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FLUE GAS DESULFURIZATION: COST AND FUNCTIONAL ANALYSIS OF LARGE SCALE PROVEN PLANTS

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COST AND FUNCTIONAL ANALYSIS OF LARGE - SCALE AND PROVEN PLANTS

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ABSTRACT

Flue Gas Desulfurization is a method of controlling the emission of sulfurs, which causes the acid rain. The following study is based on 26 utilities which burn coal, have a generating capacity of at least 50 Megawatts (MW) and whose Flue Gas Desulfurization devices have been operating for at least 5 years. An analysis is made of the capital and annual costs of these systems using a comparison of four main processes: lime, limestone, dual alkali and sodium carbonate scrubbing. The functional analysis, based on operability, allows a readjustment of the annual costs and a determination of the main reasons for failure. Finally four detailed case studies are analyzed and show the evolution of cost and operability along the years.

Thesis Supervisor: Dr. Dan Golomb

Title: Visiting Scientist

A C K N O W L E D G E M E N T

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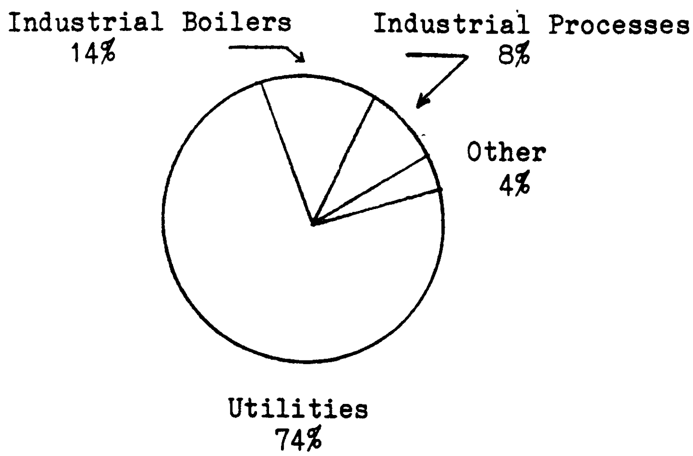
1.1 Origin and Consequences of "Acid Rain"

Acid precipitation may be one of the most polarizing yet least understood energy/environment issues of the 1980s. Its implications for environment quality and national energy policy, particularly regarding increased coal use as a substitute for imported oil are profound.

1.1.1 Origin of "Acid Rain"

The causes of acid precipitation remain an area of wide controversy. Advocates of regulation claim that convincing evidence shows that man-made sources, particularly older coal-fired plants in the Midwest, cause acid precipitation in the Northeast and in Canada. Opponents of regulation on the other hand contend that their evidence constitutes insufficient proof.

The environmentalists as well as the utility industry recognize that wet and dry acid deposition is now occuring and favor the expansion of monitoring in order to obtain detailed measurements. (Curtis, 1980) Both also agree that the movement of air masses can transport air pollutants up to many hundreds of miles and that chemical reactions can transform these pollutants into sulfuric and nitric acids. However they disagree on the quantitative details like transport paths, transformation and deposition rates. Therefore accurate quantitative connections between source regions and receptor areas are uncertain. Figures 1.1 and 1.2 show a breakdown of man-made SO_2 and NO_x emmission in the U.S. for 1980.



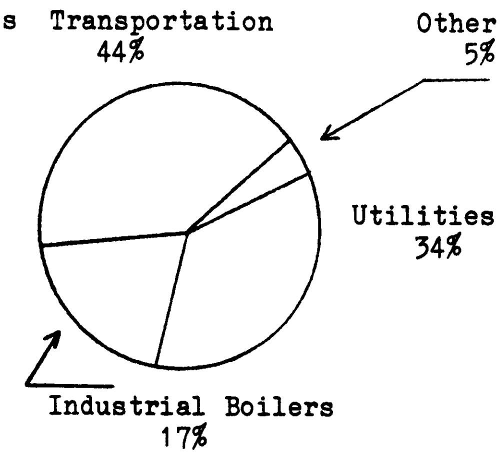


Figure 1.1

SO_2 emissions in the 31 eastern states. Percent of 1980 emissions by source categories.

Figure 1.2

NO_x emissions in the 31 eastern states. Percent of 1980 emissions by source categories

Source: U.S.-Canada Work Group 3B under the Memorandum of Intent on Transboundary Air Pollution

These figures show that electric utilities contribute the majority of U.S. SO_2 emissions, and are significant contributers of nitrogen oxides. Whereas electric utilities account for 74% of all U.S. SO_2 emmissions from non ferrous smelters, by comparison, which are major sources of Canadian SO_2 emmissions (42%) contribute only 8% to total U.S. SO_2 emissions, and that occurs further west than the areas which are of maximum concern in present acid deposition. Electric utilities emit 34% of total man-made nitrogen oxides emissions, second only to transportation sources which contribute 40%.

Moreover, EPA data show that a disproportionately large share of these emissions is concentrated in the Ohio River Valley area, which includes all of Kentucky, most of West Virginia, and major portions of Illinois, Indiana, Ohio and Pennsylvania. (U.S. EPA, 1980)

Overall, most reports seem to indicate agreement that acid deposition is produced from a combination of precursors compounds originating in both local and distant regions, but there remains disagreement about the relative shares contributed by local and distant sources respectively.

1.1.2 Consequences of "Acid Rain"

Once again there are large differences of opinion. Scientific research presents convincing data that suggests damage to aquatic systems, but data on other impacts are far less conclusive. Those asserting that acid precipitation is not a sufficiently documented environmental problem acknowledge the vulnerability of these regions to acidification, but dispute most of the claims of "proven" damage.

The most common cause of decline of fish population in acidified lakes is failure in the reproduction cycle. Acidity inhibits development of reproduction organs in some fish and reduces egg production. Even if eggs are successfully hatched, the young do not develop normally. (Cowling, 1980) Somewhat less agreement exists, although still a consensus, that some mature fish are dying from acidification in Nova Scotia rivers and Adirondack lakes.

Ongoing scientific research is attempting to clarify the relationship between quantities of acid deposition and their effects on aquatic ecosystems. This research will help the scientist to predict quantitatively how much damage to aquatic ecosystems can be expected in the future from acid deposition and therefore to estimate thresholds or tolerance levels of acid deposition.

Environmental impacts other than those on aquatic ecosystems are very difficult to quantify. Acid precipitation could cause damage to plant tissues and interfere with photosynthesis. It could also stunt forest growth and reduce yields of tomatoes, beans and other agricultural crops.

Acid precipitation is also suspected to corrode buildings and statues (U.S. EPA, 1980) and to have indirect health effects. Metals such as lead or mercury can be dissolved and carried by water of greater than usual acidity and contaminate fish or drinking water.

1.2 Survey of the Different Methods of Control

Control strategies proposed to deal with acid precipitation vary substantially in their costs, energy consumption and ability to reduce emissions. The least expensive strategies-such as liming lakes and streams or coal washing- offer the smallest potential for reducing impacts, while the most expensive strategies-such as retrofitting scrubbers onto older existing power plants-reduce emissions the most. A short description of liming and coal washing follows. Scrubbing is discussed with more detail in Section 1.3 and Section 2.

1.2.1 Liming

Liming is the use of limestone (calcium carbonate) or other alkaline materials to neutralize the excess acid in lakes, streams, or ponds. Unlike many other control methods, it would deal with all sorts of acids rather than sulfuric acid only. However it would not solve the alleged impacts of acid precipitation on terrestrial ecosystems.

Ontario's Ministry of Environment reports having successfully restored the pH of four acidified lakes near the Province's Sudbury smelters to normal, at a cost of about $50 per acre. However the effects are temporary (usually three to four years) and it can only be applied in about one percent of the cases for economic and logistic reasons. (e.g. difficult access to the lakes).

1.2.2 Coal Washing

Coal washing is viewed as a relatively inexpensive technique to make moderate reductions of SO_2 emissions. it is a process that removes pyritic sulfur from coal before it is burned, and is most effective when used with high sulfur coals such as those in northern Appalachia and the Midwest. Coal washing can reduce sulfur content of Pennsylvania and Illinois coals by over 30 percent. (Chapman, et., al., 1981)

Cleaning all coals for the eight eastern and midwestern states would increase the average delivered cost of raw coal by only 10 to 20 percent. Capital and annual costs of 200 million tons per year coal washing program would be $3 billion and $1 billion, respectively.

