mid-1978 dollars per MBtu/hr versus boiler size in MBtu/hr. In this form, the economy of scale relationships between FGD system cost and boiler size is easily demonstrated. Unit costs (dollars per MBtu/hr) are larger for smaller boilers than larger boilers.

B. Conclusions

(1) The FGD system for a limestone FGD system is slightly greater than for a dual alkali FGD system, while the spray dryer FGD system is the least expensive. The primary reason for the cost differences is the complexity of the design and equipment required for the absorption modules and absorbent pumps and piping. In addition, the spray dryer FGD system requires less waste handling equipment than either the dual alkali or limestone FGD system.

(2) It should be noted that while the FGD system costs presented in this report are representative of actual installed costs, they cannot be assumed to represent the cost of any specific FGD system. Factors affecting FGD system costs such as site specific requirements, competitive bidding, regional economic conditions and local and state air pollution regulations cannot be included in a study of this nature. However, by limiting some of the cost variables identified in this report and by defining general and specific design criteria for the FGD systems, the resulting FGD system costs are as representative as reasonably can be expected.

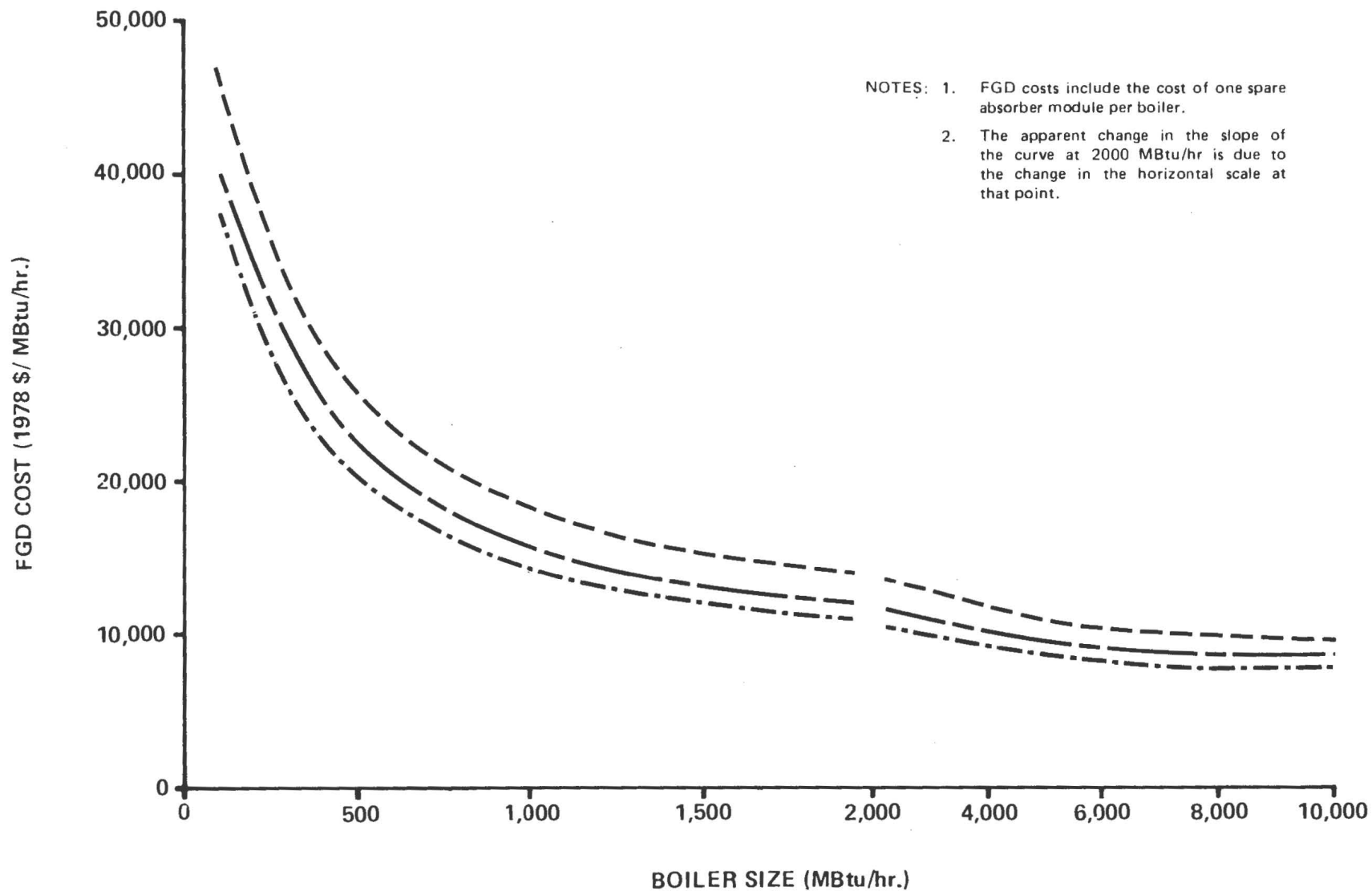
C. Comparison to Radian Report

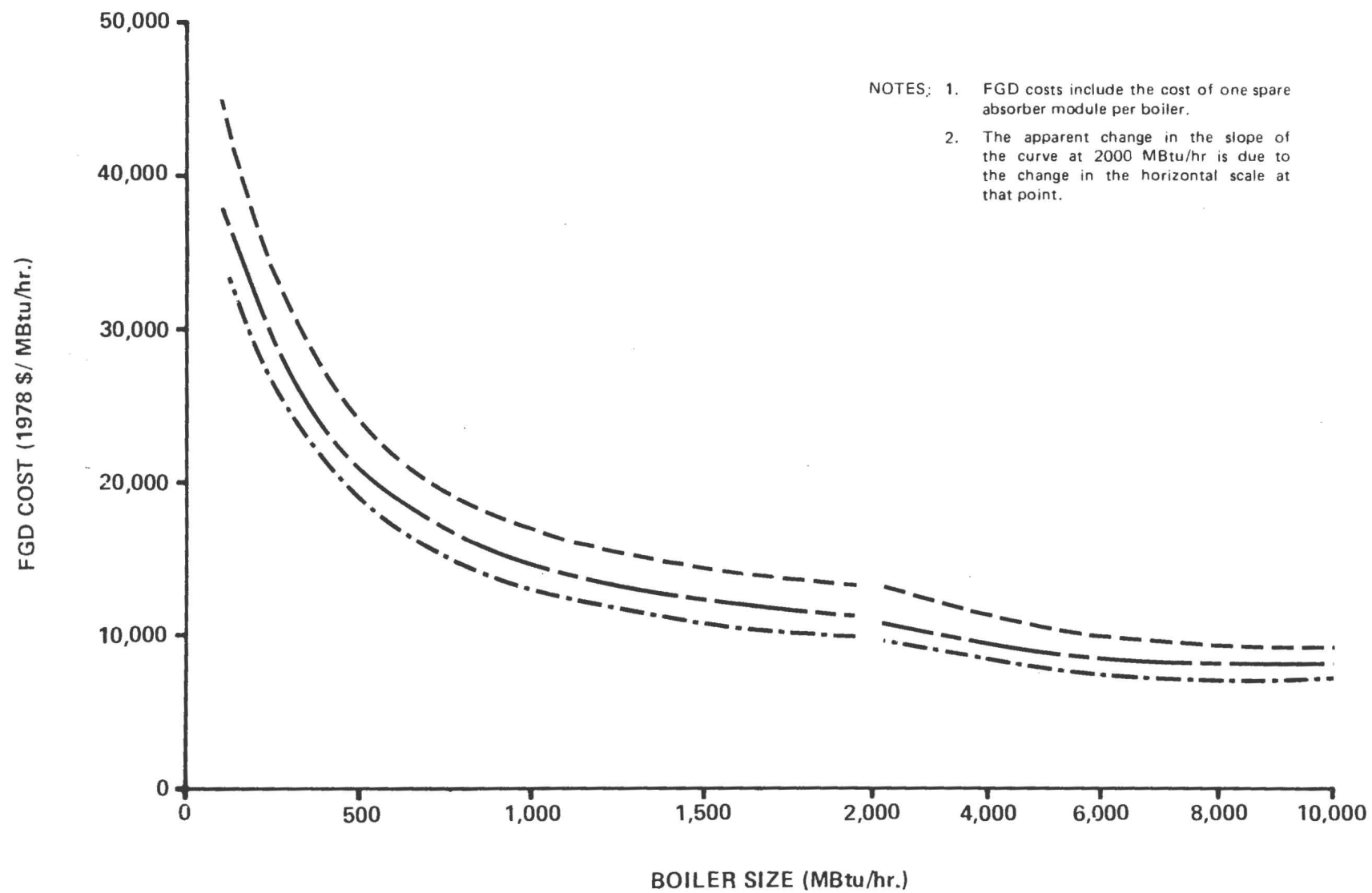
(1) The Radian report presents costs for dual-alkali and spray dry FGD systems for application on coal-fired boilers. Dual-alkali system costs are for coals at high sulfur (3.54 percent) and low sulfur (0.6 percent) and removal efficiencies of 50 and 90 percent. The spray dryer system costs are for low-sulfur coal at a 50 percent removal efficiency.

(2) Costs for both of these FGD systems were derived from equations (cost algorithms) developed by the Acurex Corporation based on cost information contained in an earlier Radian Corporation report. The Radian report does not state exactly what equipment costs are included in the algorithms although the report indicates that the algorithms provide "...total direct costs without prior computation of equipment and installation costs." (Apparently the Radian estimates do not include the cost of any redundant equipment). Flue gas desulfurization costs based on the algorithms are lower than the costs presented in this report.

