FINAL REPORT

SULFUR OXIDE CONTROL TECHNOLOGY

ASSESSMENT PANEL
(SOCTAP)

on

PROJECTED UTILIZATION OF STACK GAS CLEANING SYSTEMS

BY STEAM-ELECTRIC PLANTS

Submitted

to the

FEDERAL INTERAGENCY COMMITTEE
EVALUATION OF STATE AIR IMPLEMENTATION PLANS

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I. INTRODUCTION

This is the final report* of the Federal interagency committee established to assess the potential for utilization of flue gas desulfurization (SO_x control) systems by steam electric plants.

Previous studies have indicated that the implementation of State Air Implementation Plan (SIP) regulations limiting the sulfur content of fossil fuel can result in a demand for low sulfur coal that greatly exceeds the supply. Such studies have indicated a possible deficit in low sulfur coal in 1975 of as much as 250 million tons. This is equivalent to 100,000 megawatts, expressed as steam electric plant capacity. Flue gas desulfurization can reduce this shortage by removing sulfur oxides from the stack gas in lieu of requiring substitution of low sulfur fuel. However, it is currently estimated that less than 15,000 megawatts of SO_x control would be available by 1975.

Stack gas cleaning to reduce sulfur oxides, both in the near and intermediate future, offers potential as an important technological option to fuel switching. Recognition of this by the Federal Interagency Committee responsible for evaluation of SIP's resulted in the formation in May 1972 of an interagency task force to conduct a more detailed evaluation of SO_x control systems. This group, designated the Sulfur Oxide Control Technology Assessment Panel (SOCTAP), had as primary objectives (1) to attempt to quantify the availability of stack gas cleaning systems to steam electric utilities in 1975, 1977, and beyond, and (2) to identify possible actions that might serve to maximize the utilization of these systems, if desirable. It is important to note that this study is limited to stack gas cleaning. It does not attempt to assess other alternatives to this technology, nor to assess the relative merits of competing technologies. The task force consisted of the following members:

R. Berkowitz	Environmental Protection Agency
S. Gage	Office of Science & Technology/ Council on Environmental Quality
B. Haffner	Department of Commerce

*This report represents the view of the individual SOCTAP members and not necessarily those of their respective agencies.

R. Jimeson	Federal Power Commission
J. Padgett	Environmental Protection Agency
F. Princiotta	Environmental Protection Agency
E. Shykind	Department of Commerce

We recognized early in the study that a comprehensive analysis of every aspect of stack gas cleaning was incompatible with the manpower resources and time available for this study. We therefore chose to visit or meet with representative utilities and suppliers selected to give us a broad overview of the problems and potential of stack gas cleaning. We also solicited written comments from several additional suppliers and met with representatives of the Edison Electric Institute and the National Constructors Association. Our industry contacts led us to conclude that information on SO_x technology in Japan was essential to our study. We therefore sent two of our members to Japan for a first-hand assessment of this technology.

A preliminary draft of the final report was submitted for review and comment on November 16, 1972, to the Federal Interagency Committee for Evaluation of State Air Implementation Plans. <u>All information and findings presented are as of the date of this draft report</u>. Written comments were received from the Departments of Interior, Commerce, and Agriculture, Atomic Energy Commission, Federal Power Commission, and the Office of Emergency Preparedness. These comments were carefully reviewed by task force members and the majority of comments considered within the scope of the SOCTAP charter were accepted and integrated into the final report. The major exceptions were those by the FPC. The FPC task force member and FPC reviewers were much more pessimistic than the other task force members or other Federal Agencies relative to the technological status of stack gas cleaning. We were not able to reconcile their viewpoint with that of other task force members.

Our conclusions and recommendations are presented in Section II. Discussions of SO_x control technology, cost and performance of competing systems, environmental factors, institutional factors, and finally, a forecast of the availability of SO_x systems, are presented in Sections III through VII. A report on the trip to Japan by two of our members and reports on two U.S. plants visited are presented in the appendix.

II. SUMMARY AND RECOMMENDATIONS

A. Summary

Many factors must be considered in estimating the utilization of stack gas cleaning systems by the utility industry. These include technology, cost, adverse environmental effects, institutional barriers, and the ability of the suppliers to produce and install all of the systems demanded. These factors interact and combine to determine both the decision to buy, which must be made by the individual utility, and the aggregate supply constraints and secondary impacts which may limit the utilization. Uncertainties in the assessment of these factors have been a major barrier to widespread application of stack gas cleaning systems. We have not made an exhaustive assessment of each factor, but we believe each has been examined sufficiently to support the conclusions and recommendations presented. Detailed findings are discussed in Chapters III-VII. Our major findings are given in the following sections.

1. Technological Status

We have examined the status of stack gas cleaning technology in the United States and Japan and have concluded that sulfur dioxide removal from stack gases is technologically feasible in commercial-sized installations. We have concluded that the technological feasibility should not now be considered a decisive element in the utilization of these systems and that a large fraction of the nation's coal-fired steam electric plants can ultimately be fitted with commercially available stack gas cleaning systems.

The reliability of currently available systems has been the subject of some question. We concur that SO_x control systems must exhibit the high degree of reliability required by the utility industry. We believe that the required reliability will be achieved with the early resolution of a number of applications engineering problems related to specific hardware components and system design parameters. Solutions to each of these problems have been developed and demonstrated at one or another location. We do recognize, though, that solutions reached at one installation may not be entirely transferable to all other installations.

In view of the fact that a number of large scale plants scheduled for operation in the U.S. in the near future will provide additional engineering effort to solve these problems, we believe that an additional eighteen months operating experience (or by 1974) should effectively remove engineering barriers to the application of stack gas cleaning to many facilities.

Flue gas desulfurization systems can be classified into two general categories: (a) throwaway product systems where the sulfur product is disposed of as waste or (b) saleable product systems where the sulfur product (such as sulfuric acid) is marketed. The state of the art of SO_x desulfurization technology has advanced rapidly over the last year. Two plants with throwaway products - Chemico's calcium hydroxide scrubbing system in Japan and Babcock and Wilcox's limestone scrubbing system on a Commonwealth Edison boiler - and two plants with saleable products - Chemico's regenerative magnesium oxide process on a Boston Edison plant and Wellman Lord/MKK regenerative sodium sulfite process on a boiler in Japan - are considered particularly significant.

To date, the most successful operation of a throwaway system has been the Chemico calcium hydroxide scrubber process which has operated on the coal-fired boiler at the Mitsui aluminum plant in Japan since March 29, 1972, without any significant down-time; availability of this unit has been effectively 100 percent since start-up. Both sulfur dioxide and particulate removal efficiencies have been quite high and there is an important similarity between this application and typical U.S. requirements. Babcock and Wilcox's limestone scrubbing unit on Commonwealth Edison's Will County plant near Chicago, since its start-up in February 1972, has indicated reasonably high SO_2 removal efficiencies and the promise of reliable operation in the near future. The major problem afflicting the throwaway processes is developing techniques for disposing of sludge materials in an ecologically satisfactory manner without excessive costs. It is considered important that acceptable disposal techniques be expeditiously developed. Without these techniques, sludge disposal will remain a serious constraint to the utilization of throwaway systems at many power plant locations.

Of the regenerable systems, the Wellman Lord regenerable sodium sulfite scrubbing process has operated most reliably to date. A unit treating flue gas at Japan Synthetic Rubber's Chiba Plant has shown reliable and efficient operation since June 1971, producing high quality sulfuric acid. The main disadvantage of this system is the requirement for discarding a sodium sulfate bleed stream which is ecologically and economically undesirable. However, there are indications that bleed rates can be substantially decreased so that less than five percent of incoming flue gas sulfur need be discarded, compared to the present ten percent.

Chemico's magnesium oxide system at Boston Edison's Mystic Station started up in April 1972, and has operated intermittently since then due to mechanical difficulties. However, sulfur dioxide removal efficiencies have been in excess of 90% with no apparent scrubber problems. Preliminary experience with the critical regeneration system has been promising. There appears to be a high probability for reliable operation of this unit in the near future. Among the more advanced processes, this process is somewhat unique in that no major ecological problems have been identified. However, problems in marketing large quantities of sulfuric acid may limit acceptability of saleable product systems to only a fraction of the total potential flue gas desulfurization market.

2. Performance

When evaluating SO_2 removal efficiencies, it should be noted that a removal efficiency of about 75% is needed to meet the New Source Performance Standards with 3% sulfur bituminous coal. Generally efficiencies of 85% are sufficient to meet the sulfur dioxide emission limitations of most State Implementation Plans.

As discussed above, a number of stack gas cleaning systems are being tested and evaluated. At the Mitsui aluminum plant near Omuta, Japan, the Chemico scrubbing unit has exhibited reliable, essentially trouble-free operation, with removal efficiencies of 80% to 90% since March 29, 1972. The Wellman-Lord scrubbing unit, at the Japan Synthetic Rubber plant near Chiba, has accumulated over 9000 hours of operation since June 1971 with a removal efficiency averaging about 90%.

The only U.S. plants that have yet achieved sufficient operating experience to report long-term average removal rates are the Combustion Engineering limestone injection/ wet scrubbing systems. These have exhibited average removal rates in the range of 60% - 80%. However, performance results to date indicate that at the upper end of this range these systems are more prone to chemical scaling and other operating problems.

Short-term testing of the Babcock and Wilcox wet limestone scrubber at Commonwealth Edison's Will County plant and the Chemico wet magnesium oxide scrubber at Boston Edison's Mystic plant have exhibited removal efficiencies of 75-85% and 90%, respectively. It does not appear that there are insurmountable chemistry related problems at these higher removal efficiencies for these two plants.

It should be noted that many stack gas cleaning processes, particularly lime/limestone wet scrubber systems, are also capable of efficient particulate removal. In fact, most planned and installed stack gas cleaning systems are designed to meet both SO_2 and particulate removal specifications.

3. Cost

The incremental capital costs for including a stack gas scrubbing installation in the construction of new generating plants ranges from a low of $30 to a high of $50 per kilowatt capacity. This would include particulate control equipment, where required. The average incremental cost for new generating plants is expected to be around $40/kw.

Capital costs for retrofit installations to existing generating plants in most cases is expected to be in the $45 to $65/kw range. For some retrofitted plants, installation costs have been estimated as high as $80/kw or more. However, the practical limiting cost for retrofitting is fixed by economic considerations at each particular plant.

Based on the forecasts of the amount of stack gas cleaning that might possibly be installed under the assumptions used in this study, the total investment between 1975 and 1980 for stack gas cleaning would be $8.2 billion in addition to $78 billion of new generating capacity investment. This represents almost 10% of the total future capital requirements for the industry.

The annual costs estimated for stack gas cleaning range from 1.1 to 3.0 mills per kilowatt-hour, with a mean of about 2.0 mills/kw-hr. The average national consumer cost for power is about 17.8 mills/kw-hr. (1971, Edison Electric Statistical Yearbook). Assuming stack gas cleaning costs are passed on, consumer cost for electricity could increase by as much as 17%.

Annual costs are difficult to generalize because of the present lack of sufficient operating data on large scale installations, the variability resulting from different process type, specific installation cost factors, and variation in cost accounting procedures. In the figures for annual costs cited in this report, the fixed charge portion includes depreciation of capital equipment over 15 years on a straight line basis. Operating costs include a charge for parasitic power consumption.

4. Associated Environmental Factors

The disposal of waste products from stack gas cleaning systems still remains a major problem with serious environmental consequences. Based on a potential installation of 100,000 MW of flue gas desulfurization, calculations indicate that 48 million tons per year of throwaway sludge would be produced. This corresponds to a potential land requirement of 160 square miles assuming a 20-year storage requirement and ponding to a 10-foot depth. This should be compared to a 50 square mile requirement for flyash disposal under the same assumptions. In some rural plants, sludge materials can be disposed of in a pond on the power plant site. In urban applications the sludge can be transported for landfill, but the transportation costs may be prohibitive in certain situations. Although it is feasible to minimize potential water pollution and land deterioration problems by closing the scrubber liquor loop and by careful engineering of disposal sites, it is essential that development and demonstration efforts be accelerated in this area to obtain satisfactory solutions to this problem before its full impact is felt in the 1975-80 time period.

Due to the great difficulty of storing and marketing large quantities of sulfuric acid under future supply/demand constraints, it is estimated that only a relatively small fraction of flue gas desulfurization systems will produce saleable H_2SO_4. From an environmental viewpoint, the most manageable sulfur product appears to be elemental sulfur, since: (a) it can be economically stored for sale in certain locations; (b) it would drastically reduce land requirements if treated as a throwaway product; and (c) it is an insoluble and inert material with no apparent water pollution potential. The major obstacles to use of elemental sulfur producing control processes are the lack of demonstrated technology and unfavorable economics, if treated as a throwaway product.

5. Institutional Barriers

There are a number of institutional barriers in the electric utility and control systems industries to the accelerated application of SO_x control systems. These barriers can combine to delay the ordering, fabricating, assembling, and placing into operation of SO_x scrubbing systems. Some of the most important are (a) the adequacy of the market demand to encourage development of a supply industry; (b) necessity to maintain adequate electrical reserve generation margin; (c) lack of process chemistry expertise in the electric utility industry; and (d) fuel switching alternatives where higher costs for low sulfur fuels can be passed through to consumers by means of fuel adjustment clauses.

An important factor now restricting system installation is the currently limited market demand for the SO_x control system. This lack of demand by the electric utilities and other industries arises from a number of primary factors such as lack of confidence in the ability of the vendors to perform as promised, an anticipation that regulations may be altered in the near future, potential difficulties in raising capital and obtaining rate increases to cover expenses for pollution abatement, and the lack of suitably trained personnel in the industry to evaluate and operate these systems. With increased demand pressure, scrubber systems probably could be constructed at a higher rate than at present.

Elimination of these primary factors which are now limiting market demand will require time to accomplish. Familiarity with the technology is increasing but confidence in system reliability depends critically on scrubber operating experience during the next few months. A sudden surge of orders could swamp the productive capacity of the control systems industry, though, and scrubbers which might otherwise be brought on line in 24-30 months may be delayed a year or more.

Nationally in the electric power industry, there is certainly an upper limit to the generating capacity which can be retrofitted each year because of the necessity to maintain adequate reserve margins. While that quantity is somewhat above present estimates of market demand or what the control system vendors can now supply, this factor may preclude higher rates of installation. In particular, there may be severe scheduling problems in retrofitting scrubbers in the middle central and middle southern parts of the country where the large coal-fired utilities, already under pressure because of delays in new generating equipment, are concentrated.

There is little expertise in large-scale chemical process technology within the electrical utility industry. Thus, there may be serious operational problems once the scrubbers are installed because of the lack of familiarity with the operational details of the scrubbing system. The utilities now depend almost completely on the control systems vendors and engineering consultants for technical advice. However, because of past experience, particularly with the dry limestone injection/wet scrubbing systems, utilities are wary of vendor claims.

There are several economic disincentives involved in installing stack gas scrubbers. The utilities can meet the SO_x standards by converting coal-fired plants to low sulfur oil or by securing low sulfur coal. Both of these options have, in turn, broad implications for national economic and environmental policies. Even with much higher costs for the low sulfur fuels, many utilities are allowed to pass most of these increased fuel costs directly and immediately on to the consumer without regulatory commission action. On the other hand, utilities must apply for rate increases to cover the capital and operating expenses of the scrubbers.

In the construction industry, localized shortages of pipefitters, boilermakers, and possibly other skilled workmen may delay scrubber projects. If intense competition for skilled metal-workers does develop because of construction booms in refineries, waste treatment systems, etc., then it is certain that scrubber installation schedules will be delayed, and installation costs will be escalated.

6. Forecasting of Utilization of Flue Gas Desulfurization Systems

In the United States during the 1973-80 period, electric utilities will probably continue the current pattern in selecting wet scrubbing systems, with the majority of orders probably for wet lime/limestone scrubbers producing a throwaway sludge. There probably will be a limited number of orders for regenerative processes using reagent liquors based on magnesium, sodium, and other compounds.

Forecasts based on SOCTAP estimates of the regulatory enforcement pressures, utility demand, and supplier capabilities indicate that as much as 20,000 MWe of generating capacity could be equipped by SO_x scrubbing systems by the end of 1975 but more likely the capacity will be closer to 10,000 MWe. By the end of 1977 the equipped capacity may be 48,000-80,000 MWe which would allow the use of high sulfur coal to supply 25-40% of the utility heat required from coal in that year. Again, realism dictates that the lower end of the range would be the best guess because of the likelihood of near-term delays and the uncertainties in estimating the effect of interactions between the factors considered.

With steady growth in the control system industry based on a firm market in the utility industry, at least 75% of the coal-fired capacity conceivably could be equipped with stack gas scrubbers by 1980. This could permit the utilization of over 400 million tons of high sulfur coal in that year. Such an estimate, however, does not take into account chemical coal cleaning processes such as liquifaction and gasification which may become available on a limited basis in the 1977-1980 timeframe.

Our forecast is based on the results of many discussions with utilities, manufacturers, and others to attempt to identify and quantify those factors which might limit the utilization of SO_x control systems. These include consideration of the technology, cost, environmental effects, factors affecting utility demand, other institutional barriers, and the ability of the industry to produce and install the systems.

Our estimates are the result of an intuitive and analytical blending of these factors. The concept of "choke point" or limiting factor is an integral part of our assessment. For example, if the technology is not available, a deluge of orders by the utilities will not automatically result in increased utilization. Given the technology and sufficient orders, the "choke point" may be determined by considerations such as financing, engineering design, scrubber production, construction, or possibly the ability of the utilities to phase in the operation of SO_x control systems without risking unduly low reserve margins. It is apparent also that the choke point will change with time. Elimination of the controlling "choke point" allows the utilization rate to increase until a new factor is controlling. This new rate may or may not represent a significant increase in utilization rate.

An upper limit of 24,000 MWe and 80,000 MWe by the end of 1975 and 1977, respectively, is forecast based on the assumption that the "choke point" is supplier capability. Orders for systems for 1975 must be placed within the next 6-9 months, with 24-30 months then required to bring each system on line. The lower limit of 10,000 MWe and 48,000 MWe for 1975 and 1977, respectively, assumes the likelihood of delays in excess of 6-9 months before utility demand increases significantly. Thus, utility demand is the initial "choke point." Factors affecting this demand are many. The assumption that a combination of factors and the resulting utility demand constitute the real "choke point" leads us to conclude that the lower estimates are the more realistic.

B. Recommendations

The momentum for utilization of stack gas cleaning appears to be building and probably will continue at some rate without the need for additional assistance from the Federal government. We believe, however, that the rate of utilization of these systems could be accelerated, if it is deemed desirable, by implementing the following recommendations. Consistent with the limited objectives of this study, the recommendations are addressed only to stack gas cleaning. This is not to imply, however, that alternatives to stack gas cleaning are less desirable and should not be encouraged.

1. A major factor which limits utility demand appears to be a lack of up-to-date knowledge of the status of SO_x technology and other information needed by the individual utility to decide how to meet its local sulfur regulations and how to plan a program to implement this decision. We recommend the institution of an effective program of SO_x control technology transfer to be carried out by one or more Federal agencies to assist the utilities and industrial boiler operators in identifying potential technologies and solving technical staffing problems associated with the operation of the scrubbers. This activity would cover not only information dissemination on hardware but would address

operations and manpower problems within the utility/industry context. A possible model might be the combination of a policy committee under the Federal Council for Science and Technology or the Council on Environmental Quality and an operations office under EPA Control Systems Division. This arrangement could go a long way toward meeting the twin objectives of putting a new face on the Federal government's attempts to accelerate the application of SO_x control technology while ensuring the required level of technical expertise in the operational arm. It would also have explicit responsibility for the dissemination of information about foreign developments in SO_x control.

2. Accelerate R&D in critical areas of SO_x control technology. In particular, Federal R&D efforts should be expanded to accelerate the development of improved scrubber solid waste management processes. It also is strongly recommended that the Federal government continue support of ongoing government sponsored programs to develop SO_x control processes. The need for the development of advanced SO_x control processes is clearly recognized to expand the options available to industry and the Federal government, particularly processes with more environmentally acceptable by-products. However, the committee was not in unanimous agreement that programs for advanced processes should be wholly or predominantly funded by the Federal government.

3. Explore a variety of incentives to accelerate the application of SO_x control systems, and/or disincentives for substitute or alternative pollution control strategies. The following incentives and disincentives might be considered:

(a) Modification of the fuel adjustment clause provision now operable in many states to inhibit utilities from passing through to the consumers the high cost of low sulfur fuel rather than installing SOx control systems which would require public utility commission action to increase the rate base. This problem could be explored with the National Association of Regulatory Utility Commissions (NARUC).

(b) Simplification of the procedures required by public utility commissions for utility companies attempting to obtain rate increases to cover the costs of pollution abatement devices such as SO_x scrubbers. Removal of this disincentive is closely coupled to changes in the fuel adjustment clause and could also be explored with NARUC.

(c) Institution of a grant-in-aid program through EPA to assist in the purchase of SO_x control equipment. A variation of this approach would be a low-interest loan program in which a fraction of the loan would be forgiven when the scrubber system goes into operation.

(d) Sulfur tax with a rebate clause so that the utilities would pay a sulfur emission charge until their scrubber goes into operation and then taxes paid during the construction and shakedown phase would be rebated. Alternatively, a clause for suspension of the tax during the period of construction and shakedown phase could be considered.