Coal washing's major drawback is its limited potential for sulfur removal. If 10 to 30 percent sulfur removal is deemed sufficient to mitigate acid precipitation, then it migh be a cost-effective strategy. If however, greater SO_2 reductions are warranted, then coal washing will not suffice.

1.3 Definition of Flue Gas Desulfurization (FGD)

Flue Gas Desulfurization takes place in a complex, large-scale chemical reactor which is located between the combustion chamber and the smokestack. The combustion products (flue gases) are exposed to a lime or limestone slurry that is sprayed in their path. Sulfur dioxid in the gas reacts with the spray and goes into solution, from which it is later removed, dewatered and extruded in the form of sludge.

FGD processes can be best categorized by process (i.e. wet or dry, lime, limestone, dual alkali, sodium carbonate, etc.). FGD processes can also be categorized by the manner in which the sulfur compounds removed from the flue gases are eventually produced for disposal. In this way three main categories result:

1. Throwaway processes, in which the eventual product is disposed of entirely as waste. Disposal can include landfill, ponding, discharge to water course or ocean, or discharge to a worked-out mine.
2. Gypsum processes, which are designed to produce gypsum of

sufficient quality either for use as an alternative to natural gypsum or as a well-defined waste product with good disposal characteristics.

3. Regenerative processes, which are designed specifically to regenerate the primary reactants and concentrate the sulfur dioxide that has been removed from the flue gases and convert it into sulfuric acid, elemental suflur or liquefied sulfur dioxide.

As shown in Section 3, scrubbing is a very expensive way to reduce SO_2 emissions. Section 4 shows that it is not as effective as usually thought. Under current law (as defined by EPA) the electric utilities are forced under section 111 of the Clean Air Act to use scrubbers, even if the ambient air quality standards can be both attained and maintained by the use of low-sulfur fuels. This law is primarily due to a strange alliance between environmentalists and high-sulfur coal producers who were afraid of having their mines closed if the utilities switch to low-sulfur coal. (Ackerman _et_. _al_., 1981) Therefore FGD is a very important issue in the U.S. and should be carefully studied.

1.4 Objectives

The purpose of this thesis is to answer the two following questions:

- How much does Flue Gas Desulfurization (FGD) cost?
- How well do scrubbers work?

A journalist of the Boston Globe estimated that the adoption of FGD would add $4 to the average monthly home utility bill. However this quick answer might not be valid. For instance, four different processes have been adopted by the utilities: limestone, lime, dual alkali, and sodium carbonate scrubbing processes. Which one is the cheapest? Moreover, some of these FGD processes are installed on new plants whereas some are installed on old plants and are called retrofit. Is there a difference in cost between the new and retrofit FGD systems?

The answer to these questions will interest the utility manager who is obliged to install this FGD technology on his plant. The answer must not be ignored by the policy analyst and the legislator. It represents the first part of a cost-benefit analysis they have to make before making any decision. The contractors and designers are eager to sell their scrubbers and emphasize their high reliability. The utility engineers, confronted with the day to day problems of plugging and corrosion have a different opinion.

The following cost and functional analysis of both new and retrofit installations should provide some valuable information on the future application of FGD systems.

1.5 Method of Approach

The methods used to answer these questions are statistical, economic and financial. A group of 26 plants which operated FGD technology for at least five years and which have a generating capacity of at least 50 MW were studied. Statistics (weighted averages and variances) were used as a tool for the cost and functional analysis.

Capital costs and annual costs were calculated for each of these 26 plants then combined into a net present value which allows a better comparison between new and retrofit FGD systems.

The functional anlaysis is based on different viability indexes. The most important index is defined as the ratio of the number of FGD hours over the number of boiler hours and is called the operability. This index is useful to draw the average cost curve which links the annual cost with the quantity of sulfur removed per kWh. An operability limit, defined as the minimum level of operability necessary to meet the standards, first indicates how necessary the scrubber is and then how well it works.

In order to use the above methods the accounting reports and functional reports of the utilities are needed. These data have been collected by an EPA contractor, PEDCo Env., on a computerized data base system, available through NTIS. The information provided for this thesis comes from a report which summarizes the data from the data base. (Bruck et. al., 1981 and 1982)

2 TECHNICAL BACKGROUND

2.1 Introduction

In order to show the importance of the Flue Gas Desulfurization in the United States, Section 2.2 describes FGD growth trends. The four sections following contain a technical description of the four main FGD processes later compared in the economic and functional analysis. These processes are the limestone, lime, dual alkali and sodium carbonate scrubbing processes.

Each of the sections in this chapter contains a description of a FGD process, the chemistry involved and the equipment components. At the end of each section a short summary list the main technical advantages and disadvantages. Later in Section 3 and 4 an economic and functional comparison is made.

2.2 FGD Growth Trends

Table 2.1 summarizes the status of flue gas desulfurization (FGD) systems in the United States at the end of June 1982. (Bruck *et. al.*, 1982) A system is defined on the basis of inlet gas ducting configuration. A module or several modules that are commonly ducted to one or more boilers comprise a single system. Thus, a single FGD module that treats flue gas from only one boiler is considered a system, just as multiple FGD connected through a common duct to multiple boilers are considered one system. On the other hand, a plant that has several boilers ducted to a number of distinct modules or group of modules without any common ducting between them is considered to have two or more separate FGD systems.

Table 2.1: Number and Total Capacity of FGD Systems (June 1982)

Status	No. of Units	Total Controlled Capacity MW (a)	Equivalent Scrubbed Capacity MW (b)
Operational	96	36,744	33,254
Under Construction	43	19,228	18.742
Planned:			
Contract Awarded	19	12,348	12,235
Letter of Intent	8	6,560	6,560
Requesting/ Evaluating Bids	11	6,275	6,275
Long-term Planning	44	25,841	25,513
Total	221	106,996	102,579

a. Summation of the grossunit capacities (MW) brought into compliance by the use of FGD systems regardless of the percentage of the flue gas scrubbed by the FGD systems.

b. Summation of the effective scrubbed flue gas in equivalent MW based on the percentage of flue gas scrubbed by the FGD systems.

Current projections indicate that the total power generating capacity of the US electric utility industry will be approximately 831 GW by the end of 1999. (This value reflects the annual loss resulting from the retirement of older units, which is considered to be 0.4% of the average generating capacity at the end of each year. [U.S. Department of Energy, 1980]) Approximately 373 GW or 45% of the 1999 total will come from coal fired units. The distribution of present (December 1980) and future (December 1999) power generation sources is shown in Table 2.2.

Table 2.2: Power Generation Sources: Present and Future

	Coal	Nuclear	Oil	Hydro	Gas	Other	Total GW
December 1980	41%	10%	24%	12%	12%	1%	616
December 1999	45%	15%	19%	11%	9%	1%	831

Based on the utilities' known commitments to FGD (as presented in Table 2.1), the current and projected percentages of electrical generating capacity controlled by FGD are shown in Table 2.3.

In light of the revised New Source Performance Standards of the Clean Air Act Amendments of 1977, actual FGD control is expected to be greater than that reflected by the figures in Table 3. For example, about 50 to 60 systems (representing approximately 29,000 to 31,000 MW of generating capacity) fall into the uncommitted category. These systems cannot be

Table 2.3: FGD Controlled Generating Capacity: Present and Future

	Coal-Fired Generating Capacity Controlled by FGD, %	Total Generating Capacity Controlled by FGD, %
June 1982 (a)	14.5	5.9
December 1999	28.6	13.1

a. The number of committed FGD systems as of June 1982; however, the figure used for the total generating capacity and coal-fired generating capacity is based on the available December 1980 figures.

included in the committed group at this time because information regarding their status is not ready for public release.

To show general FGD usage and projected usage trends, Table 2.4 gives both a current (June 1982) and projected (December 1999) breakdown of throwaway product systems versus salable product systems as a percentage of the total known commitments to FGD as of the end of the second quarter 1982. (Berman, 1981)

It appears from Table 2.4 that the lime and limestone processes are the main ones. The dual alkali and sodium carbonate processes have also some importance ans since these four processes will appear in the second part, they will be studied in the four following sections. A qualitative comparison will be then possible. A quantitative comparison will be

Table 2.4: Summary of FGD Systems by Process (percentage of total MW)

Process	Byproduct	June 1982	December 1999
Throwaway Product Process			
Wet systems			
lime		38.0	24.4
limestone		45.6	51.9
Dual Alkali		3.6	3.0
Sodium Carbonate		3.8	4.2
Dry Systems			
Lime		0.3	5.6
Lime/Sodium Carbonate		0.3	0.1
Sodium Carbonate		1.3	0.6
Salable Product Process	Byproduct	June 1982	December 1999
Aqueous Carbonate/ Spray drying	Elemental Sulfur	0.3	4.8
Citrate	Elemental Sulfur	0.2	0.1
Lime	Gypsum		0.1
Limestone	Gypsum		0.6
Lime/Limestone	Gypsum		1.0
Magnesium oxide	Sulfuric Acid	0.7	1.0
Wellman Lord	Sulfuric Acid	2.8	2.0
Wellman Lord	Elemental Sulfur	3.1	0.6
Total		100.0	100.0

later detailed in part two.

