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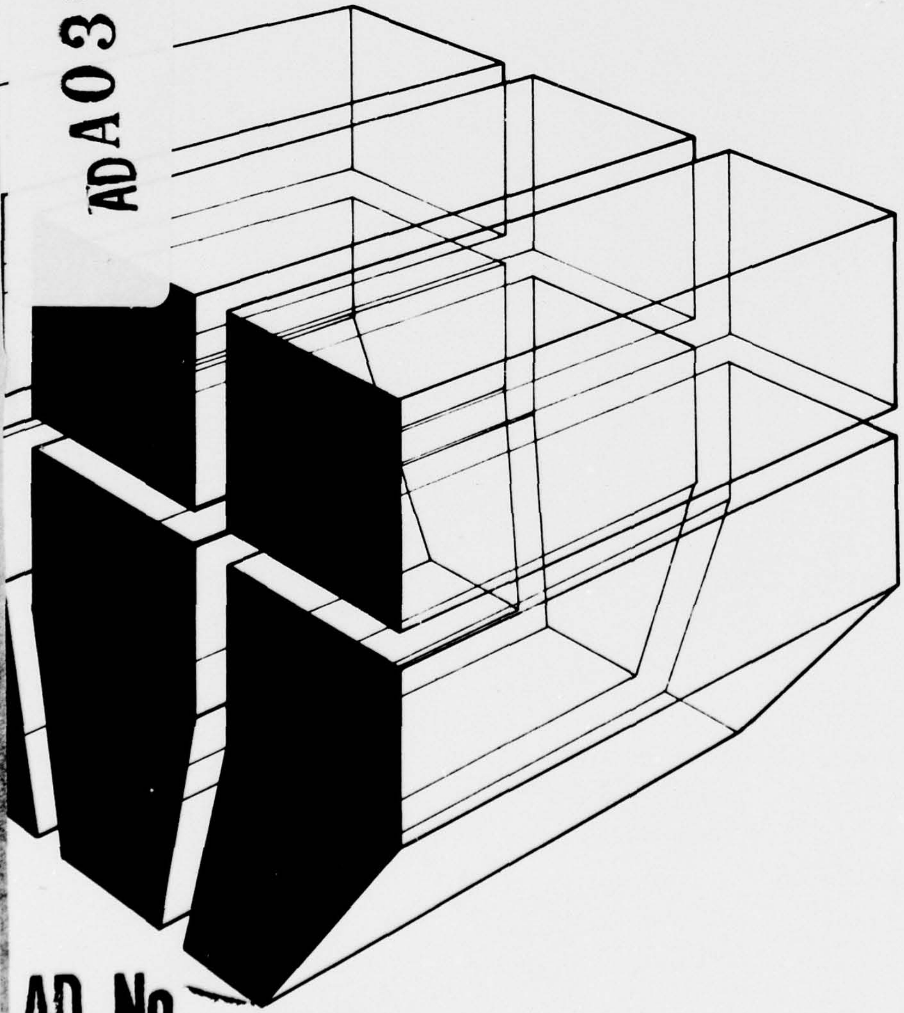
TECHNICAL REPORT N-19
February 1977
Control of Gaseous and Particulate Emissions From Boilers

EMERGING TECHNOLOGY FOR THE CONTROL OF EMISSIONS FROM EXISTING ARMY BOILERS AND INCINERATORS



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20. ABSTRACT (*Continue on reverse side if necessary and identify by block number*)

The overall objective of this study was to provide information on emerging technology for controlling gaseous and particulate emissions from Army boilers and incinerators to achieve compliance with the regulations of various federal, state, and local agencies.

From the information gathered, it was apparent that there is adequate technology for particulate control at Army installations; therefore, in →

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selecting the most promising emerging systems for further study, emphasis was placed on methods for controlling sulfur dioxide emissions.

An economic analysis of the five emerging systems analyzed was conducted on the basis that the entire emission control process would be located on the facility site. However, since three of the five systems can be arranged to permit the regeneration portion of the process to be located elsewhere and to be independently owned, the economic analysis also considered that modification of each affected system.

To identify promising new systems and methods for controlling emissions, a methodology for evaluating them was developed. This methodology is designed for use by the Army technical staff to make a preliminary decision about whether the emission control system in question deserves further consideration.

Cost data for the emerging systems were collected during the period of April through December 1975.

FOREWORD

This study was sponsored by the Directorate of Military Construction, Office of the Chief of Engineers (OCE), under Project A896, "Environmental Quality for Construction and Operation of Military Facilities"; Task T2, "Pollution Control Technology"; Work Unit 005, "Control of Gaseous and Particulate Emissions From Boilers." The QCR Number is 1.03.006 (4). The work was performed for the Construction Engineering Research Laboratory (CERL) by A. M. Kinney, Inc., Cincinnati, OH, under Contract No. DACA23-75-C-0007.

The OCE Technical Monitor was Mr. Wade Sato.

Mr. W. J. Mikucki, Chief of the CERL Environmental Engineering Team, Environmental Division (EN), was the CERL Technical Monitor. Dr. R. K. Jain is Chief of EN.

COL J. E. Hays is Commander and Director of CERL, and Dr. L. R. Shaffer is Technical Director.

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EMERGING TECHNOLOGY FOR THE CONTROL OF EMISSIONS FROM EXISTING ARMY BOILERS AND INCINERATORS

1 INTRODUCTION

Background

The Department of the Army operates many boilers and incinerators throughout the United States. In order to have the emissions from these existing units comply with the various federal, state, and local regulations, this study was undertaken to provide information on emerging technology by means of which such compliance could possibly be achieved.

For the purpose of this study, boilers were categorized into emitters from 50 MBTU/hour and under and from 51 to 250 MBTU/hour, while incinerators were categorized into municipal units of 30 tons/day and under and medical units of 100 lb/hour and under.

An emerging system is defined as one that is not commercially available, where "commercially available" denotes a system that has successfully been pilot- and demonstration-tested, has at least one system in operation for six months at its design conditions, and has required only scheduled maintenance.

A review of the air pollution regulations from all fifty states showed that prescribed limits on particulate and sulfur dioxide emissions were those most often of concern for Army boilers and incinerators. A preliminary survey of existing and emerging control methods revealed that existing methods are mainly concentrated in the field of particulate removal and use established technology, whereas the emerging control methods are mainly concentrated in the field of control of sulfur dioxide emissions and use new and advanced technology. Since a review of the survey data indicated an adequacy of existing systems to control particulate emissions at Army installations, this study placed emphasis on methods for controlling sulfur dioxide emissions. Thus the five emerging systems selected for further study all represent methods of controlling sulfur dioxide emissions in flue gases.

Although the systems selected for further study all represent sulfur dioxide control technology, it should also be noted that the existing technology for particulate removal is constantly being improved and updated. For example, while flue gas particulate scrubbing has existed for some time, charged particle scrubbing, which is an improvement of this idea, is a more recent development.

The cost data presented in this report reflect costs as of November 1975.

Purpose

The purpose of this report was to determine the nature of technology currently being developed that will be available to the Army in the next 5 to 10 years that will bring boilers and incinerators in compliance with air pollution standards.

The air pollution control systems described in this report are emerging systems rather than proven technology. Thus, this report is not meant to be used in preparing an installation's project initiation documents; rather, it is written primarily to be of benefit to engineers at Major Command (MACOM) and Headquarters levels for keeping abreast of developments in and making initial evaluations of emerging systems.

2 EMERGING CONTROL SYSTEMS

Before any emerging control system was selected for study, a survey was made of published literature. It revealed approximately forty-five emerging methods of pollution control. Each method was reviewed and placed in one of the following categories: very complex; limited applicability; abandoned; very early conceptual stage; suitable for further study. The following five most promising systems were selected from the "suitable for further study" group: dry activated carbon adsorption; ammonia absorption; caustic absorption with lime regeneration; caustic injection; and solid dry copper absorption.

In the study of each emerging system, the system of one developer was selected to represent that process. Since most of the emerging systems studied have more than one developer available, the listing of a developer does not mean or imply that the selected developer is either the best or the only one for that system.

Criteria for Evaluation. In order to provide a basis for evaluation of a sulfur emission control system, the following criteria were used in computing the owning and operating costs for each system analyzed:

(1) Emitter is a coal-fired boiler having a capacity of 250,000 pounds steam per hour, using coal having a sulfur content of 4 percent.

(2) Flue gas having an equivalent sulfur dioxide content of 3,060 ppm at boiler outlet.

(3) A required efficiency of 85 percent sulfur removal, resulting in a flue gas sulfur dioxide content of 460 ppm at stack outlet.

The bases for the selection of a coal-fired boiler as the hypothetical emitter were:

(1) It is this type of emitter which probably will require a sulfur dioxide emission control system similar to those described herein.

(2) The emission control systems currently being developed are for similar emitters.

While incinerators are similar to boilers in that they also produce a hot flue gas laden with particulate matter and sulfur dioxide, they are different in that they usually produce lower concentrations of sulfur dioxide which, together with operating at a higher excess airflow, results in a more dilute sulfur dioxide emission, usually at a concentration of less than 500 ppm. Also, depending on the refuse burned, incinerators may produce other gaseous emissions.

This and an investigation of state emissions standards reveal that primary emphasis for incinerator emissions control revolves around particulate removal. Existing technology for particulate emissions control is deemed adequate for application to incinerators; therefore, incinerator emissions control will not be discussed further in this report.

While it is conceivable that the emission control systems described herein could be modified and applied to incinerators to control sulfur dioxide emissions, this could not be done without an appreciation of the differences between the flue gases of boilers and incinerators.

Description of terms used in the report are:

(1) First cost represents the cost of purchasing, installing, and start-up of the system.

(2) First year operating cost represents the money spent during the first year of operation for labor, utilities, chemicals, maintenance, credit for by-products sold, etc., based on calendar year 1975 being the first full year of operation.

(3) Total life cycle cost represents the present (1975) worth of the total monetary outlay during the life of the system and includes first cost and the operating costs summed over the projected life of the system. The operating costs, in addition to those mentioned under first cost, also reflect the effect of escalation (inflation) in the value of goods and services as well as the time value of money.

(4) System reliability is defined as the ratio of actual projected operating time to the total operating time required, expressed as a percentage.

(5) Particulate-free flue gas is a stream from a light oil or gas burning boiler; or a heavy oil- or coal-burning boiler equipped with an electrostatic precipitator or baghouse.

(6) Reduced particulate loading flue gas is a stream from a gas, light or heavy oil-burning boiler, or a coal-burning boiler equipped with mechanical inertial separator type of gas cleaning equipment.

Dry Activated Carbon Adsorption Process. The process described herein was developed by the Westvaco Corporation of Charleston, South Carolina. It has been tested in a pilot facility producing 1500 lb of steam per hour (0.4 MW).*

Principle of Operation. Flue gas is precleaned of particulates and is then passed through a fluidized bed of activated carbon which adsorbs sulfur dioxide present in the gas stream. The exhausted activated carbon is regenerated by means of high temperature reduction with hydrogen sulfide gas, which results in direct production of elemental sulfur. The regenerated activated carbon is returned to the adsorber. A system flow diagram describing this process is shown in Figure 1.

The Westvaco process consists of the following major processing steps:

(1) Removal of sulfur dioxide from the flue gas(A).**

(2) Production of elemental sulfur from the recovered sulfur dioxide by reduction with hydrogen sulfide (B).

(3) Thermal stripping of the sulfur product along with the production of hydrogen sulfide gas(C).

(4) Recovery of the produced sulfur(D).

(5) Production of the reducing hydrogen sulfide gas(E).

The adsorber is a two-section, fluidized bed, activated carbon adsorption column. Particulate-free flue gas is passed through the first section of the adsorber at 300F, where the sulfur trioxide present is removed. A direct water spray, evaporative cooler reduces the gas temperature leaving the first section to about 170F. From there the flue gas flows through the other section of the adsorber where sulfur dioxide is removed.

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* No information is available on the theoretical lower size limit for gas cleaning effectiveness; as will be seen from the ensuing discussion, the gas cleaning portion of these systems is a small part of the overall system's capital equipment. Thus, economics, not treatment effectiveness, will dictate the lower limit of applicability.

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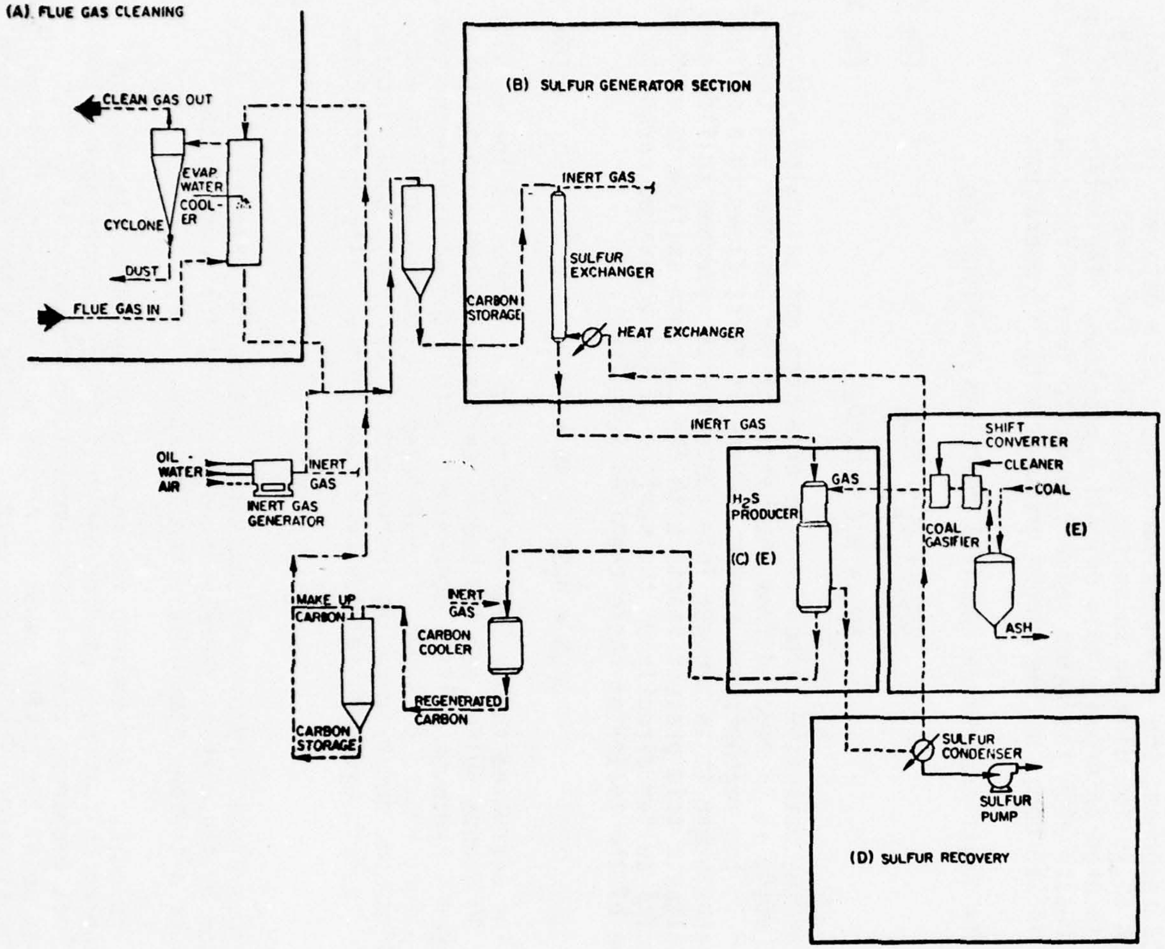

FIGURE I. FLOW DIAGRAM FOR THE WESTVACO-DRY ACTIVATED CARBON ADSORPTION PROCESS

The purpose of the higher temperature in the first section is to permit adsorption of the trace amounts of sulfur trioxide at temperatures above 212F in order to prevent the condensation of the water vapor present in the flue gas with consequent formation of sulfuric acid. It is then safe to reduce the gas temperature to 170F before it enters the second section of the adsorber. Once the sulfur dioxide is adsorbed, the activated carbon acts as a catalyst in the oxidation of sulfur dioxide to sulfur trioxide. The lower gas temperature is used to promote this oxidation reaction. The sulfur trioxide then reacts with the water vapor present to form sulfuric acid and is held in the pores of the carbon granules until regeneration.

The basic adsorption chemical reactions involved are:

$$2SO_2 + O_2 \rightarrow 2SO_3 \qquad \text{[Eq 1]}$$

$$SO_3 + H_2O \rightarrow H_2SO_4 \qquad \text{[Eq 2]}$$

As the activated carbon becomes exhausted and saturated with sulfuric acid, it is removed from the bottom of the adsorber and transported to the regeneration system. There it first flows to a sulfur generator where it is brought into contact with hydrogen sulfide gas. The sulfuric acid present reacts with the hydrogen sulfide to produce elemental sulfur directly on the surface of the activated carbon by virtue of the following basic chemical reaction:

$$3H_2S + H_2SO_4 \rightarrow 4S + 4H_2O\uparrow \qquad \text{[Eq 3]}$$

The activated carbon leaving the sulfur generator is loaded with about 20 pounds sulfur per 100 pounds carbon and flows to a sulfur stripper - hydrogen sulfide generator. Within the stripper-generator, the sulfur, heated to 1000F, is vaporized and removed from the activated carbon, and hydrogen is introduced to react with some of this sulfur to form hydrogen sulfide by virtue of the following reaction:

$$H_2 + S \rightarrow H_2S \qquad \text{[Eq 4]}$$

This process removes 99 percent of the sulfur carried into the reactor by the carbon, thereby regenerating it for reuse in the adsorber after an intermediate cooling step.

The sulfur carried into the reactor by the carbon leaves the reactor as sulfur vapor or hydrogen sulfide gas. These gases flow to a heat exchanger where their temperatures are lowered to 270F. At that point the sulfur vapor condenses to a liquid and is drawn off for storage. The hydrogen sulfide remains in the gaseous phase (thereby readily separating it from the liquid sulfur) and is recycled to the sulfur generator.

While the activated carbon is enroute to the adsorber after the regeneration process, it is surrounded by an inert gas, produced in an inert gas generator from oil, water, and air. The inert gas serves to protect the activated carbon against oxidation under the high temperatures reached in the regeneration system.

The hydrogen used in the formation of the hydrogen sulfide is produced in a coal gasification unit. The gas produced in this gasifier is first cleaned of particulates and tar and then concentrated by means of a shift converter which increases its hydrogen content to approximately 20 percent.

Specific Applicability. Activated carbon has been used for many years for purification of many gases and liquids. Moisture, hydrocarbons, and sulfur dioxide can all be removed from an airstream by activated carbon. The Westvaco process described herein is designed for the removal of sulfur dioxide from flue gases.

This process can be installed in either a new or existing facility with very little difference in the design of each. The sulfur dioxide adsorber is located at a point just before the flue gas enters the stack. The carbon regeneration equipment may be located either adjacent to the adsorber, or elsewhere at a convenient point to receive and recycle the carbon. Because the only equipment to be installed in the flue gas passage is the adsorber, the modifications to existing facilities would consist only of rearranging some flue gas ductwork and the addition of a booster fan. On units burning a fuel which produces particulate emissions, e.g., coal, a unit such as an electrostatic precipitator is required to insure a particulate-free flue gas.

This process can handle variations in flue gas flow from 60 to 100 percent of full load. The operating rate of the coal gasifier, which produces the reducing hydrogen gas, may be reduced to 25 percent of full load without detrimental effects.

This process is designed for the removal of 90 percent of the inlet sulfur dioxide. This removal efficiency can be readily adjusted by changes in the carbon feed rate and in the depth of the fluidized bed. This flexibility allows the process to be adjusted to meet future removal requirements caused by a change in either applicable laws and regulations or in the sulfur content of the fuel being burned.

Emission Control Parameters. Based on pilot plant tests, the parameters determining efficiency have been found to be: flue gas residence time; flue gas inlet velocity and temperature; the depth of the fluidized bed, the carbon feed rate; and the number of stages within each section of the adsorber. The optimum design conditions for these parameters were determined by operation and testing of the pilot plant.

The gas velocity and the bed depth combine to determine the required residence time of the flue gas in the carbon bed. A demonstration unit having a gas inlet velocity of 2 to 4 feet per second through an eight-stage adsorber, and with a residence time of 1/2 second in each of the 16-inch fluidized beds, had a sulfur dioxide removal efficiency of 90 percent during continuous service, based on an inlet sulfur dioxide concentration of 1,500 ppm.

Reliability/Maintenance Requirements. Due to the fact that this is an emerging process, actual figures on the reliability or maintenance requirements do not exist. One of the goals of a proposed prototype testing program would be to obtain data on reliability, maintainability, facility compatibility, and other engineering data that would help in the design of future actual installations.

Based on the nature and complexity of this process, a system reliability of 90 percent and an annual maintenance cost of 4 percent of the initial capital investment were projected for this process.

State of Development. The small-scale testing of a 600 and a 20,000 cfh activated carbon adsorber has demonstrated the technical feasibility of this process. This pilot test work was conducted under the sponsorship of the Federal Environmental Protection Agency, EPA Contract No. 68-02-0003.

Presently, a proposal by the Westvaco Corporation for a 15 MW prototype demonstration unit is under consideration. The purpose of this demonstration unit would be to determine:

(1) Process compatibility with the boiler interface.

(2) Control of process chemistry.

(3) Performance of the activated carbon.

(4) Performance of large-scale fluidized beds.

Advantages Over Existing Control Methods.

(1) Higher sulfur dioxide removal efficiency can be obtained.

(2) Flue gas is not saturated with water vapor when sulfur trioxide is present, thus avoiding the formation of potentially corrosive sulfuric acid.

(3) Sulfur is produced directly in the regeneration phase without the necessity for an additional process.

(4) Changes can be readily made in the sulfur dioxide removal efficiency.

(5) Removal of the sulfur dioxide from the flue gas does not generate any new liquid or solid pollutants, with the possible exception of sulfur or carbon granule carry-over.

(6) Can be readily installed in an existing facility with very few modifications required.

Disadvantages

(1) The creation of elemental sulfur requires its marketing or disposal.

(2) Flue gas entering the adsorber must be free of particulate matter, possibly requiring the use of particulate cleaning equipment.

(3) Carry-over of carbon granules may be a problem.

Energy/Material Requirements. Table 1 is a summary of the energy and material requirements for the Westvaco dry activated carbon process for a boiler installation conforming to the previously listed criteria. These values were extrapolated from a Westvaco design of a proposed 15-MW demonstration plant.

Table 1

System Operating Data for the Dry Activated Carbon Adsorption Process

Energy and material consumed per hour by the emission control system	
Activated carbon	42 lbs
Coal (for coal gasifier)	1,200 lbs
Electric power	1,100 kW
Fuel oil	105 gal
Water	2,400 gal
By-product material produced per hour by the emission control system	
Sulfur	820 lbs

Economics. Table 2 is a summary of the owning and operating costs for the Westvaco dry activated carbon process for a boiler conforming to the criteria listed previously. The summary shows first cost, first year operating costs, and life cycle costs.

The equipment costs include the adsorber, cyclone separator, carbon storage tanks, sulfur generator, hydrogen sulfide generator and sulfur stripper unit, carbon cooler, inert gas generator, coal gasifier with shift converter, and miscellaneous heat exchangers and pumps. The equipment cost does not include any cost associated with particulate precleaning of the flue gas prior to the adsorption tower.

If this control system is being applied to a heavy oil or coal burning boiler which is not already equipped with an electrostatic precipitator or a baghouse collector, then such a device will need to be installed to satisfy the requirement of particulate-free flue gas at the inlet of this control system. An electrostatic precipitator for the hypothetical boiler of this study is estimated to cost $1,450,000, and to have operating and maintenance of $200,000 and $45,000 per year, respectively. An electrostatic precipitator is considered as an optional part of the dry activated carbon adsorption process and, therefore, a possible peripheral cost.

Table 2

System Costs for the Dry Activated Carbon Adsorption Process

System First Cost		$3,600,000
Life Expectancy		15 years
First Year Operating Costs:		
Labor	$ 55,000	
Utilities	530,000	
Chemicals	100,000	
Miscellaneous	165,000	
Total First Year Operating Cost		$ 850,000
Total Life Cycle Costs:		
System First Cost		$ 3,600,000
System Operating Costs:		
Labor	$ 715,000	
Utilities	9,115,000	
Chemicals	1,570,000	
Miscellaneous	2,900,000	
Subtotal		$14,300,000
Total Life Cycle Cost		$17,900,000

This process can be modified so that the regeneration of the activated carbon could be performed at a remote site in facilities owned and operated by another party. Such a process would employ the activated carbon at the site to adsorb the sulfur dioxide, but would ship it to the remote site for the regeneration step. Such a modification would result in savings in first cost of equipment and in annual costs for chemicals, utilities, and labor; however, this would also result in a service charge for the regeneration of the carbon by the outside facility, a transportation cost involved in shipping the carbon, as well as a loss of the sulfur credit. The cost of such a modified activated carbon process is summarized in Table 3.

Table 3

System Costs for the Modified Dry Activated Carbon Adsorption Process

System First Cost		$1,000,000
Life Expectancy		15 years
First Year Operating Costs:		
Labor	$ 20,000	
Utilities	16,000	
Chemicals	102,000	
Miscellaneous (Includes costs for regeneration of carbon)	1,182,000	
Total First Year Operating Cost		$1,320,000
Total Life Cycle Costs		
System First Cost		$ 1,000,000
System Operating Costs:		
Labor	$ 290,000	
Utilities	310,000	
Chemicals	1,570,000	
Miscellaneous (Includes costs for regeneration of carbon)	16,230,000	
Subtotal		$18,400,000
Total Life Cycle Cost		$19,400,000

The values used for the system first cost and the first year operating costs were extrapolated from data on a Westvaco design proposal for a 15-MW demonstration plant and represent the best available cost information.

Ammonia Absorption Process. The process described here was developed by Catalytic, Inc., a Division of Air Products and Chemicals, Philadelphia, Pennsylvania. It was tested in pilot plant scale with the boiler rated at 11,000 lb of steam per hour (3.1 MW).

Principle of Operation. The flue gas, after particulate precleaning, enters the absorber where it is scrubbed with an aqueous solution of ammonium salts which absorb and remove the sulfur dioxide present in the gas. The spent liquor is regenerated in a three-step process with the final product produced being elemental sulfur. The elemental sulfur is removed to storage while the regenerated solution is recycled to the absorber. A system flow diagram describing this process is shown in Figure 2.

The Catalytic, Inc. process consists of four major processing steps:

(1) Removal of sulfur dioxide from the flue gas (A).*

(2) Thermal decomposition of sulfites and reduction of sulfates to produce a highly concentrated sulfur dioxide (B).

(3) Conversion of a portion of the sulfur dioxide into hydrogen sulfide gas (C).

(4) Production of elemental sulfur from the reaction of the sulfur dioxide and hydrogen sulfide (D).

The removal of sulfur dioxide from the flue gas takes place during the absorption step. The flue gas with a reduced particulate loading is passed through a multiple stage spray scrubber via a venturi type quench chamber. The purpose of the quench chamber is to protect the internal heat-sensitive surfaces of the scrubber by cooling the flue gas temperature below 170F and by removing any fine particulates remaining in the gas stream. The venturi water is recycled by a pump connected to the bottom of the scrubber.

The cooled clean flue gas continues through the absorber where it is sprayed with the ammonium salt scrubbing liquor consisting primarily of a solution of ammonium sulfite.

The following basic chemical reactions take place:

$$2NH_4OH + SO_2 \rightarrow (NH_4)2SO_3 + H_2O \qquad \text{[Eq 5]}$$

$$(NH_4)2SO_3 + SO_2 + H_2O \rightarrow 2NH_4HSO_3 \qquad \text{[Eq 6]}$$

$$(NH_4)2SO_3 + SO_3 \rightarrow (NH_4)2SO_4 + SO_2 \qquad \text{[Eq 7]}$$

Since these compounds are very soluble in the solution, scaling and plugging problems are avoided.

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[*] The letters in parentheses key each process step to the accompanying flow diagram in Figure 1.

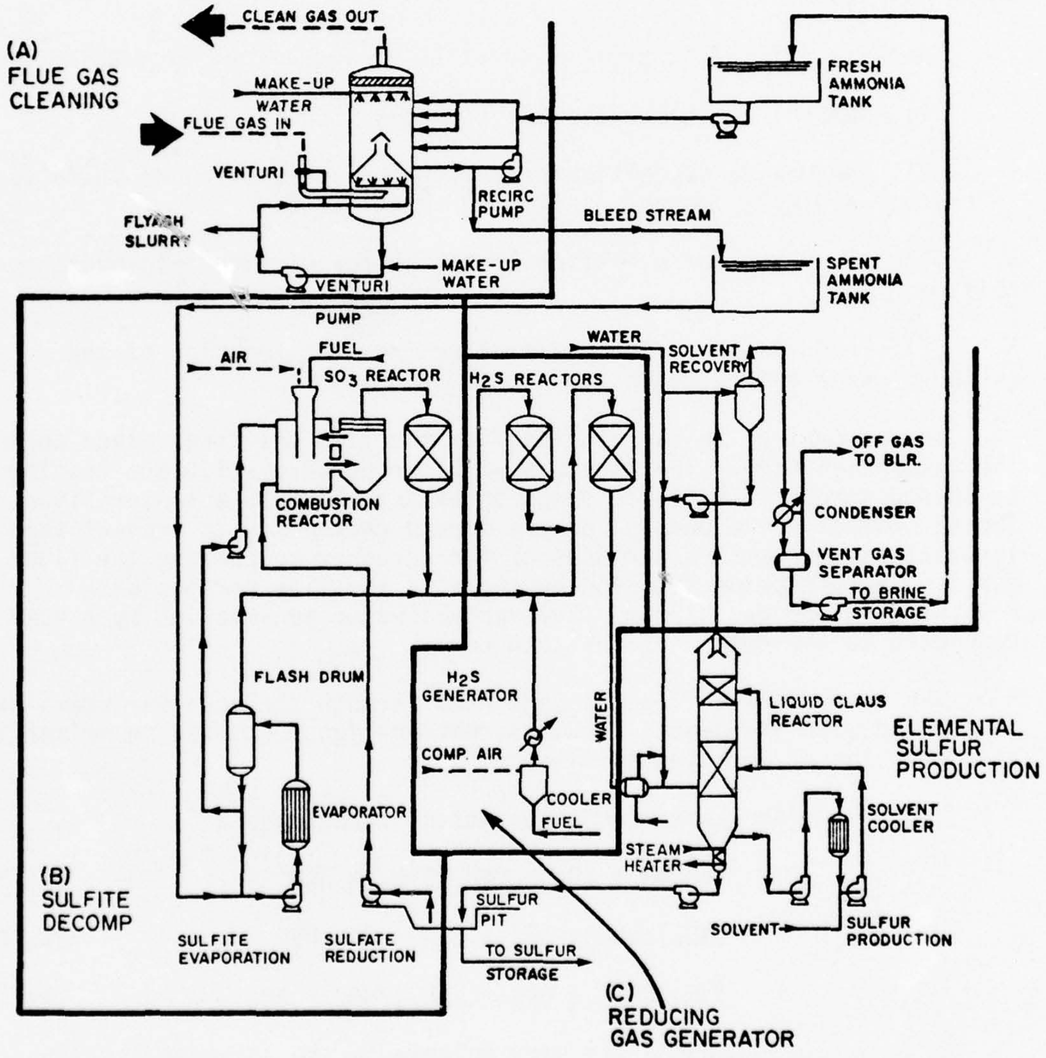

FIGURE 2. FLOW DIAGRAM FOR THE CATALYTIC, INC. AMMONIA ABSORPTION PROCESS

Spent liquor is bled from the first stage spray loop and is replaced with fresh ammonia solution at the last stage spray loop. The concentration of the liquor in the first stage is maintained at approximately 16 moles ammonium sulfite to 100 moles water by regulating the bleed stream flow to control the pH of the solution between 5.5 and 5.8.