(e) Residuals subsidy program under which a base-level price would be established for scrubber residuals such as sulfur, H_2SO_4, and $CaSO_4$ to encourage beneficiation of the scrubber sludge to a potentially useful product, even though that product may have to be stockpiled. This could avoid premature commitment of large areas of land to non-reclaimable sludge ponds.

4. Encourage Labor and Commerce Departments to determine national needs for skilled technical manpower (boilermakers, pipefitters, etc.) for which there may be intense competition among several competing industries (SO_x scrubbers, refineries, etc.). Where potential shortages are indicated, special programs to provide the manpower supply and increase its productivity may be required.

5. Encourage interagency efforts to devise policies (and propose legislation if necessary) to provide special incentives for the use of low sulfur fuel by small industrial boiler and area sources. This would direct the low sulfur fuels toward users for whom SO_x control methods would be prohibitively expensive. This would result in a strategy which would influence fuel purchasing patterns by inhibiting utilities and large industries from tying up available low sulfur fuel supplies by outbidding the small consumers with long-term contracts.

III. DESCRIPTION AND TECHNOLOGY STATUS OF FLUE GAS DESULFURIZATION SYSTEMS

There are more than fifty SO_2 flue gas desulfurization control processes, and their major variations. Of these, only five are considered developed sufficiently to enable reasonable estimation of expected performance and economics. For the purposes of this discussion, four of these five processes are considered sufficiently developed, with acceptable SO_2 removal efficiencies, to potentially make a significant contribution to the control of new or modified power plants within the next five years. The dry limestone injection process, although well characterized, has a removal efficiency too low for most boiler control requirements.

The four processes which are considered sufficiently developed to potentially desulfurize flue gas on a full-scale commercial basis, within the next five years, are:

Wet lime/limestone scrubbing
Magnesium oxide scrubbing
Catalytic oxidation
Wet sodium-base scrubbing with regeneration (Wellman-Lord Process)

An additional process, the double alkali process, is also potentially important, and could be added to the above list if process technology development is accelerated.

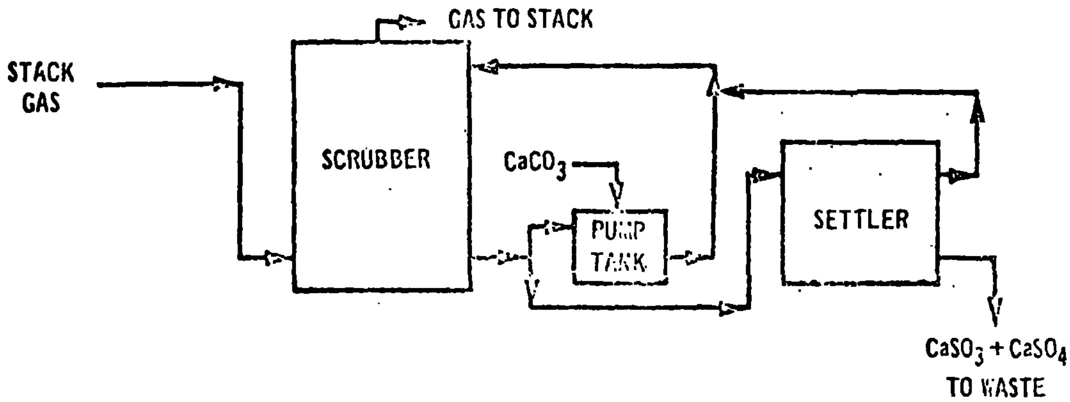
The following discussion describes and presents the status of: wet lime/limestone systems, magnesium oxide scrubbing, catalytic oxidation, the Wellman-Lord process, double alkali, and dry limestone injection control processes.

A. Wet Lime/Limestone Systems

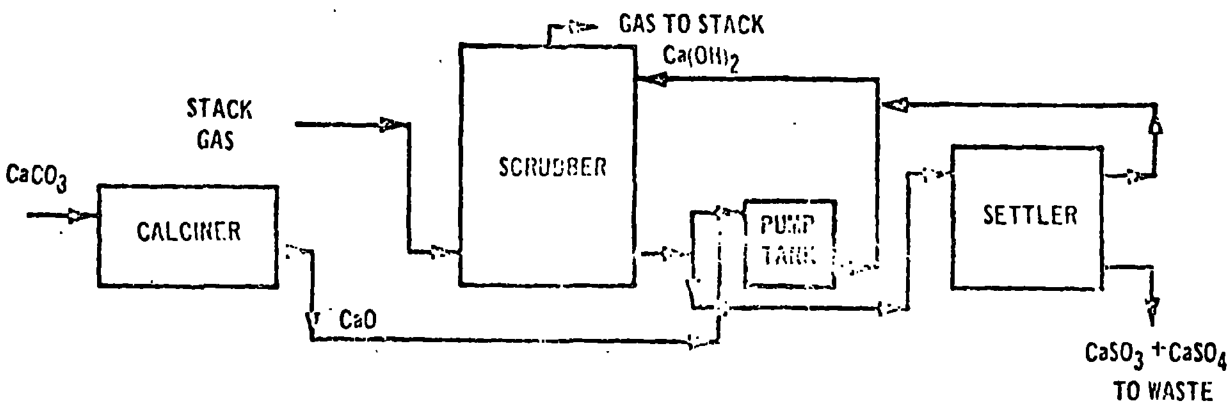
The great majority of full-size power plant desulfurization systems in both the planning and operational phases involve scrubbing with limestone or lime slurries. The primary reasons for this are that these processes are more fully characterized than other first generation systems; have relatively low capital and operating costs; and have high potential removal efficiencies. However, along with characterization comes familiarity with such process problems as chemical scaling, erosion/corrosion, solid waste disposal, and plume heating requirements.

Several methods have been developed for the use of limestone and lime in a wet scrubbing process. The major variations are schematically illustrated in Figure III-1. In Method 1, Scrubber Addition of Limestone, the flue gas is contacted with a slurry containing finely ground limestone. The limestone is added directly to a portion of scrubber effluent for recycle. Part of the scrubber discharge goes to a settler (or a pond) where the solid product is removed. Settler overflow can either be recycled as shown or discharged to waste. The next method, Scrubber Addition of Lime is similar to Method 1 except that the limestone is first calcined to lime externally before addition to the scrubber circuit; ordinarily lime is purchased by the utility from lime suppliers. In the final method, Boiler Injection, the limestone is calcined in the boiler (as in the Dry Injection System) and carried to the scrubber in the flue gas. Figure III-2 shows the Commonwealth Edison Company's Will County Station - Unit No. 1. This unit utilized limestone introduced in the scrubber circuit and shows the major equipment items needed for a typical full-size wet limestone installation.

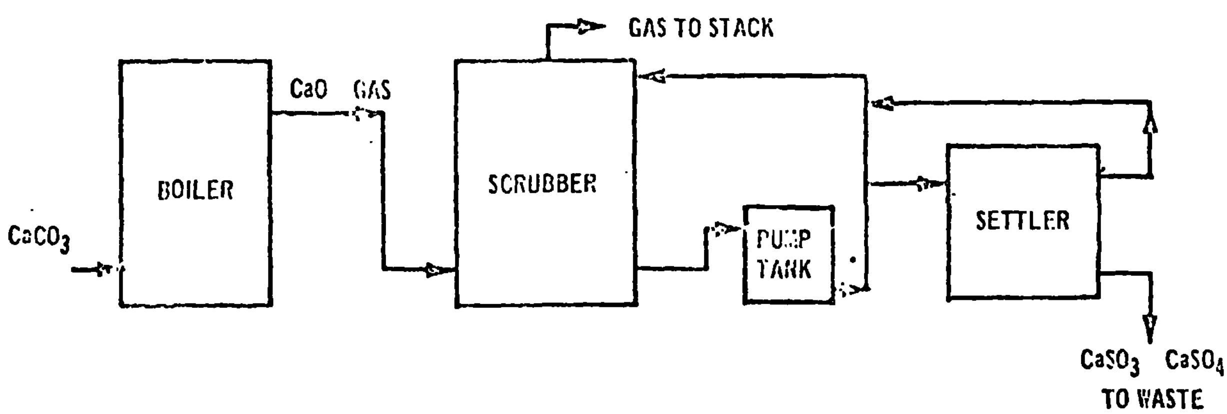
In addition to being classified according to whether lime or limestone is the reactant, the above processes are further classified as cyclic or non-cyclic. Such a classification refers to whether the aqueous liquor loop is totally recycled (cyclic operation) or totally purged (non-cyclic operation) to a stream or reservoir, giving rise to possible water pollution problems. In light of such potential water pollution problems, the great majority of the full-size installations operate, or will operate, in a total or near-total recycle mode. The ultimate disposition of the sludge solids is generally in a large pond at the power plant site; when land is not economically available, the sludge is transported to the most economical surface disposition area available.



METHOD 1. SCRUBBER ADDITION OF LIMESTONE



METHOD 2. SCRUBBER ADDITION OF LIME



METHOD 3. BOILER INJECTION

FIGURE III-1 Major Process Variations For Use Of Lime Or Limestone For Removal of SO_2 From Stack Gases

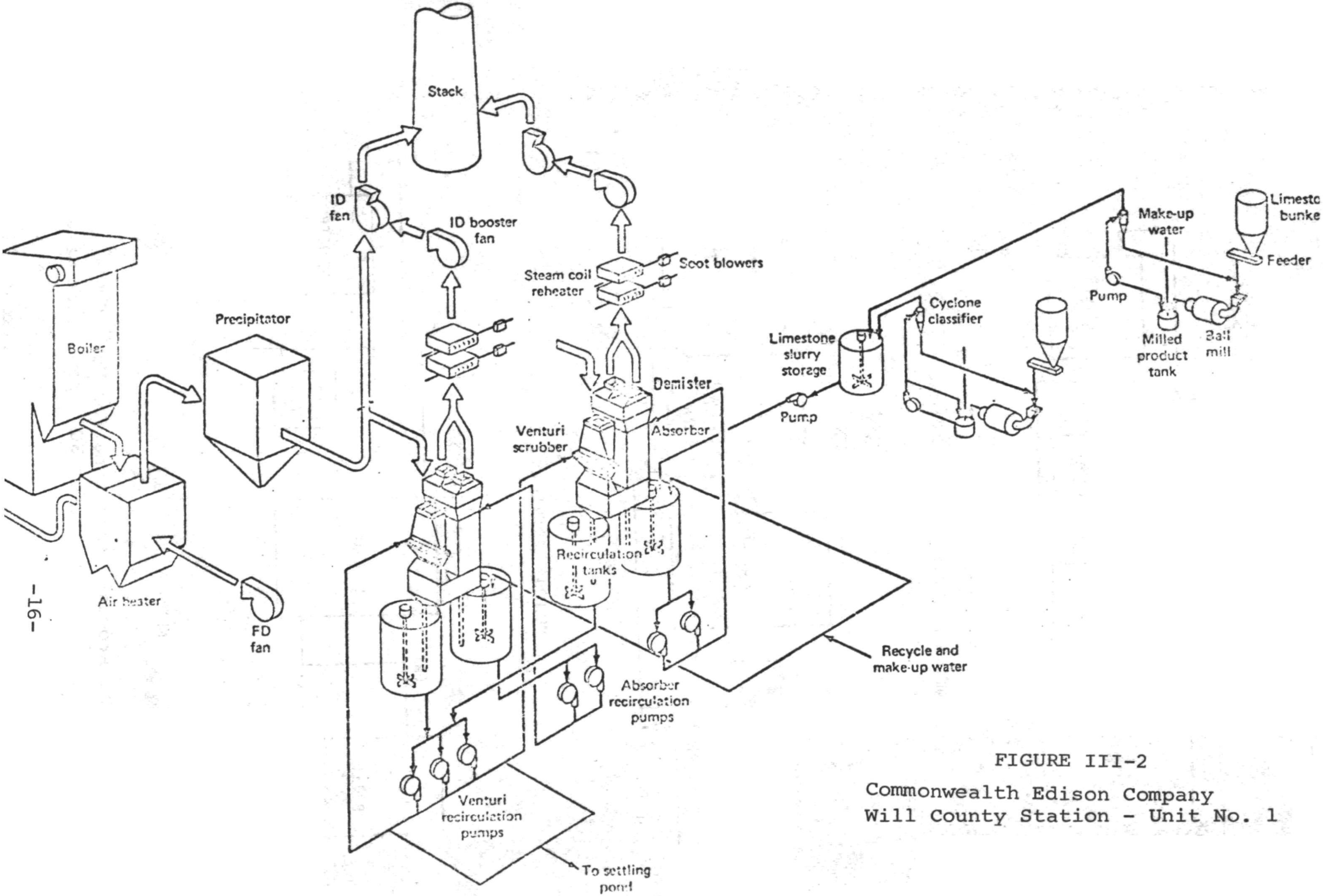


FIGURE III-2

Commonwealth Edison Company
Will County Station - Unit No. 1

The chemical reactions occurring in the above systems, although seemingly simple, are neither well understood nor universally agreed upon. The following chemical reactions have been postulated for flue gas scrubbing with limestone slurries and appear to be the most plausible on the basis of experimental data available.

$$SO_2(g) \rightleftharpoons SO_2(aq)$$
$$SO_2(aq) + H_2O \rightleftharpoons H_2SO_3 \rightleftharpoons H^+ + HSO_3^-$$
$$HSO_3^- \rightleftharpoons H^+ + SO_3^=$$
$$CaCO_3(s) \rightleftharpoons CaCO_3(aq)$$
$$CaCO_3(aq) \rightleftharpoons Ca^{++} + CO_3^=$$
$$Ca^{++} + SO_3^= + 1/2 \cdot H_2O \rightleftharpoons CaSO_3 \cdot 1/2\ H_2O(s)$$
$$CO_3^= + H^+ \rightleftharpoons HCO_3^-$$
$$H^+ + HCO_3^- \rightleftharpoons H_2CO_3(aq)$$

The overall reaction is:

$$CaCO_3(s) + SO_2(g) + 1/2\ H_2O \rightarrow CaSO_3.1/2\ H_2O(s) + CO_2(g)$$

There has been a considerable amount of bench model, pilot plant, and prototype experimental activity in the limestone wet scrubbing area. An extensive effort has been expended on a variety of scrubber types, by a large number of organizations, over the last 30 years. Over the last several years, pilot plant effort has been particularly active and substantial advances have been made in wet limestone technology. Scrubber types which have received the most attention in recent years have been the venturi, Turbulent Contact Absorber (TCA), Hydrofilter (flooded marble bed), spray tower, and packed tower. Generally, pilot plant results have indicated that under carefully selected operating conditions, all of these scrubbers, with the probable exception of the packed tower due to its inherent plugging tendencies, can be operated with relatively high SO_2 and particulate removal efficiencies with acceptable reliability. Pilot plant testing has indicated that, with relatively high liquid-to-gas ratios, high solids content in the scrubber slurry, long residence times in a delay tank following the scrubber, and a proper choice of scrubber type, the desirable combination of good removal efficiencies without excessive down-time can be achieved.

For example, the results of both the Ontario-Hydro and the Tennessee Valley Authority (TVA) pilot plant programs indicate that good performance and reliability have been obtained on a pilot-size scale. Ontario-Hydro was able to achieve

SO_2 removal efficiencies of 70-80 percent in its spray tower, under reasonable operating conditions, with good reliability; scaling or plugging was not a major problem. TVA has been able to achieve high removal efficiencies for three scrubber systems: a venturi-rod (modified venturi) spray tower, a three-stage TCA, and multi-grid tower. For the venturi-rod/spray unit, SO_2 removal efficiencies of 77 percent over a 354-hour test were achieved with only 20 hours of down-time. Particulate removal efficiency was measured at from 98.9 percent to 99.3 percent. For the TCA unit, SO_2 removal efficiencies of up to 92 percent and a particulate removal efficiency of 98.3 percent have been measured during a 172-hour test. Although the unit showed no scaling or plugging tendencies, erosion of the balls, grids, and nozzles was excessive; design modifications are being considered to minimize this problem. For the multi-grid scrubber, a 270-hour test yielded an SO_2 removal efficiency of 85 percent with no scaling or plugging. Particulate removal was about 98.9 percent. TVA reports that demister operation has been troublesome, however, with some solids buildup ($CaSO_4 \cdot 2H_2O$).

At the present time, at least six full-size scrubber facilities have been constructed and have generated varying amounts of operating data. An additional unit, the London Power Fullham Plant, was constructed and tested in the late 1930's. This unit is considered the first commercial application of wet limestone scrubbing of power plant flue gas. It was operated from 1936 to 1939, yielding very high SO_2 and particulate removals, without substantial scaling or plugging problems. In fact, many of the techniques used to control scaling and plugging on this unit have been utilized successfully in recent years. However, the facility was afflicted with corrosion and erosion problems which led to considerable down-time and high maintenance costs. The unit was taken off the line during the early stages of World War II, when the stack plumes were considered markers for enemy airmen. Before shutdown, a plant modification decreased the removal efficiency to 90 percent, but gave some promise of being able to remain in service for much longer periods without repair. This unit is considered to have been the first to indicate the feasibility of wet limestone scrubbing for power plants on a commercial basis.

In Japan, 156 MWe power plant of the Mitsui Aluminum Company has been retrofitted with two dual-stage venturi scrubber systems, each capable of handling 75 percent of the full-load gas flow. The system has exhibited reliable, trouble-free operation since being put on stream on March 29, 1972. The plant is presently burning 2 percent sulfur coal and achieving 80 - 85 percent SO_2 removal from the flue gas using carbide sludge (essentially calcium hydroxide) as the alkaline absorbent. The unit passed performance guarantee tests within four weeks of start-up which required 90 percent SO_2 removal and 90 percent flyash removal at a specified gas flow rate. Presently, the unit is operating at less stringent conditions, but with the aim of meeting the Japanese regulatory codes. It should be noted that, although the system is designed for total liquor recycle, it did not operate in a totally closed-loop mode for at least a portion of its operating lifetime. Appendix A further describes this important unit which was recently visited by SOCTAP members.

The AB Bahco system, which utilizes a two-stage inspirating scrubber with lime as the reactant, is considered an important operational scrubber facility despite its small size (the equivalent of 25 MWe for the three units). The units service three oil-fired boilers in a hospital in Stockholm, Sweden. This system, considered among the more successful of the wet lime scrubbers in operation, has been routinely operated at 95-98% removal efficiencies. After three months of service, the scrubber must be shutdown and hard sulfate scale removed from the demister section. The demisters have not been equipped with washing sprays, a possible solution to the scaling. Recently, Cottrell announced that it has licensed the Bahco process for use in the United States. At the present time, they will accept orders for scrubber facilities up to 40 MWe per module in size.

In the United States, Combustion Engineering, Inc. has constructed and operated three full-size scrubber facilities: two in 1968 at existing coal-fired power plants (the 125 MWe Kansas Power & Light Lawrence Station No. 4 and the 140 MWe Union Electric Meramec No. 2), and the third, on a new plant (the 420 MWe Kansas Power & Light Lawrence Station No. 5). These units all employ boiler injection of limestone followed by wet scrubbing in single-stage flooded-bed scrubbers (method three of Figure III-1). These plants were expected to remove about 85% of the SO_2 from flue gas generated using about 3.5% sulfur coal.

Multiple problems including corrosion, plugging of drain lines, spray nozzles, demister and reheater, lime distribution and mechanical failure of pumps and other components were experienced during early stages of operation of the 125 MWe KP&L Station No. 4. After incorporation of several modifications, the system was able to operate for extended periods with improved reliability even though the scrubber was periodically taken off line for inspection and repair and the plant boilers fired on natural gas at these times.

During the first half of 1971, the unit operated with SO_2 removal efficiencies of 50-65% and up to 90% for short periods. In a three-day test period in March 1971, efficiencies ranging from 52-87% (averaging 73%) were achieved while firing 3.4% sulfur coal.

Problems were experienced at KP&L in early 1972 when the larger (420 MWe) unit was added to the system. The scrubber on the larger boiler is said to have caused overloading of the ponding system such that scaling occurred in the scrubber beds of both units.

Another series of tests were conducted in February-March 1972, which indicated that lower gas velocity, high L/G ratio, and high solids recycle would improve the operation of the facility. The scrubbing system has been recently modified to achieve lower gas velocity, higher L/G and high recycle of solids. The object of these revisions is to demonstrate reliable operation of the system, probably with lower SO_2 removal than originally expected. The system with these modifications was tested during October 1972, for approximately two weeks. Based on results of operation during this short period, KP&L management expects to obtain 75% SO_2 removal and 99+% particulate removal with this system in long-term continuous operation. This program has been supported by EPA-funded testing on the 11,000 CFM Combustion Engineering pilot unit in Windsor, Connecticut.

The Union Electric unit was also tested in May-June 1971 with SO_2 removals similar to the 125 MWe unit. However, mechanical equipment problems, mostly unrelated to limitations in the process design, limited continuous operation to about 80 hours. Boiler pluggage was also a major problem with this unit. Recently, Union Electric has announced abandonment of this unit.

The 420 MWe unit was initially tested in September 1971 during which maldistribution of gas flow to the six scrubbers was noted. Gas flow control modifications have since been made. The unit was started up again using coal on November 28, 1971. Currently, information on SO_2 removal is not available for this unit. This unit is currently being modified to achieve conditions suggested by the February-March tests in Unit 4. Two additional scrubbers are being installed in parallel to the existing six scrubbers in order to lower the gas velocity.