(3) The Radian report does include general design criteria for the FGD systems identified. However, the criteria are limited to absorber type, materials of construction, pressure drop and liquid-to-gas ratio. This report attempts to more clearly define each FGD system process and the equipment required.

(4) The Radian report contains costs for a shop-assembled "package" and field-erected coal-fired boilers, however, the report does not indicate if any FGD systems are shop assembled. The use of shop-assembled equipment offers a cost advantage over field erection and is used to some extent on all sizes of systems. On a small industrial boiler FGD system, for example, a package lime preparation system (including reagent silo, slakers, slurry tank, pumps and piping) may be purchased shop assembled, while the absorber tower and other equipment may be too large to assemble off site. Even large FGD systems may have shop-assembled units, such as control panels and reagent silos. As a result, the cost savings for small boilers utilizing shop-assembled or package FGD systems or processes is not as dramatic as might be expected and a "break" in FGD system costs for smaller systems is not observed.



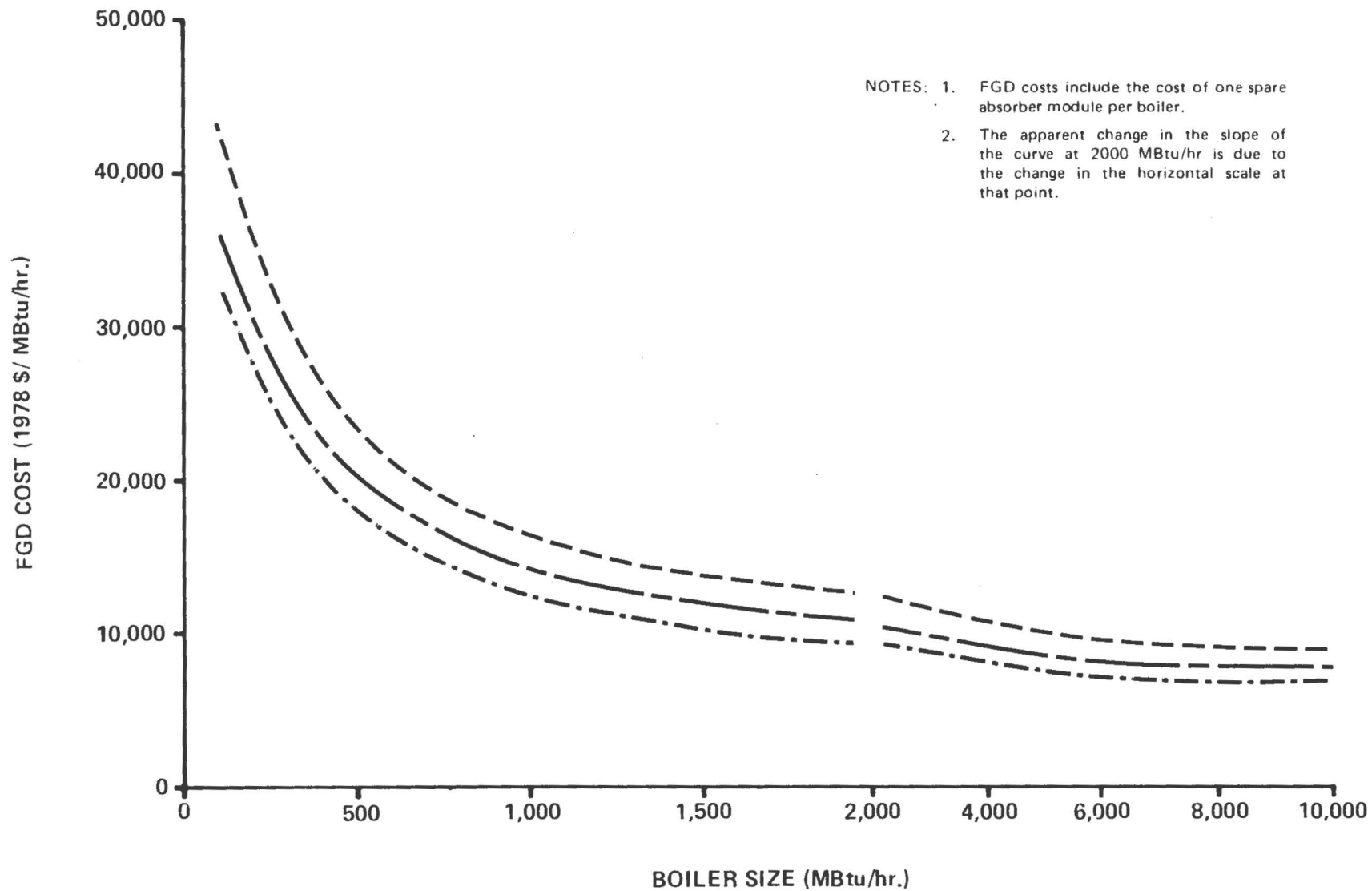


- NOTES: 1. FGD costs include the cost of one spare absorber module per boiler.
2. The apparent change in the slope of the curve at 2000 MBtu/hr is due to the change in the horizontal scale at that point.

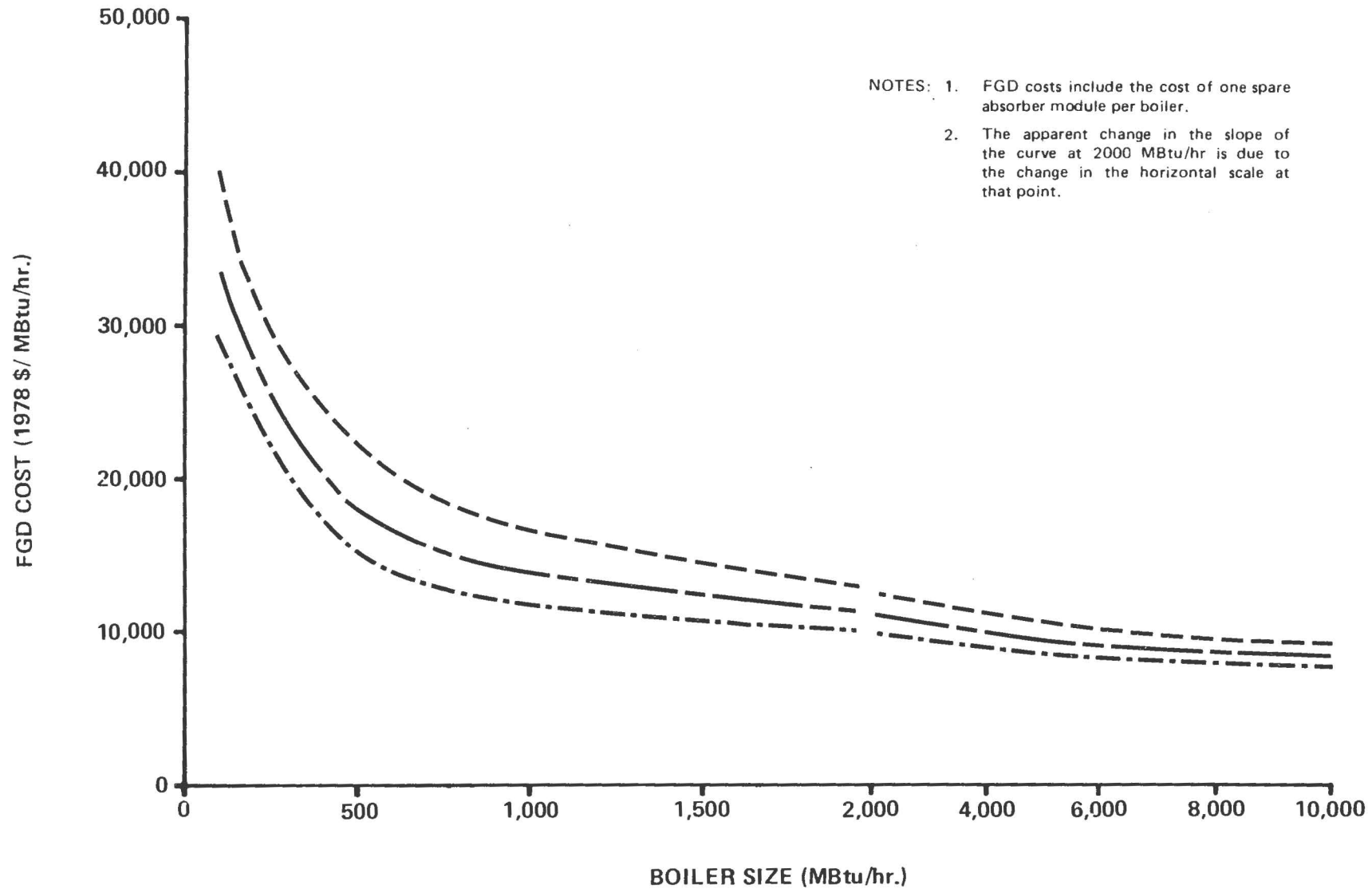
--- 3.5% SULFUR
— 2.0% SULFUR
- · - 1.0% SULFUR