The liquor bled from the absorber is transported to a regeneration system where it is processed to separate the sulfur from the ammonium solution. The first step in this process is the thermal decomposition of the sulfites and reduction of the sulfates. The ammonium solution is heated in a submerged combustion reactor and mixed with a portion of the produced elemental sulfur which causes the ammonium sulfite and ammonium sulfate to decompose into sulfur dioxide, water vapor, and ammonia by means of the following reactions:

$$(NH_4)2SO_3 \xrightarrow{\Delta Q} SO_2 + H_2O + 2NH_3 \qquad \text{[Eq 8]}$$

$$(NH_4)2SO_4 \xrightarrow{\Delta Q} NH_4H\ \ SO_4 + NH_3 \qquad \text{[Eq 9]}$$

$$2NH_4H\ \ SO_4 + S \rightarrow 3SO_2 + 2H_2O + 2NH_3 \qquad \text{[Eq 10]}$$

The result of this step is the production of a highly concentrated sulfur dioxide gas.

The next step in the regeneration process is the conversion of a portion of the sulfur dioxide into hydrogen sulfide. This is accomplished in the hydrogen sulfide reactors, which combine a reducing (hydrogen-rich) gas with the sulfur-dioxide-rich gas to produce hydrogen sulfide by means of the following reactions:

$$SO_2 + 3CO + H_2O \rightarrow H_2S + 3CO_2 \qquad \text{[Eq 11]}$$

$$SO_2 + 3H_2 \rightarrow H_2S + 2H_2O \qquad \text{[Eq 12]}$$

In the final regeneration step, the sulfur dioxide and hydrogen sulfide gases are combined in a liquid Claus reactor to produce elemental sulfur and water vapor by means of the following reaction:

$$2H_2S + SO_2 \rightarrow 3S + 2H_2O \qquad \text{[Eq 13]}$$

The elemental sulfur condenses out of the gas stream as a liquid and is pumped to storage.

The water vapor, carbon dioxide, and ammonia leave the Claus reactor where the ammonia and water are condensed from the other gases. The regenerated ammonia solution is transported to a fresh ammonia liquor storage tank for recycling back to the absorber, while the uncondensed gases are sent to the boiler for the destruction of any hydrogen sulfide gas remaining.

The described regeneration process was developed by the Institut Francais du Petrole for the production of elemental sulfur from ammonium sulfite and ammonium sulfate salts. Besides this regeneration method, three other methods have been developed to produce either gypsum, fertilizer, or sulfite liquor. Accordingly, it may be seen that the ammonia absorber can be combined with any one or a combination of the four regeneration processes to produce a choice of four sulfur by-products.

Specific Applicability. Since the pH of the ammonium scrubbing solution is basic, it has the potential to absorb acidic gases such as sulfur dioxide. The Catalytic, Inc. process as described herein is designed for the removal of sulfur dioxide from flue gases.

This process can be installed on either a new or existing facility with very little difference in the design of each. The sulfur dioxide absorber is located at a point just before the flue gas stream enters the stack. The solution regeneration equipment may be located either adjacent to the absorber, or elsewhere at a convenient point to receive, regenerate, and recycle the spent ammonia liquor. Since the only equipment to be installed in the flue gas duct is the absorber, the modifications to an existing facility would consist only of rearranging some of the flue gas ductwork and the addition of a booster fan. If a fuel, e.g., coal or heavy oil, which produces particulate matter is burned, particulate removal would be required to insure a flue gas with a reduced particulate loading.

The use of a liquid-to-gas scrubber gives the process a great deal of flexibility in meeting removal requirements over a wide range of loads. The described system is capable of handling flue gas flow variations from 25 to 100 percent of full load.

This process is reported to be capable of removing 90 percent of the inlet sulfur dioxide. This removal efficiency can be varied by changes in the concentration of the ammonium salts in the liquor or in the feed rate of the liquor. This allows the process to be readily modified to meet future changes in removal requirements caused either by changes in the requirements of applicable laws and regulations or by changes in the sulfur content of the fuel burned.

Emission Control Parameters. The results of pilot plant studies of various developers reported that a maximum sulfur dioxide removal of 97 percent was obtained during testing and that an average efficiency of 95 percent can readily be maintained. These studies have identified the major efficiency parameters to be: liquid-to-gas ratio; gas inlet velocity and temperature; number of spray stages; and, most importantly, the optimum concentration of the ammonium salt. For example, it was stated that with a concentration ratio of 16 moles ammonium salt to 100 moles water in the first stage sprays and a gas temperature of 135F, 90 to 95 percent of the inlet sulfur dioxide was removed.

Reliability/Maintenance Requirements. Pilot plant studies have shown that in continuous operation a reliability as high as 86 percent can be maintained. If absorber maintenance can be scheduled to coincide with boiler maintenance, this process can be expected to have a reliability of 90 to 95 percent. Work on the regeneration portion of the process can be accomplished without removing the absorber from service because of the inherent large surge capacity between the absorber and the regeneration sections. An annual maintenance cost of 5 percent of the initial first cost was assumed for this process.

State of Development. The feasibility of scrubbing with ammonium salt solutions has been thoroughly tested and demonstrated in France by Weiritam and by the Electricte de France, and in the United States by Catalytic, Inc., and by the Tennessee Valley Authority. Demonstration units, operated on boilers having capacities as large as 200,000 pounds of steam per hour, have shown that ammonium scrubbing is a reliable and efficient method of removing sulfur dioxide from the flue gas stream. Both the Weiritam process (marketed in this country by the Foster Wheeler Corporation) and the Catalytic, Inc., process are commercially available for installation at any boiler plant.

An initial problem with ammonium scrubbing was the formation of an ammonium sulfate (blue fume) emission from the scrubber outlet. The Catalytic, Inc., process was selected for study because it scrubs in a fumeless manner by control of the scrubber chemistry, thereby eliminating the necessity of a high pressure drop mist eliminator. The entire Catalytic, Inc., process is presently being installed on a 35-MW utility boiler in France and in two petroleum refineries in Japan.

Advantages Over Existing Control Methods

(1) Higher removal efficiency of sulfur dioxide can be achieved.

(2) Since the flue gas pollutants are readily soluble in the scrubbing liquor, there are no problems with scaling, plugging, or erosion of the interior surfaces of the scrubber.

(3) Sulfur is produced in the regeneration phase without the necessity of an additional chemical process.

(4) The process has a high degree of flexibility for adjustment to changes in sulfur dioxide removal requirements or to variations in flow volumes of flue gas.

(5) Removal of the sulfur dioxide from the flue gas does not generate any new liquid or solid pollutants requiring disposal, with the possible exception of sulfur or a similar by-product.

(6) The process may be added to an existing facility without the necessity of major modifications.

(7) There can be ready conversion of the regeneration process from one producing sulfur to one producing either gypsum or fertilizer.

Disadvantages

(1) Production of elemental sulfur or a similar by-product involves the marketing or disposal of such a by-product.

(2) Flue gas entering the absorber must have a reduced particulate loading, which may require equipment for particulate removal.

(3) Exhaust gases from the scrubber are moisture saturated, which may cause problems such as duct or stack corrosion or plume buoyancy.

(4) Possible production of fertilizer may be limited by either the economics of required higher ammonia makeup quantities or by the presence of toxic compounds in the flue gas because of the fuel being burned.

Energy/Material Requirements. Table 4 is a summary of the energy and material requirements of the Catalytic, Inc. aqueous ammonium salt scrubbing process for a boiler conforming to the criteria listed previously. The consumption values used are based on data supplied by Catalytic, Inc.

Table 4

System Operating Data for the Ammonia Absorption Process

Energy and material consumed per hour by the emission control system	
Ammonia	4 lbs
Lime	20 lbs
Natural Gas	19 mcf
Electric power	613 kW
Water	2,200 gal
By-product material produced per hour by the emission control system	
Sulfur	820 lbs

Economics. Table 5 is a summary of the cost to own and operate the Catalytic, Inc., aqueous ammonium salt scrubbing process for the assumed hypothetical boiler.

The equipment costs include the absorber, ammonia tanks, combustion reactor, sulfur trioxide reactor, hydrogen sulfide reactor, sulfite evaporator, liquid Claus reactor and solvent recovery unit, gas condenser, and miscellaneous heat exchangers and pumps. The equipment cost does not include any costs associated with precleaning the flue gas before it enters the ammonia absorber.

If this control system is being applied to a coal-burning boiler which is not already equipped with at least a mechanical, inertial separator type of dust collector, then such a device will need to be installed to satisfy the requirement of reduced particulate loading flue gas at the inlet of this control system.

A mechanical collector for the hypothetical boiler of this study is estimated to cost approximately $280,000 and to have operating and maintenance costs of $15,000 and $15,000 per year, respectively. This mechanical collector may be considered as an optional part of the ammonia absorption process and, therefore, a possible peripheral cost.

Table 5

System Costs for the Ammonia Absorption Process

System First Cost		$4,300,000
Life Expectancy		15 years
First Year Operating Costs:		
Labor	$ 55,000	
Utilities	335,000	
Chemicals	5,000	
Miscellaneous	250,000	
Total First Year Operating Cost		$ 645,000
Total Life Cycle Costs:		
System First Cost		$ 4,300,000
System Operating Costs:		
Labor	$ 715,000	
Utilities	7,000,000	
Chemicals	75,000	
Miscellaneous	4,310,000	$12,100,000
Subtotal		$16,400,000
Total Life Cycle Cost		

This process can be modified by locating the regeneration portion at a remote location owned and operated independently. The modified process would use an ammonium salt solution to remove the sulfur dioxide, but would ship spent solution to the remote locations for regeneration. While such a modification of the process would result in savings in the initial equipment investment and in the annual costs for chemicals, utilities, and labor, it would involve extra costs for the regeneration of the solution and transportation involved in shipping the solution as well as the loss of credit for sale of the by-products. The costs for the modified ammonium scrubbing process are summarized in Table 6 in a manner similar to that used in Table 5.

Table 6

System Costs for the Modified Ammonia Absorption Process

System First Cost		$1,800,000
Life Expectancy		15 years
First Year Operating Costs		
Labor	$ 20,000	
Utilities	15,000	
Chemicals	5,000	
Miscellaneous (Includes Costs for regeneration of solution)	670,000	
Total First Year Operating Cost		$ 710,000
Total Life Cycle Costs:		
System First Cost		$1,800,000
System Operating Costs:		
Labor	$ 285,000	
Utilities	300,000	
Chemicals	75,000	
Miscellaneous (Includes costs for regeneration of solution)	9,440,000	
Subtotal		$10,100,000
Total Life Cycle Cost		$11,900,000

The values used for the system first costs and the first year operating costs are based on a budget cost estimate supplied by Catalytic, Inc., for the sulfur dioxide removal system for a boiler as described earlier.

Caustic Absorption With Lime Regeneration Process. The process described herein was developed by the Buell Division of the Envirotech Corporation, Lebanon, Pennsylvania. At the time of this study, the system was beginning evaluation at 200,000 lb of steam per hour (56.8 MW).

Principle of Operation. The hot flue gases are cooled and preconditioned before entering a packed tower absorber where the gas is scrubbed with a sodium solution. A portion of the scrubbing liquor is withdrawn, regenerated, and returned to the absorber. The regeneration is accomplished by adding lime to the solution, which reacts with the sulfur to form a precipitate. A system flow diagram describing this process is shown in Figure 3.

The Envirotech process consists of three major processing steps:

(1) Removal of sulfur dioxide from the flue gas (A).*

(2) Regeneration of the spent sodium liquor with lime (B).

(3) Separating the calcium sulfites and calcium sulfates from the regenerated sodium solution (C).

The caustic scrubbing with lime regeneration, known as the double alkali process, is designed for the removal of sulfur dioxide from the flue gas. The sulfur dioxide is absorbed in a packed, mobile ball type of absorber. Before entering the absorber, the flue gas must be cooled to approximately 170F to protect the rubber and plastic parts of the absorber from excessive temperatures. This gas cooling is accomplished in an irrigated wall type of quench chamber located ahead of the absorber inlet.

The cooled flue gas enters the absorber where sulfur dioxide reacts with a sodium solution in accordance with the following:

$$2NaOH + SO_2 \rightarrow Na_2SO_3 + H_2O \qquad \text{[Eq 14]}$$

$$Na_2SO_3 + SO_2 + H_2O \rightarrow 2NaHSO_3 \qquad \text{[Eq 15]}$$

Since the sulfur dioxide is highly soluble in the sodium solution, it is readily absorbed during the scrubbing action. This solubility also insures that scale will not form on the internal surfaces of the scrubber and plugging problems are thus avoided.

As the sodium solution absorbs more and more sulfur dioxide, its pH decreases, indicating that it is becoming saturated with the absorbed sulfur dioxide. To avoid a saturated condition, the pH of the solution is maintained at approximately 5.5 by bleeding off a portion of the spent solution and replacing it with new or regenerated solution.

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* The letters in parentheses key each process step to the accompanying flow diagram in Figure 1.

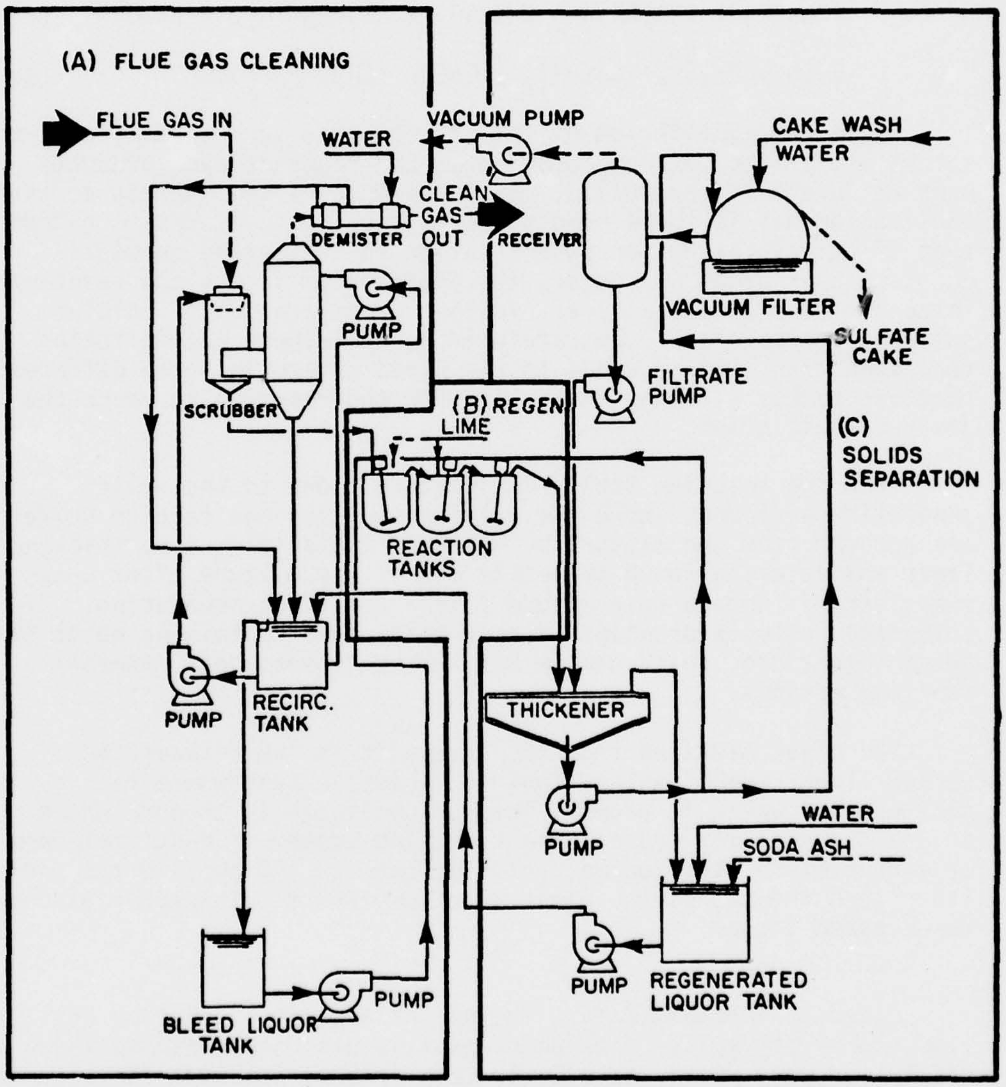

FIGURE 3. FLOW DIAGRAM FOR THE ENVIROTECH CAUSTIC ABSORPTION WITH LIME REGENERATION PROCESS

The bleed stream is transported to the regeneration system where lime is added. The lime reacts with the sodium sulfite and sodium sulfate salts to form the much less soluble calcium sulfite and calcium sulfate salts, which precipitate. This precipitation is an equilibrium reaction in accordance with the following:

$$4NaHSO_3 + 2Ca(OH)_2 \rightleftarrows 2Na_2SO_3 + 2CaSO_3 \cdot H_2O + 3H_2O \qquad \textbf{[Eq 16]}$$

$$2H_2O + Na_2SO_4 + Ca(OH)_2 \rightleftarrows CaSO_4 \cdot 2H_2O + 2NaOH \qquad \textbf{[Eq 17]}$$

Since the equilibrium of this reaction is very sensitive to the solubility of its various components, the reactants and products must be carefully controlled. As an example of the importance that equilibrium has in these precipitation reactions, it has been found that if the hydroxide ion concentration in the second chemical equation approaches 0.1 molar, the equilibrium favors the reactants instead of the products; i.e., further precipitation of calcium sulfate is suppressed. To carefully control these precipitation reactions, the lime is added to the bleed stream in three different reaction tanks, allowing ample time for the reaction to reach the desired equilibrium.

From the reaction tanks, the mixture flows to the solids separating equipment where the calcium sulfites and calcium sulfates are removed from the mixture by means of a clarifier type thickener. There solids are allowed to settle out of the mixture after which the slurry is pumped to a vacuum filter for final dewatering. The collected waste is disposed of as a solid cake containing about 50 percent moisture, which can be handled by conventional material handling methods.

The clear overflow from the thickener is the regenerated sodium liquor (NaOH) which flows to a storage tank where makeup soda ash and water is added. The sodium liquor is then returned to the absorber for reuse. The scrubbing system is kept scalefree by virtue of the low concentration of calcium (50 ppm) in the sodium liquor and the use of the clear overflow from the thickener as the regenerated liquor.

Specific Applicability. The use of a caustic solution and a lime slurry for sulfur dioxide absorption has been employed separately for many years. The Envirotech process combines the nonplugging and nonscaling qualities of the caustic system with the lower chemical cost of the lime system. Like most caustic solution processes, it has the potential to absorb other acidic gases such as nitrogen oxides.

The sulfur dioxide absorber is located at a point just before the flue gas stream enters the stack. Because of this location, this process can be installed on either new or existing facilities with very little difference in the design of each. The lime reaction tanks and solids separation equipment can be located at some convenient location either adjacent to the absorber or elsewhere.

Modifications to an existing facility would consist of flue gas ductwork rearrangement, addition of a flue gas booster fan, and the possible addition of particulate removal equipment to insure a flue gas with a reduced particulate loading, should the facility burn a fuel such as coal.

The use of a liquid-to-gas scrubber gives the process a high degree of flexibility to meet removal requirements over a wide range of loads. A system similar to that of the Envirotech process has demonstrated the capability of handling flue gas flow variations from 30 to 100 percent of full load.

The process as described is reported to be capable of removing 90 percent of the incoming sulfur dioxide. This removal efficiency can be varied by means of changes in the sodium concentration of the scrubbing solution and in the liquid-to-gas ratio. These adjustments will allow this process to meet future changes in the required removal efficiency caused by changes in either the requirements of applicable laws or in the sulfur content of the fuel.

Emission Control Parameters. Demonstration tests of a similar double alkali process have shown that a removal efficiency of 95 percent can be obtained under controlled conditions and that an average efficiency of 90 percent can easily be maintained. Based on these tests, the liquid-to-gas ratio and absorber bed depth are the important efficiency design parameters. The pH value of the scrubbing solution is an important indicator, for it gives the relative strength of the sodium scrubbing solution. It is reported that sulfur dioxide removal efficiency has varied from 85 to 95 percent within a pH range of 5.5 to 6.5, respectively.

Reliability/Maintenance Requirements. Demonstration unit operation to date has not established a figure for the reliability of the system. The process is still in the shakedown and evaluation phase of its development. Assuming adequate preventative maintenance for the process, the reliability factor is expected to range between 90 and 95 percent. Because the scrubbing liquor is free of particulate matter and solid sulfur compounds, required annual maintenance on the absorber itself is considered to be minimal and was assumed to be equal to 4 percent of the initial capital investment.

State of Development. The similar double alkali process previously mentioned is the General Motors (GM) system presently installed at the Chevrolet plant in Parma, Ohio. This near-commercial system has been undergoing testing and evaluation for the past two years. It is reported that this installation has proved the double alkali system to be a feasible method of controlling sulfur emissions.

The Envirotech double alkali system closely resembles the GM process and, with federal EPA cooperation, is presently in pilot plant operation on a 20-MW unit at the Gulf Power Company. This process is reported to be nearing commercial availability and, in the near future, should be an established existing method for control of sulfur dioxide emissions.

Advantages Over Existing Control Methods

(1) A higher sulfur dioxide removal efficiency can be obtained.

(2) Process uses a solid-free clear scrubbing liquor which should: eliminate possible problems of scaling and solids buildup; minimize erosion; and reduce fouling of the quench chamber and mist eliminator.

(3) Collected sulfur wastes can be disposed of as solid cake (50 percent solids content).

(4) Relatively inexpensive lime is used in forming the final sulfur compound, with consumption minimized at approximately 20 percent above the stoichiometric requirements.

Disadvantages

(1) Exhaust gases leaving the scrubber are saturated with moisture and may cause problems such as corrosion in the stack or plume buoyancy.

(2) May require precleaning of particulate matter from the flue gas.

(3) Requires disposal of collected waste in a landfill suitable for such wastes.

(4) Land requirements for the regeneration system are relatively large and may be difficult to provide.

Energy/Material Requirements. Table 7 is a summary of the energy and material requirements for the Envirotech double alkali scrubbing process for a boiler installation conforming to the previously listed criteria. The values used are based on a budget estimate supplied by the Envirotech Corporation.

Table 7

System Operating Data for the Caustic Absorption With Lime Regeneration Process

Energy and material consumed per hour by the emission control system	
Soda ash	200 lbs
Lime	1,660 lbs
Electric power	284 kW
Water	2,250 gal
By-product material produced per hour by the emission control system	
Solid waste	2,900 lbs

Economics. Table 8 is a summary of the owning and operating costs for the Envirotech caustic scrubbing with lime regeneration process for a boiler conforming to the criteria previously listed. The summary shows system first cost, first year operating costs, and life cycle costs.

The equipment costs include those for the absorber; bleed, recirculation and reaction tanks; thickener; vacuum filter; vacuum receiver; regenerated liquor surge tank; and miscellaneous pumps and mixers. The equipment cost does not include any allowance for the possible requirement of particulate precleaning equipment located ahead of the absorber.

If this control system is being applied to a coal-burning boiler which is not already equipped with at least a mechanical, inertial separator type of dust collector, then such a device will need to be installed to satisfy the requirements of reduced particulate loading flue gas at the inlet of this control system.

A mechanical collector for the hypothetical boiler of this study is estimated to cost approximately $280,000 and to have operating and maintenance costs of $15,000 and $15,000 per year, respectively. This mechanical collector may be considered as an optional part of the caustic absorption with lime regeneration process and, therefore, a possible peripheral cost.

Table 8

System Costs for the Caustic Absorption With Lime Regeneration Process

System First Costs		$1,300,000	
Life Expectancy		15 years	
First Year Operating Costs:			
Labor	$ 40,000		
Utilities	50,000		
Chemicals	220,000		
Miscellaneous	120,000		
Total First Year Operating Cost		$ 430,000	
Total Life Cycle Costs:			
System First Cost			$1,300,000
System Operating Costs:			
Labor	$ 575,000		
Utilities	975,000		
Chemicals	3,400,000		
Miscellaneous	1,950,000		
Subtotal			$6,900,000
Total Life Cycle Cost			$8,200,000

The values used for the system first cost and the first year operating costs are based on a budget cost estimate supplied by the Envirotech Corporation for the sulfur dioxide removal system for a boiler as previously described.

Caustic Injection Process. The process described herein was developed by the General Resources Corporation, Hopkins, Minnesota. At the time of this study, no pilot plant testing had been conducted.

Principle of Operation. After particulate cleaning, the flue gas enters a dual spray drying tower where it is sprayed with a sodium carbonate solution. Sulfur dioxide and sulfur trioxide in the flue gas are quickly absorbed into the atomized spray droplets. As the absorption takes place, the water portion of the solution is vaporized by the hot flue gas. The result of this absorption and vaporization is a mixture of solid sodium sulfite and sodium sulfate particles which can be collected by existing high efficiency particulate removal methods. A system flow diagram is shown in Figure 4.

The General Resources flue gas purification process consists of three major processing steps:

(1) Generation system for sodium carbonate solution (A).*

(2) Removal of sulfur dioxide from the flue gas (B).

(3) Collection of the solid sodium sulfite and sodium sulfate particles (C).

A supply of sodium carbonate used in the process is bulk-stored. From bulk storage, it is transferred to a day storage hopper which, in turn, feeds it to a mixing tank. There water is added to make a solution which is pumped to the dual spray drying tower.

The dual spray drying tower is designed similarly to a two-pass flue gas evaporative cooler, using a sodium carbonate solution in lieu of water to cool the gas. The highly reactive solution of sodium carbonate is sprayed into the flue gas at the inlet to the first and second passes of the tower. The sodium carbonate in the small atomized droplets produced by the spray nozzles reacts with the sulfur dioxide and sulfur trioxide gases in the flue gas to form sodium sulfite and sodium sulfate in accordance with the following reactions:

$$SO_2 + Na_2CO_3 \rightarrow Na_2SO_3 + CO_2\uparrow \qquad \text{[Eq 18]}$$

$$SO_3 + Na_2CO_3 \rightarrow Na_2SO_4 + CO_2\uparrow \qquad \text{[Eq 19]}$$

Upon evaporation of the water from the solution, dry solid particles of sodium sulfate and sulfite remain in the flue gas.

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* The letters in parentheses key each process step to the accompanying flow diagram in Figure 1.

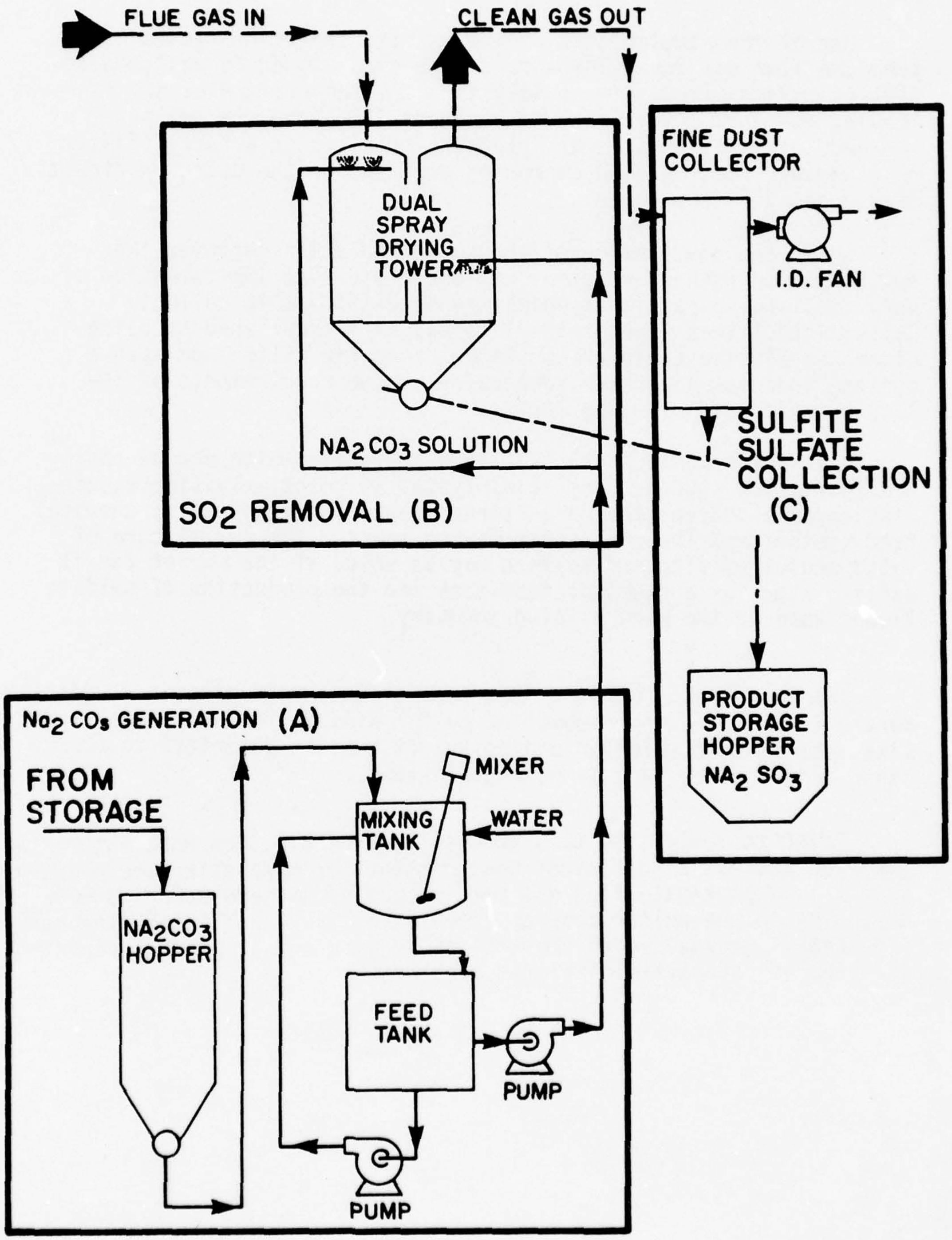

FIGURE 4. FLOW DIAGRAM FOR THE GENERAL RESOURCE CAUSTIC INJECTION SERVICE

One of the requirements of the caustic injection system is to keep the flue gas dry. The size of the spray tower is designed so that at maximum flow rate of solution, the temperature of the flue gas leaving the dual spray tower is at least 30F above the dew point of the gas. This alleviates any plugging problems in a fabric filter or plugging, scaling, and corrosion problems in the ductwork directly downstream from the tower.