In February 1972, the 175 MWe Commonwealth Edison Will County Station - Unit No. 1 (Figure III-2) started up. This unit has operated intermittently since start-up and has generally achieved SO_2 removal efficiencies in the range of 75-85%. Demister pluggage with a soft, mud-like substance has been a problem; but with automatic demister washing with make-up water via bottom sprays and other system modifications, this problem appears to be controllable. There was no hard scale noted anywhere in the system in operations to date. Economic disposal of sludge from this system appears to be a problem; however, Commonwealth Edison is presently working on this problem with Chicago Flyash Company. One of the first steps taken will be the installation of a sludge treatment system to allow disposal of sludge with a lower water content. None of the problems encountered thus far in the Will County unit appear to be insurmountable. This facility was also recently visited by SOCTAP members and a more detailed description is presented in the appendix. This system is the first full-scale installation in the United States that uses limestone introduced into the scrubber circuit. This system is representative of a trend in recent years away from the boiler injection mode due to the possibility of boiler pluggage and the tendency toward serious scaling problems.

It should be noted that EPA is conducting a major test program in the lime/limestone scrubbing area at the recently built prototype facility at the TVA Shawnee steam plant near Paducah, Kentucky. Bechtel Corporation is the prime contractor for the test program for which TVA is supplying operational and analytical personnel. The facility is very versatile and will test limestone/lime scrubbing in venturi, turbulent contact absorber and flooded marble bed scrubbers. The facility is equipped with extensive process instrumentation and sophisticated data acquisition and handling systems. Test phases involving air-water and soda-ash, water, SO_2 and flue gas, water, soda ash have been completed. Testing with limestone is presently getting underway. As testing progresses, the total body of knowledge in wet scrubbing will be greatly increased.

B. Magnesium Oxide Scrubbing

In many respects, the magnesium oxide (MgO) scrubbing process is similar to lime (CaO) scrubbing. The principal difference is that the spent magnesium sulfite and sulfate salts are regenerated producing a concentrated stream of 10-15% SO_2 and regenerated MgO for reuse in the scrubber loop. Since the reactant is recycled, it must be protected from contamination by fly ash. It is, therefore, necessary that the process be applied on an oil-fired boiler or that the fly ash be sufficiently removed from the flue gas prior to passing it into the MgO desulfurization process.

This process was first developed by the Grillo Company of Hamborn, Germany. In 1968, Grillo scaled up the small pilot plant which it has operated for about one year to a 15,000 CFM scrubbing facility installed on an oil-fired boiler of Union Kraft at Wesseling, Germany. The reactant used was principally MgO with about 6% manganese dioxide. Spent reactant from the scrubber was shipped from Wesseling to Hamborn where it was calcined in a vertical kiln with a carbon reducing agent to assist in the regeneration of MgO. In Japan, the Mitsui Aluminum Company has tested this system on a pilot-scale basis with generally encouraging results. During the development program, Grillo adopted the centralized reprocessing concept which suggests that the superior economics associated with a large regeneration facility will offset the cost of transporting spent reactant to a centralized site and the regenerated reactant back to the utility. This concept is similar to and probably stems from the custom smelting practices of certain nonferrous smelting operators, of which Grillo is one.

In the United States, the Chemico Corporation is following a nearly identical approach to that of Grillo. EPA and Boston Edison are cost-sharing the development of an MgO scrubbing and regeneration process on a 150 MWe oil-fired unit at Boston Edison's Mystic Station. The flow sheet for this process is schematically shown in Figure III-3. This facility started up in April 1972 and has operated intermittently since then. Areas of potential concern with the process, which will be evaluated during the 12-month test program, include: potential scaling and plugging problems, attainment of 90% design efficiency, potential erosion/corrosion problems, effectiveness of the regeneration step, and overall system reliability. The results of these tests will be particularly important since there is only a limited amount of information on this process based on prior pilot plant testing by Chemico and Babcock & Wilcox. Also, this demonstration represents the first time that the individual steps of scrubbing, centrifuging, and calcining have been operated on an integrated basis for the Chemico system. The system has thus far in its intermittent operation achieved 90+% SO_2 removal with no apparent scrubber related problems; the major problem area has been with the dryer's operational reliability.

In the EPA-Boston Edison demonstration, only the equipment for absorption, centrifuging, and drying is located at the power plant. Spent reactant is shipped to the Essex Chemical Plant at Rumford, Rhode Island, where it is calcined to produce SO_2 for making about 50 tons per day of 98% sulfuric acid. The SO_2 produced during regeneration will provide feed for this plant's total acid output.

A second full-scale magnesium oxide SO_2 removal facility is planned for Potomac Electric and Power's Dickerson No. 3 unit. Approximately 100 MWe of the 195 MWe of this unit will be processed. Since this facility burns coal (3% sulfur, 8% ash), the scrubbing facility consists of two separate venturi scrubbers. The first removes fly ash particulates; the second absorbs the SO_2. Present plans are to use the aforementioned calcination facility located at the Essex Chemical Plant. This facility is scheduled to start up early in 1974.

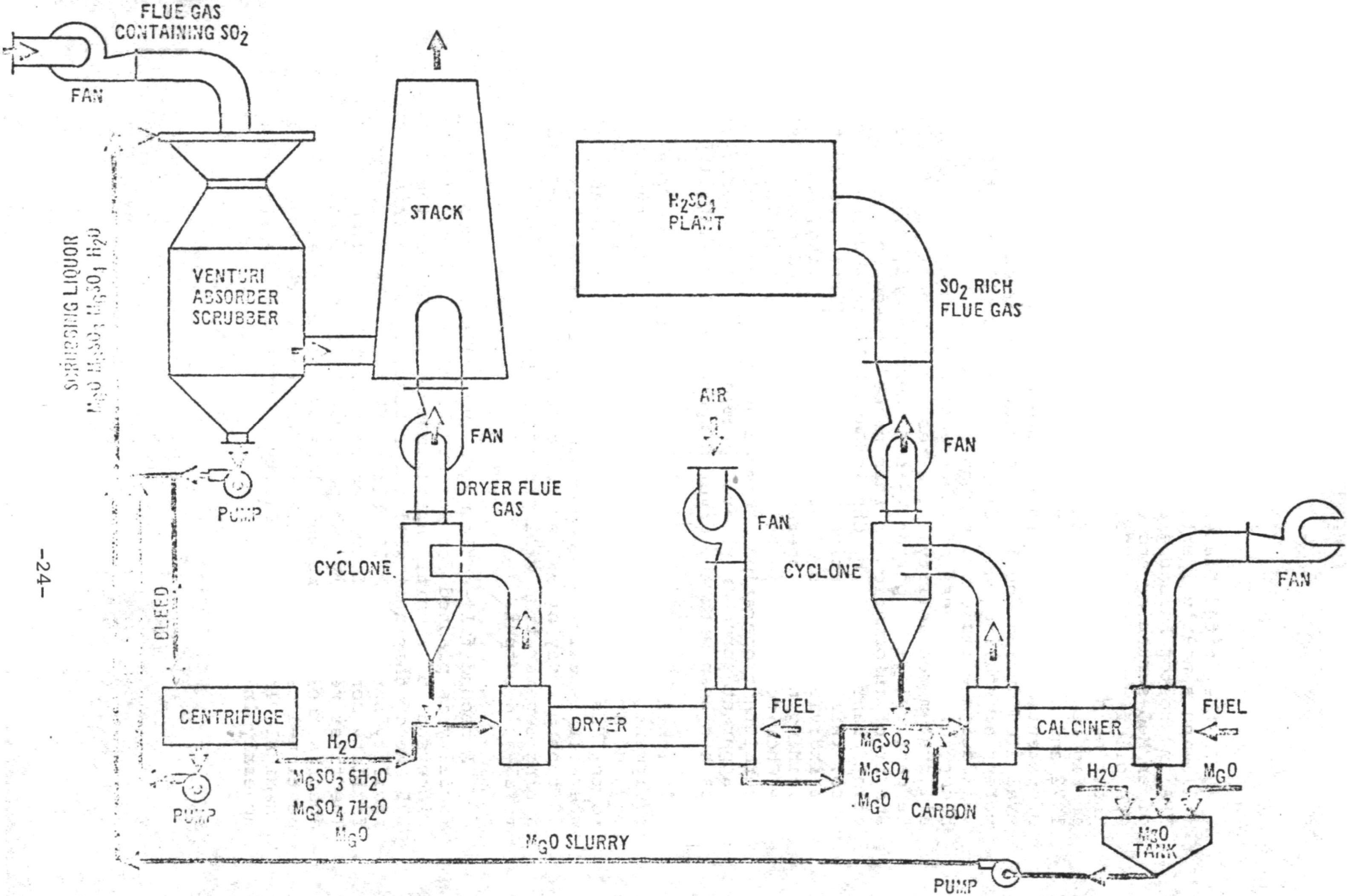


FIGURE III-3. MgO Slurry Process - For Flue Gas Free of Particulate Matter

For both the Boston Edison and Potomac units, the particulate-free, SO_2-containing flue gas from the power plant enters the venturi absorber where it contacts a dense spray of the slurry absorbing liquor. The absorbing liquor consists primarily of magnesium sulfite ($MgSO_3$), magnesium sulfate ($MgSO_4$), and magnesium oxide (MgO). Fresh MgO slurry is added as a makeup. A bleed from the absorber goes to a centrifuge for separation of the solids from the mother liquor. The mother liquor is returned to the absorber system. The wet cake from the centrifuge, containing water of hydration and surface moisture, is dried in a direct-fired rotary kiln. Hot drier exhaust gases pass to the stack where they provide reheat for the flue gas from the absorber.

The anhydrous crystals leaving the drier, after addition of carbon, are next reacted in a direct-fired calciner to regenerate MgO and release sulfur oxide. The high operating temperature (about 1800-2000°F) is needed to regenerate MgO from the relatively small quantities of $MgSO_4 \cdot 7H_2O$ that form from oxidation of $MgSO_3 \cdot 6H_2O$. The regenerated MgO produced is mixed with make-up water and reused in the absorber system. The calciner off-gases containing 15-16% SO_2 are sent to a conventional sulfuric acid plant for further processing. Table III-1 lists the chemical reactions which have been postulated for the major steps of the process. The appendix describes the status of the Boston Edison unit based on a visit by a SOCTAP member.

C. Catalytic Oxidation (Cat-Ox)

Monsanto has developed a modified version of the well-known contact H_2SO_4 process for removing SO_2 from power plant flue gas. Basically, the process consists of passing the flue gas through a fixed catalyst bed where SO_2, in the presence of O_2, is converted to SO_3. The SO_3 is then absorbed in recirculated H_2SO_4 in an absorption tower.

TABLE III-1

CHEMISTRY OF MgO SLURRY PROCESS

ABSORPTION

MAIN REACTION

$$MgO + SO_2 + 6\ H_2O \rightarrow Mg\ SO_3 \cdot 6\ H_2O$$

SIDE REACTIONS

$$Mg\ SO_3 + SO_2 + H_2O \rightarrow Mg\ (HSO_3)_2$$

$$Mg\ (HSO_3)_2 + MgO \rightarrow 2\ Mg\ SO_3 + H_2O$$

$$MgO + SO_3 + 7H_2O \rightarrow Mg\ SO_4 \cdot 7\ H_2O$$

$$MgSO_3 + 1/2\ O_2 + 7\ H_2O \rightarrow MgSO_4 \cdot 7\ H_2O$$

DRYING

$$MgSO_3 \cdot 6\ H_2O \xrightarrow{\Delta} MgSO_3 + 6\ H_2O$$

$$MgSO_4 \cdot 7\ H_2O \xrightarrow{\Delta} MgSO_4 + 7\ H_2O$$

$$H_2O\ (\ell) \xrightarrow{\Delta} H_2O\ (g)$$

REGENERATION

$$MgSO_3 \xrightarrow{\Delta} MgO + SO_2$$

$$MgSO_4 + 1/2\ C \xrightarrow{\Delta} MgO + SO_2 + 1/2\ CO_2$$

Besides being designed for the dilute SO_2 concentration found in flue gas, the Cat-Ox process differs from the conventional contact process in two principal respects: first, the flue gas entering the process must either already be at a high enough temperature, about 850°F, for the conversion of SO_2 to SO_3, or heat must be supplied. The heat of reaction alone, because of the low SO_2 concentration, is insufficient to maintain the required temperature. Second, SO_2-containing gas (flue gas) entering the system is not dried prior to entering the converter.

For power plant applications, Monsanto has proposed two versions of the process: first, the "integrated system" for use on new plants and second, the "reheat system" for use on existing plants. These variations are shown in Figures III-4 and III-5.

In the "integrated system," schematically depicted in Figure III-4 hot flue gas at about 850°F is taken directly from the boiler and passed through an efficient dust collection system (mechanical collectors plus an electrostatic precipitator) to remove at least 99.6% of the particulates. The gas then flows through a converter where, in contact with a vanadium pentoxide catalyst at about 850°F, oxidation of the SO_2 occurs. Flue gas from the converter is next cooled in an economizer followed by an air heater. By maintaining the operating temperature of these units above the dew point of H_2SO_4, corrosion problems are avoided. Sulfuric acid in the flue gas is then condensed in a packed-bed absorber by direct contact with acid recycled from an external cooler, producing an 80% acid product. Acid mist and any remaining dust in the flue gas is then removed in a highly efficient, fiber-type mist eliminator and passed out the stack.

The "reheat system" shown in Figure III-5 is similar to the "integrated system." However, the temperature of the entering gas is typically about 325°F in this system, compared to 850°F in the "integrated system." Therefore, the electrostatic precipitator need not be designed for such an extreme temperature service. High efficiency dust removal is still required, however. The low temperature of the entering gas also necessitates raising the gas to reaction

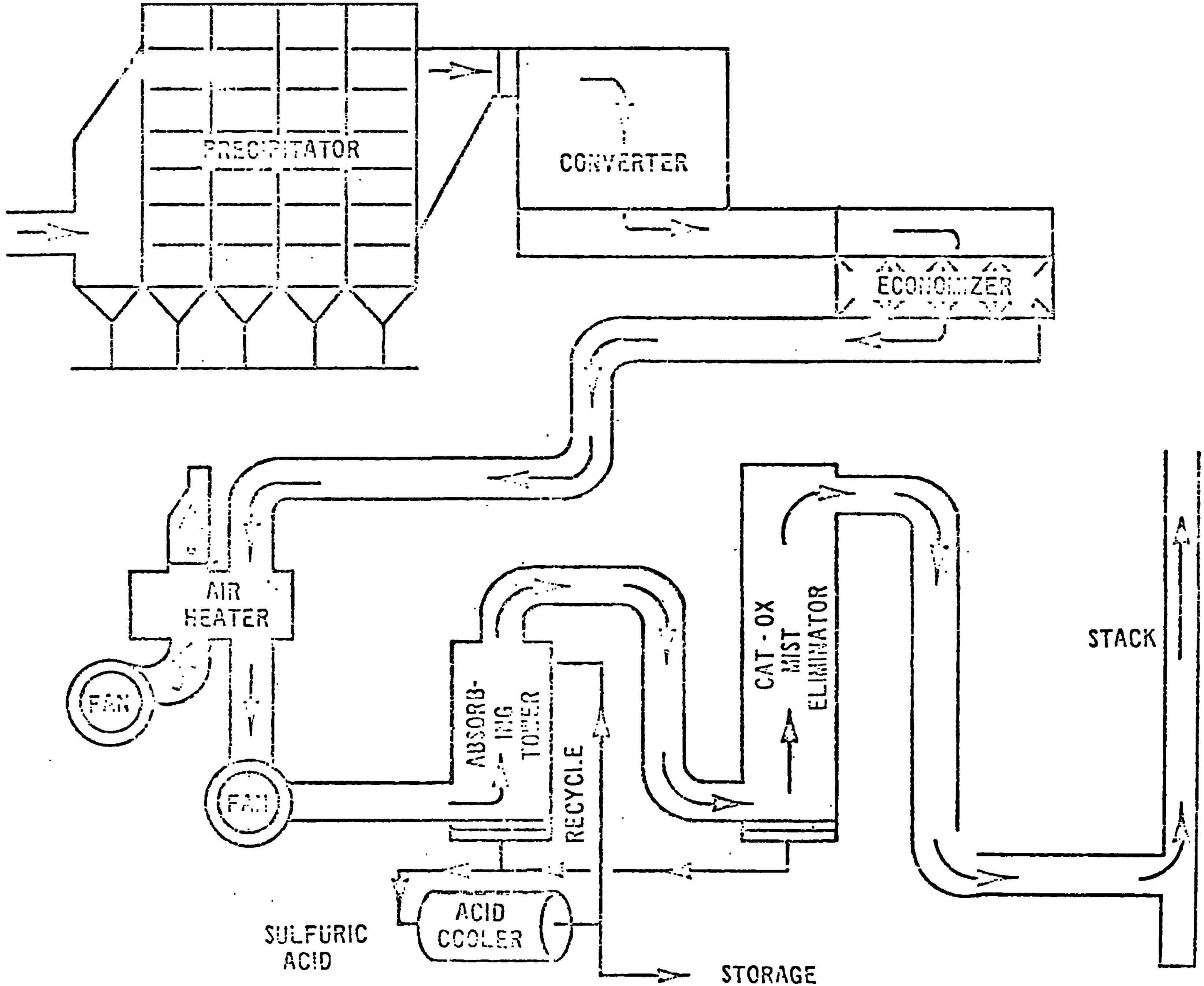


FIGURE III-4 Integrated Cat Ox Process

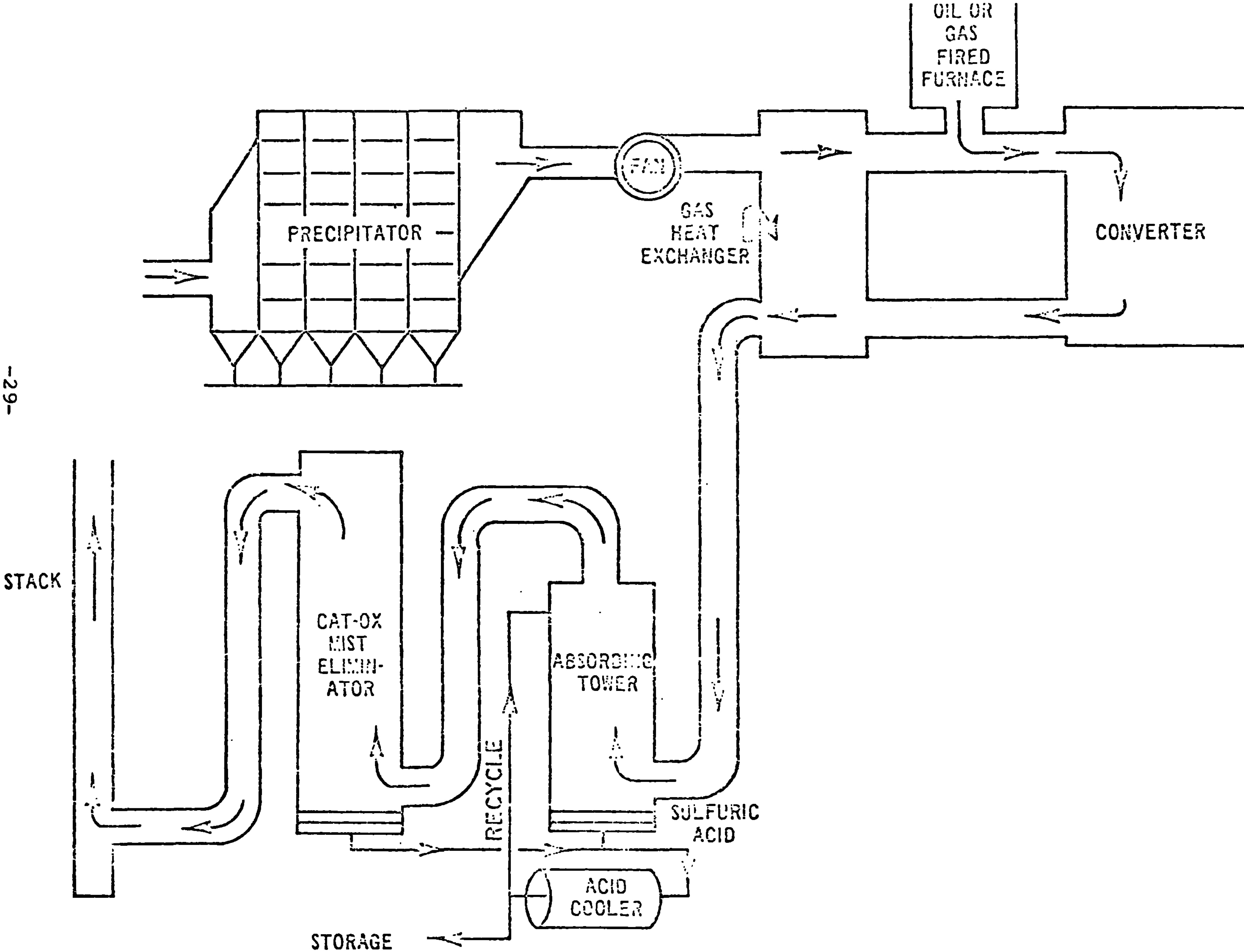


FIGURE III-5 Reheat Cat - Ox Process

temperature before it enters the converter. This is done by using the converter exhaust gases to preheat the incoming gas. To supply the additional heat required, hot gas from the combustion of oil or gas is added directly. With these exceptions, the two systems are essentially alike.

Monsanto tested the "integrated process" on a 15 MWe scale at Metropolitan Edison's Portland Station. These tests, which covered a two-year period from 1967 to 1969, indicated the capability of the process to remove 85-90% of the sulfur dioxide. In addition, the information required for scale-up of the process was obtained.