Burns & McDonnell
ENGINEERS - ARCHITECTS - CONSULTANTS

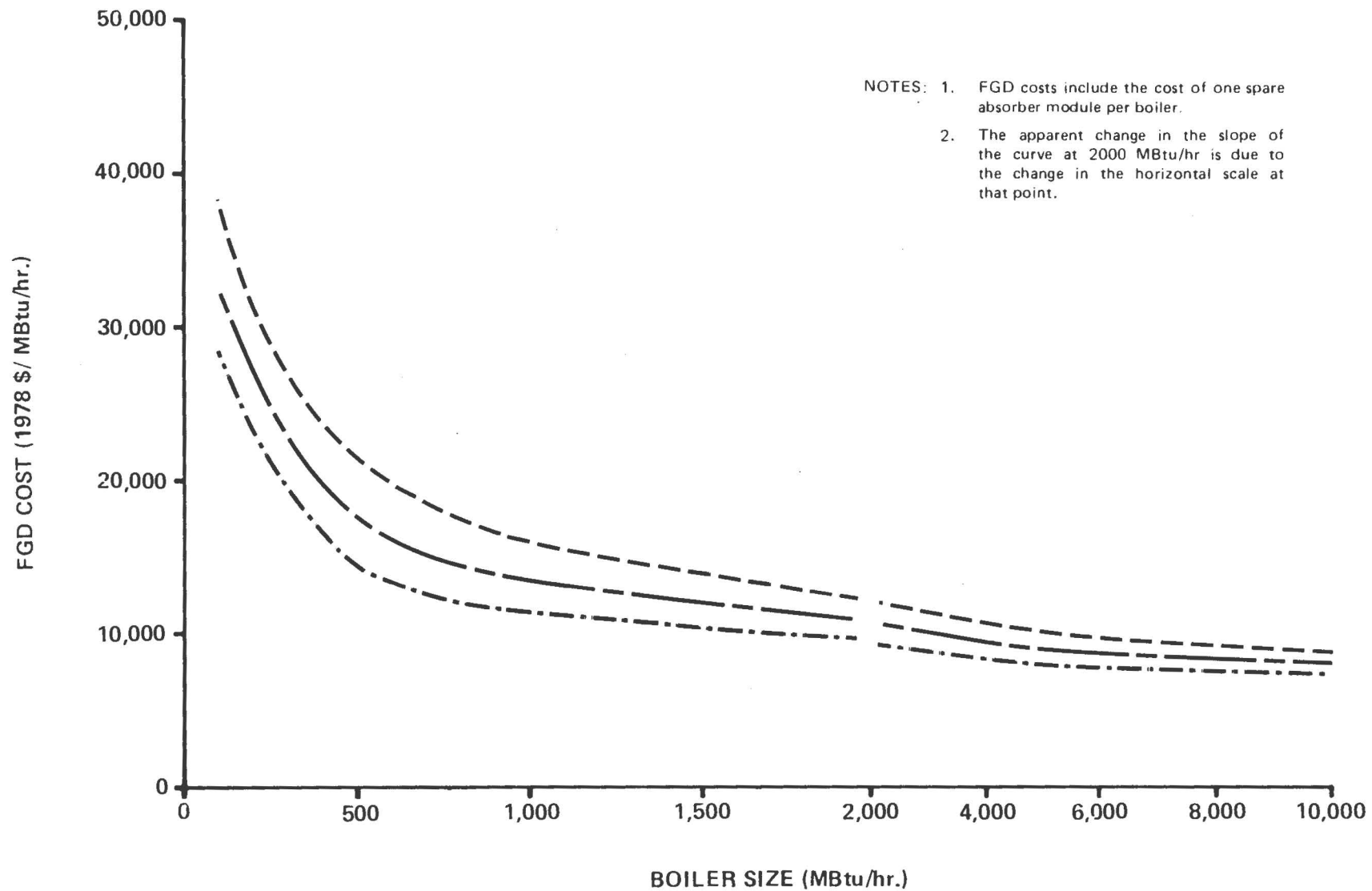
FIGURE 2
LIMESTONE FGD UNIT COSTS
AT 70% SO₂ REMOVAL



- NOTES: 1. FGD costs include the cost of one spare absorber module per boiler.
2. The apparent change in the slope of the curve at 2000 MBtu/hr is due to the change in the horizontal scale at that point.



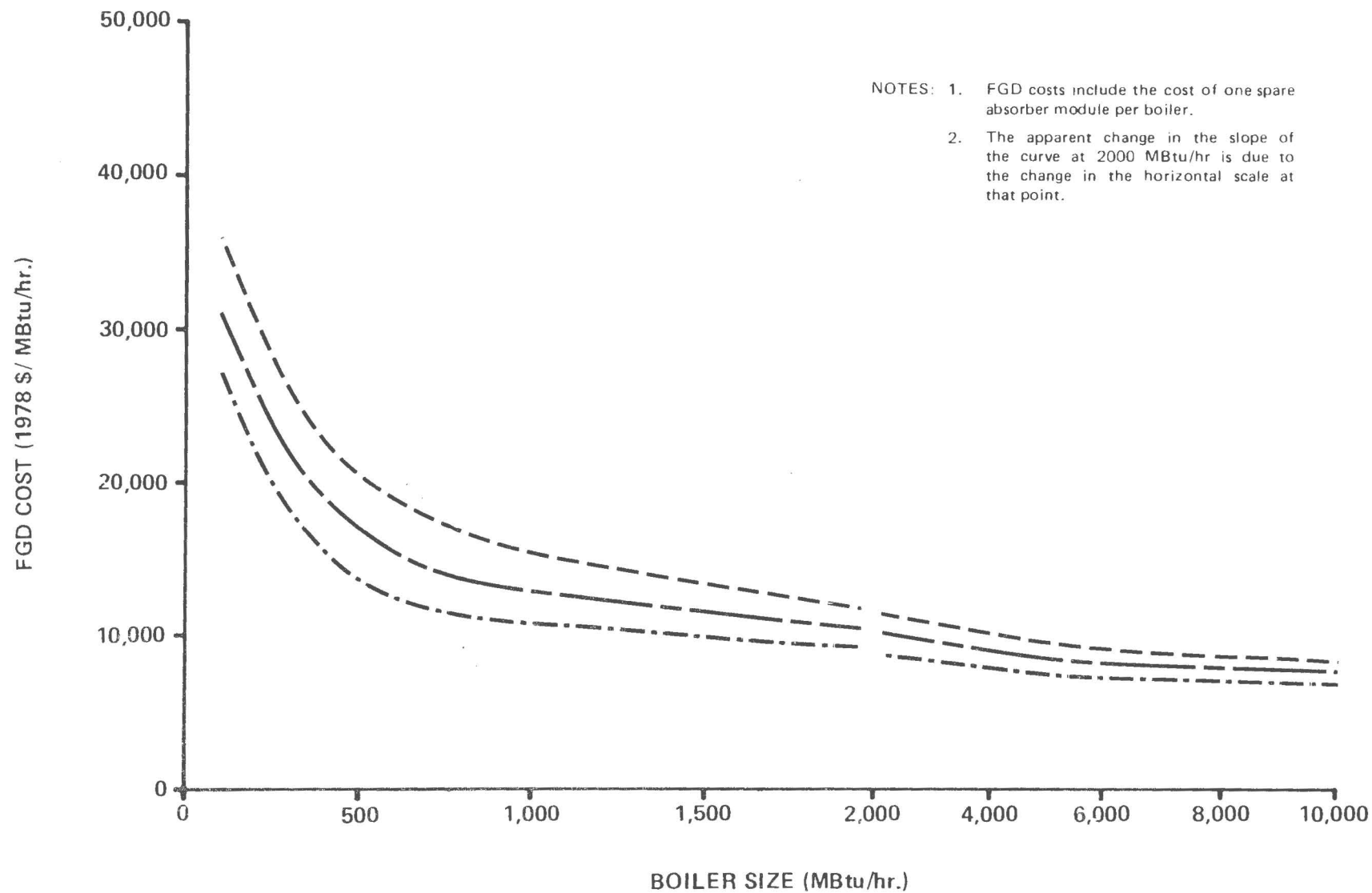
- NOTES: 1. FGD costs include the cost of one spare absorber module per boiler.
2. The apparent change in the slope of the curve at 2000 MBtu/hr is due to the change in the horizontal scale at that point.