While the atomization of the sodium solution improves the sodium-sulfur rate of reaction, it does result in the formation of very small solid particles which may be difficult to collect. Collection of this fine particulate may be accomplished by using either an electrostatic precipitator, a fabric filter, or even a cyclone inertial separator, depending on the requirements of the local particulate emission limits.

This solid waste product is in a dry state which can be easily transported or stored. The total system is relatively simple, consisting of a sodium carbonate storage hopper; mixing tanks; chemical feed system; and the dual spray drying tower. The dry mixture of solid sodium sulfite and sulfate may be sold, if the market for it exists; e.g., as a chemical feedstock for the production of sulfate liquor used in the wood pulping industry.

Specific Applicability. The General Resources process as described herein is designed for removal of sulfur dioxide from flue gases; but, like most caustic solution processes, it has the potential to absorb other acidic gases such as nitrogen oxides.

Prior to installing this process, an installation must insure that the flue gas has a sufficient heat content for completing the evaporation step. An approximate flue gas temperature of between 300F and 350F, depending on the sulfur dioxide removal required and thereby the solution flow rate, is required to complete the drying and to prevent plugging and other moist-particle-related problems.

This process can be installed on either a new or existing facility with very little difference in the design of each. The dual spray drying tower is usually located at a point just before the gas enters the stack. The sodium carbonate feed system may be located either at some convenient point near the tower or at a remote sodium carbonate storage facility.

The flue gas must have a reduced particulate loading before entering the tower. This protects the components of the tower from erosion and plugging. On units firing a particulate-producing fuel, e.g., coal, a suitable high-efficiency mechanical, inertial type collector would be necessary to preclean the gas. After leaving the dual spray drying tower, the flue gas contains entrained fine particles of sodium sulfite and sodium sulfate. The removal of these particles may require the use of an electrostatic precipitator or a fabric filter for their collection in order to meet applicable particulate emission regulations.

The use of the liquid spray drying tower gives the process a high degree of flexibility in meeting sulfur dioxide removal requirements. Variations in the gas flow rate and the required collection efficiency can be accommodated by adjustments to the chemical feed rate and the sodium carbonate concentration. This process is reported to have the capability of handling the full range of flue gas flows while easily maintaining a 90 percent removal efficiency of incoming sulfur dioxide.

Emission Control Parameters. Reports on studies conducted during the development of this process have identified the chemical feed rate, sodium carbonate concentration, spray tower mixing conditions, and inlet gas temperature as the major design parameters. Typical reported values of chemical feed rates and sodium carbonate solution concentrations are 0.3 to 0.4 gallon per 1000 standard cubic feet of flue gas and a 5 to 5-1/2 percent by weight, respectively, for a 90 percent removal efficiency when conditioning a flue gas with a sulfur dioxide concentration of 500 ppm.

The optimum flue gas temperature of 300F to 350F maintains the resulting sodium sulfite particles in the dry state required for the proper operation of the second pass sprays as well as of the particulate collection equipment. The location of the atomizing spray nozzles provides for intimate mixing of the fine spray with the flue gas.

Reliability/Maintenance Requirements. Reliability figures based on actual operating data are not available for this process. The system as described herein is a semidry control method utilizing equipment which is generally well known. The dual spray drying tower resembles an evaporative cooler. The chemical feed and the dry material handling system are assembled from existing proven equipment.

Based on the relatively simple nature of this process, a system reliability of approximately 95 percent and an annual maintenance cost of 4 percent of the initial capital investment were projected for this process.

State of Development. To date, the General Resources caustic injection process has not been built or tested in a pilot plant operation. The feasibility of the process is supported by theoretical studies and test results of a similar system.

Some of the units of equipment used in this process, such as the cyclone collectors, material handling system, pumps, and fans, are items of standard equipment the reliability of which has been proved in many installations. The chemical reactions, feed rates, and sizing have been theoretically established.

A similar process developed by the Atomics International Division of the Rockwell Corporation has undergone testing with excellent results, an analysis of which was presented at the 167th American Chemical Society National Meeting in 1974. As of the date of this report, the General Resources caustic injection system has progressed to the pilot plant stage in its development.

Advantages Over Existing Control Methods

(1) A higher sulfur dioxide removal efficiency.

(2) Flue gas is not saturated with water vapor.

(3) Process produces a dry mixture of sodium sulfite and sodium sulfate as an end product.

(4) Because of the soluble absorption solution and the reported absence of scaling or fouling of the chemical feed system, maintenance problems are expected to be minimal.

(5) The process has a high degree of flexibility for adjusting to changes in both rates of gas flow and required sulfur dioxide removal efficiency.

(6) Removal of the sulfur dioxide does not generate any new liquid or solid pollutants with the possible exception of the sodium waste produced.

(7) The collected waste product of sodium sulfite has a potential market value which is reflected in Table 10 under "Miscellaneous."

Disadvantages

(1) A final particulate collection step is required to remove the fine sodium sulfites and sulfates.

(2) The flue gas must have sufficient heat content to vaporize the water present in the sodium carbonate solution.

(3) The design has not yet been proven in an actual operating installation.

(4) The bulk storage requirements may be a problem if available space is limited.

(5) There is the necessity of marketing or disposal of sodium sulfite.

Energy/Material Requirements. Table 9 is a summary of the energy and material requirements for the General Resources caustic injection process for a boiler installation conforming to the previously listed criteria. The values used are based on a budget estimate supplied by the General Resources Corporation.

Table 9

System Operating Data for
the Caustic Injection Process

Energy and material consumed per hour by the emission control system	
Soda ash	2,750 lbs
Electric power	520 kW
Water	720 gal
By-product material produced per hour by the emission control system	
Sodium sulfite and sodium sulfate mixture	3,210 lbs

Economics. Table 10 is a summary of the owning and operating costs for the General Resources caustic injection process for a boiler installation conforming to the criteria previously listed. The summary shows the system first cost, first year operating costs, and life cycle costs.

The equipment costs include those for the sodium carbonate storage hopper; the chemical feed system; the dual spray drying tower; a final baghouse collector; a product storage hopper; and miscellaneous pumps and mixers. The equipment cost does not include any costs associated with precleaning particulates from the flue gas before it enters the spray tower.

If this control system is being applied to a coal-burning boiler which is not already equipped with at least a mechanical, inertial separator type of dust collector, then such a device will need to be installed to satisfy the requirement of reduced particulate loading flue gas at the inlet of this control system.

A mechanical collector for the hypothetical boiler of this study is estimated to cost approximately $280,000 and to have operating and maintenance costs of $15,000 and $15,000 per year, respectively. This mechanical collector may be considered as an optional part of the caustic injection process and, therefore, a peripheral cost.

Table 10

System Costs for the Caustic Injection Process

System First Costs		$800,000
Life Expectancy		15 years
First Year Operating Costs		
Labor	$ 20,000	
Utilities	85,000	
Chemicals	590,000	
Miscellaneous	- 65,000	
Total First Year Operating Cost		$630,000
Total Life Cycle Costs:		
System First Cost		$800,000
System Operating Costs:		
Labor	$ 300,000	
Utilities	1,750,000	
Chemicals	9,050,000	
Miscellaneous	- 700,000	
Subtotal		$10,400,000
Total Life Cycle Cost		$11,200,000

The values used for the system first cost and the first year operating costs are based on a budget cost estimate supplied by the General Resources Corporation for the sulfur dioxide removal system for a boiler as previously described. The negative quantity shown for miscellaneous cost is the result of the credit for by-product sale being greater than the other miscellaneous costs.

Solid Dry Copper Absorption Process. The process described herein was developed by the Shell Oil Company, The Netherlands, and is marketed by the Universal Oil Products Company, Des Plaines, Illinois. At the time of this study, a demonstration on a 650-MW boiler was being prepared.

Principle of Operation. Flue gas, free of particulate matter and at a temperature of approximately 750F, flows through a packed tower of copper oxide pellets. The sulfur dioxide in the flue gas reacts with the copper oxide to form copper sulfate, thus removing the sulfur dioxide from the flue gas. The exhausted copper pellets (now copper sulfate pellets) are regenerated by using a high temperature reducing gas, producing a concentrated sulfur dioxide gas which can be converted to elemental sulfur in a Claus reactor. A system flow diagram describing this process is shown in Figure 5.

The Shell flue gas desulfurization process consists of three major processing steps:

(1) Removal of sulfur dioxide from the flue gas (A).*

(2) Regeneration of the spent copper oxide pellets by using a reducing gas to strip the sulfur dioxide from the copper sulfate.

(3) Production of elemental sulfur from the concentrated sulfur dioxide (C).

Particulate-free flue gas at 750F passes through one of two packed towers. In cyclic operation, one tower is in service while the other is undergoing regeneration. Within the tower, the flue gas flows along, not through, a series of parallel layers of copper oxide pellets, thus reducing gas pressure losses and the possibility of tower pluggage.

When a regenerated tower is returned to service, the removal of sulfur dioxide approaches 100 percent. The copper pellets at the tower entrance are the first to become saturated with sulfur dioxide. Gradually this saturation zone moves through the rest of the bed. At an extreme limit, the bed becomes completely saturated, resulting in no sulfur dioxide removal. Due to the various possible removal efficiencies, some slip is usually designed into the system. If, for example, an efficiency of 90 percent is desired, the freshly regenerated tower may start with an efficiency of 95 percent and be regenerated when efficiency decreases to 85 percent.

When the flue gas enters the absorption tower and passes along the copper oxide packing, the sulfur dioxide diffuses into the packing material. The copper oxide is an effective acceptor of sulfur dioxide and reacts in the presence of oxygen to form copper sulfate in accordance with the following reaction:

$$2CuO + 2SO_2 + O_2 \rightarrow 2CuSO_4 \qquad \text{[Eq 20]}$$

The flue gas residence time within the bed is approximately 1/3 to 1/2 second. This short residence time is a result of the fast reaction rate provided by the high flue gas temperature of 750F.

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* The letters in parentheses key each process step to the accompanying flow diagram in Figure 1.

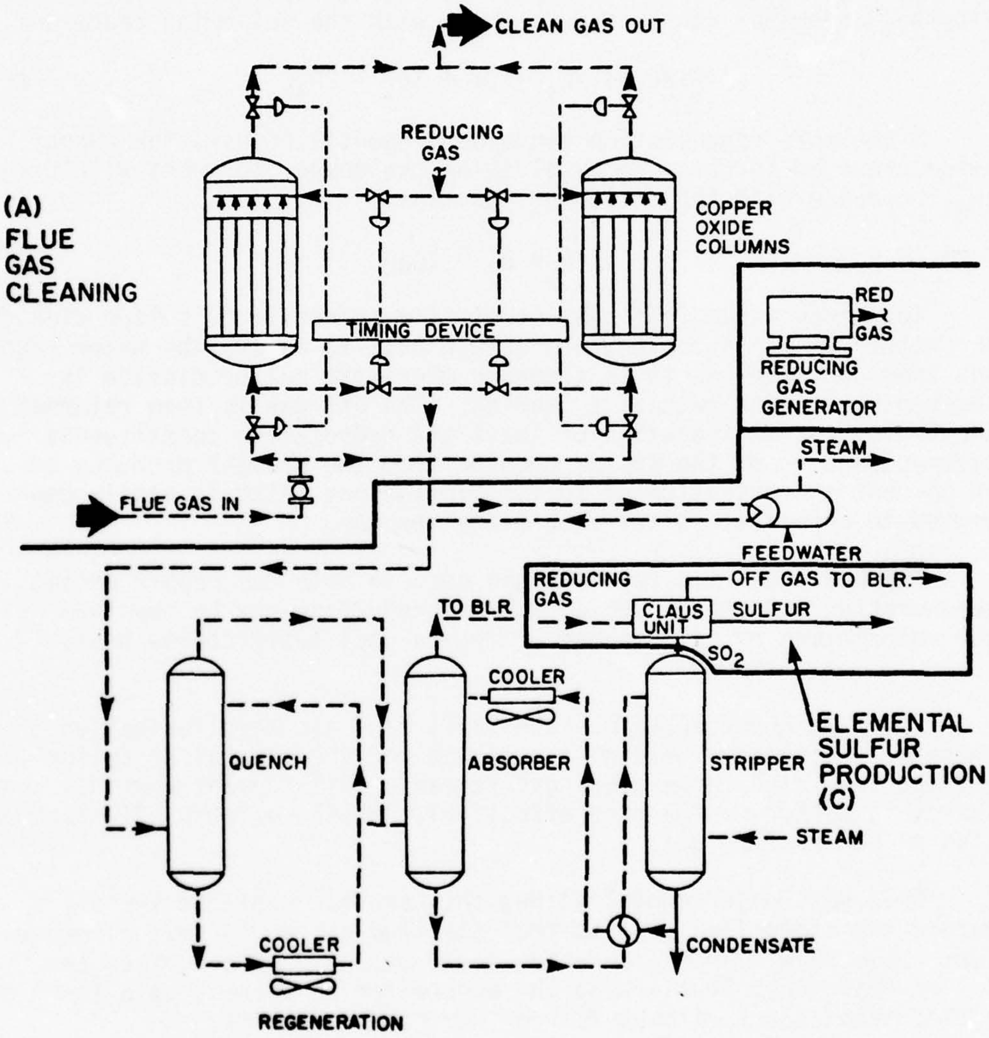

FIGURE 5. FLOW DIAGRAM FOR THE SHELL SOLID DRY COPPER ABSORPTION PROCESS

Once the removal efficiency of the absorption tower in service decreases to a predetermined level, automatic controls remove this tower from service and place the previously regenerated tower into operation. The exhausted tower is then regenerated by passing a reducing gas, e.g., a hydrogen-rich gas, over the bed at a temperature of 650F. The hydrogen reacts with the copper sulfate to produce copper, sulfur dioxide, and water vapor in accordance with the following reaction:

$$CuSO_4 + 2H_2 \rightarrow Cu + SO_2 + 2H_2O \qquad \text{[Eq 21]}$$

Since this regeneration produces elemental copper, the copper oxide required is obtained by allowing the copper to react with oxygen in accordance with the following reaction:

$$2Cu + O_2 \rightarrow 2CuO \qquad \text{[Eq 22]}$$

The regeneration off-gas, consisting primarily of sulfur dioxide and water vapor, is cooled in a quench unit to remove the water vapor and then continues on to an absorber where the sulfur dioxide is removed by solvent (water) scrubbing. The off-gas is then returned to the boiler for incineration of inert and hydrocarbon constituents. Steam stripping of the sulfur dioxide from the solvent produces a 90 percent concentration of sulfur dioxide gas which is easily converted to elemental sulfur in a Claus reactor.

The hydrogen-rich reducing gas used in both the copper pellet regeneration and the elemental sulfur production may be supplied by the reformation of natural gas or from a coal gasification unit.

Specific Applicability. The Shell flue gas desulfurization process as described herein is designed for the removal of sulfur dioxide from high temperature gas streams. Pilot plant work has shown that this method may be used effectively on oil refinery off-gases and also on boiler flue gas.

On a new boiler installation, this process would be installed before the economizer unit so that the flue gas would have a temperature above 750F. Such a location would actually help improve the boiler efficiency by allowing the economizer to operate at a lower gas outlet temperature without fear of corrosion problems.

An existing boiler having a low flue gas temperature would require a gas reheating system to achieve the 750F gas temperature needed to successfully operate the copper oxide process. Such a reheat system could include a gas or oil burner, a regenerative type gas heat exchanger, extensive rework of the flue gas ductwork, and a booster fan.

On units burning a fuel which produces particulate emissions, e.g., coal, a unit such as an electrostatic precipitator is required to insure a particulate-free flue gas.

Given the volume of flue gas flow and its sulfur content, the size of the absorption tower and time period in service can be estimated. A gas flow of less than full load would result only in a lower pressure drop across the tower while not significantly reducing efficiency. Therefore, this packed tower design should be capable of handling the full range of flue gas flows without significant effect on the operation of the absorption process.

Should the sulfur content of the fuel vary, a change in the service and regeneration time periods would maintain the desired removal efficiency. Similar adjustments would also allow the process to meet future changes in the required removal efficiency. It is believed that the process as described should remove 90 to 95 percent of the incoming sulfur dioxide.

Emission Control Parameters. The flue gas temperature, gas residence time, gas flow volume, and number of packing stages are reported to have a strong effect on absorption performance. For ease of handling, the absorption tower packing is usually fabricated in stages, with a number of stages or layers of packing placed in a single container to form a tower unit.

The 750F gas temperature is required to insure a high rate of reaction between the copper oxide and the sulfur dioxide. Reports on results of tests and studies indicate that at a temperature of 750F, a gas residence time of 1/3 second, and a service time of 45 minutes per tower, an average removal efficiency of 90 percent of the 2,000 ppm inlet sulfur dioxide was achieved.

Reliability/Maintenance Requirements. Reported results of pilot plant testing over a period of 20,000 hours, and of individual tests of some 8,000 cycles each, show that the copper oxide pellets can maintain a stable activity and pressure drop, are unaffected by chemicals normally found in flue gas, and exhibit no significant loss of mass. The use of a tower with parallel gas passages has demonstrated an acceptable method of minimizing pressure drop buildup when handling flue gas with a particulate level of 0.12 grain per scf.

Based on the reported observations during pilot plant testing, the hardware in this process should be very reliable. The two steps where reliability may become a factor of consideration are in the areas of regeneration and sulfur production, since each of those processes depends on close control and the availability of a hydrogen-rich reducing gas. With these facts in mind, it is believed that the system reliability may be expected to average 90 percent or greater, with an annual maintenance charge of 5 percent of the initial capital investment.

State of Development. The Shell Oil Company began development on its flue gas desulfurization process in 1962. In 1967, a small pilot plant began operation at a company refinery in the Netherlands. A full-scale demonstration unit was installed on an oil refinery in Japan and is reported to have achieved actual desulfurization efficiencies in excess of 90 percent.

These pilot and demonstration units have shown that the process will work satisfactorily on oil-fired flue gas. In the United States, demonstration units are presently being planned on both an oil refinery and a coal-fired boiler. Results from these units should provide information as to whether the Shell copper oxide absorption process will be a commercially acceptable method of controlling sulfur dioxide emissions.

Advantages Over Existing Control Methods

(1) Higher sulfur dioxide removal efficiency.

(2) Flue gas is not saturated with water vapor.

(3) Process produces elemental sulfur as the end product.

(4) Process has a high degree of flexibility for adjustment to changes in gas flow rates and in required sulfur dioxide removal efficiency.

(5) Removal of the sulfur dioxide does not generate any new liquid or solid pollutants with the possible exception of sulfur.

Disadvantages

(1) Necessity of marketing or disposal of elemental sulfur.

(2) Particulate removal equipment may be required to alleviate possible absorption tower plugging problems.

(3) Provision of the necessary 750F gas temperature may require a gas reheating system for existing boilers.

Energy/Material Requirements. Table 11 is a summary of the energy and material requirements for the Shell Oil solid dry copper process for a boiler installation conforming to the criteria previously listed. The values were extrapolated from the reported results of a Universal Oil Products study of a 650-MW commercial facility.

Table 11

System Operating Data for the
Solid Dry Copper Absorption Process

Energy and material consumed per hour by the emission control system	
Copper oxide	1.75 lb
Natural gas	65 mcf
Electric power	522 kW
Water	1,630 gal
By-product material produced per hour by the emission control system	
Sulfur	830 lbs

Economics. Table 12 is a summary of the cost to own and operate the Shell solid dry copper oxide process for a boiler installation conforming to the criteria previously listed. The summary shows system first costs, first year operating costs, and life cycle costs. The equipment costs include the absorbers, quench chamber, solvent absorber and stripper, modified Claus unit, reducing gas generator, and miscellaneous heat exchangers and pumps. They do not include any allowance for the flue gas reheating or the particulate cleaning equipment which may possibly be required ahead of the absorber.

If this control system is being applied to a heavy oil- or coal-burning boiler which is not already equipped with an electrostatic precipitator or a baghouse collector, then such a device will need to be installed to satisfy the requirement of particulate-free flue gas at the inlet of this control system.

An electrostatic precipitator for the hypothetical boiler of this study is estimated to cost approximately $1,450,000 and to have operating and maintenance costs of $200,000 and $45,000 per year, respectively. This electrostatic precipitator may be considered as an optional part of the solid dry copper absorption process and, therefore, a peripheral cost.

Table 12

System Costs for the Solid
Dry Copper Absorption Process

System First Cost		$ 4,400,000
Life Expectancy		15 years
First Year Operating Costs:		
Labor	$ 50,000	
Utilities	950,000	
Chemicals	50,000	
Miscellaneous	250,000	
Total First Year Operating Cost		$ 1,300,000
Total Life Cycle Costs:		
System First Cost		$ 4,400,000
System Operating Costs:		
Labor	$ 700,000	
Utilities	20,000,000	
Chemicals	800,000	
Miscellaneous	4,500,000	
Subtotal		$26,000,000
Total Life Cycle Cost		$30,400,000

The spent copper oxide pellets loaded with copper sulfate may be regenerated off-site with but few process modifications. This modified process would use the copper oxide pellets in the tower to absorb the sulfur dioxide. The spent pellets would then be shipped off-site for the regeneration phase. Such modifications to the process would result in savings in the first cost of equipment and in annual chemical, labor, and utilities costs, but would involve the added expense for the regeneration of the copper oxide pellets and transportation involved in shipping the pellets, as well as the loss of the credit for sale of the sulfur produced. The resulting savings of such off-site regeneration are reflected in Table 13, the cost summary for the modified system.

Table 13

System Costs for the Modified Solid Dry Copper Absorption Process

System First Cost		$ 1,400,000
Life Expectancy		15 years
First Year Operating Costs:		
Labor	$ 20,000	
Utilities	15,000	
Chemicals	50,000	
Miscellaneous (Includes costs for regeneration of copper pellets)	2,015,000	
Total First Year Operating Cost		$ 2,100,000
Total Life Cycle Costs		
System First Cost		$ 1,400,000
System Operating Costs:		
Labor	$ 285,000	
Utilities	275,000	
Chemicals	825,000	
Miscellaneous (Includes costs for regeneration of copper pellets)	28,515,000	
Subtotal		$29,900,000
Total Life Cycle Cost		$31,300,000

The values used for system first costs and the first year operating costs were extrapolated from exiguous data contained in a Universal Oil Products technical study of a 650 MW commercial plant, which represents the latest and only available cost information. It should be noted that, in developing costs for the modified system, many assumptions were made regarding the division of costs between the absorption and regeneration processes as well as an extrapolation to a smaller system.

3 SUMMARY

The overall objective of this study was to provide information on emerging technology by means of which gaseous and particulate emissions from Army boilers and incinerators could be controlled to achieve compliance with the regulations of various federal, state, and local governing agencies. To accomplish this objective, the study was divided and developed in the following stages:

(1) Preparation of tables of expected emission for boilers and incinerators.

(2) Preparation of tables of applicable regulations affecting emissions of gaseous and particulate matter.

(3) Survey of existing and emerging emission control systems.

(4) Selection of the most promising emerging systems.

(5) Evaluation of the technical and economic aspects of the selected systems.

The expected gaseous and particulate emissions from boilers and incinerators are presented in tabular form in Appendix A, while the pertinent air pollution regulations limiting such emissions are presented in condensed tables in Appendix B.

The list of available emission control systems resulting from a general survey was reviewed, and the various systems were classified as either existing or emerging types. (Survey is appended to this report in Appendix C.) From the survey information, it was apparent that adequate technology exists for particulate control at Army installations; therefore, in selecting the five emerging systems for further study, emphasis was placed on methods for controlling sulfur dioxide emissions.

The detailed evaluation of each of the five emerging methods was divided into the following nine major categories:

(1) Principle of operation.

(2) Process flow diagram.

(3) Specific applicability.

(4) Emission control parameters.

(5) Reliability and maintenance characteristics.

(6) State of development.

(7) Advantages and disadvantages.

(8) Energy and material requirements.

(9) System economics.

In order to provide a basis for the economic analysis, a hypothetical application was postulated: a coal-fired boiler having a capacity of 250,000 pounds of steam per hour; using coal having a sulfur content of 4 percent; flue gas having an equivalent sulfur dioxide content of 3,060 ppm at boiler outlet; a required sulfur removal efficiency of 85 percent; and an operating load factor of 70 percent. This application was selected on the basis that it represents a likely Army emitter which potentially will require a sulfur dioxide emission control system.

The economic analysis for all five systems was conducted on the basis that the entire emission control process would be located on the facility site. However, since three of the five systems can be arranged to permit the regeneration portion of the process to be located elsewhere and to be independently owned, the economic analysis also considered this modification of each affected system. The economic analysis procedure used in this study is presented in Appendix E.

The summary of the technical and economic characteristics for all five emission control methods is presented in Table 14. It shows that the system with the lowest first cost is the caustic injection system which is the simplest of the emission control systems studied. However, because of its higher annual operating cost, its total life cycle cost is greater than that of the caustic absorption with lime regeneration system.

The summary also indicates that the modified systems, which have their regeneration accomplished off-site, have significantly smaller first costs, but their total life cycle cost approaches that of on-site regeneration. In addition, off-site regeneration, although presented as being feasible, may not be so since several similar emission control systems within close proximity to each other would most likely be required to support an independent off-site regeneration facility.

The summary of the technical and economic characteristics, given in Table 14, for all five emission control methods is not to be interpreted as indicating the best or most economical system for emission control for all applications. Rather, it should be considered solely as a summary of the technical and economic characteristics of the systems described in the report for a specific hypothetical application and situation. Each project requiring application of emission control should be assessed individually in order to determine the system most suitable for a given situation. It should also be noted that costs for the particular systems were based on present knowledge and its present state of development. As the systems evolve, better cost data will become available, and these in turn will affect the economic analysis. Furthermore, since costs for labor, utilities, chemicals, etc. and their respective escalation rates would probably be different from those stated in Appendix E, an economic analysis performed at some future date would most likely indicate different results.

All five systems evaluated in this study appear to be viable emission control systems; the caustic absorption process using lime regeneration will soon be commercially available. The caustic injection process, because of its low initial cost and simplicity, is likely to develop rapidly and become commercially available in the near future.

In order to identify promising new systems and methods for controlling emissions, a methodology for evaluating them has been developed and is delineated in Appendix D. This methodology is designed for use by the Army technical staff in order to make a preliminary decision as to whether the emission control system being studied deserves further consideration.

4 CONCLUSIONS AND RECOMMENDATIONS

Conclusions. The following conclusions are based on data and information received and analyzed during the course of the study:

(1) Sufficient state-of-the-art devices exist for effective particulate control from Army emitters. Technology improvement is continuing in this area.

(2) Of the 45 emerging systems for control of sulfur oxides, the five most promising systems for Army emitters are:

a. Dry activated carbon adsorption.

b. Ammonia absorption.

c. Caustic absorption with lime regeneration.

d. Caustic injection.

e. Solid dry copper absorption.

(3) Data and results presented in this report should not be used to interpret which system is best. Each control application should be individually assessed to determine the most suitable system.

(4) The expected emissions presented in Appendix A and the emission limitation regulations presented in Appendix B can be used to preliminarily determine the minimum required control system efficiency.

(5) The new technology evaluation methodology will be useful to Army technical personnel in making preliminary decisions regarding the advisability of pursuing detailed evaluations of proposed emerging systems.

Recommendations. The following recommendations are offered in order for the material presented in this study to have continued usefulness:

(1) Periodic update of the expected emissions and regulations listed in Appendices A and B.

(2) Continued surveillance of emission control technology to insure that emerging systems are not overlooked.

(3) Update of cost data presented herein whenever the systems analyzed are being considered for specific applications.

(4) Solicitation of user experience in the application of the evaluation methodology and appropriate modification made to the methodology to improve its usefulness.

Table 14

Summary of Technical and Economic Characteristics of Various Emerging Gaseous Emission Control Methods

Emission Control Method	Sulfur Dioxide Removal Efficiency (Percent)	Projected System Reliability (Percent)	Dry or Wet System	Status: Near Commercial (C) or Study Phase (S)	System Life Expectancy (Years)	System First Cost (Millions of Dollars)	System First Year Operating Cost (Millions of Dollars)	System First Year Maintenance Cost (Millions of Dollars)	System Total Life Cycle Cost (Millions of Dollars)
Dry Activated Carbon Adsorption	90	90	Dry	C	15	3.6	.85	.14	17.9
Modified Dry Activated Carbon Adsorption	90	90	Dry	C	15	1	1.3	.04	19.4
Ammonia Absorption	95	90	Wet	C	15	4.3	.65	.21	16.4
Modified Ammonia Absorption	95	90	Wet	C	15	1.75	.71	.09	11.9
Caustic Absorption With Lime Regeneration	90	90	Wet	C	15	1.3	.43	.05	8.2
Caustic Injection	90	95	Semi-Wet	S	15	.8	.63	.03	11.2
Solid Dry Copper Absorption	90	90	Dry	S	15	4.4	1.3	.22	30.4
Modified Solid Dry Copper Absorption	90	90	Dry	S	15	1.4	2.1	.07	31.3

APPENDIX A:

EXPECTED PARTICULATE AND GASEOUS EMISSIONS

The first step in solving an air pollution problem of either a boiler or an incinerator is the determination of the amount of emissions that the emitter is discharging into the atmosphere. For design purposes, the best method of determination is an actual emission test with the emitter operating at normal conditions. Such a test provides accurate emission data, but it is a time-consuming and costly process.