The principal technical problems with the Cat-Ox process for power plant applications are associated with fly ash removal. Dust must be removed with high efficiency from the incoming flue gas. Otherwise, it will plug the converter catalyst and fiber-bed mist eliminator and contaminate the acid product. Plugging of the catalyst bed requires a 2-3 day shutdown of the converter for cleaning and results in a catalyst loss of about 2.5%. Monsanto estimates that catalyst cleaning will be required at about 2-3 month intervals. The 99.6% collection efficiency required of the precipitators is near the upper limit of presently available equipment. The technical success of the process will depend to a large extent on how well this critical requirement can be met.

This process has been retrofitted on a 100 MWe boiler at Wood River Power Plant of the Illinois Power Company. The $6.7 million cost of the demonstration will be shared by EPA and Illinois Power. Start-up is presently underway and will be followed by a one-year test program.

D. Wellman-Lord Process (Sodium Base Scrubbing with Regeneration)

In this process, schematically shown in Figure III-6, SO_2 in the flue gas is absorbed into a solution of sodium sulfite, bisulfite, and sulfate, converting some of the sulfite to bisulfite according to the following equation:

$$SO_2 + H_2O + Na_2SO_3 \longrightarrow 2NaHSO_3$$

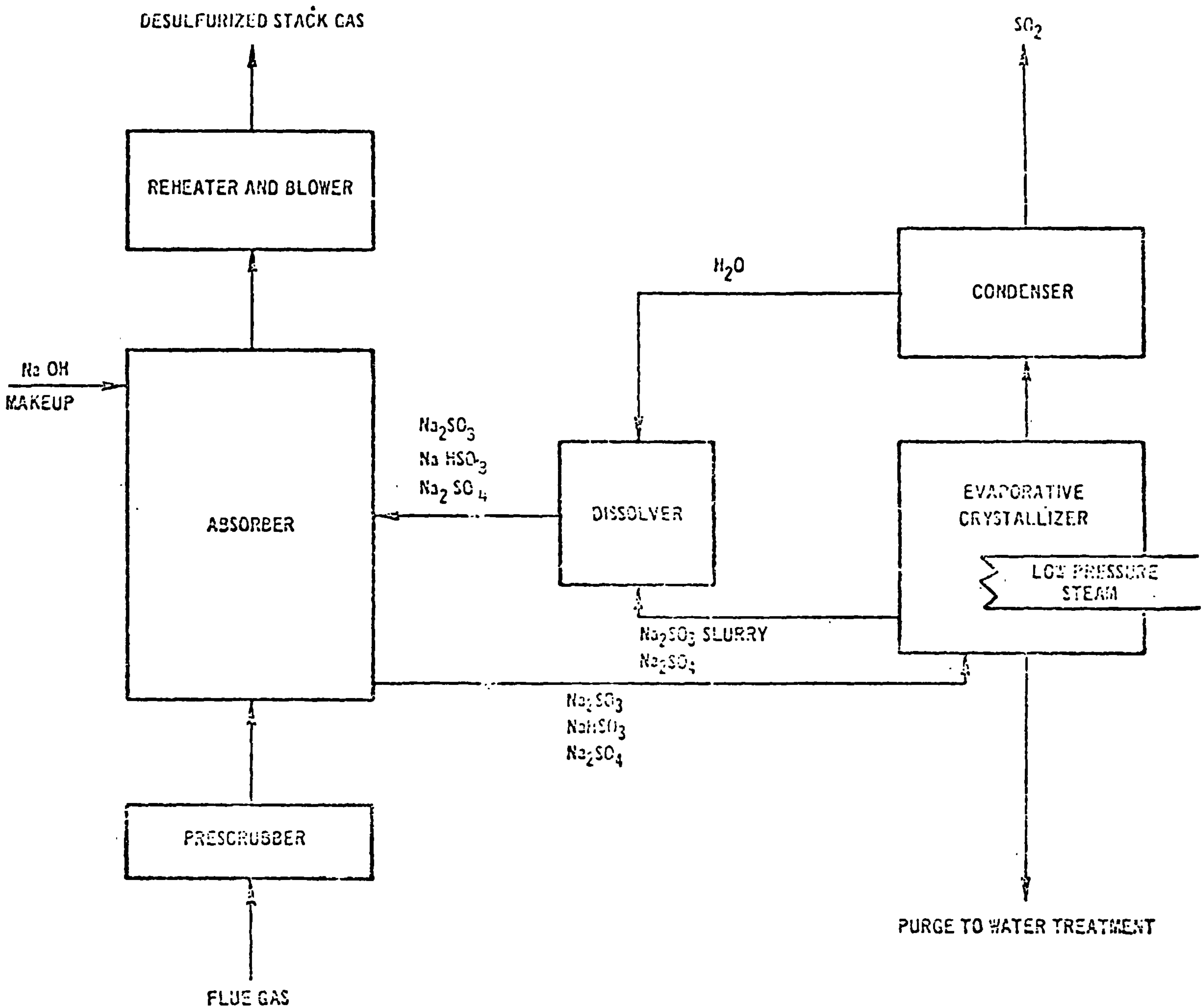


FIGURE III-6 Wellman-Lord Process Schematic

Some of the absorbed SO_2 undergoes oxidation and shows up in the solution as sulfate. The active scrubbing solution is regenerated by evaporating water and SO_2 while crystallizing sodium sulfite in an evaporative crystallizer. This step is represented by the reverse of the above reaction and is promoted by heat input. The vapor product is cooled to condense out all of the water. The pure gaseous SO_2 can be further processed to liquid SO_2, sulfur, or sulfuric acid. Condensed water is used to redissolve the sulfite solids for recycle to the scrubber. Sulfate formed in the scrubber cannot be regenerated and is removed from the system by direct purge of scrubbing solution or selective crystallization of sodium sulfate. The purge can be treated to transform sodium sulfite and sodium bisulfite to sodium sulfate to eliminate an oxygen demand problem.

The specific advantage of the Wellman-Lord process is the simplicity of its unit operations. The main disadvantage of the process is its sensitivity to buildup of contaminants necessitating bleed. The major contaminants generated in the process are sodium sulfate, sodium thiosulfate, sodium polythionates, and a small amount of elemental sulfur. As stated previously, sulfate is generated by oxidation of sulfite in the absorber. In the crystallizer, sulfites are converted to sulfate, thionates, thiosulfates, and sulfur by a disproportionation reaction which is promoted by heat. There are several ways to control these undesirable reactions, the discussion of which is considered beyond the scope of this paper.

A full-scale demonstration of the Wellman-Lord process will be undertaken by Northern Indiana Public Service Company at their D. H. Mitchell plant in Gary, Indiana, with partial funding by EPA (approximately $4.25 million). The system will be a retrofit to the 115 MWe boiler No. 11 and is designed for coal containing 3-1/2% sulfur and 11-1/2% ash. The anticipated removal efficiency will be no less than 90% in any case, and cleaned stack gas will contain less than 200 ppm SO_2 if the sulfur content of the coal is less than 3-1/2%. The contract specifies that sodium make-up shall not exceed 6.6 tons/day of sodium as Na_2CO_3. This plant will also demonstrate the technology for reduction of SO_2 to elemental sulfur. Present plans are to start construction of the unit in January 1973 and to start-up the plant in July 1974.

A very significant demonstration of Wellman-Lord technology is in Japan by the Mitsubishi Chemical Machinery (MKK) at the Japan Synthetic Rubber's Chiba Plant. This unit treats a flue gas stream equivalent to about 75 MWe from an oil-fired boiler containing 600-2000 ppm SO_2 and achieves better than 90% removal of SO_2, which is converted to high quality sulfuric acid. In general, operation has been quite reliable, operating in excess of 9000 hours since June 1971. During the past year, the scrubber has been available almost 100% of the time the boiler has been in operation. This may represent the longest successful operation of any modern large scale SO_2 control process. The main disadvantage of the system is the requirement to bleed a waste liquor stream due to sulfate formation. For the Chiba unit, this stream amounts to 1-1.5 tons/hour and contains no sodium sulfite or pyrosulfite, has a pH of approximately 7 and a COD value under 200. It is estimated that approximately 10% of the total incoming sulfur is bled from the system; this corresponds to about 4% oxidation. Recent developments by Sumitomo (Japan) have indicated these numbers can probably be decreased by 55% by the use of an oxidation retardant. SOCTAP members have visited this facility and a trip summary describing the process in more detail is included in the appendix.

E. Double Alkali Systems

There has been recent and intense interest in a new class of throwaway flue gas desulfurization systems, double alkali wet scrubbing technology. This process, which has several variations, involves scrubbing flue gas with a soluble alkali, such as sodium sulfite, and regenerating the alkali with an insoluble alkali, such as lime, producing an insoluble throwaway product, such as calcium sulfite. The process has the potential advantage of soluble alkali scrubbing without the potential scaling, plugging, and erosion problems associated with slurry scrubbing.

Figure III-7 schematically depicts a double alkali system. Flue gas entering the bottom of the absorber/scrubber is contacted with a solution of $Na_2SO_3/NaHSO_3$ in the absorber. The liquor leaving the absorber becomes rich in $NaHSO_3$ as SO_2 is absorbed and reacts with the Na_2SO_3. A calcium hydroxide slurry is prepared in a mixing tank and it is added to the caustisizer where it is mixed with the

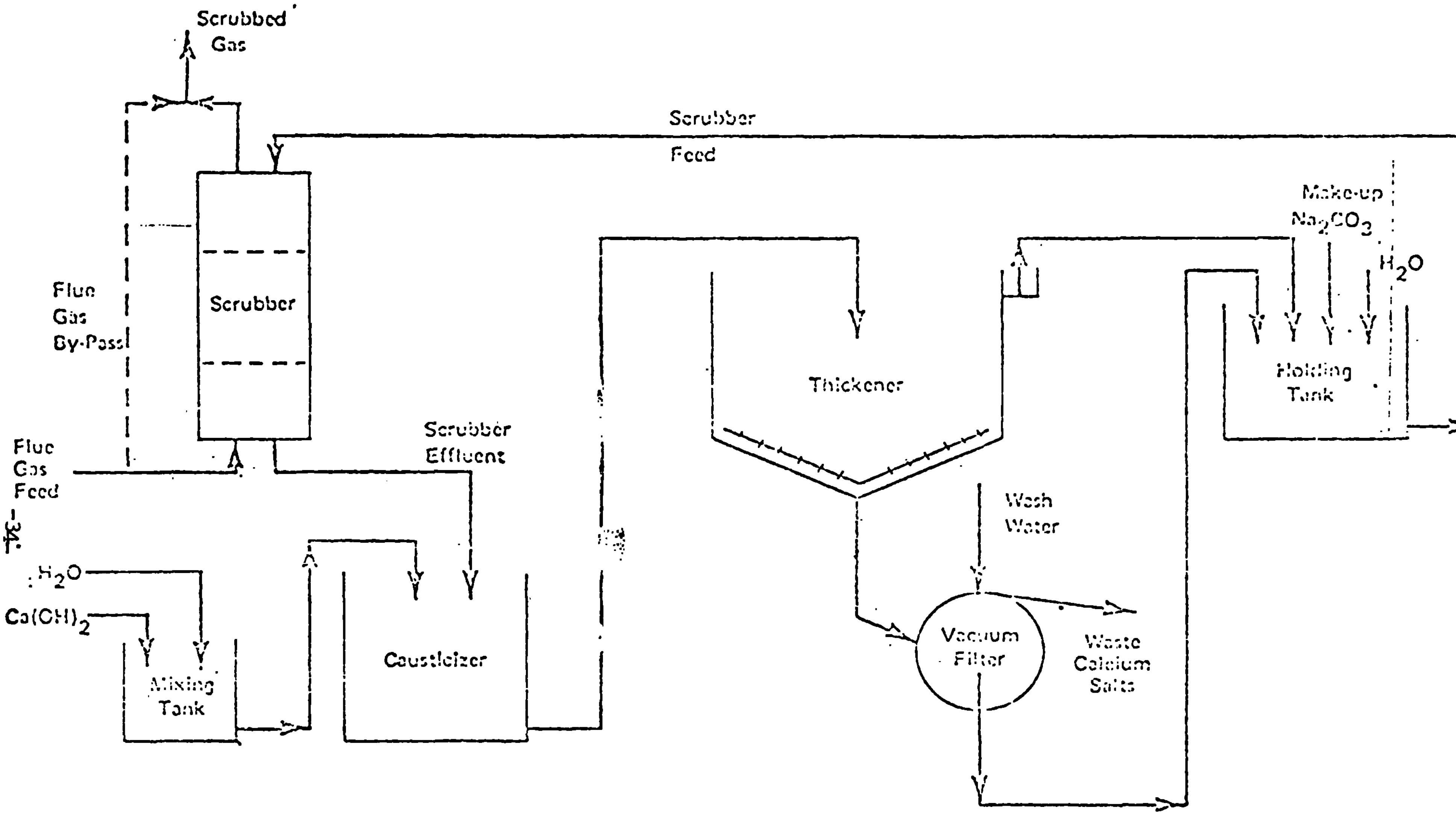


FIGURE III-7 Double Alkali Process Variation
SODIUM SCRUBBING WITH LIME REGENERATION

scrubber effluent. Regeneration occurs in the vessel and the bisulfite is converted to the sulfite with the production of calcium sulfite. Also, since some sodium sulfate forms from oxidation of sulfite and bisulfite, lime must also regenerate the sulfate by producing sodium hydroxide and gypsum. The caustisizer product is pumped to a thickener in which the precipitated calcium compounds are removed, and the overflow liquor is pumped to a holding tank where make-up Na_2Co_3, make-up water and wash water from the calcium salt cake are mixed and returned to the scrubber. The following are the chemical reactions postulated for this system:

Scrubber:

(a) $Na_2SO_3 + SO_2 + H_2O \longrightarrow 2NaHSO_3$

Caustisizer:

(b) $NaHSO_3 + Ca(OH)_2 \longrightarrow NaOH + CaSO_3 \cdot 1/2H_2O + 1/2H_2O$

(c) $Na_2SO_4 + Ca(OH)_2 + 2H_2O \longrightarrow 2NaOH + CaSO_4 \cdot 2H_2O$

(d) $NaOH + NaHSO_3 \longrightarrow Na_2SO_3 + H_2O$

Another important variation to this process involves use of both limestone, a less expensive alkali, and lime. Limestone is used for the regeneration of the bisulfite, and lime is used to regenerate the sulfate.

This process has the potential advantage of performing high efficiency particulate scrubbing and SO_2 absorption in one scrubber. This is feasible since sodium sulfite solutions are quite effective absorption solutions and are capable of yielding high SO_2 removal efficiencies in venturis, venturi-rods and similar scrubbers which are capable of efficient particulate removal but are not particularly effective mass transfer devices.

It should be noted that the driving force for reaction (c) above is not great and $SO_4^{=}/SO_3^{=}$ concentrations must be maximized to increase the driving force. Most of the variations of the double alkali process involve alternate ways of treating the Na_2SO_4 which is inevitably produced in the absorption/scrubbing device. For example, use of ammonium sulfite scrubbing systems has been studied since the thermodynamics for the regeneration of NH_4SO_4 is much more favorable as compared to Na_2SO_4. However, due to the volatility of ammonium compounds, serious fume problems have been observed which, to date, have led to unacceptably visible stack plumes. Another variation, developed in Japan, involves reaction of a soluble sulfate/sulfite/bisulfite bleed stream with H_2SO_4 and product calcium sulfite. Sodium sulfate is converted to sodium bisulfite according to the following reaction:

$$Na_2SO_4+2CaSO_3\cdot 1/2H_2O+H_2SO_4+3H_2O \rightarrow 2NaHSO_3+2CaCO_4\cdot 2H_2O$$

Such systems allow the use of the less expensive limestone for bisulfite regeneration.

To date, double alkali systems have been tested on a pilot-scale basis by several organizations. General Motors and Chemico have run pilot-scale tests on a process similar to that depicted in Figure III-7, and encouraging results have been reported. Kureha and Showa Denko, in Japan, have tested the system variation involving H_2SO_4 addition described above on a bench-scale and pilot-scale basis, respectively. Double alkali efforts to date have generally indicated high SO_2 removal efficiencies ($>90\%$), low sodium make-up requirements and generally reliable operation.

EPA is in the process of initiating a comprehensive double alkali development program on a large pilot plant to evaluate the various double alkali systems and to optimize the most attractive schemes.

F. Dry Limestone Injection

The dry limestone injection process is considered a fairly well characterized control process with only limited potential, due primarily to inherently low removal efficiencies. The process involves the injection of pulverized limestone directly into the power plant boiler where it is calcined to lime and subsequently reacts at high temperature with SO_2 and excess oxygen in the boiler to form calcium sulfate. The calcium sulfate is then removed as a solid with the fly ash by mechanical collectors and electrostatic precipitators.

Although recognized and investigated for many years, the process had not been characterized adequately to enable its confident full-scale utilization. For this reason, the most comprehensive full-scale test program on the process was initiated under a joint EPA-TVA project performed at the Shawnee Station near Paducah, Kentucky. The program has recently been completed. The process was installed on a 140 MWe boiler burning an average 2.7% sulfur, pulverized coal.

The goal of the Shawnee test program was to establish the conditions for optimum system performance and obtain comprehensive design and cost information. Results from the comprehensive test effort have indicated that:

(a) SO_2 removal efficiencies are quite low; for most limestones with the boiler operating at or near full load only about 11% per unit of stoichiometry can be expected with 95% confidence. This removal can increase by a factor up to two if a reactive limestone, such as marl, is available, and/or if the boiler is operated near 50% load conditions.

(b) Use of this process can lead to severe operating problems. For example, during testing at Shawnee, severe boiler reheater pluggage occurred after only 6 days of continuous testing. Union Electric has experienced similar pluggage problems in their boiler during testing of their boiler-injection/wet limestone system installed at their Meramec No. 2 Station. It should be noted, however, that such problems have not been severe at a similar system installed at Kansas Power & Light's Lawrence Station No. 4 or at Detroit Edison's St. Clair No. 6 Unit. Differences associated with boiler pluggage potential are attributed to specific boiler design features of which tube spacing and temperature regime are considered major parameters.

(c) Degraded electrostatic precipitator performance resulting from higher dust loading of higher resistivity particulate has been reported. Reductions in efficiency ranging from 10% average to about 25% were measured at Detroit Edison and Shawnee. Test results from the latest precipitator test program at Shawnee are not yet available.

In light of the inherently low removal efficiencies, and the potential for major reliability problems, it does not appear that the dry limestone injection process will play an important role in controlling SO_2 emissions from power plants. While the process may find some use for particular situations, its application is expected to be limited.

IV. PERFORMANCE AND COST COMPARISONS OF FLUE GAS DESULFURIZATION SYSTEMS

Any discussion or comparison of cost and performance data relating to full-scale, commercial flue gas desulfurization systems must be prefaced with the warning that generalized conclusions and figures are at best calculated opinions or scaled-up projections derived from currently incomplete data. At present there are too few installations and insufficient operating experience with any of the processes to permit historical comparison. Available information on the different processes is largely derived from non-typical examples such as pilot plant experience and experimental and prototype installations, and based on a wide range of variables, so that they cannot be compared in a precise manner. With commercial scale work on most of the processes continuing, a basis for more accurately assessing full-scale performance and installation and operating costs for different systems and specific applications will be built up over the next several years.

A. General Considerations

An examination of the rationale for switching to low sulfur fuels was outside of this Task Group's objectives. However, an estimate of the range of incremental operating costs associated with the additional cost of low sulfur fuel has been included in the summary table as a preliminary comparison with SO_2 removal processes.

Because SO_2 control processes are in an early stage of development, it was necessary to generalize from the scattered information available in order to obtain a rational picture of relative performance and costs of SO_2 removal processes.

B. New Versus Retrofit Installations

As far as SO_2 removal efficiency is concerned, there seems to be little difference whether a particular SO_2 recovery system is added to an existing utility plant, or is planned, engineered, and constructed concurrently with completely new power generating units. Operating performance and direct operating costs may be slightly affected by some of the design differences required for retrofitting. The important difference, however, between new and retrofit installations is the greatly increased cost of construction and installation of retrofitted equipment. This includes escalation for the requirements of intercepting duct work, and other special equipment; new buildings or structural revisions and enlargement of present structures; more difficult job locations, erection conditions and other site constraints; and extraordinary interconnection and startup expenses. These additional costs can increase the total investment to several times the estimate for concurrently designed and constructed facilities, and the upper limit would be what the utility is willing to spend to keep from having to convert to more costly low sulfur fuels, if he can get them. Obviously, there are many present utility installations for which it will be impractical to retrofit. For this SOCTAP study, retrofit costs were based on construction contractor's estimates for the typical or average situation at most present utilities, generally representing a substantial increase in total cost over completely new installations.

C. Throwaway Versus Saleable Product Systems

1. Throwaway Processes

In throwaway systems, the input reagents are not ordinarily regenerated and recycled, and all of the end product is considered waste material and discarded. These systems, primarily the limestone, lime or the double alkali scrubbing process, are generally less expensive to purchase and build because of their simpler technology. In addition, these throwaway processes generally do not require the removal of particulate matter (mainly fly ash) from the input gas prior to the SO_2 removal stage. Consequently, any requirement for electrostatic precipitators, or special particulate scrubbers is eliminated, as fly ash is adequately recovered by the SO_2 scrubbers. For new utility plants, the elimination of particulate removal system reduces the total out-of-pocket cost.