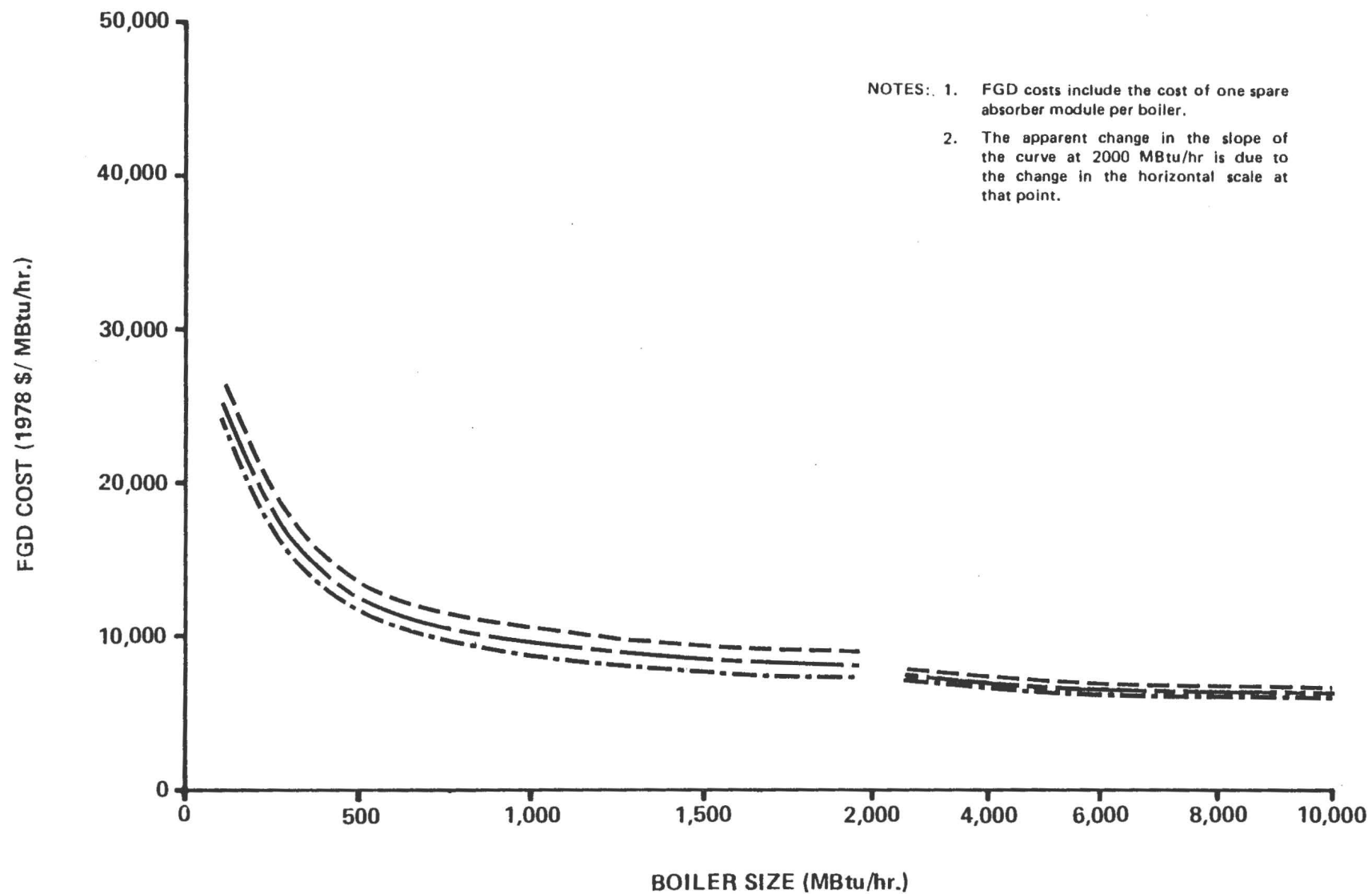
- NOTES: 1. FGD costs include the cost of one spare absorber module per boiler.
2. The apparent change in the slope of the curve at 2000 MBtu/hr is due to the change in the horizontal scale at that point.

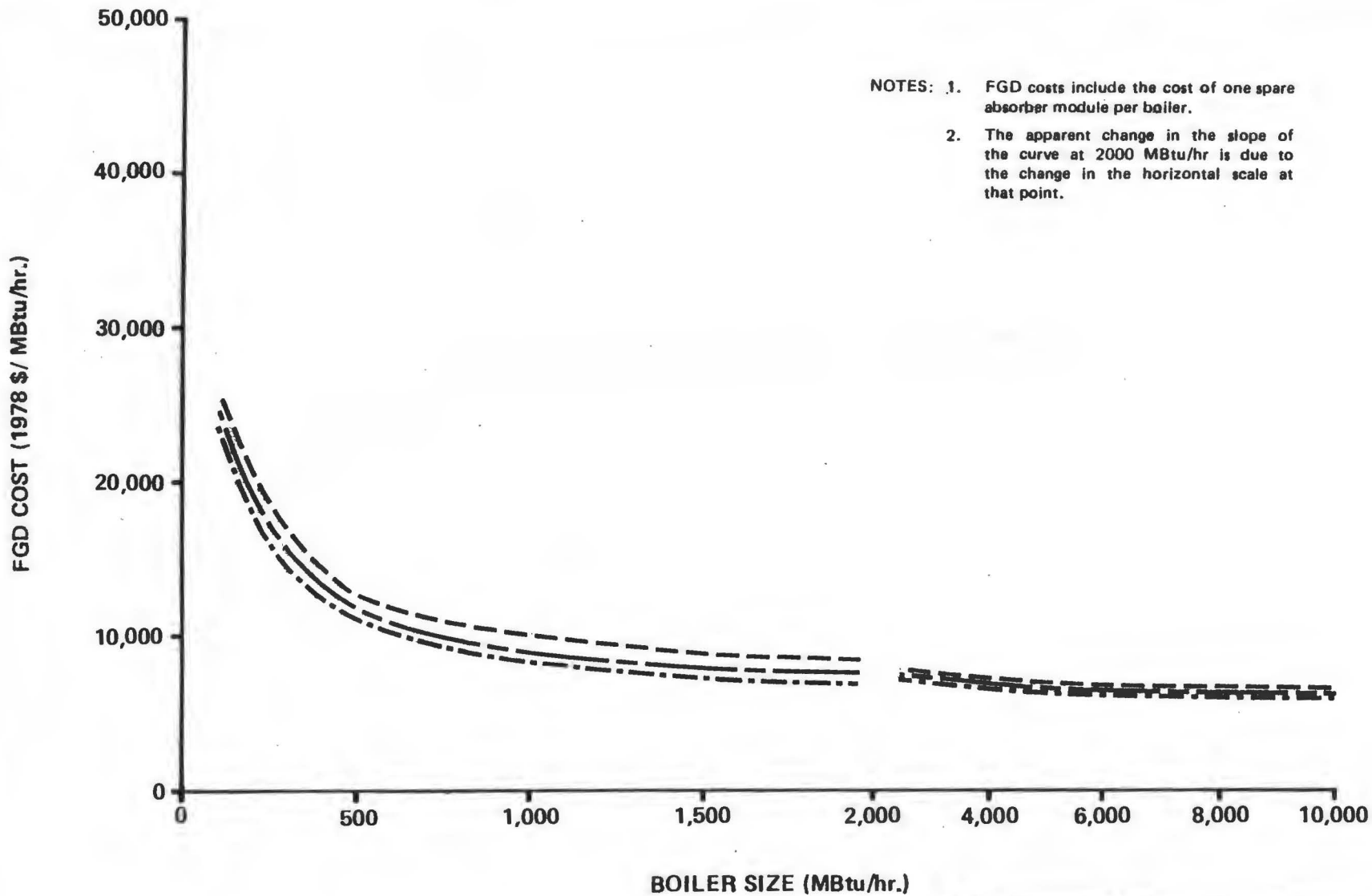
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FIGURE 5
DUAL ALKALI FGD UNIT COSTS
AT 70% SO₂ REMOVAL



- NOTES: 1. FGD costs include the cost of one spare absorber module per boiler.
2. The apparent change in the slope of the curve at 2000 MBtu/hr is due to the change in the horizontal scale at that point.



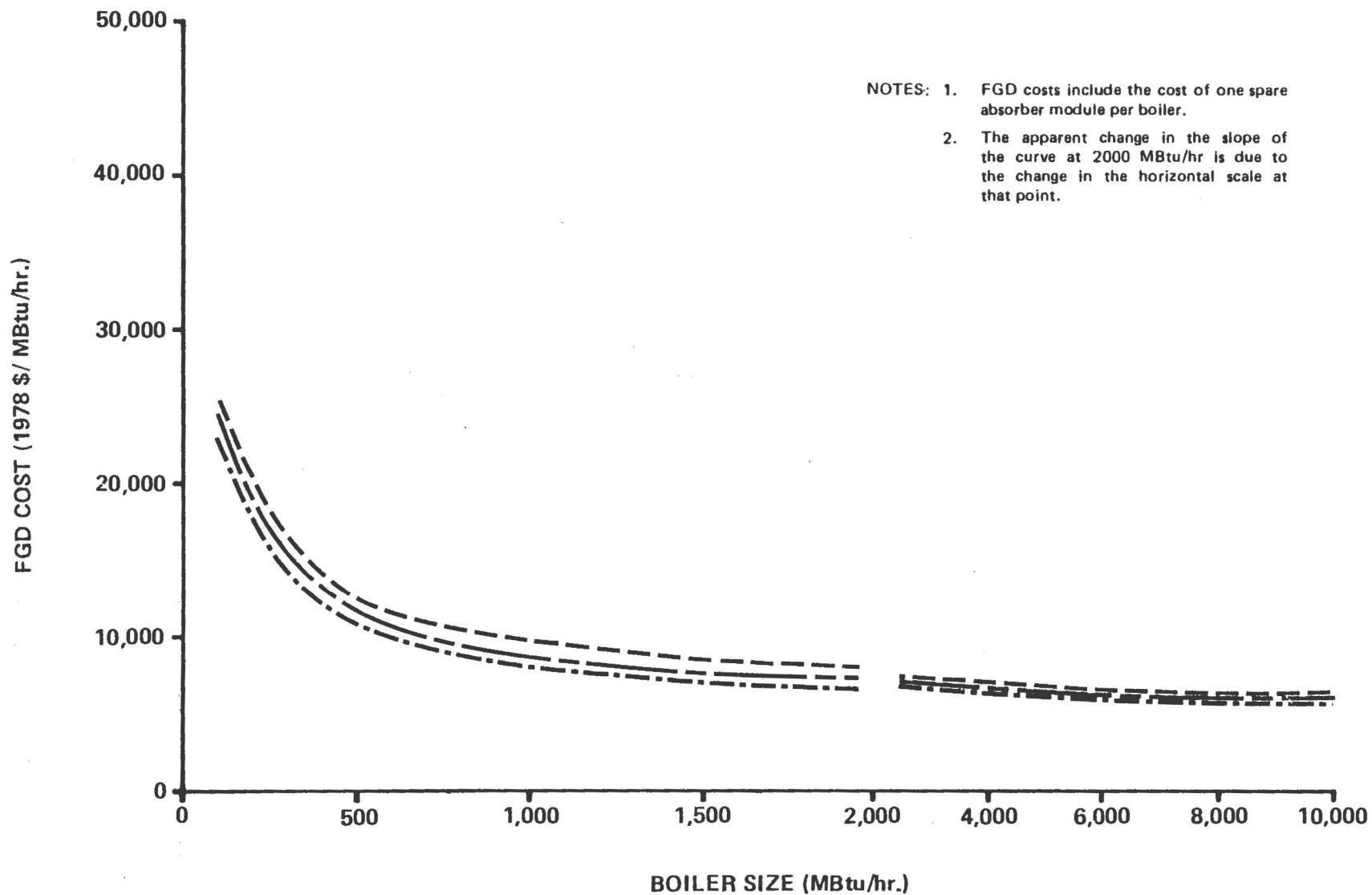


- NOTES: 1. FGD costs include the cost of one spare absorber module per boiler.
2. The apparent change in the slope of the curve at 2000 MBtu/hr is due to the change in the horizontal scale at that point.