A quick and easy method for estimating emissions is to analyze past test results of similar emitters. Such an estimate is a less accurate one because many operating variables, such as unit age or general condition, are not recorded in the available literature.

Tables A1 and A2 present historical data on the expected emissions from various types of boilers and incinerators. Expected particulate and gaseous emissions are given for each emitter in pounds of emission per unit of fuel or refuse burned. The reason for requiring the amount of emissions to be known will be explained in Appendix B; briefly, it is used in determining the approximate efficiency required of an emission control system in order for the emitter to comply with pollution regulations.

APPENDIX B:

STATE EMISSION REGULATIONS

The minimum required removal efficiency is equal to one minus the ratio of the legal allowable limits to the expected emissions. This efficiency represents the percentage of an emission that a collection device must remove from the gas stream to bring the emitter into compliance with the state air pollution emission regulations. The expected emissions from boilers and incinerators are presented in Appendix A, while the state emission regulations are presented in this appendix.

Tables B1 through B5 are a summary of the emission limits established by the regulatory agencies of the fifty states as of September 1975. These tables are only a concise summary, not a comprehensive or all-inclusive statement of the regulations. In addition, state regulations are constantly being updated and revised; thus any summary of such laws should also be updated from time to time.

Boiler and incinerator emission limits in this appendix are expressed in various values and units. These units are defined in the Standard Abbreviation listing at the end of the report. Opacity, not listed, is a measure of smoke density as determined by approved test methods such as the Ringelmann method. In order for the efficiency to be calculated in a proper manner, the units of the expected emission must agree with those of the state emission regulations. To help simplify this calculation, Table B6 was constructed to facilitate the conversion of units.

The following examples illustrate the use of Tables A1 and A2 with Tables B1 through B6 in calculating the minimum required efficiency.

Assume: a spreader stoker-fired boiler burning coal with a heating value of 12,500 BTU per pound and a sulfur content of 4 percent; located in the State of Pennsylvania, Group A region, in a facility with a total heat capacity of 100 million BTU per hour. From Table A1, the expected sulfur dioxide emission is 38A, where A is the percent sulfur in coal; therefore, the expected emission is 38 x 4 or 152 pounds of sulfur dioxide per ton of coal burned. The conversion factor from Table B6 translates the expected emission to 6.08 pounds per million BTU (152 x .04). The state sulfur dioxide emission limit is found in Table B2 as $5.1Q^{-.14}$ or 2.68 pounds per million BTU. With both the expected emission and allowable emission known, the minimum required removal efficiency is found to be 56 percent 1 - (2.68/6.08).

Assume: a new incinerator installation of the continuous traveling grate type burning municipal refuse in the State of New York with a capacity of 0.5 ton per hour. From Table A2 the expected particulate emission is 16.7 pounds of particulate per ton of refuse charged. The conversion factor to convert pounds per ton of refuse charged to pounds per hour from Table B6 is CA, where CA is tons of refuse incinerated per hour and for this example is equal to 0.5 ton; therefore, the expected emission is 8.35 pounds per hour (16.7 x 0.5). The state particulate emission limit is found in Table B5 to be equal to .003C, where C is incinerator capacity in pounds per hour and equal to .5 x 2000 or 1000 in this example. Therefore, the allowable emission is equal to .003 x 1000 or 3 pounds per hour. The minimum required removal efficiency then calculates to be 1 - (3.0/8.35) or 64 percent, based on the expected and allowable emissions.

Table A1

Expected Particulate and Gaseous Emissions From Boilers

Expected[1] Emissions	Types of Coal Burning Boilers[2]				Fuel Oil Burning Boilers[3]		Gas Burning Boilers[4]
	Pulverized Coal	Cyclone	Spreader Stoker	Other Stokers	No. 1 & 2 Fuel Oil	No. 5 & 6 Fuel Oil	
Particulates	16A[5]	2A	13A	5A	15	23	5-15
Carbon Monoxide	1	1	2	2	4	4	17-20
Sulfur Oxides	38S[6]	38S	38S	38S	144S	159S	.6[7]
Hydrocarbons	.3	.3	1	1	3	3	1-8
Nitrogen Oxides	18	55	15	15	40 (Tangentially Fired) 80 (Horizontal Fired)	40 (Tangentially Fired) 80 (Horizontal Fired)	80-700[8]

[1] *Compilation of Air Pollutant Emission Factors*, Technical Publication No. AP-42 (U. S. Environmental Protection Agency, 5/74) p.p. 1.1-3 to 1.4-2.

[2] Emissions expressed as pounds per ton of coal burned.

[3] Emissions expressed as pounds per 1000 gallon oil burned.

[4] Emissions expressed as pounds per million cubic feet gas burned.

[5] "A" stands for weight percentage of ash in fuel.

[6] "S" stands for weight percentage of sulfur in fuel.

[7] Based on Average natural gas sulfur content.

[8] Exact amount is dependent on the boiler size; i.e. domestic and commercial units @ 100, industrial units @ 200, and power plant units @ 700.

Table A2

Expected Particulate and Gaseous Emissions From Incinerators

Expected Emission (LB Emission Ton Refuse Chg.)	Medical Incinerator[1]	Types of Municipal Incinerators[2]										
		Continuous Refract. Wall				Batch Refract Wall			Continuous Water Wall			
		Rocking Grate	Recip. Grate	Trav. Grate	Grate-Kiln	Cir.	Rectang.	Hearth	Rocking Grate	Recip. Grate	Trav. Grate	Suspension Burning
Particulates	8	17.5	32	16.7	36.7	14.8	2.5	13.6	16.3	30.8	15.5	50.8
Carbon Monoxide	Neg	29.4	29.4	29.4	20.6	35.3	41.2	41.2	20.6	20.6	20.6	14.7
Sulfur Oxides	Neg	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
Hydrocarbons	Neg	2.3	2.3	2.3	1.6	2.7	3.2	3.2	1.6	1.6	1.6	1.1
Nitrogen Oxides	3	3.3	3.3	3.3	3.4	2.9	3	2.7	3.5	3.5	3.5	3.4

[1] *Compilation of Air Pollutant Emission Factors*, Technical Publication No. AP-42 (U. S. Environmental Protection Agency, 4/73) p. 2.1-3.

[2] Arthur D. Little, Inc., *Systems Study of Air Pollution From Municipal Incineration*, Technical Report Contract No. CPA-22-69-23 (U. S. Department of Health, Education, and Welfare, 3/70) p.p. V6 - V59.

Table B1

State Particulate Emission
Regulations for Boilers

State	Date[2]	Visible Emissions	Emissions Concentration[1]: Boilers Less Than 50 $\frac{MBTU}{HR}$	Emissions Concentration[1]: Boilers From 51 To 250 $\frac{MBTU}{HR}$
Alabama[3] (Class 1 County)	1/71	20% Opacity	Existing Units: $E = 1.38\ Q^{-.44}\ \frac{LB}{MBTU}$ Max $E = 0.50\ \frac{LB}{MBTU}$	Existing Units: $E = 1.38\ Q^{-.44}\ \frac{LB}{MBTU}$
(Class 2 County)	1/71	20% Opacity	$E = 3.109\ Q^{-.589}\ \frac{LB}{MBTU}$ Max $E = 0.80\ \frac{LB}{MBTU}$	$E = 3.109\ Q^{-.589}\ \frac{LB}{MBTU}$
(New Sources)	1/71	20% Opacity	$E = 1.38\ Q^{-.44}\ \frac{LB}{MBTU}$	$E = 1.38\ Q^{-.44}\ \frac{LB}{MBTU}$
Alaska	7/72	20% Opacity	$.1\ \frac{GR}{SCF}$ (Coal) $.05\ \frac{GR}{SCF}$ (Other)	$.1\ \frac{GR}{SCF}$ (Coal) $.05\ \frac{GR}{SCF}$ (Other)

Table B1 (Continued)

State	Date	Visible Emissions	Emissions Concentration	
			Boilers Less Than 50 $\frac{MBTU}{HR}$	Boilers From 51 To 250 $\frac{MBTU}{HR}$
Arizona	3/73	40% Opacity	Existing Units: $E = 1.02\ Q^{-.231}\ \frac{LB}{MBTU}$ Max $E = .599\ \frac{LB}{MBTU}$	$E = 1.02\ Q^{-.231}\ \frac{LB}{MBTU}$
Arkansas[4]	1/72	Existing Units: 40% Opacity New Units: 20% Opacity	$E = .039\ X^{.807}\ \frac{LB}{HR}$ Max $E = 2.5\ \frac{LB}{HR}$	$E = 0.39\ X^{.807}\ \frac{LB}{HR}$
California Bay Area Region	11/70	20% Opacity	Max $E = .15\ \frac{GR}{SCF}$ @ 6% O_2	Max $F = .15\ \frac{GR}{SCF}$ @ 6% O_2

Table B1 (Continued)

			Emissions Concentration	
State	Date	Visible Emissions	Boilers Less Than 50 $\frac{MBTU}{HR}$	Boilers From 51 To 250 $\frac{MBTU}{HR}$
California (Continued)				
Los Angeles Region	1/73	20% Opacity	Max $E = 10 \frac{LB}{HR}$ and Max $E = .3 \frac{GR}{SCF}$ @ 12% CO_2	Max $E = 10 \frac{LB}{HR}$ and Max $E = .3 \frac{GR}{SCF}$ @ 12% CO_2
Monterey Region	9/74	20% Opacity	Max $E = .15 \frac{GR}{SCF}$	Max $E = .15 \frac{GR}{SCF}$
Riverside Region	11/74	20% Opacity	Max $E = .1 \frac{GR}{SCF}$ @ 12% CO_2 New Units: Max $E = 10 \frac{LB}{HR}$	Max $E = .1 \frac{GR}{SCF}$ @ 12% CO_2 New Units: Max $E = 10 \frac{LB}{HR}$
Sacramento Region	2/75		Max $E = .3 \frac{GR}{SCF}$ @ 12% CO_2 and Max $E = 10 \frac{LB}{HR}$	Max $E = .3 \frac{GR}{SCF}$ @ 12% CO_2 and Max $E = 10 \frac{LB}{HR}$

Table B1 (Continued)

			Emissions Concentration	
State	Date	Visible Emissions	Boilers Less Than 50 $\frac{\text{MBTU}}{\text{HR}}$	Boilers From 51 To 250 $\frac{\text{MBTU}}{\text{HR}}$
California (Continued)				
San Bernardino Region	2/73	20% Opacity	Max E = .1 $\frac{\text{GR}}{\text{SCF}}$ @ 12% CO_2	Max E = .1 $\frac{\text{GR}}{\text{SCF}}$ @ 12% CO_2
San Joaquin Region	8/74	20% Opacity	Max E = .1 $\frac{\text{GR}}{\text{SCF}}$ @ 12% CO_2	Max E = .1 $\frac{\text{GR}}{\text{SCF}}$ @ 12% CO_2
			New Units: Max E = 10 $\frac{\text{LB}}{\text{HR}}$	New Units: Max E = 10 $\frac{\text{LB}}{\text{HR}}$
San Luis Obispo Region	5/71	40% Opacity	Max E = .3 $\frac{\text{GR}}{\text{SCF}}$ @ 3% O_2	Max E = .3 $\frac{\text{GR}}{\text{SCF}}$ @ 3% O_2
Santa Barbara Region	6/72	20% Opacity	Max E = .3 $\frac{\text{GR}}{\text{SCF}}$ @ 12% CO_2	Max E = .3 $\frac{\text{GR}}{\text{SCF}}$ @ 12% CO_2
			South Coast Basin Only: Max E = .1 $\frac{\text{GR}}{\text{SCF}}$ @ 12% CO_2 and Max E = 10 $\frac{\text{LB}}{\text{HR}}$	South Coast Basin Only: Max E = .1 $\frac{\text{GR}}{\text{SCF}}$ @ 12% CO_2 and Max E = 10 $\frac{\text{LB}}{\text{HR}}$

Table B1 (Continued)

State	Date	Visible Emissions	Emissions Concentration Boilers Less Than 50 $\frac{MBTU}{HR}$	 Boilers From 51 To 250 $\frac{MBTU}{HR}$
Colorado	2/72	20% Opacity	$E = .5\,Q^{-.26}\ \frac{LB}{MBTU}$	$E = .5\,Q^{-.26}\ \frac{LB}{MBTU}$
			$\text{Max } E = 0.5\ \frac{LB}{MBTU}$	
Connecticut	6/72	20% Opacity	Existing Units: $\text{Max } E = .20\ \frac{LB}{MBTU}$	Existing Units: $\text{Max } E = .20\ \frac{LB}{MBTU}$
			New Units: $\text{Max } E = .10\ \frac{LB}{MBTU}$	New Units: $\text{Max } E = .10\ \frac{LB}{MBTU}$
Delaware	5/74	20% Opacity	$\text{Max } E = 0.3\ \frac{LB}{MBTU}$	$\text{Max } E = 0.3\ \frac{LB}{MBTU}$
Florida[5]	12/74	20% Opacity	None	None
Georgia	1/72	20% Opacity	Existing Units: $E = .7\,(10/Q)^{.202}\ \frac{LB}{MBTU}$	Existing Units: $E = .7\,(10/Q)^{.202}\ \frac{LB}{MBTU}$
			$\text{Max } E = 0.7\ \frac{LB}{MBTU}$ For $X = 0$	

Table B1 (Continued)

State	Date	Visible Emissions	Emissions Concentration Boilers Less Than 50 $\frac{\text{MBTU}}{\text{HR}}$	Boilers From 51 To 250 $\frac{\text{MBTU}}{\text{HR}}$	
Georgia (Continued)			New Units:	New Units:	
			$E = .5\ (10/Q)^{.5}\ \frac{\text{LB}}{\text{MBTU}}$	$E = .5\ (10/Q)^{.5}\ \frac{\text{LB}}{\text{MBTU}}$	
(Within "X" miles of city limits of city of 50,000 or more)			Max $E = .48^{-}H_s\ \frac{\text{LB}}{\text{MBTU}}$ For	$H_s < 120$ Ft	For
			Max $E = 900\ \left(\frac{H_s}{300}\right)^{3}\ \frac{\text{LB}}{\text{MBTU}}$ For	$120 \leq H_s < 300$	X = 1
			Max $E = 900\ \left(\frac{H_s}{200}\right)^{2}\ \frac{\text{LB}}{\text{MBTU}}$ For	$300 \leq H_s$	
Hawaii[6]	3/72	Existing Units: 40% Opacity New Units: 20% Opacity	N/A	N/A	
Idaho	10/72	Existing Units: 40% Opacity	$E = 1.0\ Q^{-.23}\ \frac{\text{LB}}{\text{MBTU}}$	$E = 1.0\ Q^{-.23}\ \frac{\text{LB}}{\text{MBTU}}$	

Table B1 (Continued)

State	Date	Visible Emissions	Emissions Concentration: Boilers Less Than 50 $\frac{MBTU}{HR}$	Emissions Concentration: Boilers From 51 To 250 $\frac{MBTU}{HR}$
Idaho (Continued)		New Units: 20% Opacity	Max E = 0.6 $\frac{LB}{MBTU}$	
Illinois	4/72	30% Opacity	Solid Fuel: Existing Units: Max E = .1 $\frac{LB}{MBTU}$	Solid Fuel: Existing Units: Max E = .1 $\frac{LB}{MBTU}$
			(Chicago Area Only) Max E = 1.0 $\frac{LB}{MBTU}$ E = 5.18 $Q^{-.715}$ $\frac{LB}{MBTU}$	(Chicago Area Only) E = 5.18 $Q^{-.715}$ $\frac{LB}{MBTU}$
			New Units: Max E = .1 $\frac{LB}{MBTU}$	New Units: Max E = .1 $\frac{LB}{MBTU}$
			Liquid Fuel: Max E = .1 $\frac{LB}{MBTU}$	Liquid Fuel: Max E = .1 $\frac{LB}{MBTU}$

Table B1 (Continued)

State	Date	Visible Emissions	Emissions Concentration	
			Boilers Less Than 50 $\frac{MBTU}{HR}$	Boilers From 51 To 250 $\frac{MBTU}{HR}$
Indiana	5/72	40% Opacity	$E = \frac{.44\ H_s}{Q^{.75}\ n^{.25}}\ \frac{LB}{MBTU}$ Existing Units: Max $E = .8\ \frac{LB}{MBTU}$ New Units: Max $E = .6\ \frac{LB}{MBTU}$	$E = \frac{.44\ H_s}{Q^{.75}\ n^{.25}}\ \frac{LB}{MBTU}$
Chicago Area & Indianapolis Area	5/72	40% Opacity	$E = .87\ Q^{-0.16}\ \frac{LB}{MBTU}$ Max $E = .6\ \frac{LB}{MBTU}$	$E = .87\ Q^{-0.16}\ \frac{LB}{MBTU}$
Iowa	12/73	40% Opacity	$E = \frac{.44\ H_s}{Q^{.75}\ n^{.25}}\ \frac{LB}{MBTU}$ Existing Unit in Rural Area: Max $E = .8\ \frac{LB}{MBTU}$	$E = \frac{.44\ H_s}{Q^{.75}\ n^{.25}}\ \frac{LB}{MBTU}$

Table B1 (Continued)

State	Date	Visible Emissions	Emissions Concentration Boilers Less Than 50 $\frac{MBTU}{HR}$	 Boilers From 51 To 250 $\frac{MBTU}{HR}$
Iowa (Continued)			New Unit: Max $E = .6\ \frac{LB}{MBTU}$	
			Existing Unit in City Area: Max $E = .6\ \frac{LB}{MBTU}$	
Kansas		Existing Units:		
	1/71	40% Opacity	$E = 1.026\ Q^{-.233}\ \frac{LB}{MBTU}$	$E = 1.026\ Q^{-.233}\ \frac{LB}{MBTU}$
		New Units: 20% Opacity	Max $E = .6\ \frac{LB}{MBTU}$	
Kentucky[7] Priority I Region & New Units	4/72	20% Opacity	$E = .963\ Q^{-.236}\ \frac{LB}{MBTU}$ Max $E = .56\ \frac{LB}{MBTU}$	$E = .963\ Q^{-.236}\ \frac{LB}{MBTU}$
Priority II Region		40% Opacity	$E = 1.28\ Q^{-.233}\ \frac{LB}{MBTU}$	I Regions $E = 1.28\ Q^{-.233}\ \frac{LB}{MBTU}$

Table B1 (Continued)

State	Date	Visible Emissions	Emissions Concentration Boilers Less Than 50 $\frac{MBTU}{HR}$	 Boilers From 51 To 250 $\frac{MBTU}{HR}$
Priority II Region (Continued)			Max $E = .75 \frac{LB}{MBTU}$	
Priority III Region		40% Opacity	$E = 1.32\, Q^{-.216} \frac{LB}{MBTU}$ Max $E = .80 \frac{LB}{MBTU}$	$E = 1.32\, Q^{-.216} \frac{LB}{MBTU}$
<u>Lousiana</u>	1/72	20% Opacity	Max $E = .6 \frac{LB}{MBTU}$	Max $E = .6 \frac{LB}{MBTU}$
<u>Maine</u>	1/72	40% Opacity	$E = 1.08\, Q^{-.256} \frac{LB}{MBTU}$ Max $E = .60 \frac{LB}{MBTU}$	$E = 1.08\, Q^{-.256} \frac{LB}{MBTU}$
<u>Maryland</u> (Baltimore & Washington Areas)	1/72	0% Opacity	Existing Units: Oil Fired (#5 & 6): $5 < Q << 10 \frac{MBTU}{HR}$ Max $E = .03 \frac{GR}{SCF}$, & $\eta = 50\%$ $10 < Q < 50 \frac{MBTU}{HR}$	Existing Units: Oil Fired (#5 & 6): $51 < Q < 200 \frac{MBTU}{HR}$ Max $E = .02 \frac{GR}{SCF}$, & $\eta = 70\%$ $Q < 200 \frac{MBTU}{HR}$

Table B1 (Continued)

State	Date	Visible Emissions	Emissions Concentration Boilers Less Than 50 $\frac{MBTU}{HR}$	 Boilers From 51 To 250 $\frac{MBTU}{HR}$
(Baltimore & Washington Areas Continued)			Max E = .025 $\frac{GR}{SCF}$, & $\eta = 60\%$	Max E = .02 $\frac{GR}{SCF}$, & $\eta = 80\%$
			New Units: Oil Fired (#5 & 6): $5 < Q < 10 \frac{MBTU}{HR}$	*New Units:* Oil Fired (#5 & 6): $51 < Q < 200 \frac{MBTU}{HR}$
			Max E = .03 $\frac{GR}{SCF}$, & $\eta = 50\%$	Max E = .02 $\frac{GR}{SCF}$, & $\eta = 70\%$
			$10 < Q < 50 \frac{MBTU}{HR}$	$Q < 200 \frac{MBTU}{HR}$
			Max E = .025 $\frac{GR}{SCF}$, & $\eta = 60\%$	Max E = .01 $\frac{GR}{SCF}$, & $\eta = 99\%$
			Coal Fired: (All Units) Max E = .05 $\frac{GR}{SCF}$, & $\eta = 90\%$	Coal Fired: (All Units) $51 < Q < 200 \frac{MBTU}{HR}$
				Max E = .05 $\frac{GR}{SCF}$, & $\eta = 90\%$
				$Q < 200 \frac{MBTU}{HR}$
				Max E = .03 $\frac{GR}{SCF}$, & $\eta = 99\%$

Table B1 (Continued)

			Emissions Concentration	
State	Date	Visible Emissions	Boilers Less Than 50 $\frac{MBTU}{HR}$	Boilers From 51 to 250 $\frac{MBTU}{HR}$
(Rest of State)	1/72	New Units 0% Opacity	Existing Units: E= 1.026 $Q^{-.233}$ $\frac{LB}{MBTU}$ Max E = .6 $\frac{LB}{MBTU}$	Existing Units: E= 1.026 $Q^{-.233}$ $\frac{LB}{MBTU}$
		Existing Unit: 20% Opacity	New Units: Oil Fired (#586): Same as Above Coal Fired: (All Units) Max E = .03 $\frac{GR}{SCF}$, & η = 99%	New Units: Oil Fired (#586): Same as Above Coal Fired: (All Units) Max E = .03 $\frac{GR}{SCF}$, & η = 99%

Table B1 (Continued)

State	Date	Visible Emissions	Emissions Concentration	
			Boilers Less Than 50 $\frac{\text{MBTU}}{\text{HR}}$	Boilers From 51 to 250 $\frac{\text{MBTU}}{\text{HR}}$
MASSACHUSETTS	6/72	20% Opacity	Existing Units: Max $E = .15 \frac{\text{LB}}{\text{MBTU}}$	Existing Units: Max $E = .15 \frac{\text{LB}}{\text{MBTU}}$
			New Units: Max $E = .10 \frac{\text{LB}}{\text{MBTU}}$	New Units: Max $E = .10 \frac{\text{LB}}{\text{MBTU}}$
MICHIGAN	11/73	20% Opacity	P. C. Fired: $0 < S < 40 \frac{\text{KLB}}{\text{HR}}$	P. C. Fired: $0 < S < 125 \frac{\text{KLB}}{\text{HR}}$
			Max $E = .3 \frac{\text{LB}}{\text{KLB-Gas}}$	Max $E = .3 \frac{\text{LB}}{\text{KLB-Gas}}$
				$125 < S < 1000 \frac{\text{KLB}}{\text{HR}}$
				$E = .98\ S^{-.246} \frac{\text{LB}}{\text{KLB-Gas}}$
			Other Units: $0 < S < 40 \frac{\text{KLB}}{\text{HR}}$	Other Units: $0 < S < 100 \frac{\text{KLB}}{\text{HR}}$

Table B1 (Continued)

State	Date	Visible Emissions	Emissions Concentration Boilers Less Than 50 $\frac{MBTU}{HR}$	 Boilers From 51 to 250 $\frac{MBTU}{HR}$
MICHIGAN (Continued)			Max $E = .65\ \frac{LB}{KLB\text{-}Gas}$	Max $E = .65\ \frac{LB}{KLB\text{-}Gas}$
				$100 < S < 300\ \frac{KLB}{HR}$
				$E = .65-.001(S-100)\ \frac{LB}{KLB\text{-}Gas}$
MINNESOTA	6/69	New Units: 20% Opacity	$E = \frac{.44\ Hs}{Q^{.75}\ m^{.25}}\ \frac{LB}{MBTU}$	$E = \frac{.44\ Hs}{Q^{.75}\ m^{.25}}\ \frac{LB}{MBTU}$
			New Units & All Units in Minn.-St. Paul & Duluth:	New Units & All Units in Minn.-St. Paul & Duluth:
			Max $E = .4\ \frac{LB}{MBTU}$	Max $E = .4\ \frac{LB}{MBTU}$
		Existing Units: 40% Opacity	Existing Units: Max $E = .6\ \frac{LB}{MBTU}$	Existing Units: Max $E = .6\ \frac{LB}{MBTU}$
MISSISSIPPI	1/72	40% Opacity	$E = .896\ Q^{.174}\ \frac{LB}{MBTU}$ Max $E = .6\ \frac{LB}{MBTU}$	$E = .896\ Q^{.174}\ \frac{LB}{MBTU}$

Table B1 (Continued)

State	Date	Visible Emissions	Emissions Concentration Boilers Less Than 50 $\frac{MBTU}{HR}$	 Boilers From 51 to 250 $\frac{MBTU}{HR}$
MISSOURI (St. Louis Area)	3/67	Existing Units: 40% Opacity	$E = .896\ Q^{-.174}\ \frac{LB}{MBTU}$	$E = .896\ Q^{-.174}\ \frac{LB}{MBTU}$ W/Provisions for Tall Stacks
		New Units: 20% Opacity	Max $E = .6\ \frac{LB}{MBTU}$	
(Springfield & Green Counties Areas)	9/69	Existing Units: 40% Opacity	$E = 1.026\ Q^{-.233}\ \frac{LB}{MBTU}$	$E = 1.026\ Q^{-.233}\ \frac{LB}{MBTU}$
		New Units: 20% Opacity	Max $E = .6\ \frac{LB}{MBTU}$	
(Kansas City Area)	9/68	20% Opacity	$E = 1.026\ Q^{-.233}\ \frac{LB}{MBTU}$	$E = 1.026\ Q^{-.233}\ \frac{LB}{MBTU}$
			Max $E = .6\ \frac{LB}{MBTU}$	
(Rest of State)	4/71	Existing Units: 40% Opacity	Existing Units: $E = 1.026\ Q^{-.233}\ \frac{LB}{MBTU}$	Existing Units: $E = 1.026\ Q^{-.233}\ \frac{LB}{MBTU}$
		New Units: 20% Opacity	Max $E = .6\ \frac{LB}{MBTU}$	

Table B1 (Continued)

State	Date	Visible Emissions	Emissions Concentration Boilers Less Than 50 $\frac{MBTU}{HR}$	Boilers From 51 to 260 $\frac{MBTU}{HR}$
MISSOURI (rest of State) (Continued)			New Units: $E = 1.30\ Q^{-.338}\ \frac{LB}{MBTU}$	New Units: $E = 1.30\ Q^{-.338}\ \frac{LB}{MBTU}$
			Max $E = .6\ \frac{LB}{MBTU}$	
MONTANA	10/68	Existing Units: 40% Opacity	Existing Units: $E = .879\ Q^{-.166}\ \frac{LB}{MBTU}$	Existing Units: $E = .879\ Q^{-.166}\ \frac{LB}{MBTU}$
		New Units: 20% Opacity	New Units: $E = 1.026\ Q^{-.233}\ \frac{LB}{MBTU}$	New Units: $E = 1.026\ Q^{-.233}\ \frac{LB}{MBTU}$
			Max $E = .6\ \frac{LB}{MBTU}$	
NEBRASKA	2/74	20% Opacity	$E = 1.026\ Q^{-.233}\ \frac{LB}{MBTU}$	$E = 1.026\ Q^{-.233}\ \frac{LB}{MBTU}$
			Max $E = .6\ \frac{LB}{MBTU}$	

Table B1 (Continued)

State	Date	Visible Emissions	Emissions Concentration: Boilers Less Than 50 $\frac{MBTU}{HR}$	Emissions Concentration: Boilers From 51 to 250 $\frac{MBTU}{HR}$
NEVADA	9/74	20% Opacity	$E = 1.02\ Q^{-.231}\ \frac{LB}{MBTU}$	$E = 1.02\ Q^{-.231}\ \frac{LB}{MBTU}$
			Max $E = .6\ \frac{LB}{MBTU}$	
NEW HAMPSHIRE	4/74	Existing Units: 40% Opacity	Existing Units: $E = .865\ Q^{-.158}\ \frac{LB}{MBTU}$	Existing Units: $E = .865\ Q^{-.158}\ \frac{LB}{MBTU}$
		New Units: 20% Opacity	New Units: $E = 1.064\ Q^{-.249}\ \frac{LB}{MBTU}$	New Units: $E = 1.064\ Q^{-.249}\ \frac{LB}{MBTU}$
			Max $E = .6\ \frac{LB}{MBTU}$	
NEW JERSEY	3/72	$Q < 200\ \frac{MBTU}{HR}$: 0% Opacity	$E = 2.38\ Q^{-.598}\ \frac{LB}{MBTU}$	Min $E = .1\ \frac{LB}{MBTU}$
		$Q > 200\ \frac{MBTU}{HR}$: 20% Opacity	Max $E = .6\ \frac{LB}{MBTU}$	$E = 2.38\ Q^{-.598}\ \frac{LB}{MBTU}$

Table B1 (Continued)

State	Date	Visible Emissions	Emissions Concentration Boilers Less Than 50 $\frac{\text{MBTU}}{\text{HR}}$	 Boilers From 51 to 260 $\frac{\text{MBTU}}{\text{HR}}$
NEW MEXICO	3/72	20% Opacity	Coal: $E = .96\ Q^{-.234}\ \frac{\text{LB}}{\text{MBTU}}$	Coal: $E = .96\ Q^{-.234}\ \frac{\text{LB}}{\text{MBTU}}$
			$\text{Max } E = .56\ \frac{\text{LB}}{\text{MBTU}}$	$\text{Oil} > 10^6\ \frac{\text{MBTU}}{\text{YR}}$: $E = .005\ \frac{\text{LB}}{\text{MBTU}}$
NEW YORK	6/72	20% Opacity	Coal: Existing Units: $\text{Max } E = .6\ \frac{\text{LB}}{\text{MBTU}}$ (Spreader Stokers)	Coal: Existing Units: $\text{Max } E = .6\ \frac{\text{LB}}{\text{MBTU}}$ (Spreader Stokers)
			$\text{Max } E = .6\ \frac{\text{LB}}{\text{MBTU}}$	$\text{Max } E = .6\ \frac{\text{LB}}{\text{MBTU}}$
			$0 < Q < 50$	$0 < Q < 100$
			$\text{Max } E = .45\ \frac{\text{LB}}{\text{MBTU}}$ (Other Stokers)	$\text{Max } E = .45\ \frac{\text{LB}}{\text{MBTU}}$ $100 < Q < 200$ $\text{Max } E = .30\ \frac{\text{LB}}{\text{MBTU}}$ $200 < Q < 300$ (Other Stokers)