The operating costs for throwaway systems are highly sensitive to the cost of the input additives, and the cost of waste disposal. In some locations the delivered cost of the required large volume of reagents may be prohibitive. In some cases, the physical location of the utility, local land use regulations, limited storage site area, or water pollution potential may require excessive costs for secondary pollution control, or for transportation of the wastes to distant disposal areas.

Any of these factors may preclude the use of a throwaway system in certain situations, despite any advantages or desirability. Assuming moderate cost for reagents delivered to the plant and nominal disposal costs related to discharge into local settling ponds, the annual cost for throwaway systems is generally less than for other systems. In some cases where operating costs will be high due to waste disposal costs, there is a possibility that some offsetting benefit could be obtained if all or part of the waste material could be further processed into a non-polluting saleable product such as gypsum, concrete aggregate, or solid land-fill material. This problem requires further investigation since both cost and environmental benefits may be realized. Currently, a practical technology is not available, and it appears that market availability is limited and economic benefit would be marginal in most cases.

SO_2 removal efficiencies for throwaway processes are comparable to other systems, and are generally adequate, with the exception of the special process involving dry limestone injection directly into the furnace. This last process also has serious unsolved operating problems, and has been generally abandoned as a practical method of SO_2 recovery.

2. Recovery Systems

For saleable products (recovery) systems, generally the input reagent is regenerated and re-used; and the process converts the recovered SO_2 to a marketable by-product such as sulfuric acid, liquid SO_2 or elemental sulfur. The advantages of reducing the need for purchasing, storing and handling large volumes of input reagents, reducing or eliminating solid waste disposal problems and a potential for supplementary income from by-product sales, in many cases could result in lower direct operating costs than for throwaway systems.

This savings must be balanced against higher capital investment cost. The increased technical complexity of these recovery systems, plus the added costs for regenerating stages (particularly for off-site processing plants) increases the initial investment cost from 20% to 50% over a throwaway system. To be comparable to the throwaway system, this estimate includes particulate removal. In most of the recovery processes, particulate removal is effected by an additional preliminary wet scrubbing stage integrated into the SO_2 removal process, and the cost is included in the present SOCTAP study figures. In certain cases where a separate precipitator might be used, its cost would be roughly balanced by a corresponding reduction in the SO_2 systems cost as a result of eliminating the extra scrubbing stage.

The total annual cost, including annualized fixed charges, for recovery systems (not including any off-set from by-product sales) is generally higher, by at least one-fourth, than for throwaway systems.

Despite these higher annualized costs, for many utility situations, the elimination of excessive waste disposal and secondary pollution control costs, and/or the potential for recovering some of the costs through by-product sales, make recovery systems highly attractive. These benefits, however, are strictly dependent upon the marketability of the sulfur by-products. If the by-products cannot be sold (or given away), they pose transportation, storage and pollution problems and accompanying added costs that could be comparable to the disposal costs of throwaway systems. The future economics of the marketing by utilities of large quantities of by-product sulfur or sulfuric acid, in competition with potentially large low cost supplies from petroleum refineries, nonferrous smelters, and other sources is difficult to predict, and needs much additional indepth study.

D. Development of Comparable Cost Projections

The variety of estimates, opinions or guesses that have been put forward as probable overall costs for installation and operation of different pollution control systems show a wide range, depending upon the source. There is often a considerable difference in judgment as to exactly what costs should be charged to a process, depending on whether it is a utility's estimate of total out-of-pocket costs or a systems vendor's turnkey quotation.

In order to place capital or investment costs on a reasonably common basis, the cost data and estimates available to date have been reconciled to represent the manufacturers' base costs for the particular SO_2 scrubber system. Auxiliary equipment is included only if it is unique to the SO_2 removal technology. Limestone preparation and handling equipment, for instance, would be included, but the cost of modification to such items as main flues, stacks, or water supply and water pollution control equipment are excluded. Conversely, no credit is included in the SO_2 systems cost for eliminating or reducing the requirement for specific fly ash control equipment. To the base cost is added the estimated costs for construction, erection, and integration of that particular system with the power generating equipment, generally averaging about 40% of base cost. An additional increase is included for design, engineering, and procurement costs attributable to the SO_2 removal system. These costs were scaled to the requirements of a typical coal-burning installation; and separate estimates were established for both retrofitted systems on existing utility plants and for systems constructed concurrently with new generating units.

It was assumed that the typical plant size would be 200 MWe of generating capacity for retrofitted existing plants, and 1000 MWe capacity for new power generating plants. Total systems costs are expressed in terms of dollars per kilowatt of generating capacity of the associated power generating equipment.

Investment costs are given in two ranges; for each system the lower figure is an average for concurrent construction with new generating plants, and the higher figure represents an average cost for retrofitting existing plants. In either case, actual costs for particular installations will vary according to furnace and boiler characteristics, sulfur and ash content of fuels, local pollution control requirements, raw material storage and waste disposal constraints, as well as the specific type of scrubber and other equipment selected.

Presently available statistics on the direct operating costs for the different systems are less comparable than the reported capital cost estimates. The operating cost is highly sensitive to the raw material and reagent costs and to waste disposal costs. Even for the same SO_2 removal process, these costs can vary substantially from one particular installation to another. Estimates used in this study of probable operating costs for each process included only a nominal waste disposal cost where applicable, based on normal fluid discharge and ponding. A nominal range for materials costs was used, rather than a maximum possible range. Operating costs include a charge for parasitic power consumption.

The projected total annual cost, including annualized fixed charges for each process, is expressed in mills per kilowatt-hour. These are presented as a single range from typical low to typical high cost operation based on average regional variation in reagent costs, and differences in original capital costs, size, power requirements and operating results for individual installations with the same type of system. Except as indicated, no credit was included for potential by-product sales.

For all cases, annual costs were figured on an assumed 80% generating load factor, with fixed charges set at 18% of capital cost. The 80% load factor used is high compared to reported utility averages, but most of the SO_2 systems installed over the near future are assumed to be on base-load units with higher than average load factors. The levelized capital charges of 18% include interest, return on investment, taxes and insurance at typical levels for private utilities, and depreciation on a 15-year straight line basis.

E. Cost and Performance Comparisons

Table IV-1 compares SO_2 removal techniques and probable investment and annual costs for each of the particular control processes considered in this study. The figures have been derived as indicated in the text. Specific comments on each process follow.

TABLE IV-1
COMPARISONS OF SO_2 CONTROL PROCESS SYSTEMS

Processing Method	Reactant Input Requirements	Throw-Away or Recovery	Approx. Invest. Costs* for Coal-Fired Boilers $/KW	Approx. (Annual) Costs,** mills/KW-hr: No Crdt. for S Rcvry.	Approx. (Annual) Costs,** mills/KW-hr: With crdt. for S Rcvry.	SO_2 Removal Efficiency
1. Low Sulfur Fuel (Coal and oil)	N.A.	N.A.	(not estimated)	2.0-6.0	N.A.	N.A.
2. Dry Limestone Injection	Limestone (200% Stoich)	Throw-Away $CaSO_3$/$CaSO_4$	17-19	0.6-0.8	N.A.	22-45%
3. Wet Lime/Limestone/$Ca(OH)_2$ Slurry Scrubbing	Lime-(100-120% Stoich) Limestone (120-150% Stoich)	Throw Away $CaSO_3$/$CaSO_4$	27-46	1.1-2.2	N.A.	80-90%
4. Magnesium Oxide Scrubbing	MgO Alkali; Carbon and Fuel for Regeneration & Drying	Recovery of Conc. H_2SO_4 or elem. sulfur	33-58	1.5-3.0	1.2-2.7	90%
5. Monsanto Catalytic Oxidation (add-on)	Catalyst V_2O_5 (Periodic Replacement) & Fuel for heat	Recovery of Dilute H_2SO_4	41-64	1.5-2.6	1.3-2.4	85-90%
6. Wellman-Lord Process (soluble sodium scbg w/regeneration)	Sodium make-up and heat for regeneration reqmts	Recovery Conc. H_2SO_4 or sulfur	38-65/KW	1.4-3.0	1.1-2.7	90%
7. Double Alkali Process	Sodium make-up plus Lime/Limestone (100-130% Stoich)	Throw Away $CaSO_3$/$CaSO_4$	25-45	1.1-2.1	N.A.	90%

*Generally, where a cost range is indicated, the lower end refers to a new unit (1000 MWe), while the high end refers to a 200 MWe retrofit unit. Costs include particulate removal.
** Assumptions: Costs calculated at 80% load factor; fixed charges per year 18% of capital costs.

1. Low Sulfur Fuel

Switching to low sulfur fuels will involve some "investment cost" in most instances. Boiler furnace changes are necessary not only for switching to a different type of fuel (coal to oil), but the differences in heat content, ash content, and burning characteristics between high and low sulfur coals also usually require extensive furnace modification. Costs would vary widely from one situation to another, and no generalized estimate has been attempted.

2. Dry Limestone Injection

The strict interpretation of the term Dry Limestone Injection applies to the process in which the limestone and the SO_2 reaction takes place only in the combustion and flue zones in the furnace, and the resulting materials are removed from the stack gas in the dry state, without any wet scrubbing stage. The investment costs given include $5 per kilowatt for the particulate removal equipment assumed to be electrostatic precipitators. The SO_2 removal efficiency is highly dependent upon the type of limestone used and the boiler load condition.

Injection of dry limestone into the furnace, followed by wet scrubbing, is a modification of the Wet Limestone Scrubbing process and is considered under that heading.

3. Wet Lime/Limestone Scrubbing

Plant design, equipment requirements, and resulting investment costs are very similar regardless of which reagent is used, and therefore are treated as one process type. The additional cost for limestone drying and grinding equipment, if necessary, is offset to some extent by the higher costs for storage and handling facilities for the more reactive lime. Annual operating costs are about the same, the higher cost of lime being offset by the need for proportionately greater amounts of limestone, and the limestone preparation costs. Efficiency of the lime reagent usually is higher, in the 90% range, and the limestone efficiency is around 80%. Only nominal waste disposal costs have been included. In many cases the cost of treating and transporting waste could add significantly to the projected annual cost.

4. Magnesium Oxide Scrubbing

Investment costs will depend to some extent on whether off-site recovery plants are used, or an integrated on-site recovery stage is used. There are advantageous economies of scale involved in large off-site recovery process plants, if they are within reasonable transportation distance, and can serve more than one facility and costs can be shared. The costs reported in Table IV-1, however, reflect on-site recovery and acid production. Credit for sulfur recovery is based on the assumption that concentrated sulfuric acid could be marketed at $7 per ton.

5. Monsanto Catalytic Oxidation

Since the end-product of this process is relatively dilute sulfuric acid, credit for sulfur recovered is considerably less than for other processes. A market value of $4/ton for the 80% sulfuric acid is assumed.

6. Wellman-Lord

Credit for sulfur recovery based on $20 per ton for elemental sulfur, or $7 per ton for concentrated acid, is assumed.

7. Double Alkali Process

Relatively little information is available on costs or performance of this process, and the proposed figures are rough estimates only.

F. Specific Cost Examples

In the short time allowed for this study, two detailed cost analyses were obtained. These should not be considered typical applications but are included solely as examples of detailed cost breakdowns. The first was TVA's engineering analysis of calculated investment costs on its Widow's Creek #8 plant, rated at 550 MWe. The total cost for the retrofit limestone wet scrubber using a pulverized limestone slurry as reagent was set at $35,000,000 ± 30%, equivalent to about $64/KW. The design values were based on using

12,000 BTU/lb coal. Parasitic power output used to run the scrubber was set at 24.5 MWe, roughly 4.5%. Construction was scheduled to start in July 1972 and end in December 1973, 18 months. Detailed costs are shown in Table IV-2.

In the second analysis, annual operating cost details were calculated for a Chemico-Basic Mag-Ox Recycle Scrubber. These costs were based on a scrubber for a 600 MWe oil-fired boiler burning 2.5% sulfur oil at a load factor of 65%. SO_x reduction was set at the equivalent of 0.3% S oil.

The investment cost for this single stage Mag-Ox scrubber was set by Chemico at $9 million ($15/KW) which probably understates the full investment by the utility for the design and erection of this facility. Recycled MgO and by-product sulfuric acid are produced from the scrubber wastes by a central processing plant off-site. Five 600 MWe stations are predicated in the design and financing of a single process plant turning out 1000 tons of 98% sulfuric acid per day. The cost of the process plant (an acid plant and a calciner plant) is set at $8,200,000; thus, the total closed system cost would be 5 x $9 million plus $8.2 million or $53.2 million.

The annual operating cost detail supplied for the Mag-Ox system by the Chemical Construction Corporation is shown in the attached Table IV-3.

TABLE IV-2

TVA WIDOW'S CREEK #8 - LIMESTONE WET SCRUBBER — 550 MWE

Preliminary Construction and Facilities		$445,000
Yard Work	$200,000	
Unload & Handle	40,000	
Powerhouse Revisions	5,000	
Miscellaneous Buildings	200,000	
Limestone Handling & Storage Facilities		$1,890,000
Truck Rd (1 mile), Rail Track (1 1/4 miles) Scales and Structures (2), Storage Area (2 1/2 acres), Hopper with Car Shaker (175 Ton Capacity), Conveyor System, Storage Silo (7400 Tons Capacity), Dust Control System, Air & Water Piping, Drainage, Bucket Elevator, Front End Loader to Handle & Reclaim Limestone		
Scrubber System		$11,335,000 ($21/KW)
Foundations	$ 235,000	
Piping System	1,335,000	
Structural Steel	1,200,000	
Ball Mill	270,000	
Classifier	15,000	
Scrubbers (4Venturi - Rod)	3,500,000	
Pumps, Motors, Drives	550,000	
Tanks	200,000	
Draft System (Ducts , Reheaters, Piping)	3,795,000 (50°F Reheat)	
Insulation & Heat Tracing	235,000	
Disposal & Recirculation System		$1,910,000 ($3.5/KW)
Disposal Area	$1,300,000	
Pumping Station & Pumps	155,000	
Piping	415,000	
Water Intake & Skimmer	15,000	
Concrete Trenches	25,000	
Make-Up Water System		$100,000
Instrumentation		$450,000
Electrical Work		$1,000,000
Misc Equipment, Local Communication System, Painting		$46,000
SUBTOTAL		$17,176,000

TABLE IV-2 (CONT.)

Construction Facilities (10% Direct Costs)	$1,724,000
TOTAL DIRECT CONSTRUCTION	$18,900,000 ($34/KW)
Field General Expense	2,270,000
Allowance for Shakedown Modifications	2,000,000
Contingency Allowance (11% Total Cost)	3,975,000
TOTAL FIELD CONSTRUCTION	$27,145,000 ($49/KW)
Misc Engine Design & Mgt Overhead	5,865,000
Interest During Construction (8% per annum)	2,200,000
TOTAL PROJECT	$35,000,000
ADD - R&D, CONSULTANTS, PILOT PLANTS	$ 1,000,000

No overtime provision; Material cost esclation = 5% per annum

TABLE IV-3

CHEMICO-BASIC-MAG-OX RECYCLE SCRUBBER

Investment = $9 million

Operating Costs/Year:

Fixed Charges @ 20%/yr	$1.8 million
Maint @ 4%/yr	.360 million
Labor @ 5 man yrs - $10,000 each	.050 million
Supervision @ 40% of labor	.020 million
Power @ $0.01/KWH - 38×10^6 KWH/yr	.380 million
Dryer Fuel - 100,000 BBL #6 oil @ $3/BBL	.300 million
Water - 180×10^6 coal/yr @ $0.25/1000 gal	.045 million
Scrubber Costs Yearly =	$2.995 million

Acid Processing Plant: Processes $MgSO_3$ from 5-600 MW plants

Investment (Acid Plant + Calciner Plant) = $8,200,000
Annual Cost = $3,179,440 (10% amoritization, 4% interest)
Distributed to one 600 MW generating unit
= 20% x $3,179,440 = $535,900

Annual Scrubber + Processing Cost TOTAL = $3,630,900

Transportation Costs @ $5/ton ($MgSO_3$ out = 66,000 ton/yr; Mg O in = 26,000 ton/yr) = $ 460,000

* TOTAL Mag-Ox SCRUBBING ANNUAL COSTS = $4,090,900

* NOTE: No credit for sale of acid.

The $4.1 million annual operating cost for a 600 MW plant operating at 65% load can be interpreted as follows:

($4.1 million/yr (6 x 10^5KW x 5694 hrs/yr))

= 1.2 mills/KWH

V. ASSOCIATED ENVIRONMENTAL FACTORS

A. Quantification of the Problem

One of the major problems inherent in any flue gas desulfurization system is the necessity to dispose of or utilize large quantities of a sulfur product. The sulfur compounds produced by such systems generally fall into two major categories: throwaway or saleable products. To date, most utilities have favored utilization of lime or limestone scrubbing throwaway processes. Lime scrubbing processes ordinarily produce sludges containing $CaSO_3.1/2H_2O$, $Ca(OH)_2$, $CaSO_4.2H_2O$ and $CaCO_3$; limestone sludges generally contain $CaSO_3.1/2H_2O$, $CaCO_3$, and $CaSO_4.2H_2O$. For some coal installations, where efficient particulate removal is not installed upstream of the wet lime/limestone absorber, such sludges can contain large quantities of coal ash. Most systems designed to produce a saleable sulfur product at the present time yield sulfuric acid, although elemental sulfur, gypsum, and pure SO_2 are among the other potential products.

Typical quantities of potential sulfur products compared to fly ash production for a 1000 MWe coal-fired boiler are presented in Table V-1. This table provides rough comparisons between the production rate and storage requirements for a typical throwaway sulfur product compared to fly ash which is the normal disposable product from a coal-fired plant.

It should be noted that only rough estimates for specific volume were used to calculate potential storage volumes required for 20 years of scrubber operation. Depending on the process, lime sludges can be allowed to settle in a storage pond to a 30-70% solids slurry, or can be dewatered to close to a dry state by various dewatering techniques. Table V-1 also allows rough comparison between the potential production of sulfuric acid from flue gas control systems and the total U.S. production rates.

TABLE V-1
Typical Quantities of Ash and Potential Sulfur Products
from Coal-Fired Boilers Controlled with Flue Gas Desulfurization Systems

	Yearly Production 1000 MWe Plant tons/yr.	Assumed Packing Volume $ft.^3$/ton	Approx. Volume Required for storage, 1000 MWe Plant for 20 years acre - feet
Coal ash, dry	338,000	33	
Coal ash, wet (80% solids)	422,500	17	3,300
Limestone sludge, dry			
50% $CaSO_3 \cdot 1/2H_2O$	322,000		
9% $CaSO_4 \cdot 2H_2O$	47,500	n.a.	
33% $CaCO_3$ unreacted	185,000		
Total	554,500		
Limestone sludge, wet (50% solids)	1,108,000	22	11,320
Lime Sludge, dry			
76% $CaSO_3 \cdot 1/2H_2O$	322,000		
12% $CaSO_x \cdot 2H_2O$	47,000		
12% CaO $(Ca(OH)_2$	52,000		
Total	421,000	n.a.	
Lime Sludge, wet (50% solids)	842,000	22	8,680
Sulfur (90% overall recovery)	89,000	15	630
Sulfuric acid, (95%)	277,500	18	2,320

Assumptions:

Coal: 3.5% sulfur content; 12% ash; coal burned 2,816,000 tons/yr. for 1000 MWe unit, on stream 6400 hrs/yr, coal usage 0.88 lbs/Kwh.

Sludge: Based on 1.50 $CaCO_3/SO_2$ mol ratio for limestone reagent system, and 1.20 CaO/SO_2 mol ratio for lime reagent system; SO_2 recovery 90% both systems; sulfite/sulfate ratio based on performance of Chemico scrubbing unit at Mitsui Aluminum Lo, Japan.

The following are observations which can be made:

1. The production tonnages (dry basis) of throwaway sulfur product are approximately 50 percent greater (dry) than the fly ash normally produced; this leads to a total (sludge plus ash) throwaway requirement about 2.5 times the normal coal ash disposal tonnage. This indicates that production of the sludge throwaway product aggravates an already existing problem, rather than creates a totally new one. In general, the two major techniques used for ash disposal, ponding in large ash disposal ponds and transporting for landfill, appear applicable to lime/limestone sludges.

2. Large storage volumes are required for the ultimate disposition of sulfite sludges. For example, for a 1000 MWe unit over a 20-year lifetime, about 900-1100 acres (1.6 sq. miles) of disposal land would be required, assuming a wet sludge (50 percent solids) ponded to a 10-foot depth. For 100,000 MWe, about 100,000 acres or 160 square miles (to a 10-foot depth) would be necessary to dispose of the sulfur product. This should be compared to a requirement of about 50 square miles for wet ash (80 percent solids) associated with 100,000 MWe of coal-fired capability.

3. Potentially large quantities of sulfuric acid can be produced by certain flue gas desulfurization processes. Such processes include: magnesium oxide scrubbing, catalytic oxidation, and the Wellman-Lord system. Approximately 28 million tons per year of concentrated sulfuric acid can be produced from 100,000 MWe of flue gas desulfurization capability. This is close to the total annual U.S. sulfuric acid production rate, which was 29.3 million tons in 1971.

4. Elemental sulfur appears the most attractive product in terms of production rates and potential storage volume. About 89,000 tons/year of sulfur would be produced by a 1000 MWe unit per year; this leads to a potential storage or disposal area of about 63 acres for a 1000 MWe unit over a 20-year lifetime, assuming a 10-foot stacking stack height.