--- 3.5% SULFUR
 — 2.0% SULFUR
 - · - 1.0% SULFUR

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FIGURE 8
 SPRAY DRYER FGD UNIT COSTS
 AT 70% SO₂ REMOVAL

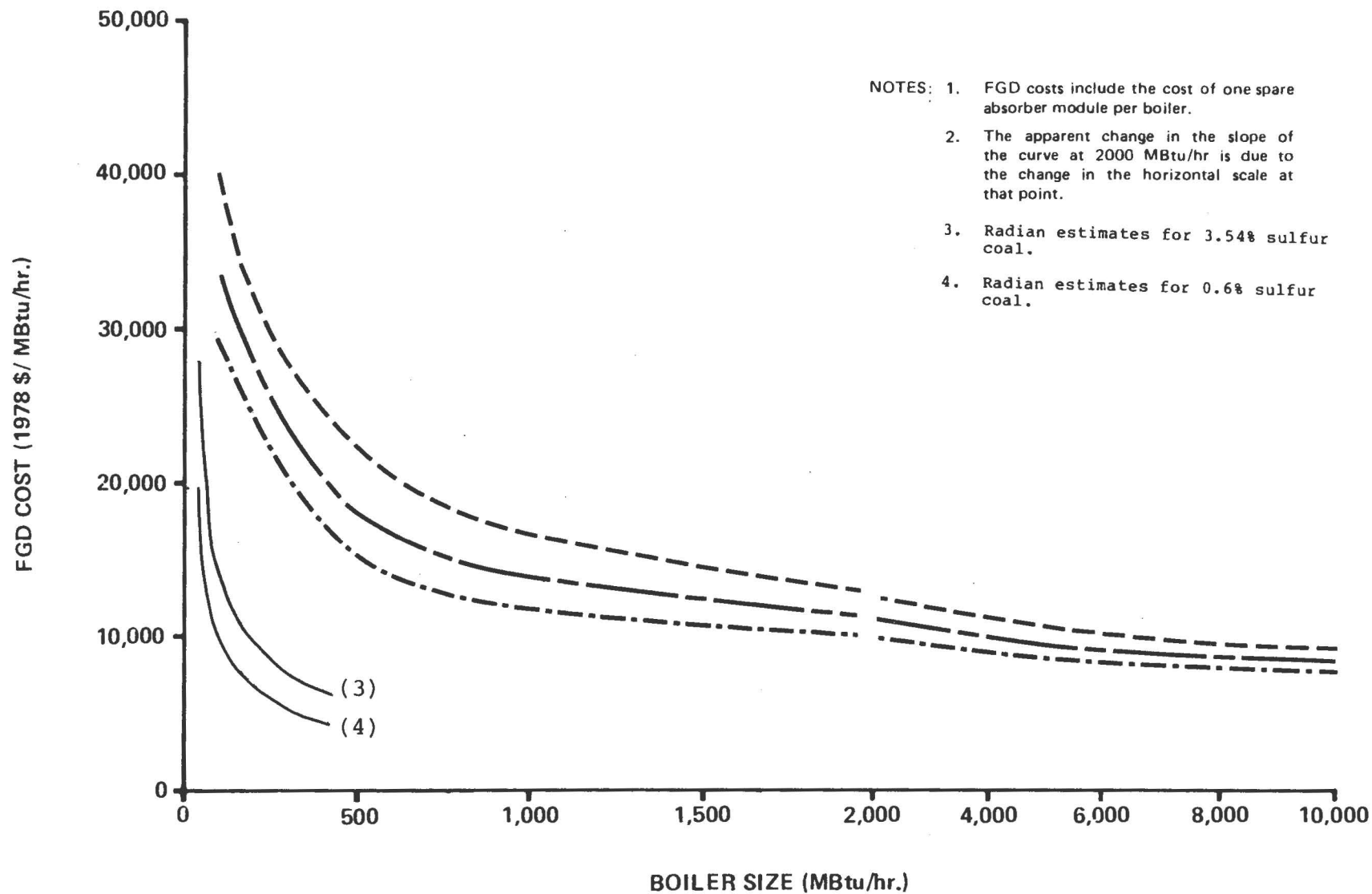


- NOTES: 1. FGD costs include the cost of one spare absorber module per boiler.
2. The apparent change in the slope of the curve at 2000 MBtu/hr is due to the change in the horizontal scale at that point.

--- 3.5% SULFUR
— 2.0% SULFUR
- · - 1.0% SULFUR

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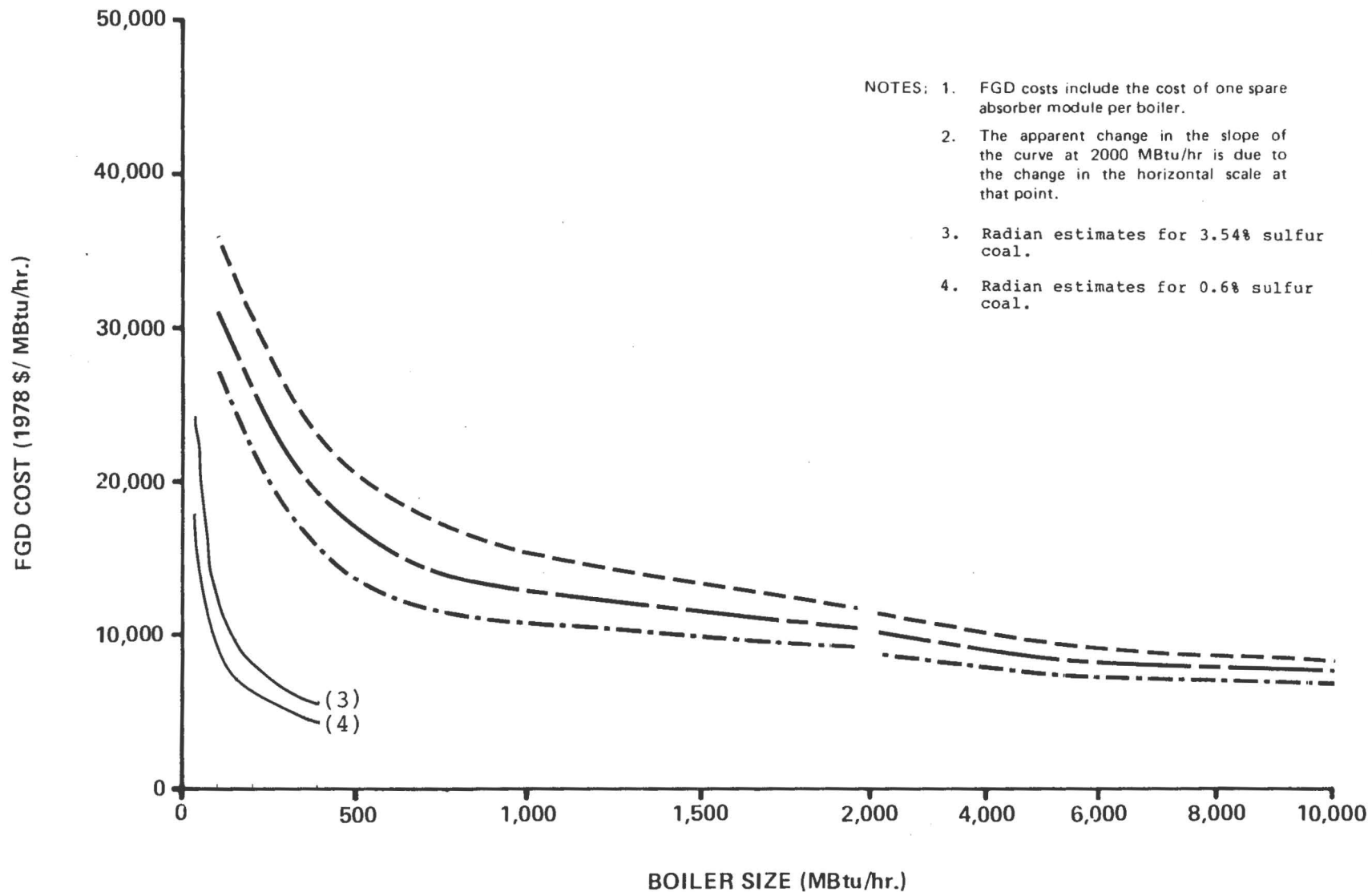
FIGURE 9
SPRAY DRYER FGD UNIT COSTS
AT 50% SO₂ REMOVAL



- NOTES:
1. FGD costs include the cost of one spare absorber module per boiler.
 2. The apparent change in the slope of the curve at 2000 MBtu/hr is due to the change in the horizontal scale at that point.
 3. Radian estimates for 3.54% sulfur coal.
 4. Radian estimates for 0.6% sulfur coal.