2.3 Limestone Scrubbing

2.3.1 Process Description (Princiotta *et. al.*, 1979)

The principles of all limestone scrubbing systems are essentially the same. When the limestone-water slurry comes in contact with flue gas containing SO_2, the SO_2 is absorbed into the slurry and reacts with the limestone to form an insoluble sludge. The by-products include gypsum ($CaSO_4$, $2H_2O$) and calcium sulfite hemihydrate ($CaSO_3$, $1/2\ H_2O$). These sludge by products are generally disposed of in a pond. Figure 2.1 is an example of a flow diagram of a 500 MW coal-fired boiler with a limestone/sludge FGD system.

2.3.2 Process Chemistry

The overall reactions that take place in the absorber are:

$$SO_2 + CaCO_3 \longrightarrow CaSO_3 + CO_2 \quad (1)$$

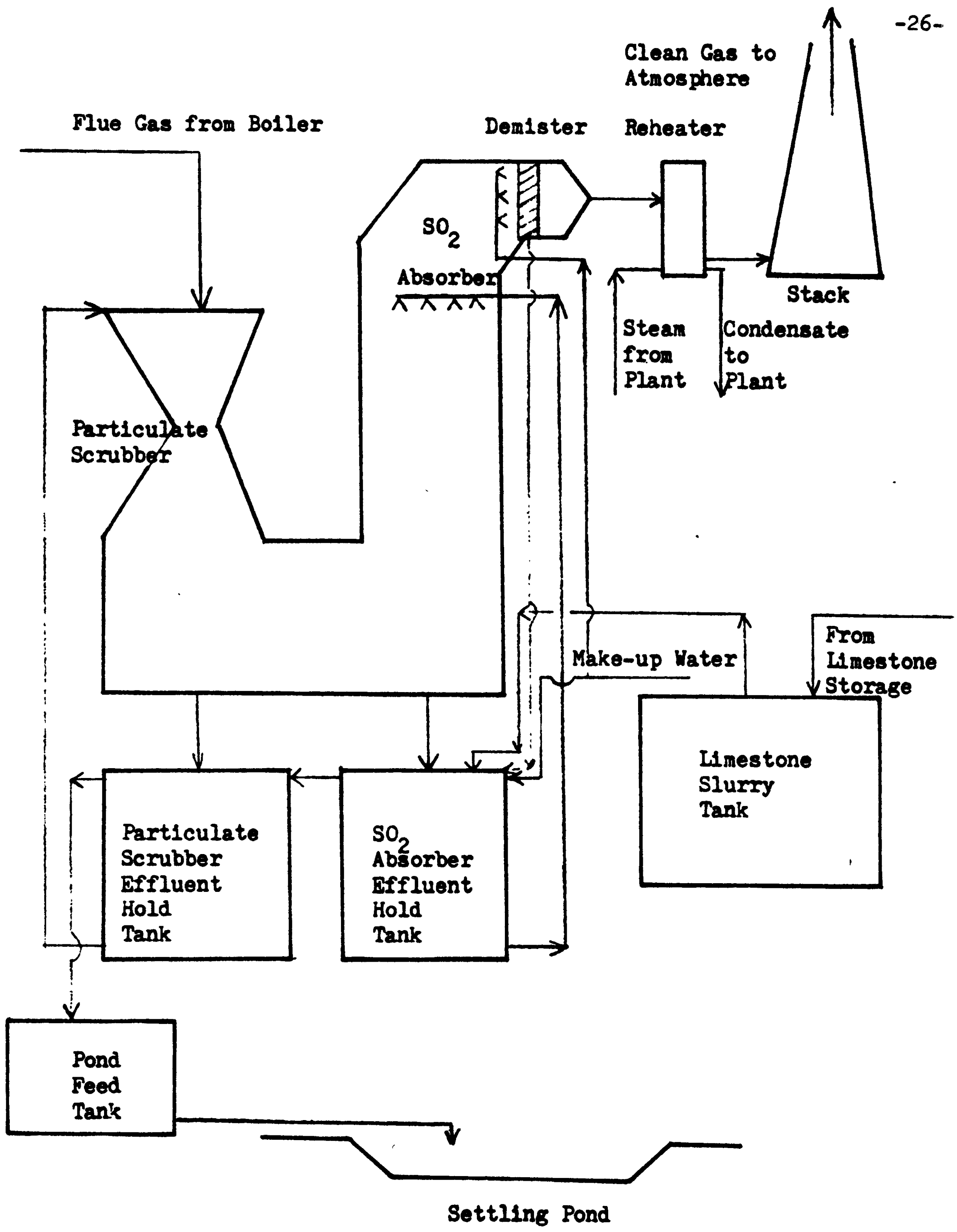
$$SO_3 + CaCO_3 \longrightarrow CaSO_4 + CO_2 \quad (2)$$

Many intermediate steps also take place, however. The calcium ion is formed during slurry preparation:

$$CaCO_3 + H_2O \longrightarrow Ca^{++} + HCO_3^- + OH^- \quad (3)$$

The SO_3 anion forms at the flue gas-slurry interface in the absorber.

$$SO_2 + H_2O \longrightarrow H_2SO_3 \longrightarrow SO_3^{--} + 2H^+ \quad (4)$$



Coal-Fired Boiler and Limestone Sludge FGD System

TVA 8 Widows Creek

Figure 2.1

The sulfite ion (SO_3^{--}) then combines with the cacium ion (Ca^{++}) to form the precipitate calcium sulfite hemihydrate:

$$Ca^{++} + SO_3^{--} + 1/2\ H_2O \longrightarrow CaSO_3 \cdot 1/2\ H_2O \qquad (5)$$

Gypsum, an additional precipitate, is formed as follows:

$$SO_3^{--} + 1/2\ O_2 \longrightarrow SO_4^{--} \qquad (6)$$

$$Ca^{++} + SO_4^{--} + 2H_2O \longrightarrow CaSO_4 \cdot 2H_2O \qquad (7)$$

As reactions 6 and 7 proceed, the calcium cation is depleted from solution and additional $CaCO_3$ dissolves to react with the sulfite ion. In a limestone sludge system, by-products occur from both reactions 6 and 7.

According to the molecular weights of limestone and SO_2 the theoretical requirement is 1 mol of limestone per mole of SO_2 removed. If a 20% excess stoichiometric amount and 95% purity of limestone are assumed, actual limestone required is 1.97 kg/kg of SO_2.

Dry sludge generated in the limestone process consists of calcium sulfite hemihydrate, carbonates, fly ash, and gypsum. Unused limestone and limestone impurities also combine with the sludge. The exact proportions of calcium sulfite hemihydrate and gypsum depend on system design; but if equal proportions are assumed, the sludge generated is 2.76 kg/kg of SO_2. When a venturi scrubber removes particulate matter, the particulates thus removed are also combined with the sludge. The final sludge to be disposed contains at least 20% water.

For instance, the projected mass flow rates of wastes for a 500 MW power plant assumed to have a 30 year lifetime of 117,500 operating hours and to operate 6,000 hours in the first year are shown below:
(The fuel is a 3.5% sulfur, 16% ash, 5830 kcal/kg high heat rate bituminous coal.)

Component	Kilograms per hour
$CaSo_3 \cdot 1/2H_2O$	16,550
$CaSO_4 \cdot 2\ H_2O$	5,670
$CaCO_3$	6,448
$CaCl_2$	433
Mg	39
Fly ash	149
Inerts	1,236
Total	30,525

The sludge disposal pond requires approximately 123 ha (305 acres) and is designed for an optimum depth of approximately 6.1 m (20ft.).