Table B1 (Continued)

State	Date	Visible Emissions	Emissions Concentration: Boilers Less Than 50 $\frac{MBTU}{HR}$	Emissions Concentration: Boilers From 51 to 250 $\frac{MBTU}{HR}$
NEW YORK (Continued)			New Units: $E = 1.02\ Q^{-.219}\ \frac{LB}{MBTU}$	New Units: $E = 1.02\ Q^{-.219}\ \frac{LB}{MBTU}$
			Max $E = .60\ \frac{LB}{MBTU}$	Max $E = .60\ \frac{LB}{MBTU}$
			Heavy Fuel Oil: Max $E = .1\ \frac{LB}{MBTU}$	Heavy Fuel Oil: Max $E = .1\ \frac{LB}{MBTU}$
NORTH CAROLINA	7/71	New Units: 20% Opacity	$E = 1.094\ Q^{-.261}\ \frac{LB}{MBTU}$	$E = 1.094\ Q^{-.261}\ \frac{LB}{MBTU}$
		Existing Units: 40% Opacity	Max $E = .6\ \frac{LB}{MBTU}$	
NORTH DAKOTA	7/70	New Units: 20% Opacity	$E = 0.811\ Q^{-.131}\ \frac{LB}{MBTU}$	$E = 0.811\ Q^{-.131}\ \frac{LB}{MBTU}$
		Existing Units: 40% Opacity	Max $E = .60\ \frac{LB}{MBTU}$	

Table B1 (Continued)

State	Date	Visible Emissions	Emissions Concentration Boilers Less Than 50 $\frac{\text{MBTU}}{\text{HR}}$	 Boilers From 51 to 250 $\frac{\text{MBTU}}{\text{HR}}$
OHIO	7/72	20% Opacity	$E = 0.8\ Q^{-.3011}\ \frac{\text{LB}}{\text{MBTU}}$ $\text{Max } E = .4\ \frac{\text{LB}}{\text{MBTU}}$	$E = 0.8\ Q^{-.3011}\ \frac{\text{LB}}{\text{MBTU}}$
OKLAHOMA	1/72	20% Opacity	$E = 1.089\ Q^{-.259}\ \frac{\text{LB}}{\text{MBTU}}$ $\text{Max } E = .6\ \frac{\text{LB}}{\text{MBTU}}$	$E = 1.089\ Q^{-.259}\ \frac{\text{LB}}{\text{MBTU}}$
OREGON	6/70	Existing Units: 40% Opacity New Units: 20% Opacity	New Units: $\text{Max } E = .1\ \frac{\text{GR}}{\text{SCF}}$ New Units: $\text{Max } E = .2\ \frac{\text{GR}}{\text{SCF}}$ 50% E. A.	New Units: $\text{Max } E = .1\ \frac{\text{GR}}{\text{SCF}}$ Existing Units: $\text{Max } E = .2\ \frac{\text{GR}}{\text{SCF}}$ 50% E. A.
PENNSYLVANIA	9/71	20% Opacity	$E = 3.6\ Q^{-.56}\ \frac{\text{LB}}{\text{MBTU}}$ $\text{Max } E = .4\ \frac{\text{LB}}{\text{MBTU}}$	$E = 3.6\ Q^{-.56}\ \frac{\text{LB}}{\text{MBTU}}$
RHODE ISLAND	2/72	20% Opacity	$\text{Max } E = .2\ \frac{\text{LB}}{\text{MBTU}}$	$\text{Max } E = .2\ \frac{\text{LB}}{\text{MBTU}}$

Table B1 (Continued)

			Emissions Concentration	
State	Date	Visible Emissions	Boilers Less Than 50 $\frac{MBTU}{HR}$	Boilers From 51 to 250 $\frac{MBTU}{HR}$
SOUTH CAROLINA	2/71	Existing Units: 40% Opacity New Units: 20% Opacity	Existing Units: $Q < 10$, Max $E = .8 \frac{LB}{MBTU}$ $Q > 15$, Max $E = .6 \frac{LB}{MBTU}$ New Units: Max $E = .6 \frac{LB}{MBTU}$	Existing Units: $Q < 10$, Max $E = .8 \frac{LB}{MBTU}$ $Q > 15$, Max $E = .6 \frac{LB}{MBTU}$ New Units: Max $E = .6 \frac{LB}{MBTU}$
SOUTH DAKOTA	1/72	20% Opacity	Max $E = .3 \frac{LB}{MBTU}$	Max $E = .3 \frac{LB}{MBTU}$
TENNESSEE	8/69 (For Visible Emissions) 4/72 (For Other Emissions)	20% Opacity	Existing Units: $E = 1.09\ Q^{-.259} \frac{LB}{MBTU}$ Max $E = .6 \frac{LB}{MBTU}$ OR $E = .4375\ H_S Q^{-.75} \frac{LB}{MBTU}$ Max $E = .6 \frac{LB}{MBTU}$ New Units: $E = 2.16\ Q^{-.557} \frac{LB}{MBTU}$ Max $E = .6 \frac{LB}{MBTU}$	Existing Units: $E = 1.09^{-.259} \frac{LB}{MBTU}$ OR $E = .4375\ H_S Q^{-.75} \frac{LB}{MBTU}$ New Units: $E = 2.16\ Q^{-.557} \frac{LB}{MBTU}$

Table B1 (Continued)

			Emissions Concentration	
State	Date	Visible Emissions	Boilers Less Than 50 $\frac{MBTU}{HR}$	Boilers From 51 to 250 $\frac{MBTU}{HR}$
TEXAS[8]	1/72	Existing Units: 30% Opacity	Solid Fuels $E = (.048\ F^{.62})\left(\frac{EFF.\ H}{STD.\ H}\right)^2$	Solid Fuels: $E = (.048\ F^{.62})\left(\frac{EFF.\ H}{STD.\ H}\right)^2$
		New Units 20% Opacity	Min $E = 3.5\ \frac{LB}{HR}$ AND Max $E = .3\ \frac{LB}{MBTU}$	Min $E = 3.5\ \frac{LB}{HR}$ AND Max $E = .3\ \frac{LB}{MBTU}$
UTAH[9]	4/71	Existing Units: 40% Opacity	N/A	Existing Units: 85% Collection Efficiency
		New Units: 20% Opacity		New Units: Apply Best Available Control Equipment
VERMONT	4/70	Existing Units: 40% Opacity	$E = 1.486\ Q^{-.473}\ \frac{LB}{MBTU}$ Max $E = .5\ \frac{LB}{MBTU}$	$E = 1.486\ Q^{-.473}\ \frac{LB}{MBTU}$
		New Units: 20% Opacity		

Table B1 (Continued)

			Emissions Concentration	
State	Date	Visible Emissions	Boilers Less Than 50 $\frac{MBTU}{HR}$	Boilers From 51 to 250 $\frac{MBTU}{HR}$
VIRGINIA[10] Group A	3/72	20% Opacity	$E = .8425\ Q^{-.2314}\ \frac{LB}{MBTU}$ $Max\ E = .3\ \frac{LB}{MBTU}$	$E = .8425\ Q^{-.2314}\ \frac{LB}{MBTU}$
Group B			$E = .8425\ Q^{-.2314}\ \frac{LB}{MBTU}$ $Max\ E = .4\ \frac{LB}{MBTU}$	$E = .8425\ Q^{-.2314}\ \frac{LB}{MBTU}$
WASHINGTON	8/74	20% Opacity	$Max\ E = .1\ \frac{GR}{SCF}$ @ 7% O_2	$Max\ E = .1\ \frac{GR}{SCF}$ @ 7% O_2
WEST VIRGINIA[11]	6/75	10% Opacity	Type b) Units: $E = .09\ Q\ \frac{LB}{HR}$ Type c) Units: $E = .73\ Q^{-.675}\ \frac{LB}{HR}$	Type b) Units: $E = .09\ Q\ \frac{LB}{HR}$ Type c) Units: $E = .73\ Q^{-.675}\ \frac{LB}{HR}$
WISCONSIN[12]	3/72	40% Opacity II 20% Opacity I, III, IV	I) $Max\ E = .15\ \frac{LB}{MBTU}$ II) $Max\ E = .6\ \frac{LB}{MBTU}$	I) $Max\ E = .15\ \frac{LB}{MBTU}$ II) $Max\ E = .6\ \frac{LB}{MBTU}$

Table B1 (Continued)

State	Date	Visible Emissions	Emissions Concentration Boilers Less Than 50 $\frac{MBTU}{HR}$	Emissions Concentration Boilers From 51 to 250 $\frac{MBTU}{HR}$
<u>WISCONSIN</u> (Continued)			III) Max E = .3 $\frac{LB}{MBTU}$ IV) Max E = .15 $\frac{LB}{MBTU}$	III) Max E = .3 $\frac{LB}{MBTU}$ IV) Max E = .15 $\frac{LB}{MBTU}$
<u>WYOMING</u>	2/72	Existing Units: 40% Opacity New Units: 20% Opacity	New Units: Max E = .1 $\frac{LB}{MBTU}$ E = .896 $Q^{-.174}$ $\frac{LB}{MBTU}$ Existing Units: Max E = .6 $\frac{LB}{MBTU}$	New Units: Max E = .1 $\frac{LB}{MBTU}$ E = .896 $Q^{-.174}$ $\frac{LB}{MBTU}$ Existing Units: Max E = .6 $\frac{LB}{MBTU}$

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[1] The boiler heating value (Q) is the cumulative values for all boilers within the facility. The burning of more than one fuel at a time within a boiler was not considered; some states do have laws regulating combination fuel firing.

[2] Existing units are those units in operation or under construction on the date shown. New units are those units which were constructed after the date shown.

[3] Alabama. A Class 2 county means that 50% of the population resides in a non-urban location or that the county exceeded in 1971 the National Secondary Ambient Air Quality Standards. A Class 1 county is one that does not meet either definition above.

Table B1 (Continued)

[4] Arkansas. "X" stands for the potential emission rate (pounds per hour) without control equipment.

[5] Florida. The state law applies to larger size units. Small units must use "the latest technology."

[6] Hawaii. The only fuel burning equipment considered in state regulations is "bagasse-burning boilers."

[7] Kentucky. Priority I includes the Louisville region. Priority II includes the Cincinnati, Paducah-Cairo, and Evansville-Henderson regions. Priority III is the rest of the state.

[8] Texas. "F" means gas flow in ACFM. "EFF. H" means effective stack height equal to physical stack height plus plume rise. "STD. H" means standard stack height based on gas flow, STD. H equals $1.05\ F^{.35}$.

[9] Utah. The best available technology to remove particulates in the gas stream of small boilers must be reviewed on a case by case basis.

[10] Virginia. Group A: Air quality control region number 7 (Clarke, Frederick, Page, Shenandoah, and Warren counties and the City of Winchester.) Group B: Rest of the state.

[11] West Virginia. Since "a)" means any fuel-burning unit used for the generation of electric power, it is inapplicable. "c)" means hand-fired or stoker-fired fuel burning units not in "a)." "b)" means any fuel burning unit not already in "a)" or "c)."

[12] Wisconsin. Category I: Applies to new or modified sources. Category II: Applies to all existing sources. Category III: Applies to all sources in Subregion 1 of the Lake Michigan AQCR (the counties of Brown, Outagamie, and Winnebago). Category IV: Applies to all sources in Southeast Wisconsin AQCR (the counties of Kenosha, Racine, Milwaukee, Waukesha, Washington, Walworth, and Ozaukee), and shall not burn coal. Standby fuel: Fuel used less than 15 days per year.

Table B2

State Sulfur Dioxide Emission Regulations for Boilers

State	Date[2]	Emissions Concentration[1] Boilers Less Than 50 $\frac{\text{MBTU}}{\text{HR}}$	 Boilers From 51 to 250 $\frac{\text{MBTU}}{\text{HR}}$
ALABAMA[3] (Priority I Region, or New Sources)	5/73	Max E = 1.8 $\frac{\text{LB}}{\text{MBTU}}$	Max E = 1.8 $\frac{\text{LB}}{\text{MBTU}}$
(Priority II & III Regions)	5/73	Max E = 4.0 $\frac{\text{LB}}{\text{MBTU}}$	Max E = 4.0 $\frac{\text{LB}}{\text{MBTU}}$
ALASKA	7/72	Max E = 500 ppm	Max E = 500 ppm
ARIZONA[4]	3/73	New Units, Coal & Oil Fired: Max E = .80 $\frac{\text{LB}}{\text{MBTU}}$ Existing Units, Coal & Oil Fired: Max E = 1.0 $\frac{\text{LB}}{\text{MBTU}}$ Special Case, High Sul. Oil: Max E = 2.2 $\frac{\text{LB}}{\text{MBTU}}$	New Units, Coal & Oil Fired: Max E = .80 $\frac{\text{LB}}{\text{MBTU}}$ Existing Units, Coal & Oil Fired: Max E = 1.0 $\frac{\text{LB}}{\text{MBTU}}$ Special Case, High Sul. Oil: Max E = 2.2 $\frac{\text{LB}}{\text{MBTU}}$
ARKANSAS[5]	7/72	NONE	NONE

Table B2 (Continued)

State	Date	Emissions Concentration Boilers Less Than 50 $\frac{\text{MBTU}}{\text{HR}}$	Boilers From 51 to 250 $\frac{\text{MBTU}}{\text{HR}}$
CALIFORNIA Bay Area Region	8/71	Max E = 300 ppm with provisions for ground level concentrations	Max E = 300 ppm with provisions for ground level concentrations
Los Angeles Region	1/73	Max E = 200 $\frac{\text{LB}}{\text{HR}}$, and	
		Max E = 2000 ppm	Max E = 2000 ppm
		Solid & Liquid Fuel: Max 0.5% Sul.	Solid & Liquid Fuel: Max 0.5% Sul.
		Gaseous Fuel: Max 50 $\frac{\text{GR}}{\text{SCF}}$ Sul.	Gaseous Fuel: Max 50 $\frac{\text{GR}}{\text{SCF}}$ Sul.
Monterey Region	9/74	Max E = 2000 ppm	Max E = 2000 ppm
		Solid & Liquid Fuel: Max 0.5% Sul.	Solid & Liquid Fuel: Max 0.5% Sul.
		Gaseous Fuel: Max 50 $\frac{\text{GR}}{\text{SCF}}$ Sul.	Gaseous Fuel: Max 50 $\frac{\text{GR}}{\text{SCF}}$ Sul.
Riverside Region	10/74	Max E = 500 ppm (West-Central Area)	Max E =500 ppm (West-Central Area)

Table B2 (Continued)

State	Date	Emissions Concentration Boilers Less Than 50 $\frac{MBTU}{HR}$	 Boilers From 51 to 250 $\frac{MBTU}{HR}$
CALIFORNIA Riverside Region (Continued)		Max E = 1500 (Rest of Region) New Units: Max E = 200 $\frac{LB}{HR}$	Max E = 1500 (Rest of Region) New Units: Max E = 200 $\frac{LB}{HR}$
Sacramento Region	2/75	Max E = 2000 ppm	Max E = 2000 ppm
San Bernardino Region	2/73	Max E = 500 ppm AND Max E = 200 $\frac{LB}{HR}$ AND Max .5% Sulfur in Fuel	Max E = 500 ppm AND Max E = 200 $\frac{LB}{HR}$ AND Max .5% Sulfur in Fuel
San Joaquin Region	8/74	Max E = 2000 ppm New Units: Max E = 200 $\frac{LB}{HR}$	Max E = 2000 ppm New Units: Max E = 200 $\frac{LB}{HR}$
San Luis Obispo Region	5/71	Existing Units: Max E = 2000 ppm New Units: Max E = 200 $\frac{LB}{HR}$	Existing Units: Max E = 2000 ppm New Units: Max E = 200 $\frac{LB}{HR}$

Table B2 (Continued)

State	Date	Emissions Concentration	
		Boilers Less Than 50 $\frac{\text{MBTU}}{\text{HR}}$	Boilers From 51 to 250 $\frac{\text{MBTU}}{\text{HR}}$
CALIFORNIA (Continued) Santa Barbara Region		Max E = 200 $\frac{\text{LB}}{\text{HR}}$	Max E = 200 $\frac{\text{LB}}{\text{HR}}$
		Solid & Liquid Fuel Max 0.5% Sul.	Solid & Liquid Fuel: Max 0.5% Sul.
		Gaseous Fuel: Max 50 $\frac{\text{GR}}{\text{SCF}}$ (Northern Area) Max 15 $\frac{\text{GR}}{\text{SCF}}$ (Southern Area)	Gaseous Fuel: Max 50 $\frac{\text{GR}}{\text{SCF}}$ (Northern Area) Max 15 $\frac{\text{GR}}{\text{SCF}}$ (Southern Area)
COLORADO	5/73	Max E = 500 ppm & 5 $\frac{\text{TON}}{\text{DAY}}$ Max (Existing Law)	Max E = 500 ppm & 5 $\frac{\text{TON}}{\text{DAY}}$ Max (Existing Law)
		Max E = 150 ppm (Effective 1/1/78)	Max E = 150 ppm (Effective 1/1/78)
CONNECTICUT	4/73	Max E = .55 $\frac{\text{LB}}{\text{MBTU}}$ (W/Gas Cleaning) OR Max .5% Sulfur in Fuel	Max E = .55 $\frac{\text{LB}}{\text{MBTU}}$ (W/Gas Cleaning) OR Max .5% Sulfur in Fuel
DELAWARE	5/74	Max 1.0% Sulfur in Coal	Max 1.0% Sulfur in Coal
		Max .3% in Fuel Oil	Max .3% in Fuel Oil

Table B2 (Continued)

State	Date	Emissions Concentration Boilers Less Than 50 $\frac{MBTU}{HR}$	 Boilers From 51 to 50 $\frac{MBTU}{HR}$
FLORIDA[6]	12/74	N/A	N/A
GEORGIA[7]	9/73	Max $E = 4000\ F\ (\frac{H_s}{300})^3\ \frac{LB}{HR}$	Max $E = 4000\ F\ (\frac{H_s}{300})^3\ \frac{LB}{HR}$
		$(H_s < 300$ Ft)	$(H_s < 300$ Ft)
		Max $E = 4000\ F\ (\frac{H_s}{300})^2\ \frac{LB}{HR}$	Max $E = 4000\ F\ (\frac{H_s}{300})^2\ \frac{LB}{HR}$
		$(H_s > 300$ Ft)	$(H_s > 300$ Ft)
HAWAII	6/74	Max 2.0% Sulfur in Fuel	Max 2.0% Sulfur in Fuel
IDAHO	1/73	Max .3% Sulfur in Fuel Oil (#1)	Max .3% Sulfur in Fuel Oil (#1)
		Max .5% Sulfur in Fuel Oil (#2)	Max .5% Sulfur in Fuel Oil (#2)
		Max 1.75% Sulfur in Fuel Oil (#5 & 6)	Max 1.75% Sulfur in Fuel Oil (#5 & 6)
		Max 1.0% Sulfur in Coal	Max 1.0% Sulfur in Coal
ILLINOIS[8] Group A Areas & New Units	4/72	Existing Units: Fuel Oil (#1 & 2): Max $E = 0.3\ \frac{LB}{MBTU}$	Existing Units: Fuel Oil (#1 & 2): Max $E = 0.3\ \frac{LB}{MBTU}$

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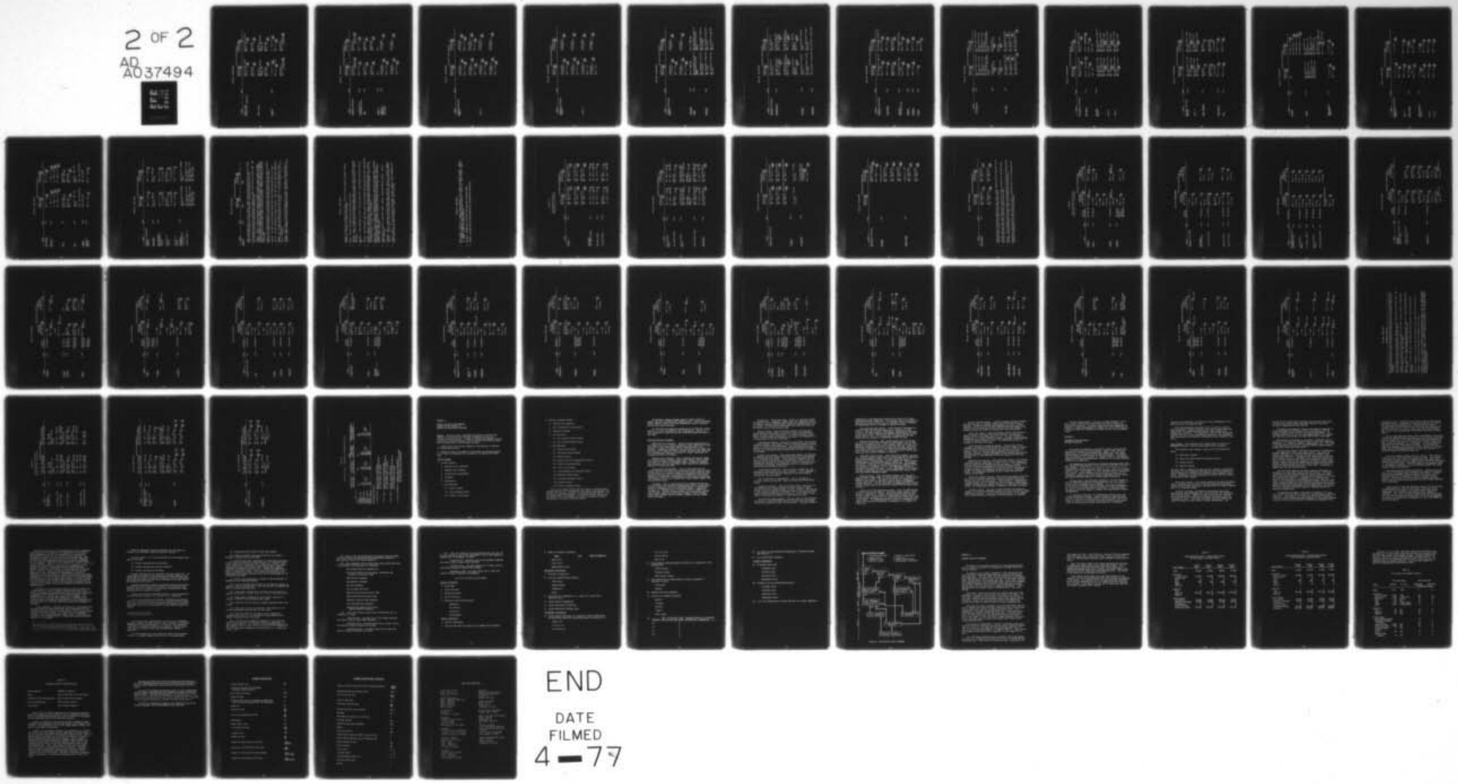

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Table B2 (Continued)

State	Date	Emissions Concentration	
		Boilers Less Than 50 $\frac{MBTU}{HR}$	Boilers From 51 to 250 $\frac{MBTU}{HR}$
Group A Areas and New Units (Continued)		Fuel Oil (#4, 5 &6): Max E = 1.0 $\frac{LB}{MBTU}$	Fuel Oil (#4, 5 & 6): Max E = 1.0 $\frac{LB}{MBTU}$
		Solid Fuel: Max E = 1.8 $\frac{LB}{MBTU}$	Solid Fuel: Max E = 1.8 $\frac{LB}{MBTU}$
Group B Areas		Fuel Oil: Max E = See Group A (above) for	Fuel Oil: Max E = See Group A (above) for
		Solid Fuel: Max E = 6.0 $\frac{LB}{MBTU}$	Solid Fuel: Max E = 6.0 $\frac{LB}{MBTU}$
<u>INDIANA</u> [9]	9/72	E = 17 $Q^{-0.33}$ $\frac{LB}{MBTU}$ Max E = 6 $\frac{LB}{MBTU}$, OR	E = 17 $Q^{-0.33}$ $\frac{LB}{MBTU}$ Max E = 6 $\frac{LB}{MBTU}$
		Priority A: Max E = $\frac{1.76\ H_s}{Q^{.75}\eta^{.25}}$ $\frac{LB}{MBTU}$	Priority A: Max E = $\frac{1.76\ H_s}{Q^{.75}\eta^{.25}}$ $\frac{LB}{MBTU}$

Table B2 (Continued)

State	Date	Emissions Concentration Boilers Less Than 50 $\frac{MBTU}{HR}$	Emissions Concentration Boilers From 51 to 250 $\frac{MBTU}{HR}$
INDIANA (Continued)		Priority B: Max E = $\frac{4.4\ H_s}{Q^{.75} n^{.25}}$ $\frac{LB}{MBTU}$	Priority B: Max E = $\frac{4.4\ H_s}{Q^{.75} n^{.25}}$ $\frac{LB}{MBTU}$
(Chicago Area & Indianapolis Area)	4/72	Max E = 1.8 $\frac{LB}{MBTU}$	Max E = 1.8 $\frac{LB}{MBTU}$
IOWA	1/75	Solid Fuel: Max E = .5 $\frac{LB}{MBTU}$ Liquid Fuel: Max E = 1.5 $\frac{LB}{MBTU}$	Solid Fuel: Max E = .5 $\frac{LB}{MBTU}$ Liquid Fuel: Max E = 1.5 $\frac{LB}{MBTU}$
KANSAS [10]	1/74	N/A	N/A
KENTUCKY [11] (New Units, All State)	4/72	Liquid Fuel: E = 5.65 $Q^{-.35}$ $\frac{LB}{MBTU}$ Max E = 2.5 $\frac{LB}{MBTU}$ Solid Fuel: E = 9.46 $Q^{-.37}$ $\frac{LB}{MBTU}$ Max E = 4.0 $\frac{LB}{MBTU}$	Liquid Fuel: E = 5.65 $Q^{-.35}$ $\frac{LB}{MBTU}$ Solid Fuel: E = 9.46 $Q^{-.37}$ $\frac{LB}{MBTU}$

Table B2 (Continued)

		Emissions Concentration	
State	Date	Boilers Less Than 50 $\frac{MBTU}{HR}$	Boilers From 51 to 250 $\frac{MBTU}{HR}$
KENTUCKY (Continued) Class I		Liquid Fuel: $E = 7.72\ Q^{-.41}\ \frac{LB}{MBTU}$ Max $E = 3.0\ \frac{LB}{MBTU}$	Liquid Fuel: $E = 7.72\ Q^{-.41}\ \frac{LB}{MBTU}$ Max $E = 3.0\ \frac{LB}{MBTU}$
		Solid Fuel: $E = 13.88\ Q^{-.44}\ \frac{LB}{MBTU}$ Max $E = 5\ \frac{LB}{MBTU}$	Solid Fuel: $E = 13.88\ Q^{-.44}\ \frac{LB}{MBTU}$ Max $E = 5\ \frac{LB}{MBTU}$
Class II		Liquid Fuel: $E = 9.46\ Q^{-.37}\ \frac{LB}{MBTU}$ Max $E = 4.0\ \frac{LB}{MBTU}$	Liquid Fuel: $E = 9.46\ Q^{-.37}\ \frac{LB}{MBTU}$
		Solid Fuel: $E = 14.20\ Q^{-.37}\ \frac{LB}{MBTU}$ Max $E = 6.0\ \frac{LB}{MBTU}$	Solid Fuel: $E = 14.20\ Q^{-.37}\ \frac{LB}{MBTU}$

Table B2 (Continued)

State	Date	Emissions Concentration	
		Boilers Less Than 50 $\frac{MBTU}{HR}$	Boilers From 51 to 250 $\frac{MBTU}{HR}$
KENTUCKY (Continued) Class III		Liquid Fuel: $E = 8.06\ Q^{-.24}\ \frac{LB}{MBTU}$ Max $E = 4.6\ \frac{LB}{MBTU}$	Liquid Fuel: $E = 8.06\ Q^{-.24}\ \frac{LB}{MBTU}$
		Solid Fuel: $E = 12.25\ Q^{-.24}\ \frac{LB}{MBTU}$ Max $E = 7.0\ \frac{LB}{MBTU}$	Solid Fuel: $E = 12.25\ Q^{-.24}\ \frac{LB}{MBTU}$
Class IV		Liquid Fuel: $E = 7.36\ Q^{-.13}\ \frac{LB}{MBTU}$ Max $E = 5.4$	Liquid Fuel: $E = 7.36\ Q^{-.13}\ \frac{LB}{MBTU}$
		Solid Fuel: $E = 10.89\ Q^{-.13}\ \frac{LB}{MBTU}$ Max $E = 8.0$	Solid Fuel: $E = 10.89\ Q^{-.13}\ \frac{LB}{MBTU}$

Table B2 (Continued)

		Emissions Concentration	
State	Date	Boilers Less Than 50 $\frac{MBTU}{HR}$	Boilers From 51 to 250 $\frac{MBTU}{HR}$
KENTUCKY (Continued) Class V		Liquid Fuel: $E = 8.02\ Q^{-.13}\ \frac{LB}{MBTU}$ $\text{Max } E = 6.0\ \frac{LB}{MBTU}$	Liquid Fuel: $E = 8.02\ Q^{-.13}\ \frac{LB}{MBTU}$
		Solid Fuel: $E = 12.03\ Q^{-.13}\ \frac{LB}{MBTU}$ $\text{Max } E = 9.0\ \frac{LB}{MBTU}$	Solid Fuel: $E = 12.03\ Q^{-.13}\ \frac{LB}{MBTU}$
LOUISIANA	1/72	Max E = 2000 ppm	Max E = 2000 ppm
MAINE	11/73	Max 1.5% Sulfur in Fuel in Metropolitan Portland Region	Max 1.5% Sulfur in Fuel in Metropolitan Portland Region
		Max 2.5% Sulfur in Fuel in Rest of Maine	Max 2.5% Sulfur in Fuel in Rest of Maine
MARYLAND	8/72	Max .5% Sulfur in Fuel Oil (#4, 5 & 6)	Max .5% Sulfur in Fuel Oil (#4, 5 & 6)
		Max .3% Sulfur in Fuel Oil (#1 & 2)	Max .3% Sulfur in Fuel Oil (#1 & 2)