B. Throwaway Product Disposal

Several techniques have been proposed for disposing of large quantities of throwaway sulfur products. To date, most of the operating lime or limestone scrubbing systems have relied on disposal of the sludge materials in a disposal pond on the power plant site. If sufficient land is available, the pond is designed to eventually store liquid sludge material over the lifetime of the power plant. Such ponds are fed by a bleed stream from the scrubber circuit which is pumped either directly to the pond or via a thickening system (clarifier, filter, centrifuge) with the thickened sludge pumped to the pond. The supernatant liquor from both the dewatering system and the pond is usually returned to the scrubber circuit.

Another important disposal technique used where land is not available at the plant site involves maximum dewatering of the throwaway bleed stream, using one of the many effective combinations of clarifying, filtering or centrifuging equipment available; the solid dewatered sludge is then transported, generally by barge and/or truck to a suitable landfill site. However, some sludge materials have been found difficult to dewater mechanically. Since such sludge products, retaining large quantities of liquor, are difficult to transport and lead to eventual land use problems due to the instability (nonsettling) of the wet sludges, chemical fixation processes are being developed. These generally involve pozzolanic (cementitious) chemical reactions requiring the presence of lime. The reactions lead to the formation of a dry, solid, and hopefully chemically inert material which is desirable for landfill purposes.

The major problems associated with sludge disposal on a large-scale basis are associated with interrelated environmental and economic factors. Although throwaway sludge materials are relatively insoluble, liquors in equilibrium with sludge materials typically have dissolved solids contents in the 3,000 to 15,000 ppm range; major constituents include Ca^{++}, $SO_4^=$, Mg^{++} and $SO_3^=$. Although there are no finalized Federal water pollution regulations and local regulations vary considerably, it is certainly environmentally undesirable to allow entry of substantial quantities of such liquors into watercourses. For this reason, it is considered important for users of flue gas desulfurization systems to operate in a closed or nearly-closed loop mode of operation. For the disposal pond operation, this means that all liquor entering the pond is recycled back to the scrubber circuit; no sludge liquor is released to any watercourse. Also, in order to avoid unintentional seepage of liquor through the walls and floor of the disposal pond into groundwaters, it may be necessary to utilize a sealant material. Visits to the Mitsui-Miike power plant in Japan and Commonwealth Edison's Will County facility indicate that attempts have been made in both installations to operate in a closed-loop mode. However, in both facilities, seepage, run-off and other mechanisms could be postulated which would allow liquor to be released into watercourses, at least periodically. Careful civil engineering of disposal ponds is needed to assure that their design is consistent with closed loop operations. It should be noted that ash ponds which have been utilized for many years have similar water pollution problems; however, there is little evidence that ash liquor contamination has been of major concern to many utilities in the past. For the landfill disposal technique, it is also necessary that potential run-off will not lead to any significant water pollution problem. For both ponding and landfill approaches a detailed evaluation of the geologic and hydrologic conditions of the disposal area is necessary to minimize water pollution potential.

Another environmental concern is the ultimate condition of the large land areas required for sludge disposal. Some ponding installations have reported poor settling characteristics of the sulfite sludge material, which could lead to permanently semi-liquid slurry ponds which would be quite difficult to reclaim for subsequent development, construction, or other land use.

C. Sale of Sulfur Products

As stated earlier, sulfuric acid is the sulfur product which has received the most attention as a flue gas desulfurization saleable product, but the future market is uncertain. Although sulfuric acid is a large volume chemical, Table V-1 indicates that each 1,000 MWe desulfurization system would produce about 278,000 tons per year of concentrated acid; this represents about 1 percent of the present total U.S. production rate. Since marketability of a relatively low-value chemical such as sulfuric acid is highly dependent on transportation costs, it is necessary that large acid producers be within about 100-150 miles of large users. By far the largest use for sulfuric acid is for fertilizer production. Other important acid uses include cellulosics applications (rayons, cellophane, pulp and paper), petroleum alkylation and chemical production (TiO_2, HF, $(NH_4)_2SO_4$, etc.). At present, the states of Florida, Louisiana, Texas, and Illinois consume close to half of the U.S. total sulfuric acid output. Of these states only the Illinois utilities normally burn large quantities of high sulfur coal; and therefore would be the ones likely to apply flue gas desulfurization systems that produce saleable sulfuric acid.

However, other potential sources of reclaimed sulfur and sulfuric acid will be major competitors in the marketplace. By-product sour gas sulfur, in particular, has made large inroads in the sulfur/sulfuric acid market. Fuel desulfurization and nonferrous smelters are other sources. Any new large source of sulfur effectively impacts the sulfuric acid market, since most sulfur produced is used for acid production. Unfortunately, sulfuric acid production from power plant flue gases cannot be adjusted to market demand for acid, since these systems must operate continuously, which further complicates their acid marketing.

Although an up-to-date and comprehensive market survey is not available to assess the situation in detail, it appears that only a relatively small fraction of the potential flue gas desulfurization system users will be induced to produce sulfuric acid, due to difficulty in marketing the acid. For those systems that can market the acid, the resulting price for H_2SO_4 might be only \$6 to \$8 per ton or less. At such prices, annualized operating costs for those systems, taking credit for acid sale, will still be somewhat higher than those of the throwaway systems.

As discussed earlier, elemental sulfur is probably the most desirable sulfur product. As opposed to sulfuric acid, sulfur can be economically stored for eventual sale. If marketing is not possible, sulfur is probably the ideal throwaway product since it is inert and insoluble, with much smaller disposal site requirements than those for throwaway processes. The major obstacles to elemental sulfur production appear to be (1) lack of demonstrated technology and (2) potential economic penalties since operating costs would be significantly higher than competing throwaway systems if sulfur cannot be sold. However, a major step has been taken in the initiation of the partially EPA-sponsored NIPSCO Wellman-Lord unit which will produce elemental sulfur. Allied Chemical technology, which utilizes natural gas as a reductant, will convert the SO_2 produced in the Wellman-Lord evaporator-crystallizer to elemental sulfur.

VI. INSTITUTIONAL BARRIERS TO THE APPLICATION OF SULFUR OXIDE CONTROL SYSTEMS

Because the successful demonstration and subsequent commercial application of SO_x control systems necessarily depend on the electric utilities and the control system vendors in the U.S., it is essential to recognize that serious impediments in either of these industries to the general application of stack gas scrubbers on coal-fired plants will retard, or even obviate, the use of flue gas desulfurization as a control strategy option.

A. Institutional Barriers in the Electric Utility Industry

Application of sulfur oxide control technology will have its greatest public health benefits when applied in the electric utility industry. It is estimated that over 25 million tons of sulfur oxides are emitted in the United States each year from coal-and oil-fired electric generating plants. This represents 55% of all sulfur oxides emitted from man-made sources. Electric power is growing rapidly, and is capturing a relatively larger share of the energy market so by the turn of the century 75% of sulfur oxides may be produced by combustion in power plants. The abatement of sulfur oxide pollution depends then critically on the ability of the electric power industry to implement sulfur oxide control technology or to find alternative sources of low-sulfur fuel, either naturally occurring or chemically cleaned.

Barriers to the application of SO_x control technology can be associated with technological, economic, or environmental factors. The technology may not be adequately and reliably demonstrated as discussed above, or the investment in the technology may be considered as too large to justify in terms of the reduced risks to human health and property or the secondary consequences of the technology such as solid waste disposal may be considered as potentially more noxious than the air pollution. However, even if all of those barriers are overcome, application of SO_x control technology can be seriously impeded by barriers in the electric power industry.

An assessment of the nature and severity of those barriers was obtained through a meeting of the SOCTAP members with representatives of the electric power industry, assembled by the Edison Electric Institute, and through contacts between individual SOCTAP members and utility personnel. The barriers which were identified are discussed below:

1. Reserve Generating Capacity and Scheduling of Retrofits

Reserve generating margins are required to meet customer demand and still conduct essential periodic equipment maintenance and cover equipment malfunctions and failures. The Federal Power Commission has stated that reserves of about 20% of peak load are essential to avoid sporadic power curtailments.

The electric power industry is organized into regional power pools which provide an increased degree of reliability through grid connections between individual utilities. Assessment of the reserve generating capacity by the Federal Power Commission for summer 1972, as shown in Table VI-1, indicates that the reserve capacity in many sections of the country was well below 20%. In addition, the reserve capacity available during late June 1972 was considerably below that anticipated for the summer peak period in a survey conducted in late May 1972. This latter fact is an indication of both the deterioration of reserve margin during the peak load period because of equipment failures and unexpected delays in bringing new equipment on line because of technical and licensing problems.

The data in Table VI-1 indicate that the lowest reserve margins were in the Southeast and West Central National Power Survey Regions. Also faced with lower than desirable margins were the Northeast and East Central Regions. These regions with low reserve margins, as can be seen in Figure VI-1, fall in a contiguous zone in the central and eastern part of the country. Because of the widespread nature of the limited reserve margins, the ability to transfer power from one region to another has been significantly reduced. Even with some inter-regional transfers, the maintenance of adequate reserve margins throughout the eastern half of the nation has been quite critical during the past three years. For a variety of reasons, this situation will probably continue for the rest of the decade.

TABLE VI-1

Generating Capacity and Reserve in the National Power Survey Regions in Summer 1972

NPS Region*	Formerly Expected as of May 31, 1972			Actual As of June 27, 1972		
	Net Dependable Resources**	Capacity Available For Reserves		Net Dependable Resources**	Capacity Available For Reserves	
	MW	MW	% of Estimated Peak Summer Load	MW	MW	% of Estimated Peak Summer Load
Northeast	71,152	10,788	17.9	68,772	8,408	13.9
East Central	60,175	9,471	18.7	59,056	8,352	16.5
Southeast	71,010	7,071	11.1	68,943	5,004	7.8
West Central	44,397	4,631	11.6	43,607	3,841	9.7
South Central	55,948	9,371	20.1	55,348	8,771	18.8
West	68,833	13,223	23.8	69,128	13,518	24.3
Contiguous U.S.	371,515	54,555	17.2	364,854	47,894	15.1

*National Power Survey (NPS) Regions are shown in Figure VI-1. In comparing the NPS with the electrical Reliability Councils, the following indentifications can be made: the Northeast Region corresponds roughly to the Northeast Power Coordinating Council and the Mid-Atlantic Area Coordination Group combined; the East Central corresponds roughly to the East Central Area Reliability Coordination Agreement; the Southeast corresponds roughly to the Southeastern Electric Reliability Council; the West Central corresponds roughly to the Mid-America Interpool Network and the Mid-Continent Area Reliability Coordination Agreement combined; the South Central corresponds roughly to the Southwest Power Pool and the Electrical Reliability Council of Texas combined; and West corresponds to the Western Systems Coordination Council.

**Includes net firm power purchases but does not include fossil plants on line for testing. For nuclear plants, includes only megawatts actually being operated under license limits.

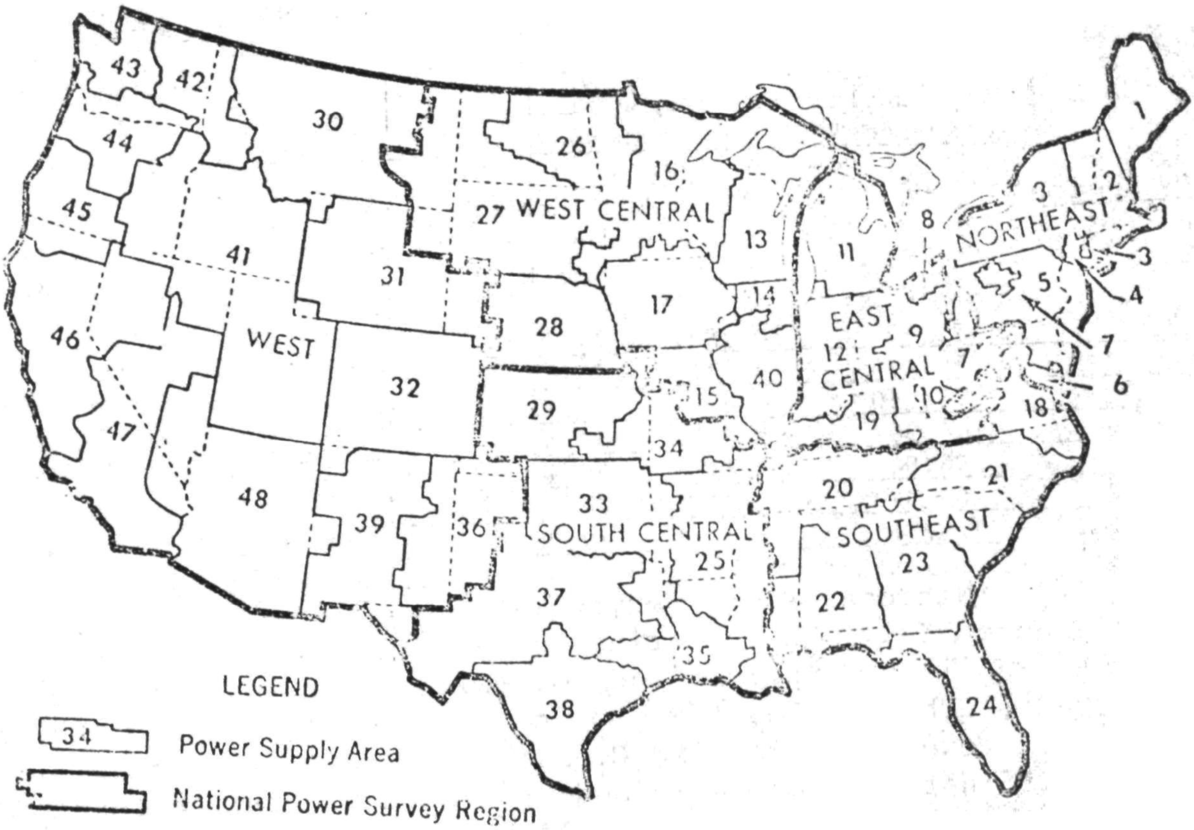


FIGURE VI-1 National Power Survey Regions
and Power Supply Areas

The electric power industry has been characterized by an extremely high rate of growth for the past two decades, e.g., its 8-10% growth rate has been twice that of growth in total energy utilization. These trends will in all likelihood continue throughout the remainder of this decade. In Table VI-2 a recent forecast of the growth in the electric power industry by Electrical World, September 15, 1972, is summarized. The data show that the trend of vigorous growth will probably continue and, although fossil-fuel plant additions will have a decreasing share of the total yearly additions, large blocks of new fossil capacity, on the order of 20 million Kw, will be brought on line annually in the late 1970's. Of this 20 million Kw average addition, approximately 55-65% is coal-fired capacity, with 5-15% of the coal-fired capacity capable of dual-fuel operation, i.e., easy conversion to oil- or gas-firing (Steam-Electric Plant Factors, 1971 Edition, National Coal Association).

Another factor which must be noted is that economies of scale and technological developments have increased the size of both fossil-fuel and nuclear plants significantly over the past few years, the oil- and coal-fired plants going to 600-800 MWe and nuclear plants to 1000-1200 MWe. This has meant that, in many utility pools, larger reserve generating margins must be maintained to cover the scheduled and unexpected outages of the big plants. The construction lead times for fossil-fuel plants are now 4-5 years and for nuclear 8-10 years. These long lead times tend to freeze the planning schedules of the utilities and when delays occur there is often little if anything the utilities can do to obtain alternative sources of power on short notice. The delays which have been experienced in bringing many nuclear plants on line also serve to erode the available reserve margin. In several of the power pools, the status of nuclear capacity of 1000-3000 MWe threatened by delays due to litigation over environmental questions or technical problems has been the difference between adequate and inadequate reserves. Nationwide, close to 10,000 MWe of nuclear capacity originally scheduled for 1971-1972 has been delayed. Thus, even though a record 34,500 MWe of additional capacity will be brought on line by the end of 1972, growth of 28,000 MWe in the non-coincidental annual peak has resulted in a drop in the gross reserve margin. Uncertainty about the status of delayed plants and possible limitations on the crash-building of gas turbine and internal combustion generation equipment to substitute for the delayed plants certainly cloud the immediate future. Whether these problems can be solved by the time that SO_x control equipment must be installed in great quantities remains to be seen.

TABLE VI-2

Predicted Trends in the Electric Power Industry

(<u>Electrical World</u>, September 15, 1972)

Actual	Annual Non-Coincidence Peak Millions Kw	Capability at Peak, Millions Kw	Gross Margin, %Peak	Net Total Generating Additions Millions Kw	Net Fossil Generating Additions Millions Kw	Total Generation Capital Expend., Billions$
1961	141	185	31.0	12.7	9.3	2.2
1962	152	199	31.0	10.4	8.1	1.8
1963	161	211	30.2	18.7	15.5	1.8
1964	175	217	23.7	11.7	9.4	1.9
1965	187	230	22.9	13.8	11.6	2.0
1966	204	242	18.4	11.7	8.8	2.6
1967	214	259	20.8	21.4	15.4	3.6
1968	239	280	17.2	21.8	16.1	4.4
1969	258	301	16.6	22.3	14.9	5.6
1970	275	328	18.7	27.7	16.8	7.0
1971	294	353	19.9	26.3	17.6	9.2
Forecast						
1972	322	386	19.6	34.4	20.3	10.1
1973	353	425	20.5	43.2	19.5	10.4
1974	381	470	23.5	46.2	23.9	9.6
1975	414	513	24.1	40.2	20.8	9.8
1976	447	549	22.9	33.6	19.2	10.3
1977	482	586	21.6	38.8	16.9	11.7
1978	517	629	21.5	45.2	20.9	12.4
1979	556	675	21.5	47.9	21.5	13.3
1980	593	722	21.7	45.1	20.0	14.5
1985	820	1009	23.0	59.0	22.5	15.6
1990	1103	1321	20.1	72.0	32.0	20.2

Across most of the country, electric power demand peaks in the summer, and then again at a somewhat lower level in the winter. Installation of scrubber equipment on existing plants therefore would have to be scheduled for the off-peak spring and fall periods. In a sample power pool investigated - the Michigan pool composed of Detroit Edison and Consumers Power - the amount of capacity which could be spared for maintenance varied from about 100 MWe in winter to 1200 MWe in spring out of 11,000 MWe pool capacity and zero in summer to 1,500 MWe in fall out of 12,000 MWe pool capacity; i.e., 10-13% of the capacity could be spared, and only during these periods.

In a typical utility operation, each plant is rescheduled for routine maintenance at least once a year, depending on the age of the plant, i.e., older plants require more frequent maintenance. This maintenance may require 1-3 weeks, which from all estimates would be too short a time to install even a pre-assembled scrubbing system.

Once every 4-5 years, again depending on its vintage, a plant is scheduled for major maintenance requiring 5-8 weeks. With careful scheduling, this time should be adequate for the majority of retrofits. Thus, a power plant might be available for installation of a scrubbing system once in the 4-5 year cycle during the spring or fall maintenance period, i.e., on the average, an upper limit of 20% of the power plant capacity would be available for SO_x control equipment installation each year. However, because an even smaller fraction of the capacity can be spared for scheduled maintenance, scrubbing installations would have to be carefully scheduled and the installation time kept to a minimum in order to approach scrubber installations on 20% of the system capacity in any one year.

To put the point more clearly, the scrubber installation time would have to be short enough during the 3-month spring or fall period so that the utility could also complete the maintenance scheduled on other boilers without exceeding the limit of 10-15% margin for maintenance. Because of probable stretch-outs early in the expansion of the control system industry, it is likely that somewhat less than 20% of the coal-fired capacity could be retrofitted each year and in specific cases, such as the Michigan Power Pool and many other largely coal-firing utility pools in the middle central and middle south, no more than 10-13% of the capacity can be retrofitted each year.

2. Lack of Familiarity with Chemical Processing Technology within the Electric Power Industry

Traditionally the electric utilities have concentrated on what they do best - generating electrical power. Until recently, state regulatory commissions have generally been unsympathetic to proposed rate adjustments to allow utilities to conduct R&D on new equipment and methods. Utilities generally paid for R&D through higher prices on capital equipment, the R&D having been performed by the manufacturers. Consequently utility staffs have been composed largely of mechanical engineers for the fuel-handling and boiler operations and electrical power engineers for the generation and transmission operations. Only in isolated instances have utilities ventured into fuel cleaning or other activities which involve large-scale chemical process technology. Flue gas desulfurization confronts the utilities with massive, complicated chemical processing plants, a challenge for which they are neither adequately nor appropriately staffed.

The experience gained during the recent rapid growth of nuclear electric power provides some insight. During the late 1950's and early 1960's, only a few of the most progressive utilities developed nuclear power divisions within their organizations. The bulk of the utilities either were unreceptive to suggestions that they begin staffing with nuclear engineers on the grounds that nuclear power was "so far off" that it would not enter into their 10-25 year planning activities or indicated that they would rely on consulting engineering firms and the manufacturers to provide the required expertise if it were ever needed. However, with the rush of orders for nuclear units in the late 1960's and early 1970's, many utilities suddenly attempted to build their in-house nuclear capability for siting plants, preparing safety analysis and environmental reports, etc., and found, not unexpectedly, that the supply of appropriately trained engineers had been depleted and that it would take 2-5 years to revamp and expand graduate programs to meet their needs. Further, the utilities found themselves competing with the manufacturers for what manpower there was available.

A somewhat similar pattern appears to be repeating itself in the field of flue gas desulfurization. Most utilities do not yet feel that they will be directly involved in chemical processing, (either SO_x control technology or chemical cleaning of fuels), and their engineering staffs have remained little changed. There is a general feeling in the utilities that they can ultimately rely on the vendors; yet there is general skepticism of the vendors' claims at this time. If an early decision is made at the management level that the utilities must turn to stack gas scrubbing as an abatement strategy, there will be heavy demand for in-house engineering talent to prepare specifications, review bids, provide liaison during the construction and shakedown phases, and assume responsibility for reliable operation of the scrubbers. That type of manpower will probably be in a very short supply.