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FIGURE 10
**DUAL ALKALI FGD UNIT COSTS
AT 90% SO₂ REMOVAL
WITH COMPARISON TO RADIAN
COST ESTIMATES**



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FIGURE 11
**DUAL ALKALI FGD UNIT COSTS
AT 50% SO₂ REMOVAL
WITH COMPARISON TO RADIAN
COST ESTIMATES**

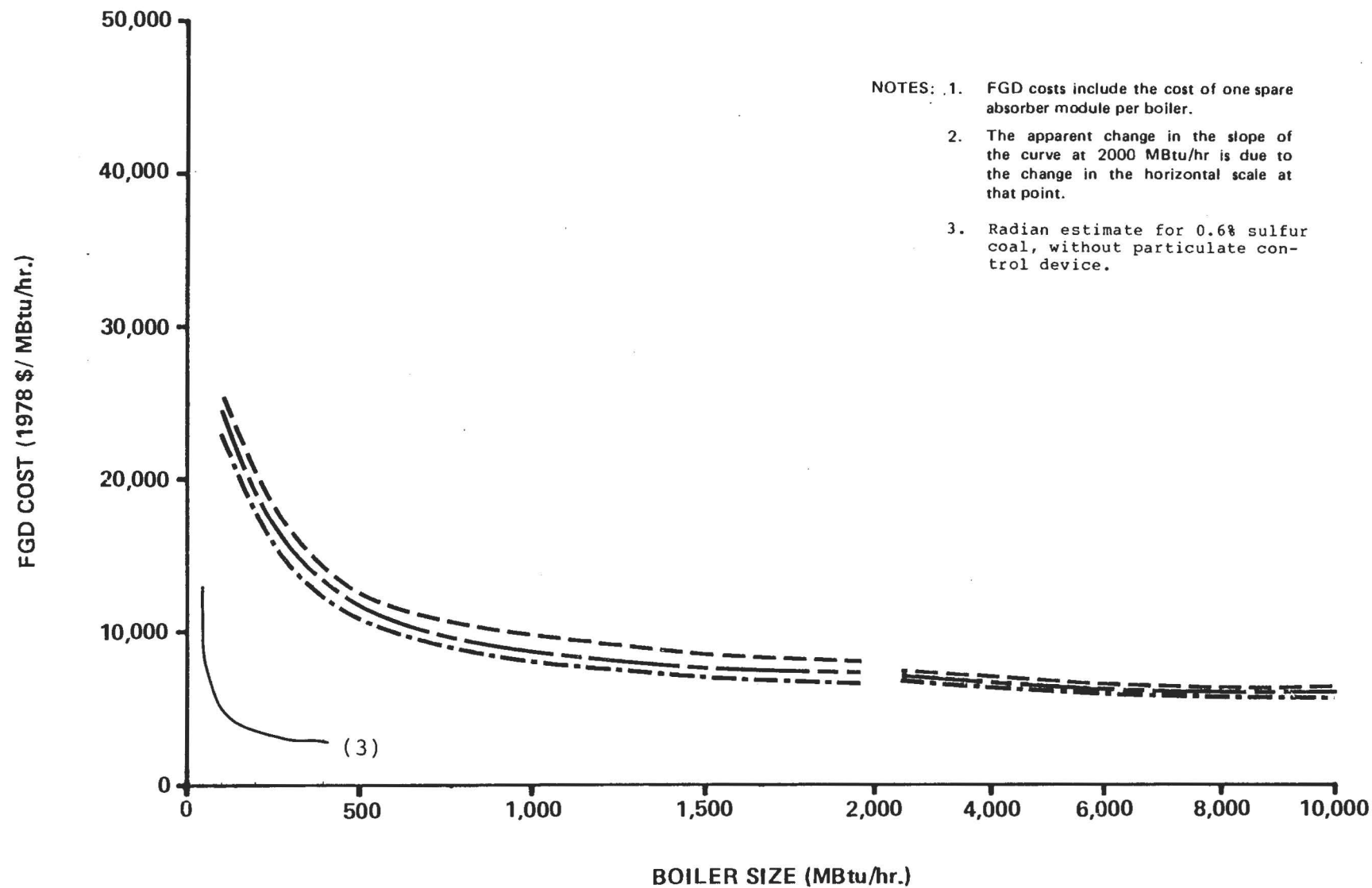


FIGURE 12

SPRAY DRYER FGD UNIT COSTS
 AT 50% SO₂ REMOVAL
 WITH COMPARISON TO RADIAN
 COST ESTIMATES

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J.G.C.

Memo From

RED CAVANEY

July 21, 1983

Dear Jim:

Attached is a letter which outlines a potential problem area which might be converted to the plus column by a timely review on the part of the Administration. Would be glad to fill you in on the details.

Hope all is well and best wishes for a good summer.

Red



American Paper Institute, Inc.

1619 Massachusetts Avenue, NW, Washington, DC 20036
(202) 332-1050

Canaway, Red

July 21, 1983

Mr. Edwin L. Harper
Assistant to the President for the
Office of Management and Budget
The White House
Washington, D. C. 20500

Dear Ed:

I am writing to request an appointment with you or one of your staff in the immediate future to discuss a matter of great concern--restoration of the quality of our nation's waters--and the need for reasonable nonpoint source pollution control programs in order to meet that objective. Nonpoint source pollution involves runoff from diffuse sources such as urban streets and agricultural lands.

As you are aware, the Senate Environment and Public Works Committee is presently considering the addition of a nonpoint source pollution control amendment to the package of Clean Water Act amendments reported by the Committee on June 28. We anticipate Committee action on the nonpoint source issue in early August.

Under the provisions of the 1972 Clean Water Act, a number of state programs have been developed in order to control nonpoint sources. Nevertheless, on many water bodies nonpoint source pollution remains a significant problem. Consequently, public interest groups are calling for some additional federal and state emphasis on nonpoint source pollution.

API has been working along with the National Forest Products Association, American Farm Bureau Federation, National Cattlemen's Association, Public Lands Council, National Association of Conservation Districts, Association of State and Interstate Water Pollution Control Administrators, National Association of Home Builders, National Grange, National Cotton Council of America, the American Consulting Engineers Council, and other groups to foster the adoption of a reasonable provision addressing nonpoint sources this year. However, we have serious reservations with the proposal being considered by the Committee. The proposal could substantially impact farm, forest, ranch and construction activities, as well as federal, state and local government programs. Moreover, we fear the amendment, if reported, could result in a controversy that may make passage of any Clean Water Act amendments impossible this year or next.

Canaway, Red

Mr. Edwin L. Harper

July 21, 1983

-2-

However, with the assistance of the Administration, we believe a reasonable provision can be developed, providing a middle ground for the diverse factions currently involved in the discussion of nonpoint sources. To date, the Administration has elected to not participate in this debate. I understand that the Office of Management and Budget and the Environmental Protection Agency are in conflict over the wisdom of Administration participation in the nonpoint source issue because the former agency objects to the Committee's--or any substantial--authorization for the nonpoint program.

I appreciate the problems involved in additional federal outlays at this time. However, with a modest level of federal involvement, a reasonable program can be developed. Operated primarily at the state and local level, such a program can make great strides to clean up nonpoint source pollution, and avoid unproductive and unnecessary regulation.

Further, the measure presently being considered by the Senate Committee may have major resource implications for other federal agencies, such as the Corps of Engineers and the Bureau of Reclamation, which generate some nonpoint problems through their activities. The implications of this provision may not have been fully reviewed by the affected agencies. Given this proposal's possible impacts, the ultimate costs to the Administration upon enactment may well be far greater than the addition of a modest nonpoint source program.

The Administration has the opportunity to take a leadership role in seeking a constructive solution that will be both effective in reducing nonpoint pollution, and acceptable to farm, ranch and forest land owners; state and local public officials; and environmental groups. A small delegation of the above affected groups would welcome the opportunity to talk with you about this critical issue.

Sincerely,



Red Cavaney
Vice President
Government Affairs

RC/MR/lr



American Paper Institute, Inc.

1619 Massachusetts Avenue, NW, Washington, DC 20036
(202) 332-1050

April 12, 1983

The Honorable Faith Ryan Whittlesey
Assistant to the President for
Public Liaison
The White House
Washington, D.C. 20500

Dear Faith:

Thought you might like the attached copy of our position paper (for internal use only) regarding the Administration's natural gas proposal.

We have been very active on the Hill on behalf of the President and have found contract abrogation and concerns over total deregulation of "old" gas as the major obstacles. We feel some hybrid may be able to get out of the Senate Energy Committee.

Best of luck on a good vote.

Warmest regards,

Red Cavaney
Vice President
Government Affairs

RC/jdp
Attachment
CC: K. Duberstein
J. Cicconi

Jim - hope all is well w. you. Give me side on conversations + work together. Maybe I can steal you away for a lunch before too long.

**PAPER INDUSTRY POSITIONS ON THE
ADMINISTRATION'S NATURAL GAS DECONTROL PROPOSAL**

As approved by API's Executive Committee
April, 1983

OVERVIEW:

In keeping with the paper industry's long-standing support of the free market system, it fully supports the Administration's efforts to deregulate the wellhead price of all natural gas by a date certain. While various provisions of the decontrol bill are not consistent with a free market approach, it is recognized that these are transitional measures, leading to full decontrol by 1/1/86. For the long term, the industry particularly endorses the concept of contract carriage to provide purchaser access to all gas supplies at competitive market prices.