2.3.3 Description of Equipment Components

a. Primary Particulate Removal

The venturi scrubber is the first unit in most limestone FGD systems. This unit scrubs particulate from the gas; however, some SO_2 removal also occurs. The venturi scrubber has an advantage over an electrostatic precipitator (ESP) for particulate removal because the venturi cools and humidifies the flue gases before they enter the absorber section. A flue-gas cooler and humidifier must be used in connection with an ESP to cool the flue gases, generally to 50^0 C, prior to absorption. Moreover, if particulate is removed before the absorber, corrosion problems are reduced. Booster fans are sometimes installed in series with the venturi to provide the power necessary to force the gas through the scrubber system.

b. SO_2 Absorber

The absorber is the primary SO_2 removal unit in the system. Each of the many available designs employs a different method to contact the flue gas with the slurry. The most common unit designs include fixed packing, mobile-bed packing (hollow or solid spheres), and horizontal or vertical spray towers. Although each unit performs differently, identical parameters have the same general effect on performance. Because of its simplicity, however, the spray tower is gaining popularity.

The scrubber must be constructed of materials that resist corrosion, erosion and scaling. Scrubber bodies are fabricated of stainless steel or mild steel lined with an acid resistant coating such as fiber glass reinforced polyester (FRP), rubber or glass flake. Scrubber internals are made of a variety of materials such as stainless steel, which has a tendancy to pit; high nickel alloys, which are expensive; or FRP, which is fragile. No one material seems to stand above the others.

The size and number of modules in a scrubber system are directly related to boiler size, turndown (reduction in boiler output) requirements, system availability, and gas liquid distribution. Boiler system loads fluctuate, and the srubber system must change to maintain optimum scrubber performance. One method of adjusting to turndown is to shut down scrubber modules as the load decreases. The more modules in the system, the smoother the transition. Scrubber modules not being used can be scheduled for cleaning and maintenance during periods of low system load, thereby reducing overall scrubber downtime. The use of multiple modules also has the advantage of permitting the modules to be smaller. Smaller cross sectional areas in the scrubber module promote uniform gas liquid distribution and improve efficiency. Scrubber module sizes range from about 25 to 200 MW.

c. Demister

A demister is necessary to remove entrained droplets from the scrubber outlet gas to reduce downstream equipment corrosion and scaling and to reduce reheat requirements. Most of the droplets are large enough to be removed with a simple change in flue gas direction; this is provided by baffles. Two banks of demisters are usually sufficient, but more can be added for additional demisting capability. Demisters are also installed to reduce this tendency, and materials of construction must be carefully selected.

d. Reheater

Reheating of stack gas is generally necessary to increase the kinetics of the reactions described in Section 2.3.2 and to reduce downstream corrosion. Thus, reheat not only helps meet ambient air standards, it also protects downstream equipment and prevent formation of acid mist. Reheating can be accomplished by installing a gas or low sulfur oil burner that exhausts directly into the stack, or by-passing some hot flue gas around the FGD system directly into the stack. (increasing emissions of SO_2) In-line heat exchangers are the most popular because of their low initial capital cost, but they tend to corrode and scale. Soot blowers, better demisters, and better materials of construction reduce these problems.

e. Slurry Makeup

Limestone can be received in a crushed and milled state or can be crushed and milled on site. In the latter case, the limestone is ground (wet or dry) in a ball mill to a size not larger than 200-mesh and often finer than 325-mesh. Finer grinding reduces the amount of limestone that remains unreacted and would otherwise be disposed of in the sludge. Water is added until the solids content reaches 15 to 25%. The slurry is then sent to a feed tank and to an absorber holding tank where it is mixed with aborber effluent. The slurry from the absorber holding tank is pumped to the absorber, where it reacts with SO_2 in the flue gas and is then returned to the holding tank. Slurry from the absorber holding tank is pumped to the venturi holding tank and from there to the venturi to scrub out fly ash. The slurry containing the fly ash returns to the venturi holding tank, from which it is pumped to the sludge disposal area for final treatment.

f. Sludge Disposal

Sludge disposal can require 200,000 m^2 at a small plant and as much as 4,000,000 m^2 at a large plant. Disposal practices are very site specific. A power plant in an arid location might pump the sludge into an unlined pond, allowing the water to evaporate or seep into the ground. In an area where surface runoff or leaching could be a problem, the sludge sometimes is dewatered before being pumped into a lined pond. The water is returned to the system or purged after treatment to reduce chloride ions in the slurry.

2.3.4 Advantages and Disadvantages

The process is well developed chemically, but mechanical problems are still encountered in certain facilities as described in sections 4 and 5. These problems include: fan vibration; pump and pipe erosion; scale buildup in the scrubber, demister and reheat sections; potential pollution in openwater systems; and corrosion and erosion.

The system operates well on large boilers. On small systems with low operating factors, labor and capital charges can be a limiting factor. Strict solid waste and water regulations either in force or imminent could necessitate more careful consideration of sludge disposal approaches. It may be necessary to incorporate an oxidation step to produce acceptable materials for landfill disposal. The advantages of the limestone/sludge systems can be summarized as follows:

(1) The basic process is fairly simple and has few process steps.

(2) The reserves of limestone are fairly abundant.

(3) SO_2 removal efficiencies can be as high as 95%.

(4) The two-stage treatment of flue gases permits removal of SO_2 and particulates.

(5) Many years of operating experience have led to a greater understanding of the basic principles of this process.

(6) Fly ash does not adversely affect the system.

The disadvantages of the limestone/sludge systems are as follows:

(1) Large quantities of waste must be disposed of in an acceptable manner.

(2) If not designed carefully or operated attentively, limestone systems

have a tendency toward chemical scaling, plugging, and erosion which can frequently halt its operation.

(3) The scrubber requires high liquid-to-gas (L/G) ratios necessating large pumps with attendant electrical requirements.

(4) The sludge may have poor settling properties when it has high sulfite content. Forced oxidation or soluble Mg in the slurry have been shown to lower sulfite content.

2.4 Lime Scrubbing

2.4.1 Process Description (Haug et. al., 1979)

The principles of all lime scrubbing systems are essentially the same as the limestone scrubbing systems described in Section 2.3.1. Figure 2.2 is an example of a flow diagram of a 2000 MW coal-fired boiler with a lime/sludge FGD system.

2.4.2 Process Chemistry

The overall reactions that take place in the absorber are:

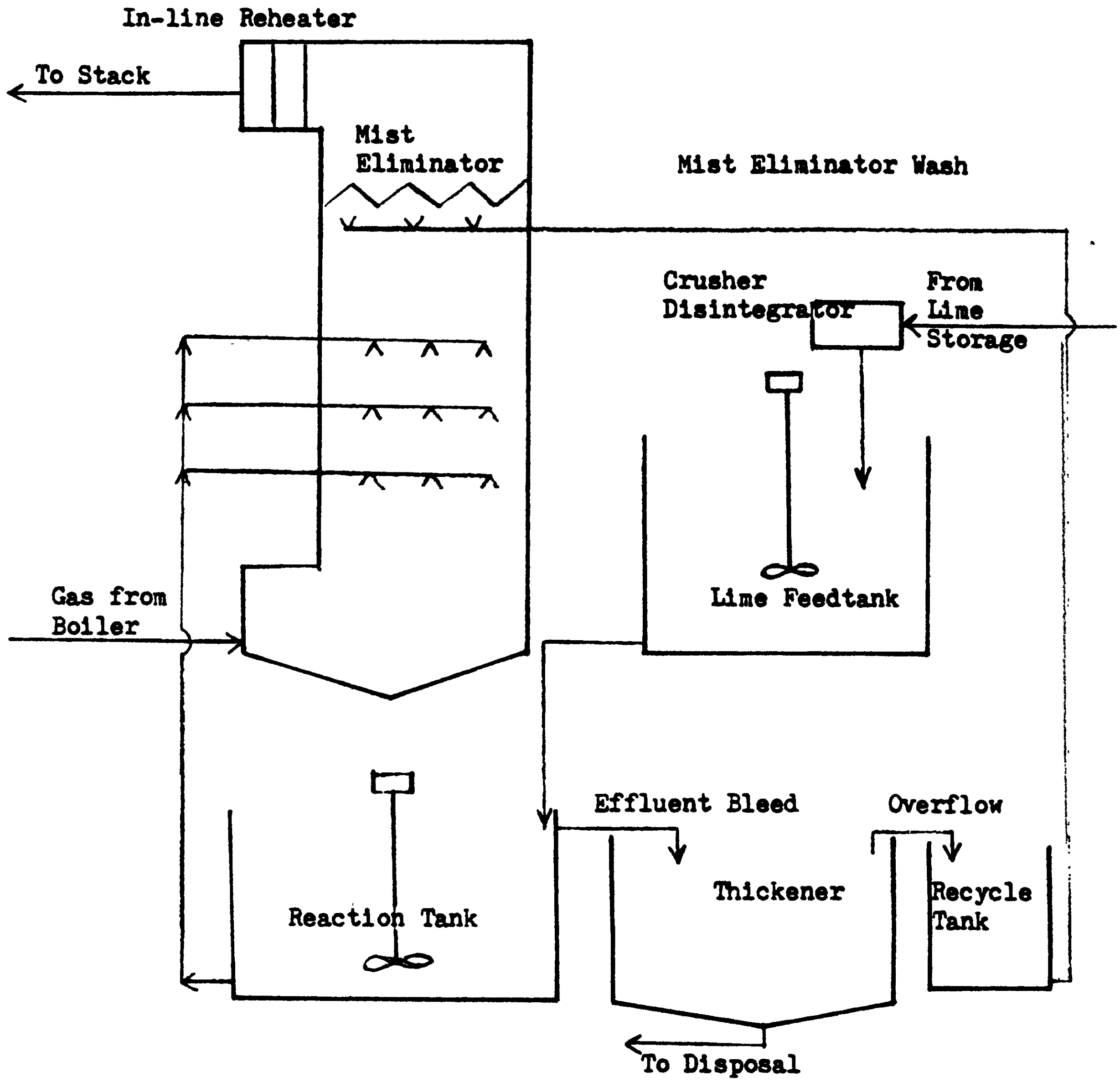
$$CaO + H_2O \longrightarrow Ca(OH)_2 \quad (1)$$