On the operational side, the situation appears even more discouraging. Visits by SOCTAP members to the most ambitious SO_x control projects-Commonwealth Edison's Will County plant and Boston Edison's Mystic plant - revealed a low degree of interest or involvement in the shakedown phase by the utilities installing those two projects. While Babcock & Wilcox and Chemico, respectively, have responsibility for bringing those plants on line, the operational staff available from the utilities for those projects are neither adequately nor appropriately manned. Although both facilities have had a series of unfortunate delays due largely to mechanical problems, utility personnel have had little direct experience with their scrubbers. Labor-management factors have also strongly affected these two utilities' manning of their scrubber installations and operation, representing yet another impediment to the rapid application of flue gas cleaning technology.

3. Competing Fuel Supply/Environmental Protection Strategies

Besides serious question of the electric power industry toward the national and state sulfur oxide and nitrous oxide standards, there is in many utilities genuine confusion as to the best approach to be pursued. The options open to the utilities are to commit capital resources to an uncertain and expensive technology to remove SO_x from the stack gases or to convert from coal to oil, hoping for a steady supply of low sulfur oil at only reasonable price increases or to contract for low sulfur coal, largely from Montana and Wyoming. While full discussion of these alternatives lies outside of the SOCTAP mandate, it is necessary to point out several factors which serve as serious disincentives to rapid growth of SO_x control equipment.

The two low sulfur fuel alternatives do appear more attractive to many utilities because they involve only small capital investments and shift the environmental protection strategy to an operating cost. In a number of states, utilities are now able to pass on to the consumer most of the incremental operating costs of higher-priced fuels by means of "fuel adjustment" provisions. The fuel adjustment charges may be passed directly to the consumer via the monthly bill without further action by the regulatory commission. On the other hand, increases in generating costs due to carrying charges on or operating costs of capital equipment can be compensated only by rate increases which require commission action. Not only do the utilities claim that they must wait for this compensation until the regulatory commissions act but also they claim that they often have to "absorb" some of the additional costs, particularly from nonproductive equipment such as pollution abatement devices. This situation tends to force utilities to secure as much low sulfur fuel as is available and then wait to see what the Environmental Protection Agency or state agencies will do to enforce the standards. In this regard, it should also be pointed out that sulfur emissions tax would help only to the extent that it might force utilities to install stack gas scrubbers on those plants for which the utility could not secure low sulfur fuel.

While the probable dislocations in fuel supply resulting from these factors raise many questions, one of the most disturbing is the precipitous rush by the utilities to obtain low sulfur coal contracts and thus to show "good faith" in compliance insofar as the low sulfur coal is available. Vigorous utility competition for low sulfur coal from new and proposed mines in Wyoming and Montana has led to widespread speculation in land and water rights, particularly in the Powder River Basin. Much of the coal in this region lies under land whose surface rights are privately owned but whose mineral rights are either owned by the Federal government or Indian tribes. Few mines are operating today but many applications for leasing public mineral rights are pending and blocks of coal deposits owned by the railroad and other private interests, the states, and Indian tribes (off the reservations) are being unitized for exploitation. Acceptable reclamation of these semi-arid lands has yet to be demonstrated. The sudden surge for development of these resources finds both states and the responsible Federal agencies inadequately prepared to cope with the array of immediate problems presented by the development let alone long-range cumulative effects on the economic, physical, and social environment of the region. Since stack gas cleaning represents a technological alternative in the near-term to such a culture- and environment-shattering resource development, the full implications of both options should be explored.

B. Institutional Barriers in the Control Systems Industry

One of the major choke points limiting the growth of stack gas scrubbing technology could be institutional constraints on the various design, construction, and material supply organizations who will be called upon to expand their efforts to meet the sizable demand forecasted for 1975-1980.

In order to obtain a scope of this problem the SOCTAP members interviewed: (a) the engineering department of a major utility...Southern Services, the people who must specify the need for scrubbing on particular plants, prepare the in-house documentation for technical and financial decision-making, participate in the implementation process and sign-off on the final product; (b) a major engineering-consultant contractor...Bechtel who shares the engineering-design responsibilities with the in-house staff; participates in preliminary development involving alternate process evaluation and selection, preparation of bid plans and specifications, hiring local construction and material sub-contractors, job supervision and approval, and final start-up check-out runs; (c) two of approximately fifteen* scrubbing system vendors... Chemico and Combustion Engineering, who supply drawings, pilot plant data, and the scrubber and its peripheral equipment; and (d) the National Constructors Association...an organization representing heavy construction contractors around the country. The consensus of these sources is as follows:

*Including: Babcock & Wilcox, Combustion Engineering, Chemico, Peabody, Universal Oil Products (Procon), Krebs, Envirotech, Zern, Monsanto, Enviroengineering, Joy, Research-Cottrell, Wellman-Lord; North American Rockwell, Consolidated Coal.

1. Utility Engineers

Although the institutional barriers within the electric utilities to the rapid application of SO_x control devices were described in detail in the previous section, it is well to reiterate one important point. Because the utilities do not typically have chemical processing expertise on their engineering staffs and because there will undoubtedly be a shortage of experienced chemical engineers if and when scrubbers are ordered in quantity, the utilities will have to rely in large part on the manufacturers and consulting engineers. This may result in delays in preparing detailed specifications for the scrubbers and in deterioration of performance once the scrubber operation is turned over to the utility.

2. Consulting Engineers

The consulting engineers provide an interface between the utilities and the scrubber vendors. These companies can be divided into two groups - those who traditionally deal with electric utilities on large construction jobs and those who do not. For those with utility experience, the corporate division handling scrubbers are significantly smaller than divisions working on power plant design, either fossil fuel or nuclear power. A typical scrubber system requires 20 men from the consultant's staff (engineers, designers, draftsmen) plus 20 men from the scrubber vendor's staff. One of the major consultants is currently working on 5 scrubber systems. To expand further, the Scrubber Division would have to borrow staff from the Power Division which is currently working at capacity on nuclear plants.

For consultants without utility experience, it would be necessary to create new divisions to build scrubbers. In either case, a significant expansion of the demand for scrubbers would cause an immediate shortage of experienced manpower since all retrofit and many new scrubber systems will be custom-made products.

3. Scrubber Vendors

Currently there are some fifteen vendors (see list above) who are more or less established in the flue-gas scrubbing business. A realistic assessment of the current capabilities of vendors indicates that there are three, possibly four, who have sufficient experience and available manpower and corporate backing to expand rapidly, i.e., within the coming year. There are another three or four who are gaining experience and could probably expand although at a slower rate. The remainder of the vendors which have very limited experience could possibly play an important role in the late 1970's but their ability to design, fabricate, and deliver an entire system is largely unproven. Finally, new suppliers may be expected to enter the market with new processes under license if the scrubber market develops substantially.

At this time there are some 20 units committed or underway. It takes two to two-and-a-half years to complete a scrubber and about the same time to develop experienced, competent engineer-designers. There will probably be intense competition for experienced manpower if the market develops rapidly.

Most vendors do not do their own fabrication. Thus, there may be choke points at the level of component suppliers or local fabrication shops. While no specific data were obtained on this subject, several areas were mentioned by those interviewed, including:

a. Pumps (lead time approx. 12 months)
b. Fans (long lead times)
c. Rubber-lined pipes
d. Instrumentation (e.g. magnetic flow meters)

Almost everyone interviewed by the Interagency Task Force predicted that the growth of scrubber installations would be hindered by construction labor shortages in critical skill areas...welders, pipe-fitters, electricians, boilermakers, and craftsmen who install the rubber liners in the scrubbers. These shortages will be local in nature, reflecting the constrained and declining membership of many local craft unions, and the reduced willingness of skilled workers to travel to find new work.

An EPA review of the construction industry shows the following:

a. Environmental standards will result in major new demands on the construction industry for the remainder of the decade. Besides stack gas scrubbing facilities there will be sizable growth in the demand for: municipal sewage treatment facilities including sewers, refinery facilities for lead-free gasoline and low sulfur fuel, thermal pollution reduction facilities for power plants, industrial waste treatment facilities, and new coal mining facilities. In addition there will be a major new shipbuilding program and a doubling of installed electrical generating capacity.

b. Shortages in process engineering talent will be qualitative (due to lack of experience) rather than quantitative.

c. Due to the difficulties in obtaining performance bonding and sufficient working capital the contracting business is highly stratified, with a few large firms handling the larger jobs. Thus, as more large jobs come up for bids we can expect fewer qualified bidders.

d. Labor strength is a local characteristic with over 10,500 union locals divided into more than thirty different specialized trades. As a rule of thumb, large non-residential work (over $500,000) in all urban areas other than the Southeast and Southwest is performed by unionized workers.

e. The skilled worker is no longer mobile in most regions due to a reduction in the seasonality of employment, union restrictions requiring work permits to allow entry into other areas, fringe benefits tied to local union contracts, and the general immobility resulting from a higher personal income.

f. Some of the craft unions show stagnant or declining membership due to restrictive membership barriers. The apprenticeship program for a boilermaker takes four years although six months experience may be sufficient to enable a man to handle most journeyman tasks.

g. Unlike labor, basic materials (concrete, steel, cast iron, plywood, electrical system components) rarely create a check on industry capacity. Problems which may occur relate to higher prices rather than a lack of availability.

h. Productivity in the construction industry has not increased significantly in a decade and is not likely to advance in the coming ten years. Technological advance is sporadic. Pre-fabrication may serve to create "captive" craftsmen, further immobilizing skilled union laborers, but it will not significantly reduce skilled labor requirements on the site due to union work rules and transportation constraints limiting the size of pre-fabricated parts.

i. Due to factors relating construction activity to seasonal and business cycles, many projects are on-going at the same time and pace. Since wages are fixed by local union contracts, the workers tend to move between jobs on the basis of available overtime. Thus, if pipe-fitters are getting more overtime on site #2 than on site #1 they can be expected to migrate even though there is still work to be done on site #1. Thus, cost estimates based on a 40-hour straight-time work week will be underpriced.

j. New environmental standards have created an inelastic demand for new construction which will probably reach its peak in the middle of this decade. The incremental figure for <u>all</u> such pollution control construction during the decade is estimated not to exceed four billion dollars (at 1967 prices), representing an increase of approximately 4 percent over a baseline figure of about $100 billion (1967 prices). The impact of this incremental demand will be felt mainly as price increases.

k. In 1980, an incremental demand for $4 billion of construction at 1967 prices would result in $2-4 billion of other construction being foregone because of insufficient supply to carry it out, and in the cost of projects constructed on schedule being raised between $2.3 and $5.2 billion (1967 prices). So the "effective" price of the increased demand will be $6.3 to $9.2 billion, rather than the apparent $4 billion.

l. A heavier impact will be felt at the regional and local level where a relatively small increment can result in a sharp increase in price due to a lack of interested bidders and/or shortages of key trades.

These conditions will cause contractors to include large contingencies in their bids for delays and overtime.

m. Of the $4 billion construction increment, the "non-equipment elements of air pollution control construction will not be significant."

The implications for scrubber installations in the remainder of this decade are: higher costs and construction delays with local labor factors determining their magnitudes. It would appear to be safe to say that "institutional constraints" will limit scrubber installation to the extent that less than 10% of the potential demand can be met by 1975, and that full demand can be met by 1980 only by extraordinary circumstances of growth in the vendor industry and skilled labor force.

VII. FORECASTING SULFUR OXIDE CONTROL TECHNOLOGY

Recent trends in utility orders for flue gas desulfurization systems have been examined and forecasts for the application of these systems in the period from 1975-1980 are presented. Implications of the projected expansion in the use of SO_x control technology are described.

A. Recent Trends in Orders for Flue Gas Desulfurization Systems

By analyzing present and planned flue desulfurization systems in the United States, it is possible to roughly ascertain trends in the degree of flue gas desulfurization system utilization and the types of systems which are presently favored by utilities. In Table VII-1 the full-size desulfurization systems planned or operating in the United States are compiled. Note that the table is arranged in chronological sequence within category type; the facilities completed earliest are listed first. Based on this summary, the following observations can be made:

1. Presently, twenty-two flue gas desulfurization systems are planned or in operation; sixteen are lime or limestone scrubbing units; two are sodium-based; three are magnesium oxide systems, and one is a catalytic oxidation system. Eleven of the limestone systems utilize injection of dry limestone into the furnace followed by either wet or dry scrubbing; the remaining eleven lime/limestone systems utilize only wet post-combustion scrubbing with a lime/limestone slurry. Both the recent sales patterns and opinion within the utility industry indicate that few, if any, dry limestone injection systems will be purchased in the future.

2. The great majority of the systems are installed on coal-fired units; only two of the twenty-two are on oil-fired units.

3. The great majority of the systems are retrofitted onto existing boiler facilities; only five of the twenty-two are systems for new boilers.

TABLE VII-1

PLANNED AND OPERATING FULL SIZE FLUE GAS DESULFURIZATION FACILITIES IN THE UNITED STATES

UTILITY COMPANY/PLANT/NEW OR RETRO	MEGAWATTS	STARTUP	FUEL
LIMESTONE SCRUBBING			
1. UNION ELECTRIC CO. (ST. LOUIS)/ MERAMEC NO. 2/RETRO	140	SEPTEMBER 1968	3.0% S COAL
2. KANSAS POWER & LIGHT/LAWRENCE STATION NO. 4/RETRO	125	DECEMBER 1968	3.5% S COAL
3. KANSAS POWER & LIGHT/LAWRENCE STATION NO. 5 NEW IN 1971	430	NOVEMBER 1971	3.5% S COAL
4. COMMONWEALTH EDISON (CHICAGO AREA)/ WILL COUNTY STATION NO. 1/RETRO	175	FEBRUARY 1972	3.5% S COAL
5. CITY OF KEY WEST/STOCK ISLAND*/NEW	37	OCTOBER 1972	2.75% S FUEL OIL
6. KANSAS CITY POWER & LIGHT/HAWTHORNE STATION NO. 3/RETRO	130	LATE 1972	3.5% S COAL
7. KANSAS CITY POWER & LIGHT/HAWTHORNE STATION NO. 4/RETRO	130	LATE 1972	3.5% S COAL
8. LOUISVILLE GAS & ELECTRIC CO./ PADDY'S RUN STATION NO.6/RETRO	70	NOVEMBER 1972	3.5 S COAL
9. KANSAS CITY POWER & LIGHT/LA CYGNE STATION/NEW	820	DECEMBER 1972	5% S COAL
10. DETROIT EDISON CO./ST. CLAIR STATION NO. 6/RETRO	180	DECEMBER 1973	3.7%-3.8% S COAL
11. ARIZONA PUBLIC SERVICE CO./CHOLLA STATION/RETRO	115	JANUARY 1973	0.4%-1% S COAL
12. UNION ELECTRIC COMPANY (ST. LOUIS)/ MERAMEC NO. 1/RETRO	140	SPRING 1973	3.0% S COAL
13. DUQUESNE LIGHT CO. (PITTSBURGH)/ PHILIPS STATION/RETRO	100	SPRING 1973	2% S COAL
14. TENNESSEE VALLEY AUTHORITY/WIDOW'S CREEK STATION NO. 8/RETRO	550	APRIL 1975	3.7% S COAL
15. NORTHERN STATES POWER CO. (MINNESOTA) SHERBURNE CO. STATION NO. 1 & 2/NEW	1360 2-680	MAY 1976 FIRST UNIT	0.8%-1.2% S COAL
16. SOUTHERN CALIFORNIA EDISON & OTHER SOUTHWESTERN UTILITIES/NAVAJO/NEW	2250 3-750	1-UNIT/MAR. 1976 3-UNIT/MAR. 1977	0.3-0.8% S COAL
SODIUM-BASE SCRUBBING			
17. NEVADA POWER CO./REID GARDNER STATION/RETRO	250	MID 1973	0.5%-1.0% S COAL
18. NORTHERN INDIANA PUBLIC SERVICE CO./ D.H. MITCHELL NO. 11 (WELLMAN-LORD PROCESS)*/RETRO	115	JULY 1974	3.5% S COAL
MAGNESIUM OXIDE SCRUBBING			
19. BOSTON EDISON/MYSTIC STATION NO.6*/RETRO	150	APRIL 1972	2.5% S FUEL OIL
20. PHILADELPHIA ELECTRIC CO./EDDYSTONE 1/RETRO	120	MID 1973	2.5% S COAL
21. POTOMAC ELECTRIC & POWER (MARYLAND)/ DICKERSON NO. 3*/RETRO	100	EARLY 1974	3.0% S COAL
CATALYTIC OXIDATION			
22. ILLINOIS POWER/WOOD RIVER*/RETRO	100	SEPT.-OCT. 1972	3.25% S COAL

*PARTIAL FUNDING BY THE ENVIRONMENTAL PROTECTION AGENCY

4. The total megawatts represented by these units is about 7,500 MWe, 3,600 MWe representing systems installed on new boilers.

5. Presently, about 3,400 MWe of control capability is scheduled to be installed as of the end of 1974, which includes 950 MWe utilizing dry limestone injection. Since any additional commitments would require from two to three years for design and construction, it is not expected that the actual total capacity will be much greater than that already scheduled for 1974. The corresponding number for 1975 is about 4,000 MWe. This amount could be increased substantially only if utilities make decisions to install such systems between now and about mid-1973.

6. The utilities to date have committed capital expenditures for flue gas desulfurization systems of approximately $330 million.

B. Forecasting Applications of Flue Gas Desulfurization Systems

Based on the results of many discussions with utilities, manufacturers, and others, an attempt has been made to predict potential growth patterns for the application of sulfur dioxide control systems in the electric power industry. With many uncertainties in regulatory strategy, utility management policy, operations experience in SO_x control demonstration plants, and the capability of the control system vendors to deliver reliable products, these forecasts can at best be considered as rough estimates of optimistic schedules for application of stack gas cleaning equipment to central station generating plants.

It is impossible to characterize these forecasts in a simple way, other than to say that they result from the intuitive and analytical blending of many factors: pressures from New Source Performance Standards and the State Implementation Plans; the realities faced in the electric power industry today, including delays in nuclear capacity and fossil fuel shortages; and the uneven progress of equipment manufacturers in developing SO_x control devices.

Two forecasts are presented in Tables VII-2 and VII-3 to illustrate possible trends in the application of SO_x control equipment in the electric power industry. Some of the guidelines used in constructing these projections are described here. The modeling was simplified by considering only coal-fired central station electric plants. There are several limitations implicit in this assumption which should be mentioned. Many smaller coal-fired plants may be converted to oil-firing, and a number of midwestern coal-fired plants may begin burning low sulfur Western coal instead of high sulfur coals. An offsetting factor may be the installation of SO_x control equipment on oil-fired boilers, depending on increasing costs of low sulfur oil.

New and retrofit SO_x control equipment installations were considered separately. It was assumed that, because of the New Source Performance Standards and the State Implementation Plans, all new coal-fired plants would be equipped, if possible, with SO_x control devices. In the forecasts, this annual demand was satisfied first. The rest of the estimated capacity of the control system vendors was applied to retrofitting existing coal-fired plants.

The pacing factors or "choke points" in these projections are two-fold: the ability of the control system vendors to convince the utilities that they have developed reliable systems and the ability of the vendors to initiate quickly many new projects, to bring those systems on line with minimum delay and adverse publicity, and to continue to take on new projects with negligible choke effects. In both of the projections, the potential for delays due to shortages in engineering and skilled construction manpower and for delays in acquiring material and equipment was recognized.

For purposes of simplicity, the manufacturers were grouped three categories: Vendor A group included 3 to 4 major manufacturers which have considerable experience with SO_x control and have reasonably large engineering staff; Vendor B group included 4 to 5 manufacturers with some experience in SO_x control and with extensive experience in some phase of air pollution control or chemical processing; and Vendor C group included all other manufacturers, including such organizations as TVA which engineers its own scrubber systems.

TABLE VII-2

FORECAST OF SULFUR OXIDE CONTROL EQUIPMENT ON ELECTRIC POWER STATION, 1975-1980
-OPTIMISTIC SCENARIO-

Vendor Type	Type Install.	Thru 1974[2]	Number of Scrubbers Brought on Line[1]					
			1975	1976	1977	1978	1979	1980
A	New		16	16[4]	14	16	16	16
	Retro		25	25	45	45	59	59
B	New				2	2	2	2
	Retro		15	25	35	35	45	45
C	New							
	Retro		6[3]	10	20	30	40	50
Install. Totals	New		16	16	16	20	20	20
	Retro		46	60	100	110	144	154
Capacity Totals, MWe	New	860	12,000	12,000	12,000	15,000	15,000	15,000
	Retro	1570	9,500	12,000	20,000	22,000	29,000	31,000
Total Cap., MWe		2430	21,500	24,000	32,000	37,000	44,000	46,000
Cumulative, MWe		2500	24,000	48,000	80,000	117,000	161,000	207,000

[1] Average size of new plants assumed to be 750MW; retrofitted plants assumed to be 200 MW.

[2] Plants using dry limestone injection not included in compilation or in projection.

[3] This number includes TVA's 550 MW Widow's Creek Plant

[4] This number includes Northern States Power's 1400 MWe Sherburne Co. Plant.