Table B2 (Continued)

State	Date	Emissions Concentration Boilers Less Than 50 $\frac{\text{MBTU}}{\text{HR}}$	Boilers From 51 to 250 $\frac{\text{MBTU}}{\text{H}}$
MARYLAND (Continued)		Max 1.0% Sulfur in Solid Fuel	Max 1.0% Sulfur in Solid Fuel
MASSACHUSETTS	9/72	For Coal or #4, 5, 6 Fuel Oil in Cities: Max E = .28 $\frac{\text{LB SUL}}{\text{MBTU}}$	For Coal or #4, 5, 6 Fuel Oil in Cities Max E = .28 $\frac{\text{LB SUL}}{\text{MBTU}}$
		For Coal or #4, 5, 6 Fuel Oil in Other Places: Max E = .55 $\frac{\text{LB SUL}}{\text{MBTU}}$	For Coal or #4, 5, 6 Fuel Oil in Other Places: Max E = .55 $\frac{\text{LB SUL}}{\text{MBTU}}$
		For #1 & 2 Fuel Oil, Anywhere: Max E =.17 $\frac{\text{LB SUL}}{\text{MBTU}}$	For #1 & 2 Fuel Oil, Anywhere: Max E =.17 $\frac{\text{LB SUL}}{\text{MBTU}}$
MICHIGAN	11/73	Max 2% Sulfur in Fuel by 7/1/75	Max 2% Sulfur in Fuel by 7/1/75
		Max 1-1/2% Sulfur in Fuel by 7/1/78	Max 1-1/2% Sulfur in Fuel by 7/1/78
MINNESOTA	6/69	Max 2% Sulfur in Solid Fuel	Max 2% Sulfur in Solid Fuel

Table B2 (Continued)

State	Date	Emissions Concentration Boilers Less Than 50 $\frac{\text{MBTU}}{\text{HR}}$	 Boilers From 51 to 250 $\frac{\text{MBTU}}{\text{HR}}$
MINNESOTA (Continued)		Max 2% Sulfur in Fuel Oil OR Max E = 1.75 $\frac{\text{LB}}{\text{MBTU}}$	Max 2% Sulfur in Fuel Oil OR Max E = 1.75 $\frac{\text{LB}}{\text{MBTU}}$
MISSISSIPPI	1/72	Max E = 4.8 $\frac{\text{LB}}{\text{MBTU}}$	Max E = 4.8 $\frac{\text{LB}}{\text{MBTU}}$
		Modified Units: Max E = 2.4 $\frac{\text{LB}}{\text{MBTU}}$	Modified Units: Max E = 2.4 $\frac{\text{LB}}{\text{MBTU}}$
MISSOURI [12] (St. Louis Area)	3/71	Max 2% Sulfur in Fuel OR Max E = 2.3 $\frac{\text{LB}}{\text{MBTU}}$	Max 2% Sulfur in Fuel OR Max E = 2.3 $\frac{\text{LB}}{\text{MBTU}}$
MONTANA	6/68	Max 1.0 $\frac{\text{LB SUL}}{\text{MBTU}}$	Max 1.0 $\frac{\text{LB SUL}}{\text{MBTU}}$
NEBRASKA	2/74	Max E = 2.5 $\frac{\text{LB}}{\text{MBTU}}$	Max E = 2.5 $\frac{\text{LB}}{\text{MBTU}}$
NEVADA	9/74	E = .7 Q $\frac{\text{LB}}{\text{HR}}$	E = .7 Q $\frac{\text{LB}}{\text{HR}}$ Max E = 175 $\frac{\text{LB}}{\text{HR}}$

Table B2 (Continued)

State	Date	Emissions Concentration	
		Boilers Less Than 50 $\frac{\text{MBTU}}{\text{HR}}$	Boilers From 51 to 250 $\frac{\text{MBTU}}{\text{HR}}$
NEW HAMPSHIRE	10/72	Max .4% Sulfur in Fuel Oil (#2) Max 1.0% Sulfur in Fuel Oil (#4) Max 1.5% Sulfur in Fuel Oil (#5 & 6) Max 2.2% Sulfur in Fuel Oil (#5 & 6) Androscoggin Valley	Max .4% Sulfur in Fuel Oil (#2) Max 1.0% Sulfur in Fuel Oil (#4) Max 1.5% Sulfur in Fuel Oil (#5 & 6) Max 2.2% Sulfur in Fuel Oil (#5 & 6) Androscoggin Valley
	10/70	Existing Units: 2.8 $\frac{\text{LB SUL}}{\text{MBTU}}$ in Coal	Existing Units: 2.8 $\frac{\text{LB SUL}}{\text{MBTU}}$ in Coal
		New Units: 1.5 $\frac{\text{LB SUL}}{\text{MBTU}}$ in Coal	New Units: 1.5 $\frac{\text{LB SUL}}{\text{MBTU}}$ in Coal
NEW JERSEY	10/71	Max .2% Sulfur in #2 Fuel Oil or Max E = .3 $\frac{\text{LB}}{\text{MBTU}}$ Max .3% Sulfur in #4 Fuel Oil or Max E = .3 $\frac{\text{LB}}{\text{MBTU}}$ Max .3% Sulfur in #5 & 6 Fuel Oil or Max E = .3 $\frac{\text{LB}}{\text{MBTU}}$	Max .2% Sulfur in #2 Fuel Oil or Max E = .3 $\frac{\text{LB}}{\text{MBTU}}$ Max .3% Sulfur in #4 Fuel Oil or Max E = .3 $\frac{\text{LB}}{\text{MBTU}}$ Max .3% Sulfur in #5 & 6 Fuel Oil or Max E = .3 $\frac{\text{LB}}{\text{MBTU}}$

Table B2 (Continued)

State	Date	Emissions Concentration	
		Boilers Less Than 50 $\frac{\text{MBTU}}{\text{HR}}$	Boilers From 51 to 250 $\frac{\text{MBTU}}{\text{HR}}$
NEW JERSEY (Continued)		Max .2% Sulfur in Coal or Max E = .3 $\frac{\text{LB}}{\text{MBTU}}$	Max .2% Sulfur in Coal or Max E = .3 $\frac{\text{LB}}{\text{MBTU}}$
NEW MEXICO	1/72	Oil Q > 1,000,000 $\frac{\text{MBTU}}{\text{YR}}$ Max E = .34 $\frac{\text{LB}}{\text{MBTU}}$ Coal: N/A	Oil Q > 1,000,000 $\frac{\text{MBTU}}{\text{YR}}$ Max E = .34 $\frac{\text{LB}}{\text{MBTU}}$ Coal: N/A
NEW YORK [14]	10/74		
Group A:		Max .2% Sulfur in Fuel Oil (#1 & 2) Max .3% Sulfur in Fuel Oil (#4, 5 & 6) Max .2 $\frac{\text{LB SUL}}{\text{MBTU}}$ in Coal	Max .2% Sulfur in Fuel Oil (#1 & 2) Max .3% Sulfur in Fuel Oil (#4, 5 & 6) Max .2 $\frac{\text{LB SUL}}{\text{MBTU}}$ in Coal
Group B:		Max .37% Sulfur in Fuel Oil (All) Max .2 $\frac{\text{LB SUL}}{\text{MBTU}}$ in Coal	Max .37% Sulfur in Fuel Oil (All) Max .2 $\frac{\text{LB SUL}}{\text{MBTU}}$ in Coal
Group C:		Max 1.0% Sulfur in Fuel Oil (All) Max .6 $\frac{\text{LB SUL}}{\text{MBTU}}$ in Coal	Max 1.0% Sulfur in Fuel Oil (All) Max .6 $\frac{\text{LB SUL}}{\text{MBTU}}$ in Coal

Table B2 (Continued)

State	Date	Emissions Concentration Boilers Less Than 50 $\frac{\text{MBTU}}{\text{HR}}$	Emissions Concentration Boilers From 51 to 250 $\frac{\text{MBTU}}{\text{HR}}$
NEW YORK (Continued) Group D:	10/74	Max 1.1% Sulfur in Fuel Oil (All) Max 1.4 $\frac{\text{LB SUL}}{\text{MBTU}}$ in Coal	Max 1.1% Sulfur in Fuel Oil (All) Max 1.4 $\frac{\text{LB SUL}}{\text{MBTU}}$ in Coal
Group E:		Max 2% Sulfur in Fuel Oil (All) Max 1.9 $\frac{\text{LB SUL}}{\text{MBTU}}$ in Coal	Max 2% Sulfur in Fuel Oil (All) Max 1.9 $\frac{\text{LB SUL}}{\text{MBTU}}$ in Coal
NORTH CAROLINA	7/71	New Units: Max E = 1.6 $\frac{\text{LB}}{\text{HR}}$ Existing Units: Max E = 2.3 $\frac{\text{LB}}{\text{HR}}$ (1.6 by 1980)	New Units: Max E = 1.6 $\frac{\text{LB}}{\text{HR}}$ Existing Units: Max E = 2.3 $\frac{\text{LB}}{\text{HR}}$ (1.6 by 1980)
NORTH DAKOTA	12/73	Max E = 3.0 $\frac{\text{LB}}{\text{MBTU}}$	Max E = 3.0 $\frac{\text{LB}}{\text{MBTU}}$
OHIO	7/72	Max E = 1.0 $\frac{\text{LB}}{\text{MBTU}}$	Max E = 1.0 $\frac{\text{LB}}{\text{MBTU}}$

Table B2 (Continued)

		Emissions Concentration	
State	Date	Boilers Less Than 50 $\frac{\text{MBTU}}{\text{HR}}$	Boilers From 51 to 250 $\frac{\text{MBTU}}{\text{HR}}$
<u>OKLAHOMA</u>	7/72	N/A	All Units, $Q > 50 \frac{\text{MBTU}}{\text{HR}}$ Gas Fired: Max $E = .2 \frac{\text{LB}}{\text{MBTU}}$ Oil Fired: Max $E = .8 \frac{\text{LB}}{\text{MBTU}}$ Coal Fired: Max $E = 1.2 \frac{\text{LB}}{\text{MBTU}}$
<u>OREGON</u>	1/72	Max .3% Sulfur in #1 Fuel Oil Max .5% Sulfur in #2 Fuel Oil Max 1.75% Sulfur in #4, 5 & 6 Fuel Oil Max 1% Sulfur in Coal	Max .3% Sulfur in #1 Fuel Oil Max .5% Sulfur in #2 Fuel Oil Max 1.75% Sulfur in #4, 5 & 6 Fuel Oil Max 1% Sulfur in Coal For Units with $Q > 150$: Max $E = 1.4 \frac{\text{LB}}{\text{MBTU}}$ (Liquid Fuel) Max $E = 1.6 \frac{\text{LB}}{\text{MBTU}}$ (Solid Fuel)
<u>PENNSYLVANIA</u>[15] Group A:	9/71	$E = 5.1\ Q^{-.14} \frac{\text{LB}}{\text{MBTU}}$ Max $E = 3 \frac{\text{LB}}{\text{MBTU}}$	$E = 5.1\ Q^{-.14} \frac{\text{LB}}{\text{MBTU}}$ Max $E = 3 \frac{\text{LB}}{\text{MBTU}}$

Table B2 (Continued)

State	Date	Emissions Concentration	
		Boilers Less Than 50 $\frac{MBTU}{HR}$	Boilers From 51 to 250 $\frac{MBTU}{HR}$
PENNSYLVANIA (Continued)			
Group B:		$E = 1.7\ Q^{-.14}\ \frac{LB}{MBTU}$ $\text{Max } E = 1\ \frac{LB}{MBTU}$	$E = 1.7\ Q^{-.14}\ \frac{LB}{MBTU}$
Group C:		$\text{Max } E = 4.0\ \frac{LB}{MBTU}$	$\text{Max } E = 4.0\ \frac{LB}{MBTU}$
RHODE ISLAND	10/71	$\text{Max } .55\ \frac{LB\ SUL}{MBTU}$ OR $\text{Max } E = 1.1\ \frac{LB}{MBTU}$	$\text{Max } .55\ \frac{LB\ SUL}{MBTU}$ OR $\text{Max } E = 1.1\ \frac{LB}{MBTU}$
SOUTH CAROLINA 16	1/74		
Group A:		$Q < 10\ \frac{MBTU}{HR},$ $\text{Max } E = 3.5\ \frac{LB}{MBTU}$	$Q > 10\ \frac{MBTU}{HR},$ $\text{Max } E = 2.3\ \frac{LB}{MBTU}$
Group B:		$\text{Max } E = 3.5\ \frac{LB}{MBTU}$	$\text{Max } E = 3.5\ \frac{LB}{MBTU}$
Group C:		$\text{Max } E = 3.5\ \frac{LB}{MBTU}$	$\text{Max } E = 3.5\ \frac{LB}{MBTU}$

Table B2 (Continued)

State	Date	Emissions Concentration Boilers Less Than 50 $\frac{MBTU}{HR}$	 Boilers From 51 to 250 $\frac{MBTU}{HR}$
SOUTH DAKOTA	1/72	Max E = 3.0 $\frac{LB}{MBTU}$	Max E = 3.0 $\frac{LB}{MBTU}$
TENNESSEE [17]	4/72	I: Max E = 1.6 $\frac{LB}{MBTU}$ II: Max E = 3.0 $\frac{LB}{MBTU}$ III: Max E = 4.0 $\frac{LB}{MBTU}$	I: Max E = 1.6 $\frac{LB}{MBTU}$ II: Max E = 3.0 $\frac{LB}{MBTU}$ III: Max E = 4.0 $\frac{LB}{MBTU}$
TEXAS	3/72	Liquid Fuel: Max E = 440 ppm Solid Fuel: Max E = 3.0 $\frac{LB}{MBTU}$	Liquid Fuel: Max E = 440 ppm Solid Fuel: Max E = 3.0 $\frac{LB}{MBTU}$
UTAH	9/71	Fuel Oil: Max 1.5% Sulfur Coal: Max 1.0% Sulfur	Fuel Oil: Max 1.5% Sulfur Coal: Max 1.0% Sulfur
VERMONT	10/72	Max 1.5% Sulfur	Max 1.5% Sulfur
VIRGINIA [18] Group A:	3/72	Max E = 1.06 Q $\frac{LB}{HR}$	Max E = 1.06 Q $\frac{LB}{HR}$

Table B2 (Continued)

State	Date	Emissions Concentration	
		Boilers Less Than 50 $\frac{MBTU}{HR}$	Boilers From 51 to 250 $\frac{MBTU}{HR}$
VIRGINIA (Continued) Group B:		Max E = 2.64 Q $\frac{LB}{HR}$	Max E = 2.64 Q $\frac{LB}{HR}$
WASHINGTON	8/74	Max E = 1000 ppm @ 7% O_2	Max E = 1000 ppm @ 7% O_2
WEST VIRGINIA [19] Priority I & II Regions:	6/75	Max E = 3.1 Q $\frac{LB}{HR}$ (= 2.3 Q by 6/78)	Max E = 3.1 Q $\frac{LB}{HR}$ (= 2.3 Q by 6/78)
Priority III Regions:		All Units: Max E = 3.2 Q $\frac{LB}{HR}$ (= 2.3 Q by 6/78)	All Units: Max E = 3.2 Q $\frac{LB}{HR}$ (= 2.3 Q by 6/78)
Priority IV Regions:		Max E = 1.6 Q $\frac{LB}{HR}$	Max E = 1.6 Q $\frac{LB}{HR}$
WISCONSIN [20] Priority Regions I, II, III	3/72	None Except for Standby Fuels:	None Except for Standby Fuels:
Priority Region IV		Max .7% Sulfur in Fuel Oil (#1 & 2) Max 1.0% Sulfur in Fuel Oil (#4, 5 & 6) Max 1.50% in Coal	Max .7% Sulfur in Fuel Oil (#1 & 2) Max 1.0% Sulfur in Fuel Oil (#4, 5 & 6) Max 1.50% in Coal

Table B2 (Continued)

		Emissions Concentration	
State	Date	Boilers Less Than 50 $\frac{MBTU}{HR}$	Boilers From 51 to 250 $\frac{MBTU}{HR}$
WYOMING[21]	5/74	NONE	NONE

[1] Where the maximum sulfur in fuel is given, a higher sulfur content may be used if flue gas cleaning brings the stack emissions to below the level equal to burning the maximum sulfur coal.

[2] Existing units are those units which were in operation or under construction by the date shown. New units are those which were constructed after the date shown.

[3] Alabama. Priority I region includes the counties of Baldwin, Colbert, Cullman, DeKalb, Escambia, Franklin, Jackson, Lauderdale, Lawrence, Limestone, Madison, Marion, Marshall, Mobile, and Morgan. Priority II region includes the counties of Bibb, Blount, Chilton, Fayette, Greene, Hale, Jefferson, Lamar, Pickens, St. Clair, Shelby, Sumter, Tuscaloosa, and Walker. Priority III region is the rest of the state.

[4] Arizona. "This regulation applies to an installation operated for the purpose of producing electric power with a resulting discharge of sulfur dioxide in the installation's effluent gases."

[5] Arkansas. The state law only regulates ground level sulfur dioxide concentrations at 0.2 ppm.

[6] Florida. The state law applies to larger size units. Small units must use "the latest technology".

[7] Georgia. $F = 1$ if unit is within 5 miles of the city limits of a city (50,000 persons or more). $F = 2$ if unit is within the city limits and $Q < 10$ MBTU/HR. $F = 3$ if unit is within the city limits and $Q > 10$ MBTU/HR.

[8] Illinois. Group A Area; The cities of Chicago, East St. Louis, and Peoria, and the counties of Champaign, Macon, Winnebago, Rock Island, Sangamon, and McLean. Group B Area: The rest of the state.

Table B2 (Continued)

9 Indiana. Priority A is the area of Lake County. Priority B is the counties of Dearborn, Marion, and Warrick. Priority C is the rest of the state.

10 Kansas. The state law applies only to the larger size units.

11 Kentucky. Class I - Jefferson and McCracken counties, Class II - Bell, Clark, and Woodford counties, Class III - Pulaski county, Class IV - Hancock, Muhlenburg and Webster counties, Class V - rest of the state.

12 Minnesota. Either regulation is valid; if the low sulfur fuel is not available, then Max E must be met.

13 Missouri. The only general state law found is one that governs the maximum ground level concentrations.

14 New York. Group A: New York City. Group B: Nassau, Rocklan and Westchester counties. Group C: Suffolk county and cities of Babylon, Brookhaven, Huntington, Islip, and Smithtown. Group D: Erie and Niagara counties. Group E: Rest of the state.

15 Pennsylvania. Group A: Allentown--Bethlehem--Easton Basin, Erie Basin, Harrisburg Basin, Johnstown Basin, Lancaster Basin, Reading Basin, Scranton-Wilkes-Barre Basin, and York Basin. Group B: Allegheny Basin, Beaver Valley Basin, Monongahela Valley Basin, and Southeast Pennsylvania Basin. Group C: Rest of the state.

16 South Carolina. Group A: Charleston county. Group B: Aiken and Anderson counties. Group C: Rest of the state.

17 Tennessee. Class I: counties of Sullivan, Roone, Maury, and Polk. Class II: county of Humphrey. Class III: rest of state. Also, new and existing sources have the same regulation after 7/1/75.

18 Virginia. Group A: Air quality control region number 7 (Clark, Frederick, Page, Shenandoah, and Warren counties and the City of Winchester. Group B: Rest of the state.

Table B2 (Continued)

19 West Virginia. Priority I: Brooke, Hancock, Marshall, Ohio, Grant, and Mineral counties. Priority II: Jackson, Pleasants, Tyler, Wetzel, and Wood counties. Priority III: Rest of state. Region 4: Kanawha, Putnam, and Fayette counties.

20 Wisconsin. *Standby fuel* is *any fuel* used less than 15 days per year.

21 Wyoming. No state law was found concerning the SO_2 emissions from boilers.

Table B3

State Gaseous Emission Regulations for Boilers

State	Date[2]	Emissions Concentration[1] Boilers Less Than 50 $\frac{MBTU}{HR}$	Boilers From 51 to 250 $\frac{MBTU}{HR}$
ARIZONA[3]	3/73	New, Gas Fired Units: NO_2: Max E = .2 $\frac{LB}{MBTU}$	New, Gas Fired Units: NO_2: Max E = .2 $\frac{LB}{MBTU}$
		New, Oil Fired Units: NO_2: Max E = .3 $\frac{LB}{MBTU}$	New, Oil Fired Units: NO_2: Max E = .3 $\frac{LB}{MBTU}$
		New, Coal Fired: NO_2: Max E = .7 $\frac{LB}{MBTU}$	New Coal Fired: NO_2: Max E = .7 $\frac{LB}{MBTU}$
CALIFORNIA Los Angeles Region	1/73	NO_2: Max E = 140 $\frac{LB}{HR}$ CO: Max E = 2000 ppm	NO_2: Max E = 140 $\frac{LB}{HR}$ CO: Max E = 2000 ppm
Monterey Region	9/74	NO_2: Max E = 140 $\frac{LB}{HR}$	NO_2: Max E = 140 $\frac{LB}{HR}$
Riverside Region	10/74	New:Units: NO_2: Max E = 140 $\frac{LB}{HR}$ CO: Max E = 2000 ppm	New Units: NO_2: Max E = 140 $\frac{LB}{HR}$ CO: Max E = 2000 ppm

Table B3 (Continued)

		Emissions Concentration	
State	Date	Boilers Less Than 50 $\frac{MBTU}{HR}$	Boilers From 51 to 250 $\frac{MBTU}{HR}$
San Bernardino Region	2/73	NO_2: Max E = 140 $\frac{LB}{HR}$ CO: Max E = 2000 ppm	NO_2: Max E = 140 $\frac{LB}{HR}$ CO: Max E = 2000 ppm
San Joaquin Region	5/72	New Units: NO_2: Max E = 140 $\frac{LB}{HR}$	New Units: NO_2: Max E = 140 $\frac{LB}{HR}$
San Luis Obispo Region	5/71	For the First 10,000 Cubic Feet per Hour: NO_2: Max E = 1000 ppm Thereafter: NO_2: Max E = 250 ppm @ 3% O_2	For the First 10,000 Cubic Feet per Hour: NO_2: Max E = 1000 ppm Thereafter: NO_2: Max E = 250 ppm @ 3% O_2
Santa Barbara Region	6/72	South Coast Basin Only: NO_2: Max E = 140 $\frac{LB}{HR}$ CO: Max E = 2000 ppm	South Coast Basin Only: NO_2: Max E = 140 $\frac{LB}{HR}$ CO: Max E = 2000 ppm
Connecticut[4]	6/72	All Gas Fired Units: NO_2: Max E = .2 $\frac{LB}{MBTU}$	All Gas Fired Units: NO_2: Max E = .2 $\frac{LB}{MBTU}$

Table B3 (Continued)

State	Date	Emissions Concentration Boilers Less Than 50 $\frac{\text{MBTU}}{\text{HR}}$	Emissions Concentration Boilers From 51 to 250 $\frac{\text{MBTU}}{\text{HR}}$
CONNECTICUT (continued)		All Oil Fired Units: NO_2: Max E = .3 $\frac{\text{LB}}{\text{MBTU}}$	All Oil Fired Units: NO_2: Max E = .3 $\frac{\text{LB}}{\text{MBTU}}$
		New Coal Fired Units: NO_2: Max E = .7 $\frac{\text{LB}}{\text{MBTU}}$	New Coal Fired Units: NO_2: Max E = .7 $\frac{\text{LB}}{\text{MBTU}}$
		Existing Coal Fired Units: NO_2: Max E = .9 $\frac{\text{LB}}{\text{MBTU}}$	Existing Coal Fired Units: NO_2: Max E = .9 $\frac{\text{LB}}{\text{MBTU}}$
ILLINOIS	12/73	CO: Max E = 200 ppm @ 50% E.A.	CO: Max E = 200 ppm @ 50% E.A.
NEW MEXICO	12/74		Oil and Existing Gas Fired Units With Q > 1,000,000 $\frac{\text{MBTU}}{\text{YEAR}}$: NO_2: Max E = .3 $\frac{\text{LB}}{\text{MBTU}}$

Table B3 (Continued)

State	Date	Emissions Concentration Boilers Less Than 50 $\frac{MBTU}{HR}$	Emissions Concentration Boilers From 51 to 250 $\frac{MBTU}{HR}$
NEW MEXICO (Continued)			New Gas Fired Units With Q > 1,000,000 $\frac{MBTU}{YEAR}$: NO_2: Max E = .2 $\frac{LB}{MBTU}$
OKLAHOMA	7/72		New Units W. Q > 50 Gas Fired Units: NO_2: Max E = .20 $\frac{LB}{MBTU}$ Oil Fired Units: NO_2: Max E = .30 $\frac{LB}{MBTU}$ Coal Fired Units: NO_2: Max E = .70 $\frac{LB}{MBTU}$
RHODE ISLAND	2/72		Units W. Q > 100 Gas Fired Units: NO_2: Max E = .2 $\frac{LB}{MBTU}$ Oil Fired Units: NO_2: Max E = .3 $\frac{LB}{MBTU}$

Table B3 (Continued)

State	Date	Emissions Concentration	
		Boilers Less Than 50 $\frac{\text{MBTU}}{\text{HR}}$	Boilers From 51 to 250 $\frac{\text{MBTU}}{\text{HR}}$
<u>SOUTH DAKOTA</u>	1/72	Gas Fired Units: NO_2: Max E = .2 $\frac{\text{LB}}{\text{MBTU}}$ Oil Fired Units: NO_2: Max E = .3 $\frac{\text{LB}}{\text{MBTU}}$	Gas Fired Units: NO_2: Max E = .2 $\frac{\text{LB}}{\text{MBTU}}$ Oil Fired Units: NO_2: Max E = .3 $\frac{\text{LB}}{\text{MBTU}}$

[1] States without air pollution regulations in this area, or whose regulations were found not to be applicable, were omitted from states listed within this table.

[2] Existing units are those units which were in operation or under construction by the date shown. New units are those which were constructed after the date shown.

[3] Arizona. "This regulation applies to an installation operated for the purpose of producing power with the resulting discharge of nitrogen oxides in the installation effluent gases.

[4] Connecticut's NO_2 regulations apply unless the state "is satisfied that it is not technically or economically feasible for a unit of the size considered."

Table B4

State Particulate Emission Regulations for Incinerators

State	Date[2]	Visible Emissions	Emissions Concentration[1]	
			Municipal Incinerators Less Than 30 $\frac{\text{TONS}}{\text{DAY}}$	Medical Incinerators Less Than 100 $\frac{\text{LB}}{\text{HR}}$
<u>ALABAMA</u>	7/72	20% Opacity	Max E = $\frac{.2 \text{ LB}}{100 \text{ LB CHG}}$	Max E = $\frac{.2 \text{ LB}}{100 \text{ LB CHG}}$
<u>ALASKA</u>	7/72	20% Opacity	$C \leq 1041$: Max E = .2 $\frac{\text{GR}}{\text{SCF}}$ $C \leq 2500$: Max E = .1 $\frac{\text{GR}}{\text{SCF}}$ @ 12% CO_2	Max E = .3 $\frac{\text{GR}}{\text{SCF}}$ @ 12% CO_2
<u>ARIZONA</u>	3/73	20% Opacity	Max E = $\frac{.17 \text{ LB}}{1000 \text{ LB GAS}}$ @ 50% EA	Max E = $\frac{.17 \text{ LB}}{1000 \text{ LB GAS}}$ @ 50% EA
<u>ARKANSAS</u>	1/72	40% Opacity (Existing Units) 20% Opacity (New Units)	$C > 200$; Max E = .2 $\frac{\text{GR}}{\text{SCF}}$ @ 12% CO_2	Max E = .3 $\frac{\text{GR}}{\text{SCF}}$ @ 12% CO_2

Table B4 **(Continued)**

			Emissions Concentration	
State	Date	Visible Emissions	Municipal Incinerators Less Than 30 $\frac{\text{TON}}{\text{DAY}}$	Medical Incinerators Less Than 100 $\frac{\text{LB}}{\text{HR}}$
ARKANSAS (Continued)			C < 200 : Max E = 0.3 $\frac{\text{GR}}{\text{SCF}}$ @ 12% CO_2	
CALIFORNIA Bay Area Region	11/70	20% Opacity	Max E = .15 $\frac{\text{GR}}{\text{SCF}}$ @ 6% O_2	Max E = .15 $\frac{\text{GR}}{\text{SCF}}$ @ 6% O_2
Los Angeles Region	1/72	20% Opacity	Existing Units: Max E = 0.3 $\frac{\text{GR}}{\text{SCF}}$ New Units: Max E = .1 $\frac{\text{GR}}{\text{SCF}}$ @ 12% CO_2	Max E = 0.3 $\frac{\text{GR}}{\text{SCF}}$ @ 12% CO_2
Monterey Region	9/74	20% Opacity	Max E = .15 $\frac{\text{GR}}{\text{SCF}}$	Max E = .15 $\frac{\text{GR}}{\text{SCF}}$
Riverside Region	10/74	20% Opacity	Max E = .25 $\frac{\text{GR}}{\text{SCF}}$ @ 12% CO_2	Max E = .1 $\frac{\text{GR}}{\text{SCF}}$ @ 12% CO_2

Table B4 (Continued)

State	Date	Emissions	Emissions Concentration	
			Municipal Incinerators Less Than 30 $\frac{TONS}{DAY}$	Medical Incinerators Less Than 100 $\frac{LB}{HR}$
<u>CALIFORNIA</u> (Continued)				
Sacramento Region	2/75		Max E = .3 $\frac{GR}{SCF}$ @ 12% CO_2	Max E = .3 $\frac{GR}{SCF}$ @ 12% CO_2
San Bernardino Region	6/72	20% Opacity	Max E = .3 $\frac{GR}{SCF}$ @ 12% CO_2	Max E = .3 $\frac{GR}{SCF}$ @ 12% CO_2
San Joaquin Region	5/72	20% Opacity	Max E = .1 $\frac{GR}{SCF}$ @ 12% CO_2	Max E = .1 $\frac{GR}{SCF}$ @ 12% CO_2
San Luis Obispo Region	5/71	40% Opacity	Max E = .3 $\frac{GR}{SCF}$ @ 6% O_2	Max E = .3 $\frac{GR}{SCF}$ @ 6% O_2
Santa Barbara Region	6/72	20% Opacity	Max E = .3 $\frac{GR}{SCF}$ South Coast Basin Only: C > 100: Max E = .1 $\frac{GR}{SCF}$ @ 12% CO_2	Max E = .3 $\frac{GR}{SCF}$ @ 12% CO_2

Table B4 (Continued)

			Emissions Concentration	
State	Date	Visible Emissions	Municipal Incinerators Less Than 30 $\frac{\text{TONS}}{\text{DAY}}$	Medical Incinerators Less Than 100 $\frac{\text{LB}}{\text{HR}}$
COLORADO[3] (Outside Air Pollution Control Areas)	2/72	20% Opacity	Max E = .15 $\frac{\text{GR}}{\text{SCF}}$ @ 12% CO_2	
(Inside Air Pollution Control Areas)		20% Opacity	New Units: Max E = .10 $\frac{\text{GR}}{\text{SCF}}$ Existing Units: Max E = .15 $\frac{\text{GR}}{\text{SCF}}$ Ex. After 1/1/77: Max E = .10 $\frac{\text{GR}}{\text{SCF}}$ @ 12% CO_2	New Units: Max E = .10 $\frac{\text{GR}}{\text{SCF}}$ Existing Units: Max E = .15 $\frac{\text{GR}}{\text{SCF}}$ Ex. After 1/1/77: Max E = .10 $\frac{\text{GR}}{\text{SCF}}$ @ 12% CO_2
CONNECTICUT	6/72	20% Opacity	New Units: Max E = .08 $\frac{\text{GR}}{\text{SCF}}$ @ 12% CO_2 Existing Units: Max E = $\frac{.4 \text{ LB}}{1000 \text{ LB GAS}}$ @ 50% E.A.	New Units: Max E = .08 $\frac{\text{GR}}{\text{SCF}}$ @ 12% CO_2 Existing Units: Max E = $\frac{.4 \text{ LB}}{1000 \text{ LB GAS}}$ @ 50% E.A.