$$Ca(OH)_2 + SO_2 \longrightarrow CaSO_3 + H_2O \quad (2)$$

$$CaSO_3 + SO_2 + H_2O \longrightarrow Ca(HSO_3)_2 \quad (3)$$

$$Ca(HSO_3)_2 + Ca(OH)_2 \longrightarrow 2CaSO_3 + 2H_2O \quad (4)$$

Sulfate formation (detrimental), scaling:



Coal-Fired Boiler and Lime Sludge FGD System

Cane Run 5

Figure 2.2

$$2CaSO_3 + O_2 \longrightarrow 2CaSO_4 \qquad (5)$$

Scrubbing liquor is a slurried mixture of calcium hydroxide and calcium sulfite in water. The pH of slurry entering the scrubber is 8 to 10. Low pH can cause gypsum scaling whereas high pH can cause formation of carbonates. The presence of MgO in the lime allows a subsaturated mode of operation and improves the SO_2 removal efficiency.

The reaction with SO_2 in the flue gas takes place in the liquid phase. The dissolution of calcium sulfite is the rate controlling step for SO_2 absorption. In other cases the mass transfer through the interface between gas and liquid is the rate controlling step.

2.4.3 Description of Equipment Components

The equipment components are similar to those described for the limestone scrubbing process.

2.4.4 Advantages and Disadvantages

Generally inexpensive lime can be provided to the FGD plants and, as far as available, carbide sludge from chemical industry or alkaline fly ash can be utilized as scrubbing agent. The lime scrubbing technology is well developed. Current R&D efforts aim at the following chemical, mechanical and design areas:

- Precipitation of calcium sulfate (gypsum) may cause scaling, which is particularly unwanted in mist eliminators.

- Dissolved salts in the scrubbing agent and chloride built-up in the recycle water can cause corrosion, which is possibly aggravated by the erosive nature of the slurry.
- Pumps, fans and agitators allow mechanical improvements as to their use in this technology.
- Interrelated mechanical and chemical factors may influence the lifetime of expansion joints and piping.
- Finally the optimization of the design parameters like gas flow and slurry distribution, liqid-to-gas ratio, control instrumentation and accessibility for maintenance has to be mentioned.

The advantages of the lime scrubbing system are similar to those listed for the limestone scrubbing process.

The disadvantages are also similar to those listed for the limestone scrubbing process. In addition, although fly ash does not adversely affect the process in general it can adversely affect the process by intensification of mechanical wear and erosion in the washing cycle and by increased load of the thickener.

2.5 Dual Alkali Scrubbing

2.5.1 Process Description (Kaplan, 1979)

As in the limestone slurry system, dual-alkali processes dispose of removed SO_2 as throwaway calcium sludge. Unlike limestone, however, absorption of SO_2 and production of disposable waste are separated; the addition of limestone or lime occuring outside the scrubber loop. The scrubbing step uses an aqueous solution of soluble alkali. The absorption reaction depends on gas/liquid chemical equilibrium and mass transfer rates of sulfur oxides (SO_x) from flue gas to scrubbing liquid instead of limestone dissolution, the limiting factor in limestone scrubbing.

Therefore, SO_x absorption efficiency in a double-alkali system is potentially higher than in a limestone system with the same physical dimensions and liquid-to-gas (L/G) flow rates. Scaling and plugging in the absorption area are reduced because calcium slurry is confined to the regeneration and disposal loop and soluble calcium is minimized in the scrubber liquor. Figure 2.3 is an example of a flow diagram of a 125 MW coal-fired boiler with a dual-alkali scrubbing FGD system.

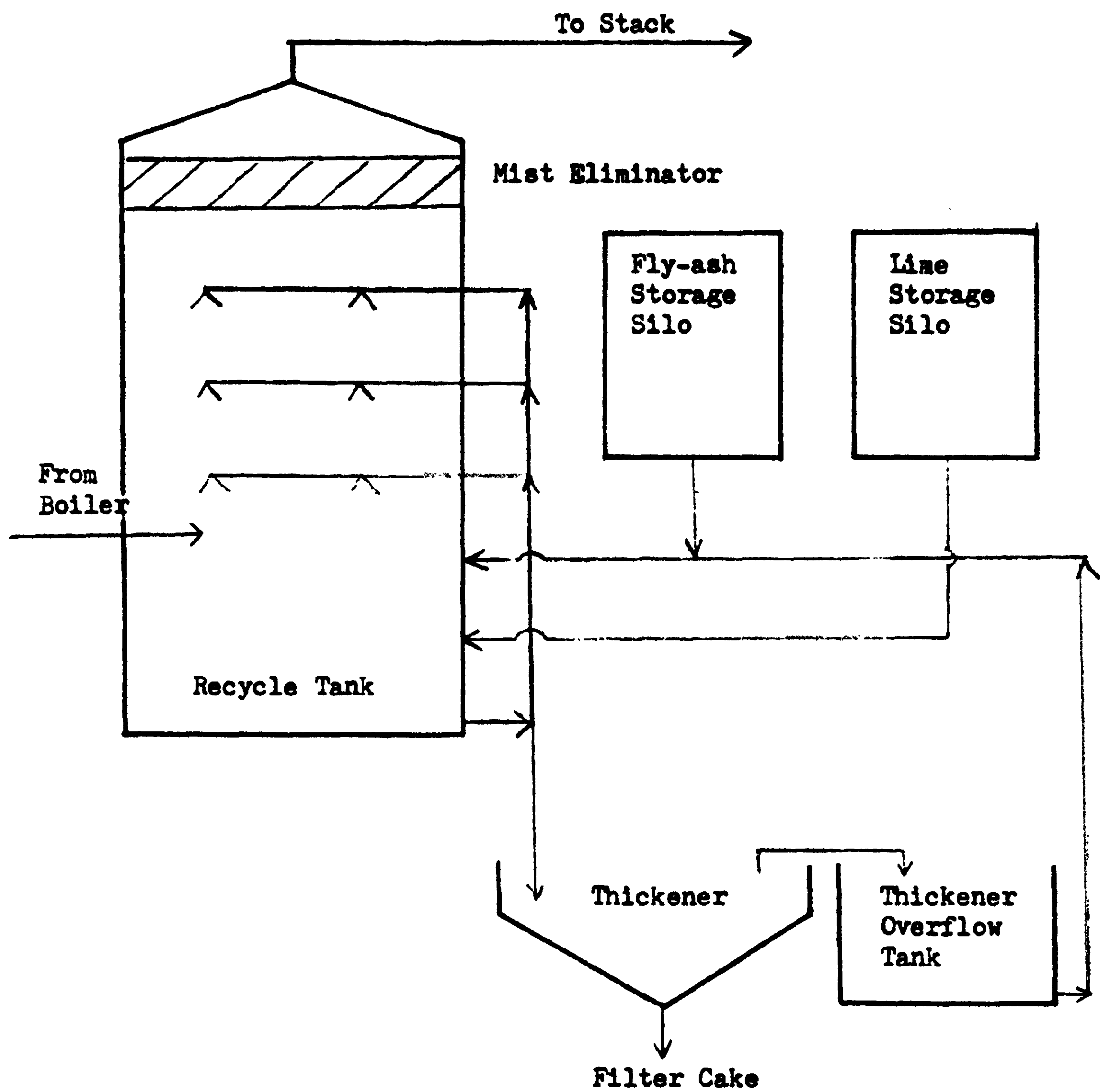
2.5.2 Process Chemistry

Technically, the use of any combination of alkaline compounds, organic or inorganic, for SO_2 removal and disposal can be classified as a dual-alkali process. The process described in this section is a sodium sulfite absorbent-lime reactant system.