Major provisions of the Administration's decontrol proposal are:

- 1) **PROVISION:** All new and renegotiated contracts to be deregulated.
POSITION: The industry supports this provision in keeping with its established position supporting the free market system.
- 2) **PROVISION:** Unilateral termination of non-renegotiated first sale contracts during calendar year 1985.
POSITION: The industry fully supports the sanctity of contracts negotiated between a willing buyer and a willing seller, and finds it inappropriate for any government agency to cause these agreements to be abrogated. However, it is recognized that the majority of the natural gas contracts were negotiated in an artificial and controlled environment and do not represent free market conditions. Therefore, in order to correct those market distortions caused by regulated conditions, intervention by the federal government on a one time basis may be necessary to facilitate the transition to a free market.
- 3) **PROVISION:** Transition price controls - average of new and renegotiated contracts (gas caps) or NGPA price levels.
POSITION: The industry supports this provision of the legislation for the orderly elimination of wellhead price controls on all gas by a date not later than 1/1/86.
- 4) **PROVISION:** Passthrough restrictions on costs incurred by pipeline companies including pipeline production affiliates.
POSITION: Recognizing that the passthrough restrictions are transitional, the industry fully supports the legislative intent to deregulate the wellhead price of all gas by 1/1/86. However, it believes that prudently incurred costs should be passed through in an expeditious manner during the transition period.

(continued)

- 5) PROVISION: Other contract adjustments:
- a. Take-or-pay reduction to 70% with associated transportation obligation;
 - b. Limits by price caps on indefinite escalator clauses;
 - c. Area rate provision agreements tied to price caps.
- POSITION: The industry fully supports these interim provisions leading to full decontrol of the wellhead price of gas not later than 1/1/86.
- 6) PROVISION: Removal of access limitations.
- POSITION: The industry strongly supports the provisions which will facilitate the flow of gas between markets, including the removal of impediments to interstate movements of gas, and especially supports the contract carrier authorization.
- 7) PROVISION: Repeal of use restrictions.
- POSITION: The industry strongly supports the repeal of the restrictive industrial and utility Fuel Use Act provisions and Title II of the NGPA - incremental pricing.
- 8) PROVISION: Repeal sections of the NGPA allowing the President or Congress to reimpose price controls.
- POSITION: The industry strongly supports repeal of this authority.

JAMES E. COLEMAN, JR.*
 PHILIP S. WOODBROOK
 CLYDE E. TRUITT
 WARREN CHRISTOPHER**
 EVERETT B. CLARY
 JAMES E. CROSS
 R. BRADBURY CLARK
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 CHARLES G. BAKALY, JR.**
 WILLIAM W. VAUGHAN
 RICHARD E. SHERWOOD
 PHILIP D. IRWIN
 DONALD V. PETRONI
 DONN B. MILLER
 DONALD R. HODGMAN
 RICHARD S. VOLPERT
 JOHN H. RONEY**
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OF COUNSEL
 JOHN F. AISO
 PERRY A. LERNER
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*MEMBER D. C. BAR
 **MEMBER CALIF. AND D. C. BARS
 OTHERS ADMITTED IN CALIF. NOT D. C.

O'MELVENY & MYERS

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July
 28th
 1983

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 PARIS 8*, FRANCE
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 TELEX 842-660715

OUR FILE NUMBER

WRITER'S DIRECT TELEPHONE

(202) 457-5325

Honorable James W. Cicconi
 Special Assistant to the President
 and to the Chief of Staff
 The White House
 Washington, D.C.

Dear Jim:

As you know, I serve as Chairman of the Board of the NAACP Legal Defense and Educational Fund, Inc. ("LDF"). As a result of a lawsuit filed by LDF in 1980, NAACP Legal Defense and Educational Fund, Inc. v. Campbell, 504 F.Supp. 1365 (D.D.C. 1981), which resulted in a ruling by Judge Gesell favorable to us, the Legal Defense Fund has participated in the Combined Federal Campaign for the last two years. Judge Gesell ruled that the requirement that CFC participants provide "direct services to persons in the fields of health and welfare services" was invalidated in 1981 as "too vague to comport with the strict standards of specificity" required by the First Amendment. LDF v. Campbell, 504 F.Supp. at 1366-67.

On January 10, 1983, President Reagan issued Executive Order No. 12404 in an effort to reinstate the direct services requirement but with greater specificity. The announced purpose of the new Executive Order was to exclude legal defense funds from the CFC. Devine memorandum of Feb. 2, 1982, "New Executive Order for the Combined Federal Campaign."

On July 15, 1983, however, Judge Joyce Green ruled that Executive Order 12404 violated the First Amendment. NAACP Legal Defense and Educational Fund, Inc. v. Devine, No. 83-0928 (D.D.C.). Judge Green ruled that the CFC constitutes a limited public forum and that the government cannot exclude some charitable organizations because their message is controversial.

The issue that must now be resolved is what rules will govern the 1983-84 campaign. It is important that this question be resolved expeditiously because preparations for the 1983 Campaign are already well under way.

Although legal defense funds must be allowed to participate in the 1983-84 Campaign as the result of Judge Green's order, the Office of Personnel Management has not yet begun to implement the Court's decision. Rather, Director Devine has announced that he plans to appeal the Court's ruling but he has not yet done so. In the meantime, Local Federal Coordinating Committees still are operating under instructions from OPM to make eligibility decisions on the basis of Executive Order 12404, even though Judge Green has declared it invalid. Furthermore, while Director Devine has announced that the start of the Campaign will be delayed until mid-October, in order to permit orderly resolution of the claims of legal defense funds, we were informed last week by one Local Committee that its Campaign will begin on September 13, and that the NAACP Legal Defense Fund will be excluded on the basis of the Executive Order. When informed of Judge Green's decision, the Local's reply was that OPM had not changed its instructions.

This type of confusion will severely damage the 1983-84 Campaign. The only fair action at this time is for OPM to announce immediately that the 1983 Campaign will be conducted under the pre-existing regulations. The government has the right to appeal Judge Green's decision, although I do not believe such an appeal should be taken. However, in the event an appeal is taken, it should be directed toward future Campaigns and should not be used to further delay and confuse the current Campaign.

Specifically, I urge that should an appeal be taken, the government not seek a stay of Judge Green's ruling. In addition to the confusion that would result, such a stay would be inequitable. It was the Office of Personnel Management that delayed resolution of the lawsuit until the eve of

Honorable James W. Cicconi

Page Three

the Campaign, by delaying issuance of regulations under Executive Order 12404. Moreover, our participation in the 1983-84 Campaign will not harm the CFC. Legal defense funds have participated in the past two years, and in each year contributions increased significantly. It seems to me the only fair and just thing is to announce that the 1983-84 Campaign will be conducted under the same rules as applied in the 1982-83 Campaign. As you know, the Majority Leader of the Senate has sent a letter to Ed Meese making the same request.

Please call me and I will be happy to discuss this matter further.

With kindest regards,

Sincerely,

William T. Coleman, Jr.

No copy in (has already handled)

OFFICE OF CABINET AFFAIRS ACTION TRACKING WORKSHEET

Action resulting from:

- ☒ document (attached)
☐ telephone call
☐ meeting (attach conference report if available)

Document Date: 83, 08, 01From: Jim CicconiDate Received: 83, 08, 02

Subject: Sends Fuller letter to Cicconi from William T. Coleman, Jr. re: new regulations governing CFC for stuffing + distribution

ACTION CODES:

- A — Appropriate Action D — Draft Response R — Direct Reply w/Copy
 B — Briefing Paper F — Furnish Fact Sheet S — For Signature
 C — Comment/Recommendation I — Info Copy Only/No Action Necessary X — Interim Reply

ROUTE TO:

Date Sent	Name	DD	Action Codes	Date Due	Action Taken
83/08/04	1. Clarey		A	/ /	To Joe Morris via H.P. Goldfick
83/08/11	2. FULLER		A	/ /	for response letter attached
83/08/11	(3) Cicconi		A	/ /	
/ /				/ /	
/ /	No need to respond			/ /	
/ /				/ /	

COMMENTS: OPM put together a long letter, but H.P. & I felt that the W.H. should avoid direct involvement so a short response is attached

(3) Response attached

Originator: ☐ Dunlop ☐ Faoro ☒ Fuller ☐ Gonzalez ☐ Hart ☐ Hodapp

KEEP THIS WORKSHEET ATTACHED TO THE ORIGINAL INCOMING MATERIAL AND WHEN THE ASSIGNED ACTION IS COMPLETE, RETURN TO:

Office of Cabinet Affairs
Attention: Karen Hart (x-2823)
West Wing/Ground Floor

THE WHITE HOUSE
WASHINGTON

August 1, 1983

159621

MEMORANDUM FOR CRAIG FULLER

FROM: Jim Cicconi,
SUBJECT: Letter from Bill Coleman

Attached is a letter from Bill Coleman, who is writing about the proposed new regulations governing the Combined Federal Campaign. He is writing in his capacity as chairman of the NAACP Legal Defense and Educational Fund.

It is forwarded for staffing and for distribution as you feel appropriate.

Thanks.

cc: Joe Wright

THE WHITE HOUSE

WASHINGTON

August 11, 1983

Dear Bill:

Thank you for your letter of July 28, 1983 regarding the Combined Federal Campaign. I recognize and appreciate your special interest in the rules governing the CFC. While I was very concerned about the issues raised in your letter, given the fact that such issues are currently in litigation, it would be inappropriate for the White House to become involved.

I would, however, suggest that you contact Joseph A. Morris, General Counsel of the Office of Personnel Management, in order that they be fully apprised of all relevant information as appropriate.