TABLE VII-3

FORECAST OF SULFUR OXIDE CONTROL EQUIPMENT ON ELECTRIC POWER STATION, 1975-1980
-ONE YEAR DELAY SCENARIO-

Vendor Type	Type Install.	Thru 1974[2]	Number of Scrubbers Brought on Line[1] 1975	1976	1977	1978	1979	1980
A	New		5	11[4]	16	14	16	16
	Retro		10	15	25	45	45	59
B	New					2	2	2
	Retro		5	10	25	35	35	45
C	New						2	2
	Retro		3[3]	3	10	20	30	40
Install. Totals	New		5	11	16	16	20	20
	Retro		18	28	60	100	110	144
Capacity Totals, MWe	New	860	3750	8,250	12,000	12,000	15,000	15,000
	Retro	1570	3600	5,600	12,000	20,000	22,000	29,000
Tot. Capacity, MWe		2430	7350	13,850	24,000	32,000	37,000	44,000
Cumulative, MWe		2500	10,000	24,000	48,000	80,000	117,000	161,000

[1] Average size of new plants assumed to be 750 MW; retrofitted plants assumed to be 200 MW.

[2] Plants using dry limestone injection not included in compilation or in projection.

[3] This number includes TVA's 500 MW Widow's Creek Plant

[4] This number includes Northern States Power's 1400 MWe Sherburne Co. Plant.

The first forecast given in Table VII-2 describes what we considered an "optimistic" scenario for the application of SO_x control devices. Critical to this forecast is the ability, particularly of the major manufacturers, to expand rapidly during 1973-1974 so that they can handle 40 or more projects at the same time. Also critical is the requirement that utilities will have to order the scrubbers scheduled for operation in 1975 within the next six to nine months since the time needed to specify, fabricate, and assemble a scrubber is 24-30 months.

The second forecast given in Table VII-3 is more realistic than the first forecast, in that it assumes the likelihood of delays in excess of six to nine months before utilities begin placing substantial orders. Some of the reasons for such delays have been described above, but probably include evidence of long-term reliable operation with Chemico's Mag-Ox scrubber in Boston or Babcock and Wilcox's limestone scrubber near Chicago. This second forecast assumes that the 62 scrubber units scheduled for 1975 (under the optimistic scenario) would not be completed until the end of 1976. Twenty-three units were assumed to come on line in 1975 and 39 units in 1976. Thus, the postulated expansion of the scrubber application would be delayed by one year.

The cumulative sulfur oxide control capacity predicted in these two forecasts is presented graphically in Figure VII-1. From these two curves, one can see that the electrical generating capacity out-fitted with SO_x control equipment may be between 10,000 and 24,000 MWe in 1975 and between 48,000 and 80,000 MWe in 1977. While it may be possible to use only an incremental 25-60 million tons of high sulfur coal because of the limited availability of SO_x control devices in 1975, the amount of high sulfur coal which could be used in 1977 may grow to 120-200 million tons.

Although projections for the use of coal during the coming decade also vary widely, it is instructive to compare the quantities of high sulfur coal which could be used with the availability of SO_x control devices predicted in these two scenarios. In Table VII-4 total steam electric coal requirements are projected and compared to the quantities of high sulfur coal made usable with SO_x control technology. From this table, one can see that, in the first "optimistic" scenario, the market for SO_x control equipment would probably soften after 1977 because

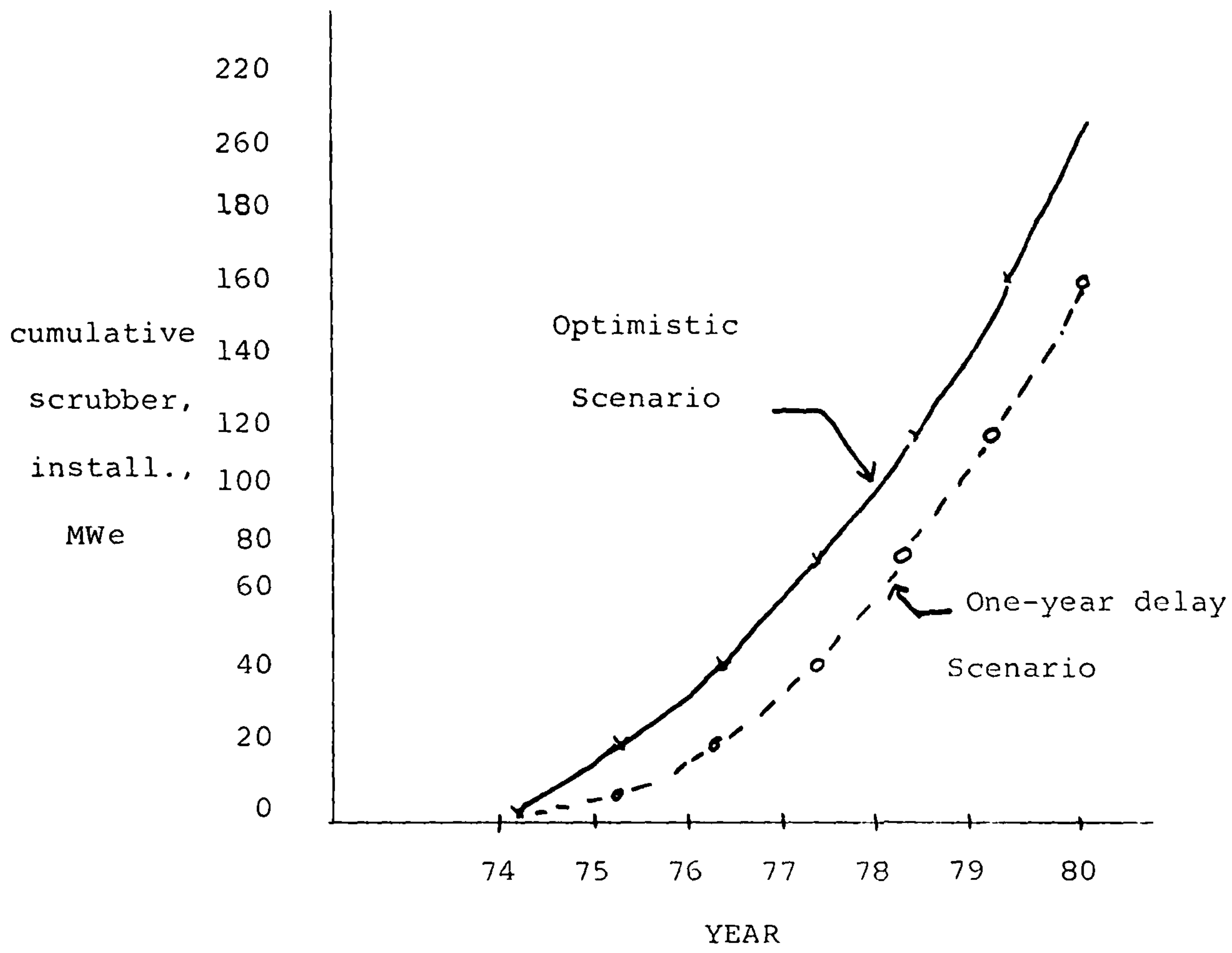


FIGURE VII-1

FORECASTS OF CUMULATIVE STACK GAS SCRUBBER INSTALLATIONS

TABLE VII-4

Comparison of High Sulfur Coal Usable with SO_x Control Technology to Total Consumption in Steam Electric Plants

	Steam Electric Coal Consumption,[1] 10^6 tons	Maximum High Sulfur Coal Used with SO_x Control-Scen. 1 10^6 tons	Maximum High Sulfur Coal Used with SO_x Control-Scen. 1 %Usable	Maximum High Sulfur Coal Used with SO_x Control-Scen.2 10^6 tons	Maximum High Sulfur Coal Used with SO_x Control-Scen.2 %Usable
1975	440	61	14	26	6
1977	485	200	41	120	25
1980	545	525	96	410	75

[1] Consumption of coal for steam electric plants assumed to grow 6% per year from 328 million tons in 1970 through 1975, drop to 5% in 1976-1977, and then drop to 4% in 1978-1980.

of the rapidly diminishing market, the higher installation costs in the remaining smaller and older boilers and the competition from low sulfur coal and oil conversions for the remaining plants. It appears, however, that the market in the second "realistic" scenario would probably remain reasonably firm beyond 1977 with diminished "overshoot" capability in the control systems industry as the retrofit market would decrease appreciably in size only in the early 1980's. These estimates, however, do not take into account chemical coal-cleaning processes such as liquefaction and gasification which may become available on a limited basis in the 1977-1980 time frame.

The question of maintaining adequate reserve generating capacity is a complex one, as described in Chapter VI. Referring to Table VI-2, one can see that, on an overall national basis, even a 10% maintenance margin might allow as much as 40,000 MWe to be available for SO_x scrubbing system retrofit installations in 1975. SO_x control for new plants can be installed while the boiler is being constructed and does not require a maintenance outage for installation. Only existing units will have to be retrofitted and brought on line during the spring and fall maintenance periods at a rate not to exceed the available maintenance margin of 40,000 MWe. For both scenarios, the projected additions of retrofitted systems are well within this limitation.

On the other hand, in the middle central and middle south sections of the Nation, many utilities are equipped only to burn coal, thus the Nation's coal-fired capacity is concentrated in that area and the bulk of the burden of retrofitting may fall on those utilities. Because of the limited ability to shift large blocks of electrical power except within power pools (as pointed out in Chapter VI), there will probably be localized problems in these geographical areas in bringing retrofitted SO_x control equipment on line, just as the problems of bringing nuclear plants on line will probably continue to exacerbate the reserve margin difficulties. The application of SO_x control equipment, i.e., the slope of the cumulative capacity curves as shown in Figure VII-1 will decrease.

An analysis of the direct cost of a sulfur oxide control program such as incorporated in the "realistic" scenario is given in Table VII-5.

In summary, we feel that a realistic estimate of SO_x control system installation may be 10,000 MWe by the end of 1975 and 48,000 MWe by the end of 1977. This estimate is based on extrapolations of the current status of stack gas cleaning and does not attempt to evaluate all possible alternatives for SO_x pollution abatement.

TABLE VII-5

Comparison of SO_x Control Expenditures in "Realistic" Scenario with Total Utility Capital Expenditures for Generating Equipment (1972 Dollars)

	Expenditures $ Millions					
	1975	1976	1977	1978	1979	1980
SO_x Control for New Plants[1]	150	330	480	480	600	600
SO_x Control for Retrofitted Plants[2]	220	340	720	1,200	1,320	1,740
SO_x Control Totals	370	670	1,200	1,680	1,920	2,340
Total Utility Capital for Generating Equipment[3]	9,800	10,300	17,700	12,400	13,300	14,500

[1] The cost of SO_x control equipment for new plants was assumed to be $40/KWe

[2] The cost of SO_x control equipment for plants requiring retrofitting was assumed to be $60/KWe

[3] The capital expenditures for generating equipment were taken from Electrical World, September 15, 1972.

APPENDIX

STATUS REPORTS ON IMPORTANT MAJOR SO_x SCRUBBING FACILITIES IN THE UNITED STATES AND JAPAN VISITED BY SOCTAP MEMBERS

Process: Magnesium Oxide Scrubbing with Thermal Regeneration
Process Supplier: Chemical Construction Corporation (Chemico)
Constructor: Chemical Construction Corporation
System Location: Boston Edison's Mystic Station in Boston, Massachusetts

Conclusions and Analysis of Significance:

In April 1972, the shakedown period began for the Mag-Ox scrubbing system on a 150 MW oil-fired boiler at Boston Edison's Mystic Station. The venturi scrubber has operated intermittently since then due to mechanical difficulties. During operation, the scrubber has achieved SO_2 removal efficiencies in excess of 90% with no apparent scrubber-related problems. The major problem has been with the design and operation of the $MgSO_3$ crystal dryer. Redesign of the dryer and a change of fuel to a low viscosity oil appear to be resolving these problems. Other problems with centrifuging the sulfite crystals from the scrubbing liquor and properly calcining the sulfite to regenerate MgO appear to be manageable. If new problems are not confronted, the scrubber system should begin long-term test runs in the near future.

This project is quite important because it will be the first time the individual steps of scrubbing, centrifuging, and calcining on an integrated basis for the Chemico process have been combined. Partially funded by EPA, the project involves not only the scrubber, centrifuge, and dryer at the Boston Edison plant but also the calcining and acid plant at Essex Chemical Company in Rumford, Rhode Island.

The process has not yet been demonstrated on a coal-fired plant, however, a full-scale Mag-Ox scrubber is planned for Potomac Electric and Power's Dickerson Plant. Approximately 100 MW of the 195 MW of Dickerson Unit 3 will be processed. Since the plant burns coal (3% S, 8% ash), the scrubbing facility will use one venturi scrubber to remove the particulate and a second to remove the SO_2. The scrubber is scheduled to start up in early 1974 and to use the calcining plant at Essex Chemical.

Process: Limestone Scrubbing with Throwaway Product
Process Supplier: Babcock & Wilcox
Constructor: Babcock & Wilcox
System Location: Commonwealth Edison Co.'s Will County Station in Romeoville, Illinois

Conclusions and Analysis of Significance:

In February, 1972, the 175 Mw Commonwealth Edison Will County Station Unit No. 1 started up. The system consists of two identical parallel wet limestone scrubbing systems, each consisting of a venturi for particulate removal, followed in series by a turbulent contact absorber (TCA) for SO_2 absorption. This unit has operated intermittently since start-up and has generally achieved SO_2 removal efficiencies in the range of 75-85%. Demister pluggage with a soft, mudlike substance has been a problem; but with automatic demister washing with make-up water via bottom sprays, this problem area may lend itself to control. Additional droplet disengagement space upstream of the demister may also help alleviate the problem.

Economic disposal of sludge from this system appears to be a problem; however, Commonwealth Edison is presently working on this problem with Chicago Flyash Company. One of the first steps taken will be the installation of a sludge treatment system, to allow disposal of sludge with a lower water content. Eventual disposition of the sludge materials would be at an unspecified landfill site, although a disposal pond was temporarily used for storage. None of the problems encountered thus far in the Will County unit appears to be insurmountable.

This system is the first full-scale installation in the United States that uses limestone introduced into the scrubber circuit. This system is representative of a trend in recent years away from the boiler injection mode due to the possibility of boiler pluggage and the tendency toward serious scaling problems. This facility is considered very important for the general U.S. control situation, since the Will County unit is typical of many coal-fired retrofit situations. Despite the demister, mechanical and sludge disposal problems, it appears likely that the system will be made to operate reliably with adequate disposal of sludge material, in the near future.

Process: Lime Scrubbing with Throwaway Product
Process Supplier: Chemical Construction Corporation (Chemico)
Constructor: Mitsui Miike Machinery Co.
System Location: Miike Power Station, Omuta Works, Mitsui Aluminum Co., (near Omuta, Japan)

Conclusions and Analysis of Significance:

The SO_x control system on the Miike Power Station of Mitsui Aluminum Company, Ltd., located near Omuta in Kyushu has exhibited reliable, essentially trouble-free operation since March 29, 1972. After its performance passed the guarantee tests in late April, the control system has been operated under less stringent conditions just adequate to meet the current Japanese SO_x standards. No serious chemical or mechanical problems have been detected in the two-stage venturi scrubbing system.

The sludge in the disposal pond appears to be settling quite well, in fact, much better than experienced at U.S. facilities. Ultimate disposal of the throwaway product, a major problem in the U.S., remains an open question.

It should be noted that the reliable performance of this system to date is of real significance to the United States air pollution control program, since the design ground rules for the Japanese unit are quite similar to those of many of our power utilities requiring desulfurization systems. The following are among the areas of commonality: use of existing coal-fired boiler, moderately efficient electrostatic precipitators, installation on moderately-large size boiler (156 Mw), production of a throwaway product, and availability of calcium hydroxide. The unit takes on additional significance since the system was designed based on U.S. technology (Chemico) and a similar unit, using calcium hydroxide on a coal boiler, is being constructed in the U.S. for Duquesne Light Company's Phillips Station, with start-up scheduled during spring 1973.

It should be noted that long-term reliability of the Mitsui unit has not yet been demonstrated. Also, there is some question regarding the validity of extrapolating Mitsui performance to those U.S. applications with substantially different design ground rules, such as: much higher SO_2 inlet concentrations, units with widely varying boiler loads, and much higher inlet ash concentrations.

Process: Soluble Sodium Scrubbing with Thermal Regeneration (Wellman-Lord Process)
Process Supplier: Wellman Power Gas
Constructor: Mitsubishi Chemical Machinery (MKK)
System Location: Japan Synthetic Rubber (near Chiba, Japan)

Conclusions and Analysis of Significance:

Successful reliable operation of the Wellman-Lord SO_x control process at Chiba for greater than 9,000 hours for the last year and a half is considered quite significant for the U.S. SO_x control situation. This process has been demonstrated to reliably remove in the order of 90 percent of the inlet flue gas on a 75 Mw oil-fired boiler. It appears that the process should be applicable to coal-fired boilers if fly ash removal equipment is installed upstream of the absorber. A Northern Indiana Power Service Co. (NIPSCO) unit, partially funded by EPA, will evaluate such systems on a coal-fired boiler. Cost studies indicate that capital and operating costs for a Wellman-Lord system in the U.S. on a coal-fired boiler are not a great deal higher than those for wet lime/limestone or magnesium oxide scrubbing systems, which are generally considered the least expensive of the flue gas desulfurization systems.

The major problem with the process is the requirement for a bleed to remove contaminants, primarily Na_2SO_4. Present information indicates about 10 percent of the total incoming sulfur is lost as soluble Na_2SO_4. This is undesirable from an environmental viewpoint, since future Federal regulations for waste streams will probably prohibit such discharge; also, sodium make-up costs are quite significant. However, based on an oxidation retardant identified by Sumitomo, such losses might be reduced by 55 percent. Other techniques for decreasing or eliminating this discharge will probably have to be considered for U.S. applications.

Another potential problem with this and all the other concentrated SO_2 producing processes is the requirement to sell large quantities of low-value sulfur product. Although there is little doubt that H_2SO_4 can be marketed in the U.S. in certain localities (near H_2SO_4 users), it does not appear that such production can be absorbed by users if a large percentage of U.S. electrical utilities would produce acid. However, elemental sulfur, which will be produced in the NIPSCO unit, is another potential product which is both storable and potentially saleable; this could ultimately be the most desirable end product of all, including the throwaway sludges associated with lime/limestone processes.

Process: Lime Scrubbing with Gypsum Production
Process Supplier: Mitsubishi Heavy Industries - Japanese Engineering Consulting Co.
Constructor: Mitsubishi Heavy Industries
System Location: Amagasaki Power Plant of Kansai Electric (near Osaka, Japan)

Conclusions and Analysis of Significance.

The Mitsubishi/JECO lime-gypsum SO_x control system on the Amagasaki power plant of Kansai Eletric has exhibited reliable, trouble-free operation for approximately a three-month period since April, 1972. This process with its demonstrated oxidation technology allows production of high-purity gypsum ($CaSO_4 \cdot 2H_2O$) instead of sludge-rich in $CaSO_3 \cdot 1/2H_2O$. The oxidation technology has been demonstrated over the last eight years in the lime-gypsum system treating sulfuric acid tail gases in the Koyasu Mill of Nippon Kokan K. Gypsum has advantages over calcium sulfite for throwaway systems, since it is much more easily dewatered, either by settling, centrifuging, or filtering operations. This can lead to lower volume requirements for sludge disposal ponds and allow more economical reclaiming of such ponds. For throwaway systems where the sludge is transported for land fill, disposal costs can be reduced since a drier (lower weight) material would be handled and transported to the disposal site.

It should be noted that there are certain factors relative to this unit which make extrapolations to the United States situation difficult. The 35-Mw boiler burns low-sulfur residual oil giving an inlet SO_2 concentration to the scrubber of only 700 ppm. Most U.S. utilities require control on boilers burning high-sulfur coal or oil with inlet concentrations to a desulfurization system generally greater than 2000 ppm. Experience has indicated lime scrubbing systems are more prone to scaling, plugging and other reliability problems at higher inlet SO_2 concentrations. Also, utilization of the Mitsubishi technology in the United States would be more difficult compared to use of Chemico and Wellman-Lord technology, for example, since they are U.S. based companies.

Process: EPA Prototype Test Facility - Limestone and Lime Scrubbing with Throwaway Product
Major Contractor: Bechtel Corporation
Constructor: Tennessee Valley Authority (TVA)
System Location: TVA's Shawnee Steam Plant near Paducah, Kentucky

Conclusions and Analysis of Significance:

The EPA prototype test facility consists of three parallel scrubber systems, each capable of treating 30,000 acfm (10Mw) of flue gas, which are integrated into the flue gas ductwork of an existing coal-fired boiler. Bechtel, as the prime contractor, has designed the facility and has overall responsibility for the test program, whereas TVA has constructed and is operating the system. This facility was designed for maximum flexibility; it can evaluate four scrubber types, lime or limestone as the scrubbing medium, various solids handling systems, and a variety of flow configurations and a range of test conditions. The facility has a high degree of instrumentation for control and recording of data over a wide range of operating conditions.

Since the facility started up during April, 1972, it has generated important data during air-water and sodium carbonate testing. Recently, testing has been initiated using limestone slurries. It is expected that such limestone and subsequent lime testing will supply information important to the design and/or operation of present and future facilities utilizing a wet limestone or lime scrubbing process. Such information will include: a comparison of performance and reliability for various scrubber types, evaluation of lime versus limestone for effectiveness, a comparison of solid disposal techniques, and determination of optimum operating conditions for maximum removal efficiency and reliability.