Sodium sulfite in solution absorbs SO_2 in the scrubbing step represented by equation (1):

$$SO_3^{--} + SO_2 + H_2O \longrightarrow 2HSO_3^{-} \qquad (1)$$

Sodium hydroxide formed in the regeneration step and sodium carbonate added as solution makeup react with SO_2 as shown below. The absorption reactions actually involve reaction of SO_2 with an aqueous base such as sulfite,



<u>**Coal-Fired Boiler and Dual Alkali FGD System**</u>

<u>**Milton R Young 2**</u>

<u>**Figure 2.3**</u>

hydroxide, or carbonate rather than sodium ion which is present only to maintain electrical neutrality.

$$2OH^- + SO_2 \longrightarrow SO_3^{--} + H_2O \qquad (2)$$

$$CO_3^{--} + SO_2 \longrightarrow SO_3^{--} + CO_2 \qquad (3)$$

The use of lime for regeneration allows the system to be operated over a wider pH range which in turn included the complete range of active alkali hydroxide/sulfite /bisulfite. Limestone regeneration operates only in the sulfite/bisulfite range.

$$Ca(OH)_2 + 2HSO_3^- \longrightarrow SO_3^{--} + CaSO_3 \cdot 1/2\ H_2O + 3/2\ H_2O \qquad (4)$$

$$Ca(OH)_2 + SO_3^{--} + 1/2\ H_2O \longrightarrow 2OH^- + CaSO_3 \cdot 1/2\ H_2O \qquad (5)$$

$$Ca(OH)_2 + SO_4^{--} \longrightarrow 2OH^- + CaSO_4 \qquad (6)$$

$$Ca(OH)_2 + SO_4^{--} + 2H_2O \longrightarrow 2OH^- + CaSO_4 \cdot 2H_2O \qquad (7)$$

Total oxididizable sulfur (TOS) is the total concentration of sulfite and bisulfite in solution. Oxidation of TOS to sulfate may occur in any part of the system and is affected by composition of the scrubbing liquor, oxygen content of the flue gas, impurities in the lime, and design of the equipment.

$$SO_3^{--} + 1/2\ O_2 \Longrightarrow SO_4^{--} \qquad (8)$$

$$HSO_3^- + 1/2\ O_2 \Longrightarrow SO_4^{--} + H^+ \qquad (9)$$

The sum of concentrations of NaOH, Na_2CO_3, $NaHCO_3$, Na_2SO_3 and $NaHSO_3$ in the scrubbing solution is termed active alkali. The active alkali concentration in a system can be dilute or concentrated; a concentrated mode (active concentration of sodium greater than 0.15 M) was chosen for this discussion. In this mode high sulfite levels prevent the precipitation of calcium sulfate ($CaSO_4$) as gypsum ($CaSO_4 \cdot 2H_2O$), equation 7. However, $CaSO_4$ is precipitated along with calcium sulfite ($CaSO_3 \cdot 1/2$

H_2O) as shown in equations 4-6. In this way the system can keep up with sulfite oxidation at the rate of 25 to 30% of the SO_2 absorbed without becoming saturated with $CaSO_4$. Usually, soluble calcium levels are less than 100 ppm in the regenerated liquor of a concentrated mode dual-alkali process.

2.5.3 Description of Equipment Components

The dual-alkali process has been divided into the following operating areas:

- Materials Handling. This area includes facilities for receiving pebble lime from an across-the-fence limestone calcination plant, lime storage silo, and in-process storage for supply to the slakers. Soda ash storage is also provided.
- Feed Preparation. Included in this area are two parallel slaking systems and the facilities for dissolving makeup soda ash in water before feeding to the absorption system.
- Gas Handling. Fan location and duct configuration are the same as in the limestone scrubbing process.
- SO_2 Absorption Four tray tower absorbers with presaturators, recirculation tanks, and pumps are included.
- Stack Gas Reheat. Equipment in this area includes indirect steam reheaters and soot blowers for the coal variations.
- Reaction. Reaction tanks with agitators and pumps are provided in this area.

- Solids Separation. Separation of calcium salts is accomplished by thickener and filters.
- Solids Disposal. Filter cake is reslurried in this area and purged to the disposal pond. A pond return pump is included.

2.5.4 Advantages and Disadvantages

System reliability can be adversely affected by two classes of problems: mechanical and chemical.

Mechanical problems include malfunction of instrumentation and mechanical and electrical equipment such as pumps, filters, centrifuges, and valves. These problems in a commercial FGD system can be minimized by careful selection of materials of construction and equipment and by providing spares for equipment items such as pumps and motors which are expected to be in continuous operation.

Chemical problems which may be associated with a dual-alkali system include scaling, production of poor-settling solid waste product, excessive sulfate buildup, water balance, and buildup of nonsulfur solubles which enter the system as impurities in the coal or lime.

One of the primary reasons for development of dual-alkali processess was to circumvent the scaling problems associated with lime/limestone wet scrubbing systems. Since scrubbing in dual-akali systems employs a clear solution rather than a slurry, there is a tendency to ignore potential scaling problems. However testing experience has indicated that scaling can occur and be particularly troublesome since the flue gas path through the scrubber can shut down the boiler/scrubber system and lower reliability.

2.6 Sodium Carbonate Scrubbing

2.6.1 Process Description (Slack et. al., 1975)

The sodium carbonate method is shown in figure 2.4. Addition of Na_2CO_3 to the thickener precipitates enough calcium to keep the calcium content of the liquor to the scrubber well on the safe side of saturation (about 100 ppm below saturation). It is expected that the Na_2CO_3 makeup requirement will be at least very high because of losses in the filter cake.