Table B4 (Continued)

			Emissions Concentration	
State	Date	Visible Emissions	Municipal Incinerators Less Than 30 $\frac{TONS}{DAY}$	Medical Incinerators Less Than 100 $\frac{LB}{HR}$
DELAWARE	5/74	20% Opacity	C < 1000:	
			Max E = $\frac{.2\ LB}{100\ LB}$ CHG	Max E = $\frac{.2\ LB}{100\ LB}$ CHG
			C > 1000:	
			Max E = .2 + $\frac{.15}{100}$ LB CHG	
FLORIDA	12/74	0% Opacity	N/A	N/A
GEORGIA	1/72	New Units: 20% Opacity	New Units: Max E = .1 $\frac{GR}{SCF}$	New Units: Max E = .1 $\frac{GR}{SCF}$
		Existing Units: 40% Opacity	Existing Units: Max E = .2 $\frac{GR}{SCF}$	Existing Units: Max E = .2 $\frac{GR}{SCF}$
			@ 12% CO_2	@ 12% CO_2
HAWAII	6/73	Existing Units: 40% Opacity	Max E = $\frac{.2\ LB}{100\ LB}$ CHG	Max E = $\frac{.2\ LB}{100\ LB}$ CHG
		New Units: 20% Opacity		

Table B4 (Continued)

			Emissions Concentration	
State	Date	Visible Emissions	Municipal Incinerators Less Than 30 $\frac{\text{TONS}}{\text{DAY}}$	Medical Incinerators Less Than 100 $\frac{\text{LB}}{\text{HR}}$
IDAHO	10/72	Existing Units: 40% Opacity New Units: 20% Opacity	Max E = $\frac{.2\ \text{LB}}{100\ \text{LB CHG}}$	Max E = $\frac{.2\ \text{LB}}{100\ \text{LB CHG}}$
INDIANA	4/72	40% Opacity	C < 1000: Max E = $\frac{.7\ \text{LB}}{1000\ \text{LB GAS}}$ C > 1000: Max E = $\frac{.4\ \text{LB}}{1000\ \text{LB GAS}}$ @ 50% E.A.	Max E = $\frac{.7\ \text{LB}}{1000\ \text{LB GAS}}$ @ 50% E.A.
ILLINOIS	4/72	30% Opacity	C > 2000: Max E = .08 $\frac{\text{GR}}{\text{SCF}}$ C < 2000: Existing Units: Max E = .2 $\frac{\text{GR}}{\text{SCF}}$	Existing Units: Max E = .2 $\frac{\text{GR}}{\text{SCF}}$ New Units: Max E = .1 $\frac{\text{GR}}{\text{SCF}}$

Table B4 (Continued)

State	Date	Emissions	Emissions Concentration Municipal Incinerators Less Than 30 $\frac{TONS}{DAY}$	 Medical Incinerators Less Than 100 $\frac{LB}{HR}$
ILLINOIS (Continued)	4/72	30% Opacity	New Units: Max E = .1 $\frac{GR}{SCF}$ @ 12% CO_2	
IOWA	12/73	40% Opacity	C < 1000: Max E = .35 $\frac{GR}{SCF}$ C > 1000: Max E = .2 $\frac{GR}{SCF}$ @ 12% CO_2	Max E = .35 $\frac{GR}{SCF}$ @ 12% CO_2
KANSAS	1/71	20% Opacity	Max E = .2 $\frac{GR}{SCF}$ @ 12% CO_2	Max E = .3 $\frac{GR}{SCF}$ @ 12% CO_2
KENTUCKY	4/72	20% Opacity	Max E = .2 $\frac{GR}{SCF}$ @ 12% CO_2	Max E = .2 $\frac{GR}{SCF}$ @ 12% CO_2
LOUISIANA	1/72	20% Opacity	Max E = .2 $\frac{GR}{SCF}$ @ 50% E.A.	Max E = .2 $\frac{GR}{SCF}$ @ 50% E.A.

Table B4 (Continued)

State	Date	Visible Emissions	Emissions Concentration Municipal Incinerators Less Than 30 $\frac{\text{TONS}}{\text{DAY}}$	 Medical Incinerators Less Than 100 $\frac{\text{LB}}{\text{HR}}$
MASSACHUSETTS	6/72	20% Opacity	Existing Units: Max E = .10 $\frac{\text{GR}}{\text{SCF}}$ @ 12% CO_2 New Units: Max E = .05 $\frac{\text{GR}}{\text{SCF}}$ @ 12% CO_2	None (New Units Must Have State Approval)
MAINE	1/72	20% Opacity	Max E = .2 $\frac{\text{GR}}{\text{SCF}}$ @ 12% CO_2	Max E = .2 $\frac{\text{GR}}{\text{SCF}}$ @ 12% CO_2
MARYLAND[4] Regions I, II, V, and VI	1/72	New Units: 0% Opacity Existing Units: 20% Opacity	New Units: C < 2000: Max E = .10 $\frac{\text{GR}}{\text{SCF}}$ C > 2000: Max E = .03 $\frac{\text{GR}}{\text{SCF}}$ Existing Units: C < 300: Max E = .30 $\frac{\text{GR}}{\text{SCF}}$	New Units: Max E = .03 $\frac{\text{GR}}{\text{SCF}}$ Existing Units: Max E = .1 $\frac{\text{GR}}{\text{SCF}}$

Table B4 (Continued)

State	Date	Visible Emissions	Emissions Concentration Municipal Incinerators Less Than 30 $\frac{\text{TONS}}{\text{DAY}}$	Emissions Concentration Medical Incinerators Less Than 100 $\frac{\text{LB}}{\text{HR}}$
MARYLAND (Continued)	1/72		C > 200: Max E = .20 $\frac{\text{GR}}{\text{SCF}}$ @ 12% CO_2	
Regions III and IV	1/72	0% Opacity	Max E = .03 $\frac{\text{GR}}{\text{SCF}}$ @ 12% CO_2	Max E = .03 $\frac{\text{GR}}{\text{SCF}}$ @ 3.5% CO_2
MICHIGAN	11/73	20% Opacity	Max E = .30 $\frac{\text{LB}}{\text{1000 LB GAS}}$ @ 50% E.A.	Max E = .2 $\frac{\text{LB}}{\text{1000 LB GAS}}$ @ 50% E.A.
MINNESOTA	7/69	20% Opacity	C < 200: Max E = .3 $\frac{\text{GR}}{\text{SCF}}$ 200 < C < 2000 Max E = .2 $\frac{\text{GR}}{\text{SCF}}$ C > 2000: Max E = .1 $\frac{\text{GR}}{\text{SCF}}$ @ 12% CO_2	Max E = .3 $\frac{\text{GR}}{\text{SCF}}$ @ 12% CO_2

Table B4 (Continued)

State	Date	Emissions	Emissions Concentration	
			Municipal Incinerators Less Than 30 $\frac{TONS}{DAY}$	Medical Incinerators Less Than 100 $\frac{LB}{HR}$
MISSISSIPPI	1/72	40% Opacity	Max E = .2 $\frac{GR}{SCF}$	Max E = .2 $\frac{GR}{SCF}$
			Unit Close to Residential Area: Max E = .1 $\frac{GR}{SCF}$	Unit Close to Residential Area: Max E = .1 $\frac{GR}{SCF}$
			@ 12% CO_2	@ 12% CO_2
MISSOURI	9/70	Existing Units: 40% Opacity New Units: 20% Opacity	C < 200: Max E = .3 $\frac{GR}{SCF}$	Max E = .3 $\frac{GR}{SCF}$ @ 12% CO_2
			C > 200: Max E = .2 $\frac{GR}{SCF}$ @ 12% CO_2	
MONTANA	6/68	20% Opacity	C < 200: Max E = .3 $\frac{GR}{SCF}$	Max E = .3 $\frac{GR}{SCF}$ @ 12% CO_2
			C > 200: Max E = .2 $\frac{GR}{SCF}$ @ 12% CO_2	

Table B4 (Continued)

State	Date	Visible Emissions	Emissions Concentrations	
			Municipal Incinerators Less Than 30 $\frac{TONS}{DAY}$	Medical Incinerators Less Than 100 $\frac{LB}{HR}$
<u>NEBRASKA</u>	2/74	20% Opacity	C < 2000: Max E = .2 $\frac{GR}{SCF}$ C > 2000: Max E = .1 $\frac{GR}{SCF}$ @ 12% CO_2	Max E = .2 $\frac{GR}{SCF}$ @ 12% CO_2
<u>NEVADA</u>	9/74	20% Opacity	C > 2000: E = 40.7 x 10^{-5}C $\frac{LB}{HR}$ C < 2000: Max E = 3 $\frac{LB}{TON}$ CHG	Max E = 3 $\frac{LB}{TON}$ CHG
<u>NEW HAMPSHIRE</u>	4/70	New Units: 20% Opacity Existing Units: 40% Opacity	C < 200: Max E = .3 $\frac{GR}{SCF}$ 200 < C: Max E = .2 $\frac{GR}{SCF}$ @ 12% CO_2	Max E = .3 $\frac{GR}{SCF}$ @ 12% CO_2

Table B4 (Continued)

State	Date	Visible Emissions	Emissions Concentration Municipal Incinerators Less Than 30 $\frac{TONS}{DAY}$	 Medical Incinerators Less Than 100 $\frac{LB}{HR}$
NEW JERSEY	8/68	20% Opacity	Max E = .1 $\frac{GR}{SCF}$ @ 12% CO_2	Max E = .1 $\frac{GR}{SCF}$ @ 12% CO_2
NEW MEXICO[5]	6/71	20% Opacity	None	None
NEW YORK[6]	1/68	New Units: 20% Opacity Existing Units: 40% Opacity	New Units: E = .003C $\frac{LB}{HR}$ Existing Units: E = 0.5 $\frac{LB}{100\ LB\ CHG}$	New Units: E = .003C Min E = .3 $\frac{LB}{HR}$ Existing Units: E = .005C
NORTH CAROLINA	7/71	New Units: 20% Opacity Existing Units: 40% Opacity	E = .002C LB/HR Max E = 4.0 $\frac{LB}{HR}$	E = .002C Max E = .2 $\frac{LB}{HR}$
NORTH DAKOTA	7/70	20% Opacity	$C < 1000$: E = .00515 $C^{.90}$ $\frac{LB}{HR}$ $1000 < C$ E = .0252 $C^{.67}$ $\frac{LB}{HR}$	E = .00515 $C^{.90}$

Table B4 (Continued)

State	Date	Visible Emissions	Emissions Concentration	
			Municipal Incinerators Less Than 30 $\frac{TONS}{DAY}$	Medical Incinerators Less Than 100 $\frac{LB}{HR}$
OHIO	2/72	20% Opacity	$C < 100$:	
			Max $E = .2 \frac{LB}{100\ LB\ CHG}$	Max $E = .2 \frac{LB}{100\ LB\ CHG}$
			$100 < C$:	
			Max $E = .1 \frac{LB}{100\ LB\ CHG}$	
OKLAHOMA	7/71	20% Opacity	$E = 2.5 \frac{LB}{HR}$ @ $C = 1000$	$E = .4 \frac{LB}{HR}$ @ $C = 100$
			$E \simeq .0132\ C^{0.741} \frac{LB}{HR}$	$E \simeq .0132\ C^{0.741} \frac{LB}{HR}$
OREGON	6/70	Existing Units: 40% Opacity New Units: 20% Opacity	$C < 200$:	
			Max $E = .3 \frac{GR}{SCF}$	Max $E = .3 \frac{GR}{SCF}$
			@ 12% CO_2	@ 12% CO_2
			$200 < C$:	
			Existing Units: Max $E = .2 \frac{GR}{SCF}$	
			New Units: Max $E = .1 \frac{GR}{SCF}$	
			@ 12% CO_2	

Table B4 (Continued)

State	Date	Visible Emissions	Emissions Concentration Municipal Incinerators Less Than 30 $\frac{\text{TONS}}{\text{DAY}}$	 Medical Incinerators Less Than 100 $\frac{\text{LB}}{\text{HR}}$
<u>PENNSYLVANIA</u>	9/71	20% Opacity	Max E = .1 $\frac{\text{GR}}{\text{SCF}}$ @ 12% CO_2	Max E = .1 $\frac{\text{GR}}{\text{SCF}}$ @ 12% CO_2
<u>RHODE ISLAND</u>	1/74	20% Opacity	C < 2000: Max E = .16 $\frac{\text{GR}}{\text{SCF}}$ C > 2000: Max E = .08 $\frac{\text{GR}}{\text{SCF}}$ @ 12% CO_2	Max E = .08 $\frac{\text{GR}}{\text{SCF}}$ @ 12% CO_2
<u>SOUTH CAROLINA</u>	7/71	20% Opacity	Max E = .5 $\frac{\text{LB}}{\text{MBTU}}$	Max E = .5 $\frac{\text{LB}}{\text{MBTU}}$
<u>SOUTH DAKOTA</u>	1/72	20% Opacity	Max E = .2 $\frac{\text{LB}}{\text{100 LB CHG}}$	Max E = .2 $\frac{\text{LB}}{\text{100 LB CHG}}$
<u>TENNESSEE</u>	4/72	20% Opacity	New Units: C < 2000: Max E = .2 $\frac{\text{GR}}{\text{SCF}}$	New Units: Max E = .2 $\frac{\text{GR}}{\text{SCF}}$

Table B4 (Continued)

State	Date	Visible Emissions	Emissions Concentration Municipal Incinerators Less Than 30 $\frac{\text{TONS}}{\text{DAY}}$	Emissions Concentration Medical Incinerators Less Than 100 $\frac{\text{LB}}{\text{HR}}$
TENNESSEE (continued)			$C > 2000$: Max $E = .1\ \frac{\text{GR}}{\text{SCF}}$	
			Existing Units: $C < 200$: Max $E = .6\ \frac{\text{GR}}{\text{SCF}}$	Existing Units: Max $E = .6\ \frac{\text{GR}}{\text{SCF}}$
			$200 < C$: Max $E = .4\ \frac{\text{GR}}{\text{SCF}}$	
TEXAS	1/72	Existing Units: 30% Opacity New Units: 20% Opacity	Max $E = .08\ \frac{\text{GR}}{\text{SCF}}$ @ 12% CO_2	Max $E = .08\ \frac{\text{GR}}{\text{SCF}}$ @ 12% CO_2
UTAH	4/71	20% Opacity	New Units: Apply Best Available Control Equipment	New Units: Apply Best Available Control Equipment

Table B4 (Continued)

State	Date	Visible Emissions	Emissions Concentration Municipal Incinerators Less Than 30 $\frac{\text{TONS}}{\text{DAY}}$	 Medical Incinerators Less Than 100 $\frac{\text{LB}}{\text{HR}}$
VERMONT	4/70	Existing Units: 40% Opacity New Units: 20% Opacity	Max $E = .1 \frac{\text{LB}}{\text{100 LB CHG}}$	Max $E = .1 \frac{\text{LB}}{\text{100 LB CHG}}$
WEST VIRGINIA	9/69	20% Opacity	$C < 200$: $E = 8.25\ C\ \frac{\text{LB}}{\text{HR}}$ $C > 200$: $E = 5.4\ C\ \frac{\text{LB}}{\text{HR}}$	$E = 8.25\ C\ \frac{\text{LB}}{\text{HR}}$
VIRGINIA	3/72	20% Opacity	Max $E = .14 \frac{\text{GR}}{\text{SCF}}$ @ 12% CO_2	Max $E = .14 \frac{\text{GR}}{\text{SCF}}$ @ 12% CO_2
WASHINGTON	8/74	20% Opacity	Max $E = .1 \frac{\text{GR}}{\text{SCF}}$ @ 7% O_2	Max $E = .1 \frac{\text{GR}}{\text{SCF}}$ @ 7% O_2

Table B4 (Continued

State	Date	Visible Emissions	Emissions Concentration Municipal Incinerators Less Than 30 $\frac{\text{TONS}}{\text{DAY}}$	 Medical Incinerators Less Than 100 $\frac{\text{LB}}{\text{HR}}$
WISCONSIN[8] Class I	3/72	20% Opacity	C < 500: Max E = $\frac{.3 \text{ LB}}{1000 \text{ LB GAS}}$ C > 500: Max E = $\frac{.2 \text{ LB}}{1000 \text{ LB GAS}}$	Max E = $\frac{.3 \text{ LB}}{1000 \text{ LB GAS}}$
Class II		40% Opacity	C < 500: Max E = $\frac{.6 \text{ LB}}{1000 \text{ LB GAS}}$ C > 500: Max E = $\frac{.5 \text{ LB}}{1000 \text{ LB GAS}}$	Max E = $\frac{.6 \text{ LB}}{1000 \text{ LB GAS}}$
Classes III & IV		20% Opacity	Max E = $\frac{.3 \text{ LB}}{1000 \text{ LB GAS}}$	Max E = $\frac{.3 \text{ LB}}{1000 \text{ LB GAS}}$
WYOMING	2/72	20% Opacity	Max E = $\frac{.2 \text{ LB}}{100 \text{ LB CHG}}$	Max E = $\frac{.2 \text{ LB}}{100 \text{ LB CHG}}$

Table B4 (Continued)

Footnotes Table B4

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[1] Most states require that an incinerator burning municipal wastes be of the multiple chamber design. Although exact values were not set, most states also require that all objectionable odors must be eliminated.

[2] Existing units are those units which were in operation or under construction by the date shown. New units are those which were constructed after the date shown.

[3] Colorado. Air pollution control regions include the city areas of Denver, Boulder, Lirthen-Weind, and the counties of El Paso, Mesa, and Pueblo.

[4] Maryland. Region III is the Baltimore Metropolitan Area. Region IV is the Washington Metropolitan Area. Regions I, II, V, and VI include the rest of the state.

[5] New Mexico. The only state law on incinerator particulate emissions is the visible emissions regulation.

[6] New York. Incinerators in the New York City Area shall meet the state code for the new units.

[7] Tennessee. Existing units must meet new unit standards by July, 1975.

[8] Wisconsin. Class I: means new or modified sources throughout the state. Class II: means existing sources throughout the state. Class III: means existing sources subregion 1 of the Lake Michigan Intrastate Air Quality Control Region. Class IV: means existing sources in the Southeast Wisconsin Air Quality Control Region.

Table B5

State Gaseous Emission Regulations for Incinerators

State	Date	Emissions Concentration Municipal Incinerators Less Than 30 TONS/DAY	Medical Incinerators Less Than 100 LBS/HOUR
CALIFORNIA			
Bay Area Region	11/70	SO_2: 300 ppm H.C.: 25 ppm Carbonyls: 25 ppm @ 6% O_2	SO_2: 300 ppm H.C.: 25 ppm Carbonyls: 25 ppm @ 6% O_2
Los Angeles Region	1/73	SO_2: Max E = 2000 ppm	SO_2: Max E = 2000 ppm
Monterey Region	9/74	SO_2: Max E = 2000 ppm NO_x: Max E = 250 ppm (New Sources)	SO_2: Max E = 2000 ppm NO_x: Max E = 250 ppm (New Sources)
Riverside Region	10/74	West-Central Area: SO_2: Max E = 500 ppm Rest of Region: SO_2: Max E = 1500 ppm CO: Max E = 2000 ppm	West-Central Area: SO_2: Max E = 500 ppm Rest of Region: SO_2: Max E = 1500 ppm CO: Max E = 2000 ppm
Sacramento Region	2/75	SO_2: Max E = 2000 ppm	
San Bernardino Region	1/75	SO_2: Max E = 500 ppm CO: Max E = 2000 ppm	Max E = 500 ppm Max E = 2000 ppm

Table B5 (Continued)

State	Date	Emissions Concentration Municipal Incinerators Less Than 30 TONS/DAY	Emissions Concentration Medical Incinerators Less Than 100 LBS/HOUR
CALIFORNIA (Continued)			
San Joaquin Region	5/72	SO_2: Max E = 2000 ppm	SO_2: Max E = 2000 ppm
San Luis Obispo Region	5/71	Existing Units: SO_2: Max E = 2000 ppm	Existing Units: SO_2: Max E = 2000 ppm
		New Units: SO_2: Max E = 200 $\frac{LB}{HR}$	New Units: SO_2: Max E = 200 $\frac{LB}{HR}$
		For the First 10,000 Cubic Feet per Hour: NO_2: Max E = 1000 ppm	For the First 10,000 Cubic Feet per Hour: NO_2: Max E = 1000 ppm
		Thereafter: NO_2: Max E = 250 ppm @ 3% O_2	Thereafter: NO_2: Max E = 250 ppm @ 3% O_2
GEORGIA	9/73	For $H_s < 300$ ft.: SO_2: Max E = $3200 \left(\frac{H_s}{300}\right)^3 \frac{LB}{HR}$	For $H_s < 300$ ft.: SO_2: Max E = $3200 \left(\frac{H_s}{300}\right)^3 \frac{LB}{HR}$
		For $H_s > 300$ ft.: SO_2: Max E = $3200 \left(\frac{H_s}{300}\right)^3 \frac{LB}{HR}$	For $H_s > 300$ ft.: SO_2: Max E = $3200 \left(\frac{H_s}{300}\right)^3 \frac{LB}{HR}$

Table B5 (Continued)

State	Date	Emissions Concentration Municipal Incinerators Less Than 30 TONS/DAY	 Medical Incinerators Less Than 100 LBS/HOUR
GEORGIA (Continued)		For H_s < 300 ft.: NO_2: Max E = 9300 $(\frac{H_s}{300})^3 \frac{LB}{HR}$	For H_s < 300 ft.: No_2: Max E = 9300 $(\frac{H_s}{300})^3 \frac{LB}{HR}$
		For H_s > 300 ft.: NO_2: Max E = 9300 $(\frac{H_s}{300})^2 \frac{LB}{HR}$	For H_s > 300 ft.: NO_2: Max E = 9300 $(\frac{H_s}{300})^2 \frac{LB}{HR}$
WASHINGTON	6/75	SO_2: Max E = 1000 ppm @ 7% O_2 CARBONYLS: Max E = 100 ppm @ 7% O_2	SO_2: Max E = 1000 ppm @ 7% O_2 CARBONYLS: Max E = 100 ppm @ 7% O_2

Table B6

Conversion Table - Expected and Allowable Emissions

	FROM			
To	Coal Firing Lbs/Ton-Coal	Oil Firing Lbs/1000 Gal-Oil	Gas Firing Lbs/10^6 Ft^3-Gas	Refuse Incineration Lbs/Ton Refuse
Lb/Hr	CA	CA	CA	CA
Lb/100 Lb Chg	-	-	-	.05
Lb/MBTU	.04	.007	.001	.11
Lb/1000 Lb Gas	.053	.009	.0014	.156
Lb/SCF	3.9×10^{-6}	$.68 \times 10^{-6}$	$.104 \times 10^{-6}$	11.7×10^{-6}
Lb/SCF @ 50% Ea	2.6×10^{-6}	$.45 \times 10^{-6}$	$.069 \times 10^{-6}$	7.8×10^{-6}
Gr/SCF	.027	.005	.00073	.082
Gr/SCF @ 50% Ea	.018	.003	.0005	.055

Calculations based on:

1 Coal Firing - Heating value @ 12,500 Btu/lb
Air/fuel ratio @ 7.6 lb air/10,000 Btu
CA is the ton/hr coal burned

2 Oil Firing - Heating value @ 147,000 Btu/gal
Air/fuel ratio @ 7.46 lb air/10,000 Btu
CA is the 1000 gal/hr oil burned

3 Gas Firing -- Heating value @ 1000 Btu/CF
Air/fuel ratio @ 7.19 lb air/10,000 Btu
CA is the MCF/hr gas burned

4 Refuse Incineration - Heating value @ 4450 Btu/lb
Air/fuel ratio @ 3.21 lb air/lb refuse
CA is the ton/hr refuse incinerated

APPENDIX C:

SURVEY OF EXISTING AND EMERGING SYSTEMS FOR THE CONTROL OF GASEOUS AND PARTICULATE EMISSIONS

General. Emissions control technology applicable to existing Army boilers and incinerators was reviewed to identify existing and emerging, advanced systems. In order to differentiate between existing and emerging, advanced systems, existing systems were defined as those which satisfied both of the following criteria:

1. Systems which have existing commercial installations in addition to a demonstration plant.

2. Systems for which the commercial installation has been operational in its design configuration for a minimum of six months after shakedown.

List of Systems

1. Existing Systems
    - a. Mechanical dust collectors
    - b. Baghouse dust collectors
    - c. Electrostatic precipitators
    - d. Scrubbers
    - e. Afterburners
    - f. Gas Absorption
        - (1) Caustic process
        - (2) Lime-limestone process
        - (3) Sulfuric acid process

2. Emerging, Advanced Systems

    a. Fluidized bed combustion

    b. Coal liquefaction or gasification

    c. Catalytic oxidation

    d. Gas adsorption

        (1) Dry activated carbon process

        (2) Wet activated carbon process

    e. Gas Absorption

        (1) Alkaline ash process

        (2) Alkalized alumina process

        (3) Ammonia process

        (4) Caustic with lime regeneration process

        (5) Caustic injection process

        (6) Citric acid process

        (7) Lime-limestone dry injection process

        (8) Magnesium oxide process

        (9) Potassium phosphate process

        (10) Seawater process

        (11) Solid dry copper process.

Many of the systems listed under the heading "existing systems" are ones that are still continuously being improved and updated. The listing of a system as "existing" is not meant to imply that it is in a stagnant state of development. The charged particle scrubber and the variable inlet vane mechanical cyclone are examples of recent improvements to existing collection methods.

The emerging, advanced systems chosen for detail analysis, because they were considered most promising, were: the dry activated carbon; ammonia; caustic with lime regeneration; caustic injection; and solid dry copper processes.

The fluidized bed combustion system was not selected for further study as it is only applicable to new installations. Analysis of coal liquefaction or gasification was considered beyond the scope of the study.

Brief Description of Systems

Mechanical dust collectors. These collectors separate particulate matter from a gas stream by imparting a centrifugal force to the dust particle which then moves toward the outside wall of the collector. Examples of mechanical dust collectors are the single and multiple cyclone separators with or without variable inlet vanes and/ or a secondary gas flow, each of which is a recent improvement for increased collection efficiency.

Baghouse dust collectors. Dust is removed from the gas stream by filtering the gas through a porous fabric medium, usually formed into bags of a tubular or rectangular shape. Examples of baghouse dust collectors are the intermittent shaker type and the continuous reverse air or pulse jet type.

Electrostatic precipitators. Dust or liquid particles are removed from the gas stream by first placing a static electric charge on the particle as it passes through an electrostatic field and then collecting the particles on an oppositely charged collection plate. Examples of electrostatic precipitators are the single and two-stage precipitators, with dry or irrigated wall type of matter removal from the collection plates.

Scrubbers. Dust or liquid particles are removed from the gas stream by wetting the particles through contact with a liquid droplet and then subsequently collecting the wetted matter by impingement, diffusion, or condensation on a collecting surface. Examples of scrubbers are: the wet cyclone scrubber; orifice scrubber; impingement scrubber; mechanical centrifugal scrubber; venturi scrubber; packed tower scrubber; mobile bed tower scrubber; and the charged particle scrubber.

Afterburners. Combustible gases, liquids, or completely burned particulates enter a combustion chamber where the combustion process is completed, thereby reducing their respective concentrations in the gas stream. The two types of afterburners most generally found are the direct fired and the catalytic type.

Caustic process. After particulate removal, the flue gas is passed through a tower where a solution of caustic soda and water absorb its sulfur oxide constituents. The spent absorption liquid, high in sodium sulfate and sodium sulfite content, is disposed of as a liquid waste or sold as a by-product.

Lime-limestone process. After particulate removal, the flue gas is passed through a tower where a lime or limestone and water slurry absorb its sulfur oxide constituents. The spent absorption slurry is sent to a clarifier, where the solid calcium sulfates and calcium sulfites are separated and sent to waste while the water is returned to the tower.

Sulfuric acid process. After particulate removal, the flue gas is washed with dilute sulfuric acid which contains an iron catalyst and is saturated with oxygen. Sulfur dioxide is absorbed from the flue gas by this solution and is converted into sulfuric acid. To maintain the solution as a dilute acid, a portion of the solution is continuously withdrawn, concentrated and sold as a by-product, or neutralized and returned to the cycle.

Fluidized bed combustion. Coal or refuse is burned in a low temperature fluidized bed of ash and limestone. Sulfur compounds in the burning fuel react with the limestone in the bed instead of entering the flue gas stream.

Coal liquefaction or gasification. Coal is reduced to a virtually sulfur- and ash-free liquid or gaseous fuel before being burned.

Catalytic oxidation. After particulate removal, flue gas at a high temperature is passed through a catalytic converter which oxidizes the sulfur dioxide present to sulfur trioxide. The flue gas is then cooled by spraying it with water, which also reacts with the sulfur trioxide to form dilute sulfuric acid. The dilute acid may then be neutralized for disposal or concentrated for sale.