With best wishes,

Sincerely,

James W. Cicconi
Special Assistant
to the President

Mr. William T. Coleman, Jr., Esq.
O'Melveny & Meyers
1800 M Street, NW
Washington, D.C. 20036-5857

cc: Joseph A. Morris

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May
 9th
 1983

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OUR FILE NUMBER

750,110-59

WRITER'S DIRECT TELEPHONE

202/457-5325

Mr. James W. Cicconi
 Special Assistant to the President
 and Special Assistant to the Chief of Staff
 The White House
 Washington, D.C. 20500

Re Further Consideration of the Status of Kuwait
 Under the Mineral Lands Leasing Act of 1920

Dear Jim:

We spoke earlier this year concerning the then-pending reconsideration by the Department of the Interior of the December 1982 decision that Kuwait is a qualified country under the Mineral Lands Leasing Act of 1920 (MLLA), which would affect our client Santa Fe International Corporation. As you know, on March 10, 1983, Secretary Watt determined that Kuwait is disqualified under the MLLA on the ground that Kuwait discriminated against American companies during the 1970's as it reduced or eliminated private ownership in the oil sector. We believe that this decision was based on incomplete and erroneous information about Kuwait's practices, largely as a result of the fact that the Interior Department did not provide Santa Fe or its shareholder, Kuwait Petroleum Corporation, an opportunity to comment on this discrimination issue.

I have enclosed a copy of a letter to Secretary Watt and accompanying materials delivered on May 4, 1983. The enclosed memorandum demonstrates that companies with American ownership long enjoyed a paramount position in the oil industry in Kuwait and that Kuwait did not discriminate in any way against American interests as it increased governmental control over the oil industry. We believe that

#2 - Mr. James W. Cicconi - 5/9/83

this information should compel the Secretary to consider this matter further and to confirm the qualified status of Kuwait under the MLLA. Qualification of Kuwait would be consistent with long-standing interpretations of the MLLA, with the fundamental American policy favoring the attraction of foreign investment, with the pressing need for capital formation to permit frontier oil and gas exploration, and with good diplomatic relations with Kuwait and other countries which have found it necessary to choose state ownership in the oil sector.

We have requested a meeting with Secretary Watt on this matter on May 18. We would appreciate your supporting further consideration through the Senior Inter-Departmental Group on International Economic Policy or other appropriate avenues now that more complete and accurate information is available. I have also written to Danny Boggs in this connection.

Thank you for your attention to this matter. We would be happy to respond to any questions or to provide any additional information.

Very truly yours,

William T. Coleman, Jr.
of O'MELVENY & MYERS

Enclosures

Foreign Agents Registration Act
No. 3346

THE WHITE HOUSE

WASHINGTON

May 16, 1983

MEMORANDUM FOR JIM CICCONI

FROM: DANNY BOGGS

SUBJECT: Status of Kuwait Under the MLLA of 1920

I spoke to Coleman and his associates sometime earlier in the year, between the suspension of the original decision and the March 10 determination of disqualification. I have not done any kind of definitive legal study on this, but I would put some credence in the argument that a strict application of the Kuwait decision to all similar situations might reduce the number of companies or countries able to lease federal land to a very small number.

THE WHITE HOUSE
WASHINGTON

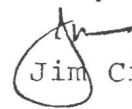
May 10, 1983

TO: DANNY BOGGS

Please see the attached letter
from Bill Coleman.

What do you think of his
argument? (I have not yet
responded to him.)

Thanks.


Jim Cicconi

F.G.C.

THE WHITE HOUSE
WASHINGTON

was coord'd
w/ State, SIG-EP
and NSC

"Watt made clear his
intentions: Shultz
said to do what
you have to"

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OUR FILE NUMBER

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WRITER'S DIRECT TELEPHONE

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Mr. James W. Cicconi
 Special Assistant to the President
 and to the Chief of Staff
 The White House
 Washington, D.C. 20500

Dear Jim:

I am enclosing herewith the note which the Kuwait Ambassador has given to the State Department. After reading it, you can understand why I have been trying to get some attention paid to the foreign policy aspect of any decision which Secretary Watt might make.

With kindest regards,

Sincerely,

Bill

William T. Coleman, Jr.
 of O'MELVENY & MYERS

Enclosure

Translation of Diplomatic Note From the
Minister of Foreign Affairs of the State of Kuwait
to the Secretary of State of the United States of America
(Delivered March 4, 1983)

I wish you the best of times. I am pleased to express our pleasure for the good relations existing between our two countries and that we hope it will increase and develop. I would like to refer to the American decision concerning the utilization of the federal American lands that has a negative impact on the Kuwaiti interests in the United States.

As you are aware, my government has for some years been concerned about its status as a "reciprocal nation" under the Mineral Lands Leasing Act. My government has pursued this question because of Kuwait's practical interest in doing business in the energy industries of the United States.

Kuwait has long viewed the United States as an area of singular commercial opportunity. The United States is the largest single industrial economy in the world and it exemplifies, par excellence, that commercial and entrepreneurial ethos which also characterizes, we believe, Kuwait's own participations in local and in international trade.

As you know, this lively Kuwaiti interest in U.S. business opportunities is shared also by the Kuwait Petroleum Corporation (KPC), and it led to the successful bid by KPC in October 1981 for all of the shares of Santa Fe International Corporation (SFIC). My government was gratified by the positive view of that acquisition which was taken by the U.S. administration, notably under the formal review processes supervised by the Committee on Foreign Investment in the United States (CFIUS). We believe that the explanations given by KPC (notably the well-publicized views of KPC's Chairman, Sh. Ali Khalifa Al-Sabah; also the testimony to a Congressional Committee by KPC's Deputy Chairman, Mr. Abdul Razak Hussain) convinced the various U.S. authorities of KPC's bona fides -- particularly the non-political and commercial policies which it would observe. KPC has lived up to its stated intentions regarding the future of Santa Fe under Kuwaiti ownership and has more than doubled SFIC's capital investments in the year following the acquisition.

Detailed legal comments in support of my government's application for recognition of its reciprocal status have been made by our U.S. legal advisors and by the lawyers of SFIC. It would be superfluous to refer here to this extensive documentation.

I have to inform you that my government is seriously disappointed over the handling by the Interior Department of Kuwait's application for recognition of its reciprocal status under the Mineral Lands Leasing Act of 1920 (MLLA). Our formal request for recognition dates from about two and a half years ago. We fully understood the necessity to wait our turn in a review process which involved other countries and we have taken care to respond as fully as possible to the queries raised by the responsible Department. It nevertheless remains a fact that the review process has taken an extraordinarily long time to come to a conclusion.

Given the nature of Kuwait's case, and the parallels which it offers with access by the public to some State-owned natural resources in say, the U.K., Mexico and Venezuela, it came as a relief to my government (but as no surprise) that the Interior Department eventually found in favour of Kuwait in its decision dated 29 December 1982. In that decision, Kuwait was declared a reciprocal nation under the MLLA by the Assistant Secretary of the Department of the Interior. The Kuwaiti government assumed, naturally enough, that thorough administrative procedures had eventually revealed that this finding was wholly consistent with the requirements of the MLLA and with the precedent decisions made by the Department of the Interior. You can doubtless comprehend my government's surprise when the Interior Department within one month actually revised its finding and delayed its final decision on Kuwait's reciprocal status.

My government and its legal advisors in the United States are both at a loss to comprehend the factual basis for the hold-up in the Department's ruling. The Kuwaiti government is concerned that unknown issues, not related to the technical and legal determination required by the MLLA, have come into play. Naturally, we were glad to learn from the evidence given by Secretary Watt on 2 February 1983 to the Senate Energy and Natural Resources Committee, that a final determination will be given "within the next 30/40 days". My government is nevertheless most anxious to have the opportunity to know fully the grounds on which this administrative delay has occurred. My government is also very concerned that it be given the opportunity to comment on these grounds and to fully discuss any additional points which may be raised by the Interior Department pertaining to Kuwait's application for recognition of reciprocal status. It goes without saying that my government wishes

to provide its views to the Department of the Interior prior to
the issuing of the "final determination".

My government believes that this hesitancy at the Interior Department has been an unfortunate development which harms legitimate Kuwaiti business interests in the United States. My government looks to full consultation with the appropriate U.S. authorities concerning this unexpected development and is confident that the facts of the matter will lead to a speedy confirmation of the earlier decision.

Therefore, I would like you to take this subject into your direct consideration hoping that you will reach the positive steps that contribute in fostering and strengthening the relations between our two countries.

Yours sincerely,

s/Shaikh Sabah A. J. Al-Sabah

Deputy Prime Minister, Minister
of Foreign Affairs and Minister
of Information

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OF COUNSEL
DAVID A. DEAN

December 22, 1983

Mr. Jim Cicconi
Special Assistant to the President
White House
1st Floor, West Wing
Washington, D.C. 20500

Dear Jim:

In a few days you will receive a special request for support from an organization that is very important to me personally: The Dean Learning Center.

There are literally millions of Americans with some form of language learning difficulty. The Dean Learning Center is addressing this special problem with a total program including an evaluation-diagnostic division serving both adults and children, a complete school from pre-primary through eighth grade, and a teacher training division that has served as the model for many others. Its faculty includes many of the most highly trained and skilled teachers, practitioners, and lecturers in the learning disability area. They are dedicated to serving others and are enthusiastic about the Center, its past accomplishments and future potential. We feel that the Center is literally on the cutting edge of research and advancements in this important area. It effects so many.

Among the numerous organizations that appeal for contributions, Dean is especially deserving. I hope you will give serious consideration to the Center's need for support and that you will join me in making a generous, tax-deductible donation.

May the holiday season be a joyous time for you and your family, and I wish you a healthy and prosperous New Year.

Sincerely,



David A. Dean

DD;cb