2.6.2 Process Chemistry

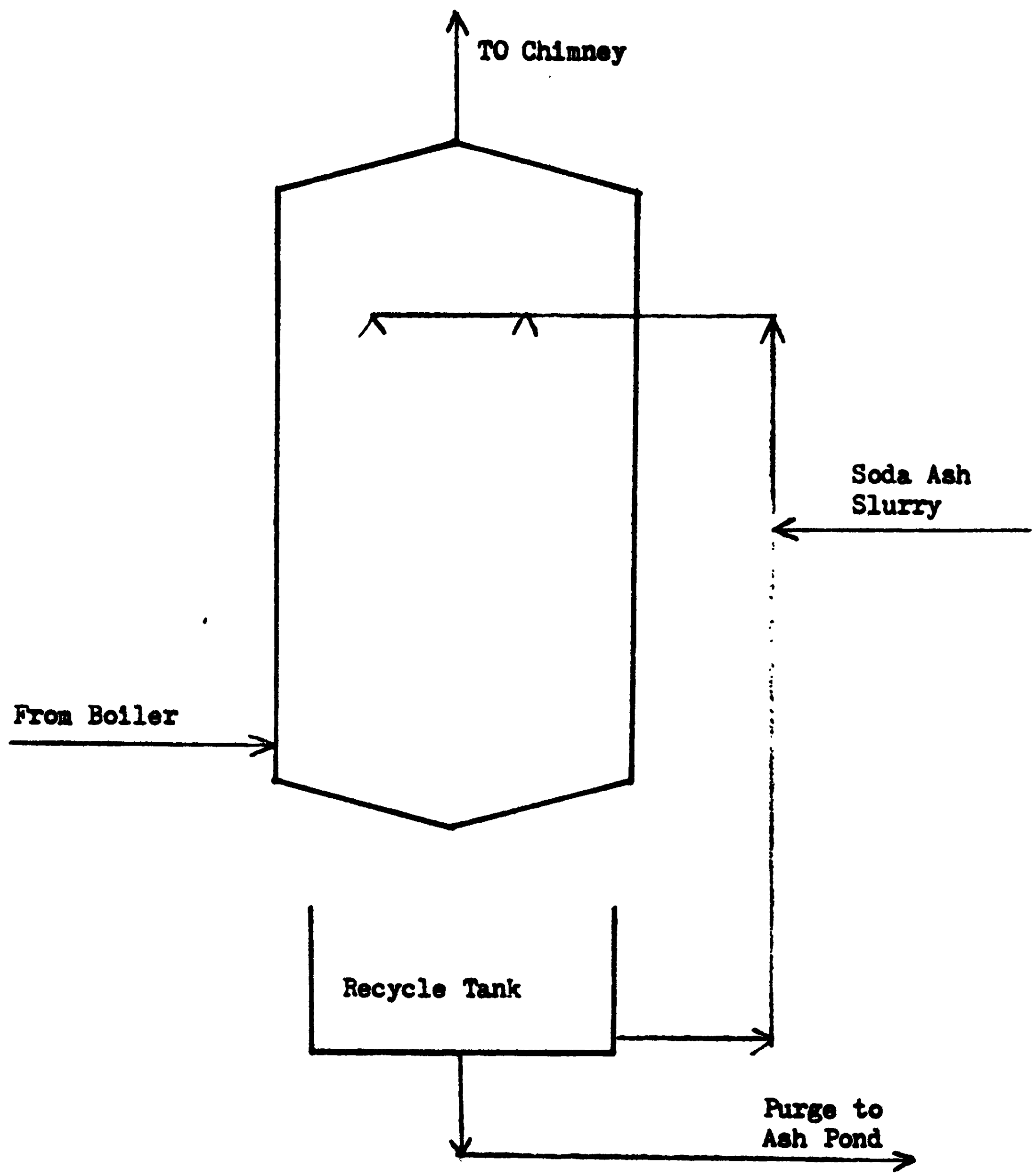
In the absorption section, absorption of SO_2 in sodium sulfite solution produces a bisulfite scrubber effluent solution according to the overall reaction:

$$Na_2SO_3 + SO_2 + H_2O \longrightarrow 2NaHSO_3 \qquad (1)$$

The sodium carbonate used as sodium makeup to the system forms sodium sulfite in the scrubber:

$$Na_2CO_3 + SO_2 \longrightarrow Na_2SO_3 + CO_2 \qquad (2)$$

The absorber feed solution will also contain sodium sulfate in solution and may contain some sodium bisulfite if neutralization is not completed in the regneration section. The sulfate is formed in the scrubber by reaction of



Coal-Fired Boiler and Sodium Carbonate FGD System

Reid Gardner 1,2 & 3

Figure 2.4

sulfite with oxigen in the flue gas:

$$2Na_2SO_3 + O_2 \longrightarrow 2Na_2SO_4 \qquad (3)$$

The rate of oxidation is a function of the absorber design, oxigen concentration in the flue gas, flue gas temperature, and the nature and concentration of the species in the scrubbing solution. As an example, for flue gas containing about 4 to 5% O_2 and 2,500 ppm SO_2, approximately 10% of the SO_2 removed from the flue gas will normally be oxidized to sulfate. The neutralization goes to completion with lime:

$$Na_2SO_3 + Ca(OH)_2 \longrightarrow 2NaOH + CaSO_3 \qquad (4)$$

The usual form of calcium sulfite produced is the Hemihydrate, $CaSO_3 \cdot 1/2\, H_2O$. Some sulfate is also precipitated, the amount depending on the sulfite and sulfate concentration and on pH.

2.6.3 Description of Equipment Components

The equipment components are similar to those decribed for the limestone scrubbing process.

2.6.4 Advantages and Disadvantages

The main drawback is that the sulfate formed incidentally by oxidation in the scrubber and in other parts of the system is more difficult to regenerate than when other absorbents are used. Much of the research in the area is concerned with this problem.

3 COST ANALYSIS OF PROVEN PGD

3.1 Introduction

The cost of Flue Gas Desulfurization (FGD) systems is an area of intense interest and substantial controversy. Few realistic cost figures have been established.

In section 2, the main FGD processes were described by looking at different technical advantages and disadvantages. However, these differences were not translated into actual dollar figures.

The following economic analysis considers the FGD systems whose commercial start-up occurred before the end of 1977. At least four years (78,79,80,81) of data about these devices are available. Devices that have been in use this long are referred to as proven FGD. The FGD systems are not pilots and are installed on relatively large scale plants, units of at least 50 MW. The processes used by these systems are the four processes described in section 2.

Section 3.2 contains an overview of the proposed methodology with emphasis on the data collection, the cost elements description and the cost adjustment procedure.

In section 3.3, the results obtained by applying this methodology are shown. The four main processes used by systems installed on either old or new plants are compared. Their capital and annual costs and their energy consumptions are analyzed. Then the impact of these costs on the consumer and the producer is studied. Finally, in the conclusion, a comparison is made with another FGD cost analysis.

3.2 Description of the methodology

3.1.1 Collection of the data

The reported figures are acquired from various sources. The most reliable information was obtained from a previous cost study initiated by PEDCo Environmental in March 1978. (Devitt et. al., 1980) In this first study each utility with at least one operational FGD system was given a cost form containing all available cost information then in the PEDCo files.

The utility was asked to verify the data and fill in any missing information. The PEDCo Environmental staff made a follow-up visit to complete and verify the data collected.

Some costs were also taken from FGD cost survey questionnaires developed by Edison Electric Institute (EEI). The EEI forms contain useful capital cost information, however, in some cases the costs were projections rather than actual dollar expenditures.

In addition to the sources just mentioned some 1978 and 1979 annual costs were made available by a few utilities via written transmittals and telephone communications.

3.2.2 Description of Cost Elements

Capital costs, expressed in \$/kW, consist of direct costs, indirect costs and other capital costs. Direct costs include the cost of the equipment (scrubber, pump, fan,...), the cost of installation (piping, instrumentation) and the site development (construction of access roads, truck facilities,...). Indirect costs include interest during construction, contractor's fees and expenses, engineering, legal expenses, taxes, insurance, allowance for start-up and shakedown and spares. Other capital costs include contingency costs (malfunctions, equipment alterations, unforeseen sources), land for waste disposal and working capital (amount of money invested in raw materials and supplies in stock).

Annual costs, expressed in mills/kWh, consist of direct costs, fixed costs and overhead costs. Direct costs include the cost of raw materials (lime, limestone,...) utilities (water, electricity,...), operating labor and supervision and maintenance and repairs. Fixed costs include those of depreciation, interim replacement, insurance, taxes and interest on borrowed capital. Overhead costs include those of plant and payroll expenses. Although they are not charged directly to a particular part of a project like FGD, they are allocated to it.

3.2.3 Cost Adjustment Procedure

In order to compare the FGD systems on a common basis, the following cost adjustments were made:

1. All capital costs are adjusted to 1981 dollars, using the escalation factors shown in Table 3.1. Actual costs were reported by utilities in dollar values since the start up date. The total figure is broken down into dollars per year and each year total is escalated to 1981 dollars and totaled again.

2. Particulate control costs are deducted. Since the purpose of the

study is to estimate the incremental cost for sulfur dioxide control, particulate control costs are deducted using either data contained in the costs breakdowns or as a percentage of the total direct cost, capital and annual.

3. All non-labor annual costs are adjusted to a common 65% capacity factor, assuming a continuous operation of 8,760 hours.

4. Sludge disposal costs are adjusted to reflect the costs of sulfur dioxide waste disposal only (i.e., excluding fly ash disposal except where usable as a sludge stabilizing agent) and to provide for disposal over the anticipated lifetime of the FGD system. This latter correction is necessary since several utilities reported costs for sludge disposal capacity that would last only a fraction of the FGD system life. The adjustments are based on a land cost of $2000/acre with a sludge depth of 50 ft in a clay lined pond (clay is assumed to be available at the site).

5. A 30 year life, value recognized by the National Power Survey of the Federal Power Commission, is assumed for all new systems that were installed for the life of the unit.

A 20 year life is assumed for retrofit systems that were installed for the life of the unit.