Dry activated carbon process. Flue gas, after its particulates are removed, is passed through a moving fluidized bed of activated carbon which absorbs the sulfur dioxide present. The spent carbon is regenerated by high temperature heating which drives off a highly concentrated sulfur dioxide gas. This gas must then be processed for conversion to either sulfuric acid or elemental sulfur for disposal. The regenerated carbon is returned to the bed for reuse.

Wet activated carbon process. Sulfur dioxide is absorbed in a slurry of water and activated carbon and is oxidized to sulfur trioxide. The spent carbon is continuously regenerated by the water in the slurry, which dissolves the absorbed sulfur trioxide to form dilute sulfuric acid. This dilute acid is concentrated and then neutralized for disposal or concentrated further for sale.

Alkaline ash process. When certain western coals are burned, the resulting flyash contains enough alkaline agents, such as lime, magnesia, or potassium, for a 2 to 5 percent slurry to be used as an absorption solution through which to pass the flue gas. While this will cause a reduction of 30 to 40 percent in the concentration of sulfur dioxide in the flue gas, it is not sufficient to satisfy most state laws, and further treatment is required.

Alkalized alumina process. After particulate removal, the flue gas is passed through a tower where its sulfur dioxide is absorbed by an alkalized alumina solution. The spent absorption agent is regenerated by a reducing agent, such as natural gas, which converts the absorbed sulfur dioxide to hydrogen sulfide gas. The hydrogen sulfide gas is released in high concentrations to a chemical process for conversion to elemental sulfur. The regenerated solution is returned to the tower for reuse. Current development of this process has been discontinued due to technical problems with losses of the alkalized alumina absorption agent.

Ammonia process. After particulate removal, the flue gas is passed through a tower where its sulfur dioxide gas is absorbed by an ammonium salt solution. The spent solution may be regenerated to produce a pure sulfur dioxide gas or may be used as an ammonium sulfate fertilizer. The gas by-product of regeneration would require further chemical processing, while the liquid fertilizer may be sold directly.

Caustic with lime regeneration process. This is a modification of the existing caustic process. After particulate removal, sulfur dioxide is absorbed in a caustic solution by passing the flue gas through a tower. Spent solution is regenerated by adding lime to it, in an external tank where the lime reacts with the sulfates and forms a precipitate. The regenerated caustic solution is returned to the tower, while the solid precipitate is disposed of in a landfill or sludge pond.

Caustic injection process. A sodium carbonate solution is mixed with the flue gas in a reactor chamber where the sulfur dioxide is absorbed. The heat of the flue gas evaporates the water, leaving a mixture of solid sodium sulfite and sodium sulfate particulate to be removed from the gas stream by existing dust collection methods.

Citric acid process. After particulate removal, the flue gas is passed through a tower where the sulfur dioxide is absorbed by a solution of citric acid and sodium citrate. The spent solution is regenerated in a complex chemical process by reacting it with hydrogen sulfide to produce elemental sulfur. The regenerated solution is returned to the tower for reuse.

Lime-limestone dry injection process. Finely ground lime or limestone is injected into the furnace of the boiler, where it reacts with the sulfur dioxide and oxygen in the flue gas to form calcium sulfate. This is a solid and can be removed by existing dust collection methods. Current development of this process has been discontinued due to lime-limestone scaling and plugging of boiler gas passages.

Magnesium oxide process. After particulate removal, the flue gas is passed through a tower where it reacts with a slurry of magnesium oxide to remove sulfur dioxide from the gas stream. The spent slurry is dried to remove the magnesium sulfite and magnesium sulfate crystals, which are then heated to release pure sulfur dioxide gas to a chemical process for conversion to sulfuric acid or to elemental sulfur. The regenerated magnesium oxide is mixed with water and returned to the tower.

Potassium phosphate process. After particulate removal, the flue gas is passed through a tower where a potassium phosphate solution absorbs the sulfur dioxide present. Spent solution is regenerated by a reducing agent, such as natural gas, which releases a concentrated hydrogen sulfide gas to a chemical process for conversion to elemental sulfur. The regenerated solution is returned to the tower for reuse.

Seawater process. Flue gas is passed through film screens of seawater or alkalized water which absorbs the sulfur dioxide and carbon dioxide gases present. Since the absorption solution is not regenerated, large quantities of seawater or alkalized water are required.

Solid dry copper process. Flue gas is passed through or over a bed of copper oxide pellets, where the sulfur dioxide present is absorbed by the pellets. The spent copper pellets are regenerated by heating in a reducing atmosphere to release the sulfur dioxide gas to a chemical process for conversion to either sulfuric acid or elemental sulfur.

APPENDIX D

METHODOLOGY FOR EVALUATING EMERGING TECHNOLOGY

New systems and methods for controlling gaseous and particulate emissions are constantly being developed. Some of these "emerging technologies" will be more promising than others, and thus would deserve greater consideration during their development. The methodology delineated in this appendix is intended to aid in a preliminary evaluation of emerging technological systems so that the more promising systems can be identified.

The methodology for evaluating an emerging technology begins with the information questionnaire, a copy of which is attached to the end of this appendix. Answers to the 24 questions listed therein are to be requested from each developer who claims to have a viable air pollution control system. These answers, in turn, form the basis for the evaluation process. While a developer may not be able to supply all the information requested, due to the stage of development of the process, the answers provided should be in as much detail as possible.

The next step in the evaluation procedure is for the reviewer to use the information supplied in conjunction with the logic diagram, a copy of which is appended to this appendix. This logic diagram is an outline of the analysis process by which the system is reviewed as to its validity and suitability in satisfying its intended purpose. The general conclusion reached is whether the system warrants further consideration.

As previously mentioned, this methodology provides only a preliminary evaluation procedure. Should a system be judged favorably from this evaluation, a more detailed investigation must then be performed by experts in the various disciplines involved in the system. Since this preliminary evaluation relies heavily on information supplied by the developer, verification of this information will be necessary during the detailed study.

While the methodology described herein is written to cover as broad and general a range as possible, some special applications may require that the information questionnaire, logic diagram, and methodology be modified. This possibility requires that the reviewer remember that this is only a preliminary evaluation and, therefore, that large quantities of detailed information are not required at this point.

Logic Diagram. The evaluation logic diagram shown in Figure D1 is designed to provide a concise step-by-step analysis procedure.

The evaluation logic diagram is made up of the following four parts:

(1) Basic merit section.

(2) Ability to control specific emissions section.

(3) Design section.

(4) Decision section.

The basic data required for use with the logic diagram are supplied by the answers to the information questionnaire, while the compatibility charts required are supplied by the reference tables shown or listed herein. Following is a brief explanation of each of the four parts of the evaluation logic diagram.

Basic Merit Section. This section summarizes the major attributes which a developer may claim for his system, evaluates the submitted support of the claimed attributes, and establishes the stage of development of the submitted system.

The major attributes are obtained from Question five of the questionnaire under advantages over, and similarities and differences with existing systems. Examples of major attributes are: improved collection efficiency; simplicity of design; low capital costs; and low operating costs. These major attributes should be based on substantial evidence in order to merit further consideration. The support for the claimed major attributes may originate from results of: analytical studies; bench scale model testing; pilot plant testing; or demonstration plant testing.

The stage of development is found in the answer to Question six of the questionnaire, and should be used in conjunction with the answer to Question eight to verify the claimed development. The following description of the four development stages is only general and should not be construed as an exact definition of each stage.

The analytical study stage is that where a conceptual idea is supported in principle only through studies of applicable theoretical principles; e.g., physical, chemical, thermodynamic, etc. This stage is one characterized by having a plausible control system on paper, unsupported by any actual test results.

The bench scale stage is that where the concept is investigated by being subjected to small-scale model testing. Such tests are normally performed in a controlled laboratory environment under pseudo-field conditions. A minimum of one hundred hours of testing with favorable results is considered to be a necessary prerequisite before leaving the bench scale stage and proceeding to larger scale testing. Bench tests usually concentrate on proving that the system concept actually achieves the desired result without giving consideration to conditions which may arise in the field. In essence, it demonstrates that the principle works.

The pilot plant stage is that where a working scale model is operated on a stream bled from an actual field source. The purpose is to prove that the system performs its specific function, under small-scale field conditions. A minimum of two hundred hours of testing with favorable results is considered to be a necessary prerequisite for proceeding to the demonstration stage. The pilot plant stage is characterized by testing conditions approaching those under actual operating conditions, and providing data relative to such major aspects as pollutant concentration and gas temperatures, but lacking firm data concerning such minor aspects as system reliability or operating turndown ratio.

The demonstration stage is that where a prototype (full size) unit is built and installed to handle full gas flow under actual field conditions. The purpose is to: locate and correct any design deficiencies; establish system operating economics; verify the extrapolated "scaled-up" data; and provide minor information not answered in the pilot plant stage. A minimum of one thousand hours of testing with favorable results is considered a necessary prerequisite to making the system available commercially. The demonstration stage is characterized by higher initial costs due to the test nature of the facility, and also as a result of major and minor design problems due in part to the extrapolation of the design from that of smaller models.

Having established the present state of development in the logic diagram, one then determines the degree to which the major attributes have been supported. If the major attributes were not supported by data or analysis, then the "no" flow arrow is followed, indicating that further consideration is not warranted. If the attributes are supported, the "yes" flow arrow is followed. For the analytical stage, one progresses to the decision section, whereas for the other three stages of development progress is to the next section; i.e., ability to control the specific emissions.

Ability to Control Specific Emissions Section. This section is a check to verify that the system actually performs. Test results from either the bench, pilot, or demonstration scale models should indicate the degree to which the system actually limits the emission(s) it is designed to control. The effectiveness of the system as given in the answers to Questions 15 and 16 determines whether the system warrants further consideration.

When undertaking the detailed evaluation, a review of the efficacy of the test methods used to determine the removal efficiencies, the operating parameters affecting removal efficiencies, and the relative quantities of secondary pollutants generated must be assessed. These points of interest must be reviewed in greater detail should the preliminary evaluation show that further consideration is warranted.

Design Section. When the system has evolved to the pilot plant or demonstration unit stage of development, conclusions can be drawn concerning the design of the system based on the testing experience. This section of the evaluation logic diagram is concerned not only with the overall system design and construction, but also with the design and construction of its various components. In essence, the suitability of components for their environment and duty is determined.

Questions 20 through 22 of the questionnaire elicit information concerning not only the materials of construction of the various system components, but also the characteristics of the various environments in which they will operate (or have operated). The described environment will cover the various chemicals comprising the materials being conveyed through or by the various components and the respective temperatures and concentrations in the vicinity of each component. Using corrosion and abrasion* reference tables, and considering the materials of construction of a component and the chemical and physical characteristics of the materials being handled, conclusions can be drawn as to the suitability of the component to resist: chemical corrosion; abrasion by high velocity particulate matter; destruction or deformation as a result of temperature. Such conclusions can cover behavior during both normal operation and conditions which can occur as a result of an operational malfunction; e.g., loss of power, loss of water. It should be noted that the materials being handled comprise not only the flue gas and its entrained pollutants, but also the chemicals and materials being supplied to the removal process and the materials resulting from the removal process.

In addition to the conclusions concerning the anticipated rate of degradation of a given component, further conclusions can be drawn as to whether the standards used in the design and construction of components were adequate for the intended environment. While components such as piping, pumps, tanks, heat exchangers, etc., should normally be designed and constructed in conformance with governing codes and standards, conformance with such regulations will not guarantee per se that the design of any particular component is adequate.

If each component is designed and constructed in accordance with the codes and/or standards which apply and is compatible with its intended environment, then the system receives a "yes" for the design section of the logic diagram. If a majority of the components is designed to the accepted standards, then a "most" is indicated. If a majority of the components fail to comply with accepted standards, then a "no" is indicated.

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* The following are excellent reference sources for data on corrosion resistance and abrasion resistence, respectively: (1) *Corrosion Data Survey* (National Association of Corrosion Engineers, 1974, 1975), and (2) *Chemical Engineer's Handbook*, J. H. Perry, ed., (McGraw Hill, 1973).

After all components have been evaluated, the evaluation can proceed to the next phase, namely the decision section.

Decision Section. This section provides for the following three types of decisions:

(1) Further consideration not warranted.

(2) Further consideration possibly warranted.

(3) Further consideration warranted.

"Further consideration not warranted" would mean either that the claimed major attributes of the system have not been supported; the system does not perform the specific function for which it was designed; or that the system is either poorly designed or has major design and construction deficiencies.

"Further consideration possibly warranted" would mean that while the major attributes and specific function of the system have been verified, there are a number of minor design, construction or other deficiencies which should be resolved.

"Further consideration warranted" would mean that the system has received favorable reviews in all sections of the evaluation.

Since this evaluation logic diagram is designed as an outlined guide for a preliminary decision on any air pollution control system, any system receiving a"further consideration warranted" or "possibly warranted" rating should be subjected to a more detailed analysis by experts.

Instructions for Completion of Information Questionnaire

The purpose of this questionnaire is to elicit all information necessary to enable the Army technical staff to perform a preliminary evaluation of the described system. In filling it out, provide as much detail as practical without being voluminous. Should insufficient space be provided on the form, add additional sheets as necessary.

A brief explanation of those questions without obvious answers follows. The number sequence matches that in the questionnaire.

(3) System description should include flow diagrams.

(4) State the specific polluting emission(s) the system is designed to remove from the gas stream.

(5) Clearly state under "advantages" the comparative attributes of the system with those of existing systems; e.g., collection efficiency, owning costs, operating costs, simplicity of design, simplicity of application, flexibility, energy effectiveness, degree of generation of secondary pollutants, etc. Support the advantages claimed by analytical studies, as well as by data from bench, pilot plant, or demonstration tests. Also, discuss similarities to and differences from existing systems as well as the disadvantages of the system being described.

(9) Give a brief explanation or outline of the principle(s) of operation of the collecting process.

(10) Flue gas preconditioning refers to the addition, removal, or change of state of the materials in the flue gas prior to entering the device or system being described.

(11) State annual consumption of utilities for the system as a function of standard cu ft/min (SCFM) of flue gas entering the system.

(12) State annual consumption of each chemical required as a function of SCFM of flue gas entering the system.

(13) State the ratio of actual to required operating time of the system.

(14) State the ratio of the system full load capacity to its minimum load capacity and the basis of this ratio.

(18) State the effects of variables such as temperature, concentration, flow, etc., of the materials being handled on the removal characteristics of the system.

(20) List the various important components of the system and indicate the materials of construction and design temperature of each; type of material, gas, liquid or solid, conveyed through or by the component; and its chemical name, concentration, and temperature. Also list applicable standards and specifications; e.g., ASTM A 36, A 106, A 178.

(21) Refer to the flow diagram given in Question three and state the various normal and maximum operating temperatures expected at each point for each of the system components.

(22) State standards, such as those listed below, which were used in the design of the system and its components.

ACI Building Code for Concrete Work

AISC Specifications for the Design, Fabrication and Erection of Structural Steel

ANSI Material Standards

ASTM Material Standards

API Tank Standards

AVS for Pumps and Piping

ASME Boiler and Pressure Vessel Code

ASME Unfired Pressure Vessel Code

Hydraulic Institute Pump Standards

ISA Instrumentation Standards

Manufacturing Chemists Association Chemical Handling Standards

(23) State the following system costs for described size (if projected, so state):

Installed cost - the total cost of the system installed and tested, ready to begin normal operation.

Operating costs - the total annual cost in labor, utility, and chemical charges to operate the system.

Maintenance costs - the total annual cost in labor and material charges to maintain the system.

(24) State the following flue gas preconditioning costs for the devices required to satisfy the requirements cited in the response to Question ten (if projected, so state):

Installed cost - the total cost of the equipment installed and tested, ready to begin normal operation.

Operating costs - the total annual cost in labor, utility, and chemical charges to operate the equipment.

Maintenance costs - the total annual cost in labor and material charges to maintain the equipment.

EVALUATION INFORMATION QUESTIONNAIRE

General Information

1. System name:

2. System developer:

3. System description:

4. Specific emission:

5. Comparison with existing systems -

   Advantages:

   Similarities:

   Differences:

   Disadvantages:

Design Information

6. Stage of development:

7. Expected date when the system will be commercially available:

8. Number of systems in operation:

Stage	Size	Hours of Operation
Bench Scale:		
Pilot Scale:		
Demonstration Scale:		

Operational Information

9. Principle of operation:

10. Flue gas preconditioning required -

Particulate:

Gaseous (name):

Temperature:

Other:

11. System utility consumption; e.g., water, air, electricity, auxiliary fuels:

12. System chemical consumption:

13. System operational reliability:

14. System operational turndown ratio:

Performance Information

15. System removal efficiency as a function of inlet concentration for particulate based on a particulate specific gravity of 2.5.

Under 2 μm:

2 μm to 5 μm:

5 μm to 10 μm:

10 μm to 20 μm:

20 μm to 50 μm:

Over 50 μm:

16. System gaseous pollutant removal efficiency as a function of inlet concentration.

Sulfur dioxide:

Nitrogen dioxide:

Other gas(es) (name):

17. Test methods used in determination of results presented in Questions 15 and 16.

Particulate:

Gaseous:

18. Removal efficiency parameters:

19. Creation of secondary pollutants:

Gas(es):

Liquid(s):

Solid(s):

Thermal:

Other (name):

20.

	Matl. of Construct.		Matl. Conveyed Through or by Component		
Component	Spec.	Design Temp.	Type	Concentration	Temperature
(1)					
(2)					
(3)					
etc.					

21. List range of system operating temperatures, including extremes that may occur.

22. List system design standards

Economic Information

23. Projected system costs

Equipment costs:

Installed costs:

Operating costs:

Maintenance costs:

24. Projected flue gas preconditioning costs:

Equipment costs:

Installed costs:

Operating costs:

Maintenance costs:

25. List life expectancies of system and each of its major components.

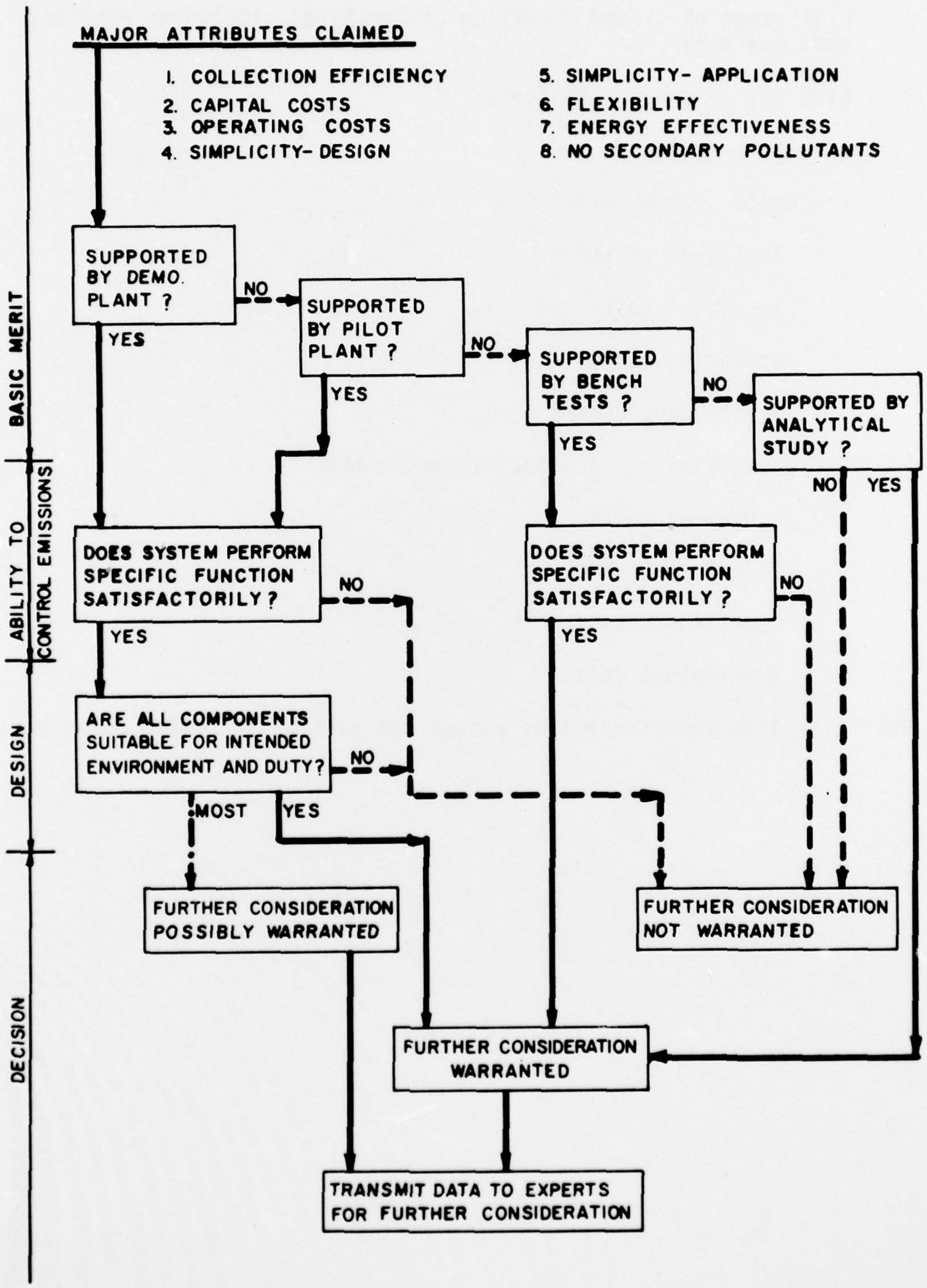

FIGURE D1. EVALUATION LOGIC DIAGRAM

APPENDIX E:

ECONOMIC ANALYSIS PROCEDURE

The purpose of the economic analysis for each emerging emission control system is to assist in the selection of systems relative to the cost involved.

The essence of the analysis procedure is the estimation of the costs involved in owning and operating each system for the present and future years. For this study, the costs occurring at the present time consisted of the system's first cost and its first year operating costs, each assumed as for calendar year 1975. Future costs, consisting of operating costs, were calculated through the use of a computerized economic program utilizing the first year operating costs and various factors for the time value of money and escalation. A brief description of the economic analysis procedure used in this study follows.

The system's first cost was based on estimates supplied by the developers, as noted for each system in the body of the report. The first year's operating cost was based on the annual cost of labor, utilities, chemicals and miscellaneous charges (also supplied by the developer). These cost items were multiplied by the appropriate current (1975) costs to arrive at the first year's operating cost.

After the first year's operating costs are established, they are used to compute each successive year's operating costs by multiplying the previous year's cost by a variable escalation factor. This computation is repeated through the entire life of the system until each individual annual cost has been calculated. Individual annual costs are then multiplied by an appropriate present worth factor [$1/(1 + i)^n$, where i is the time value of money (interest rate) and n is the individual year] to obtain the present (1975) value of the future operating costs.

This series of computations is further illustrated by the calculation of the total life cycle cost for the caustic injection process. The first step is to calculate the 1975 annual operating cost for each of the fifteen cost elements, as shown in Table E1. These values are computed by multiplying the consumption of each element by its cost.

With 1975 annual operating costs calculated, 1976 annual operating costs are calculated by multiplying 1975 costs by the appropriate escalation rate. These rates are variable and are a function of the cost element and time. (See Table E3). Costs for 1977 are projected from 1976 costs, and so forth, until 1989. Table E1 depicts the matrix of computed annual operating costs expressed as future dollar values.

Next, the future values of the annual operating costs are used to compute the present worth value of each cost element. This is accomplished by multiplying the individual future values by an appropriate present worth factor to obtain the present (1975) value associated with the respective future operating costs. The results of the conversion are presented in Table E2.

These present worth annual costs were then grouped into the chemical, utility, or miscellaneous costs and subtotaled as presented in the report. The summation of all the operating costs represents the life cycle operating cost, and it, together with the first cost of the system, is the total life cycle cost of owning and operating the system, in present (1975) dollars.

Table E1

Annual Operating Costs - Future Worth Values For The Caustic Injection Process

Cost Element	Dollars 1975	Dollars 1976	Dollars 1988	Dollars 1989
Labor	21,024	22,075	39,643	41,626
Utilities				
Electric Power	83,200	99,839	249,837	260,330
Natural Gas	0	0	0	0
Coal	0	0	0	0
Water	880	924	1,659	1,742
Steam	0	0	0	0
Fuel Oil	0	0	0	0
Chemicals				
Lime	0	0	0	0
Soda Ash	590,100	649,110	1,229,692	1,278,879
Ammonia	0	0	0	0
Miscellaneous				
Maintenance	32,000	35,200	86,134	92,163
Operating Overhead	16,000	17,600	43,067	46,081
Bed Material	0	0	0	0
Sludge Disposal	0	0	0	0
By-product Credit	- 98,350	-108,185	-204,948	-213,146

Table E2

Annual Operating Costs - Present Worth Values For The Caustic Injection Process

Cost Element	Dollars 1975	Dollars 1976	Dollars 1988	Dollars 1989
Labor	21,024	20,728	17,483	17,237
Utilities				
Electric Power	83,200	93,746	110,182	107,803
Natural Gas	0	0	0	0
Coal	0	0	0	0
Water	880	867	731	721
Steam	0	0	0	0
Fuel Oil	0	0	0	0
Chemicals				
Lime	0	0	0	0
Soda Ash	590,100	609,493	542,315	529,584
Ammonia	0	0	0	0
Miscellaneous				
Maintenance	32,000	33,050	37,986	38,164
Operating Overhead	16,000	16,525	18,993	19,082
Bed Material	0	0	0	0
Sludge Disposal	0	0	0	0
By-product Credit	- 98,350	-101,582	- 90,386	- 88,264
Subtotals	841,554	875,991	818,076	800,855

Table E3 is a list of the individual items which contribute to the operating cost of each system, along with the rate and escalation values for each item as used in the computer program. Operating overhead was taken as 2 percent of capital investment for each system studied. The characteristics of the hypothetical boiler used in arriving at the consumption values are shown in Table E4. These two tables formed the basis for computing the system operating costs.

Table E3

Cost Factor for Economic Analysis

	1975 Item Value		Item Escalation	
Costs	Dollars	Per Unit	1976-1980 (Percent Per Year)	1981-1990 (Percent Per Year)
Labor	4.80	hour	5	5
Utilities				
Electric Power	0.026	kWh	20	5
Natural Gas	2.03	1,000 cu ft	20	4.2
Fuel Oil	0.35	gallon	10	4
Coal	35	ton	10	4
Steam	2.20	1,000 pounds	10	4
Water	0.20	1,000 gallons	5	5
Chemicals				
Lime	35	ton	10	4
Soda Ash	70	ton	10	4
Ammonia	170	ton	20	5
Miscellaneous				
Maintenance Variable			10	7
Operating Overhead Variable			10	7
Copper Pellets	2,500	ton	10	4
Activated Carbon	800	ton	10	4
Sludge Disposal	5	ton	5	5
Credits				
Sulfur	20	ton	10	4
Sodium Sulfur Compounds	10	ton	10	4

Table E4

Hypothetical Boiler Characteristics

Boiler Capacity:	250,000 lb steam/hr
Fuel:	Coal at 4% sulfur and 13,000 Btu/lb
Collection Efficiency Required:	85% of inlet sulfur dioxide
Flue Gas Temperature:	450F at boiler outlet
Load Factor:	70% of boiler capacity

Each of the five systems presented in this report was assumed to have a life expectancy of 15 years with minor replacement items being part of the assumed maintenance cost. This particular life expectancy for all systems was based on the following rationale.

Firstly, an analysis of two systems and their components showed an average, dollar-weighted, life for the systems to be between 15 and 18 years. The conservative limit of this range, namely 15 years, was used in the economic calculations.

Secondly, if two or more different life expectancies are used for the systems, then the economic analysis comparing the systems should be for a period of time which is divisible by each life; e.g., with one system having a projected life of 15 years and another of 20 years, then the comparison period should be 60 years. Such an economic comparison over 60 years would be the standard method; however, the results would be highly questionable, because a small error in the assumed escalation rates or the time value of money would be magnified geometrically. Over a long period of time, such as 60 years, such small errors can completely distort an analysis. Assigning correct values for escalation rates and the time value of money is difficult for the immediate future and nearly impossible for an extended period such as 60 years. Therefore, to provide a reasonable economic comparison, all systems were assumed to have a life of 15 years.

The modified systems with off-site regeneration were considered as being independently owned and operated and serving an equivalent of 25 of the small hypothetical boilers of this study within a 50-mile radius.

The capital investment and operating costs of such a regeneration facility were extrapolated from the information provided for the hypothetical boiler: the capital investment was extrapolated by a seven-tenths factor and the operating costs were extrapolated directly. Shipping cost was assumed to be $10 per ton for the 50-mile trip. The facility was assumed to operate on a minimal 10 percent profit margin.

The off-site regeneration scheme was not proposed by any of the process developers, but was developed by the study team.

STANDARD ABBREVIATIONS

British Thermal Unit	BTU
Incinerator design refuse charging capacity, pounds per hour	C
Cubic feet per minute	CFM
Carbon dioxide	CO_2
Allowable particulate or gaseous emissions that may be legally discharged into the atmosphere	E
Excess Air	EA
Gallon per hour	$\frac{GAL}{HR}$
Grains per standard cubic foot	$\frac{GR}{SCF}$
Hydrocarbon	HC
Stack height, feet	H_s
1000 pounds per hour	$\frac{KLB}{HR}$
Kilowatt hour	kWH
Pounds per hour	$\frac{LB}{HR}$
Pounds per 1000 pounds of flue gas	$\frac{LB}{KLB\text{-}GAS}$
Pounds per million BTU of heat input	$\frac{LB}{MBTU}$
Pounds per 100 pounds of refuse charged	$\frac{LB}{100\ LB\ CHG}$
Pounds per 1000 pounds of flue gas	$\frac{LB}{1000\ LB\ GAS}$

STANDARD ABBREVIATIONS (CONTINUED)

Pounds of sulfur per million BTU of heating potential	$\frac{\text{LB SUL}}{\text{MBTU}}$
Maximum permissible emission value	Max E
Million BTU per hour	$\frac{\text{MBTU}}{\text{HR}}$
Million cubic feet	MCF
1000 cubic feet per hour	$\frac{\text{MCF}}{\text{HR}}$
Minimum emission value required	Min E
Megawatt	MW
The number of stacks at one facility	n
Nitrogen dioxide	NO_2
State law found not applicable	N/A
Oxygen	O_2
Parts per million	ppm
Boiler design capacity, MBTU of Heat per hour	Q
Boiler design capacity, KLB of Steam per hour	S
Sulfur content of fuel	SUL
Sulfur dioxide	SO_2
a less than b	$a < b$
a greater than b	$a > b$
a approximately equal to b	$a \approx b$
Collection efficiency	n
Percent	%

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