3.3 Results and Interpretation

3.3.1 Introduction

The detailed results are shown in Table 3.2. Twenty-six plants correspond to the definition given in the introduction. The four main

Table 3.1

Escalation Factors

Year (a)	Capital Investment (b)	Utilities (c)	Chemicals (d)	Operation & Maintenance Labor (e)	Cons Labor (f)
1970	0.537	0.238	0.550	0.540	0.542
1971	0.576	0.277	0.584	0.583	0.613
1972	0.600	0.321	0.603	0.630	0.669
1973	0.624	0.372	0.624	0.681	0.704
1974	0.738	0.496	0.733	0.735	0.768
1975	0.825	0.665	0.819	0.794	0.824
1976	0.875	0.762	0.866	0.857	0.887
1977	0.934	0.873	0.928	0.926	0.937
1978	1.0	1.0	1.0	1.0	1.0
1979	1.09	1.1	1.075	1.08	1.08
1980	1.188	1.21	1.156	1.166	1.166
1981	1.295	1.331	1.242	1.260	1.260

a. cost index is for mid-year (June)

b. reference: Marshall and Swift

c. includes fuel and electricity; reference: Department of Commerce

d. reference: Bureau of Mines

e. reference: Department of Labor

f. reference: Engineering News Record (Construction Labor) processes described in Section 2 are represented here. The dual alkali process is used either with lime or limestone. If the sodium carbonate process which represents a small portion of FGD systems, is not taken into account there are just two categories: the lime and the limestone process.

Ten of the scrubbers were installed on new plants. In order to ease the comparison and the interpretation of the results, these plants were divided into four different categories, according to figure 3.1.

			Number of Plants	Megawatt Size
FGD	New	Lime (NL)	6	3150
		Limestone (NLS)	7	3698
	Retrofit	Lime (RL)	8	1664
		Limestone (RLS)	2	676

Figure 3.1

3.3.2 Capital and Annual Costs

The capital and annual costs have been reported on distribution curves drawn on figures 3.2 and 3.3.

Capital costs: These results indicate that it is more expensive to

Table 3.2

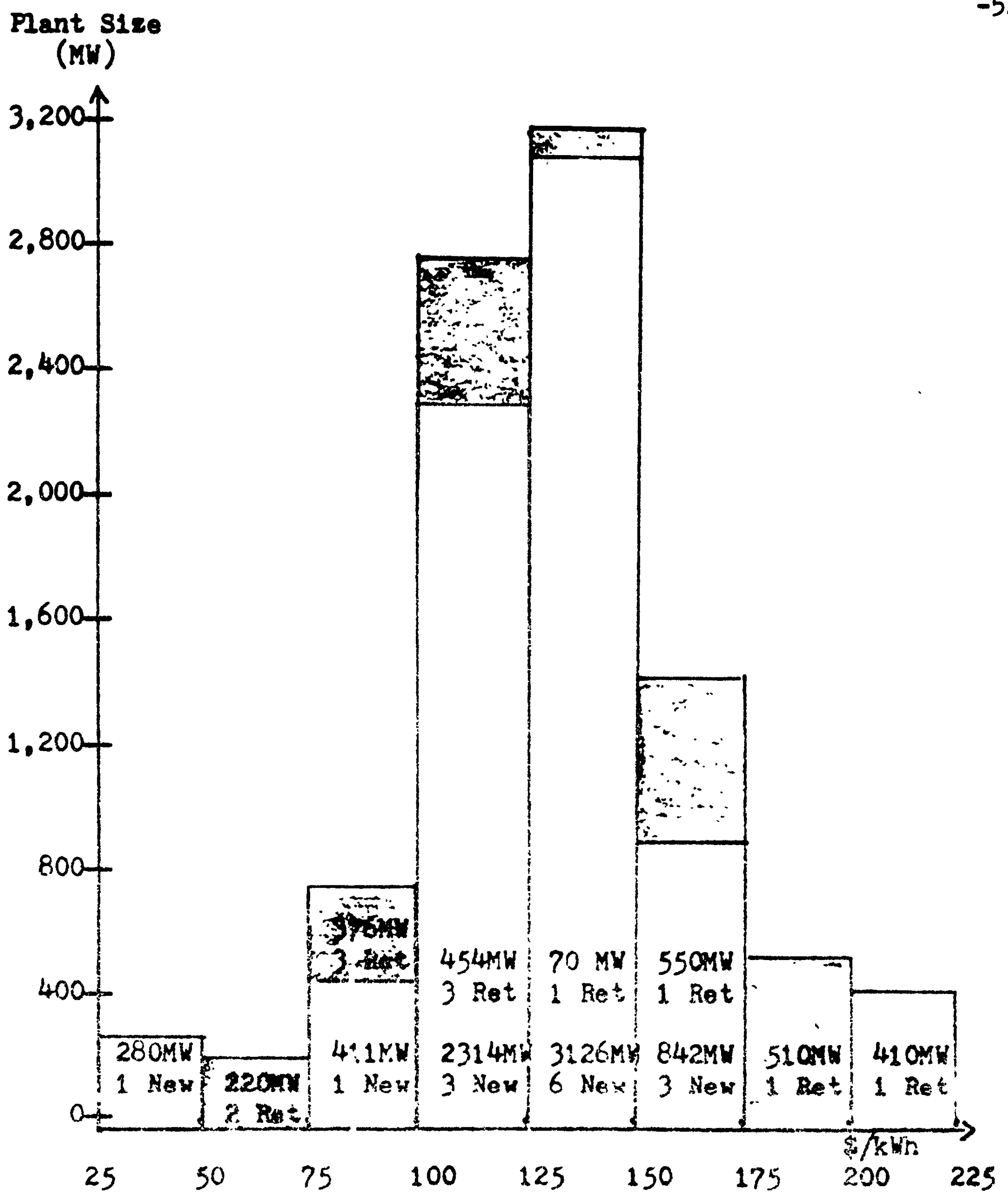
Capital and Annual Costs

Plant name	Start-up date	Eff (a)	Co (b)	MW size	Process	Capital cost $/kW	Annual cost mills/kWh	New Ret (c)
Cholla 1	10/73	55	3.4	126	Limestone	81.3	4.8	R
Duck Creek 1	7/76	85.3	2.9	378	Limestone	132.2	5.8	N
Conesville 5	1/77	89.5	3.9	411	Lime	99.4	6.8	N
Elrama 1-4	10/75	83	1.4	510	Lime	187.8	12.9	R
Phillips 1-6	7/73	83	3.4	410	Lime	210.0	17.6	R
Petersburg 3	12/77	85	2.4	532	Limestone	162.0	9.7	N
Hawthorn 3	11/72	70	2.2	110	Lime	62.8	5.2	R
Hawthorn 4	8/72	70	2.2	110	Lime	62.8	5.2	R
La Cygne 1	12/72	80	3.2	874	Limestone	100.1	11.3	N
Green River 1-3	9/75	80	3.1	64	Lime	117.8	11.0	R
Cane Run 4	8/76	85	1.6	190	Lime	115.2	6.2	R
Cane Run 5	12/77	85	1.5	200	Lime	102.4	5.3	R
Pady's Run 6	4/73	90	2.8	70	Lime	133.0	12.2	R
Milton Young 2	9/77	78	1.6	185	Lime/Alk	155.7	6.4	N
Colstrip 1	9/75	60	3.3	360	Lime/Alk	145.9	8.3	N
Colstrip 2	5/76	60	3.3	360	Lime/Alk	145.9	8.3	N
Reid Gardner 1	3/74	90	-	125	Sod./Carb	87.1	5.8	R
Reid Gardner 2	4/74	90	-	125	Sod./Carb	87.1	5.8	R
Reid Gardner 3	6/76	85	-	125	Sod./Carb	150.9	7.4	N
Sherburne 1	3/76	50	2.7	720	Limest/Al	102.6	5.4	N
Sherburne 2	3/77	50	2.7	720	Limest/Al	102.6	5.4	N
Br. Mansfield 1	12/75	92.1	6	917	Lime	144.2	11.3	N
Br. Mansfield 2	7/77	92.1	6	917	Lime	144.2	11.3	N
Winyah 2	7/77	45	1.1	280	Limestone	47.0	1.8	N
Southwest 1	4/77	80	4.6	194	Limestone	143.4	8.2	N
T.V.A. 8	5/77	70	4.7	550	Limestone	158.1	7.3	R

a. Theoretical removal efficiency expressed in percent.

b. FGD Energy consumption expressed as a percent of total energy consumption.

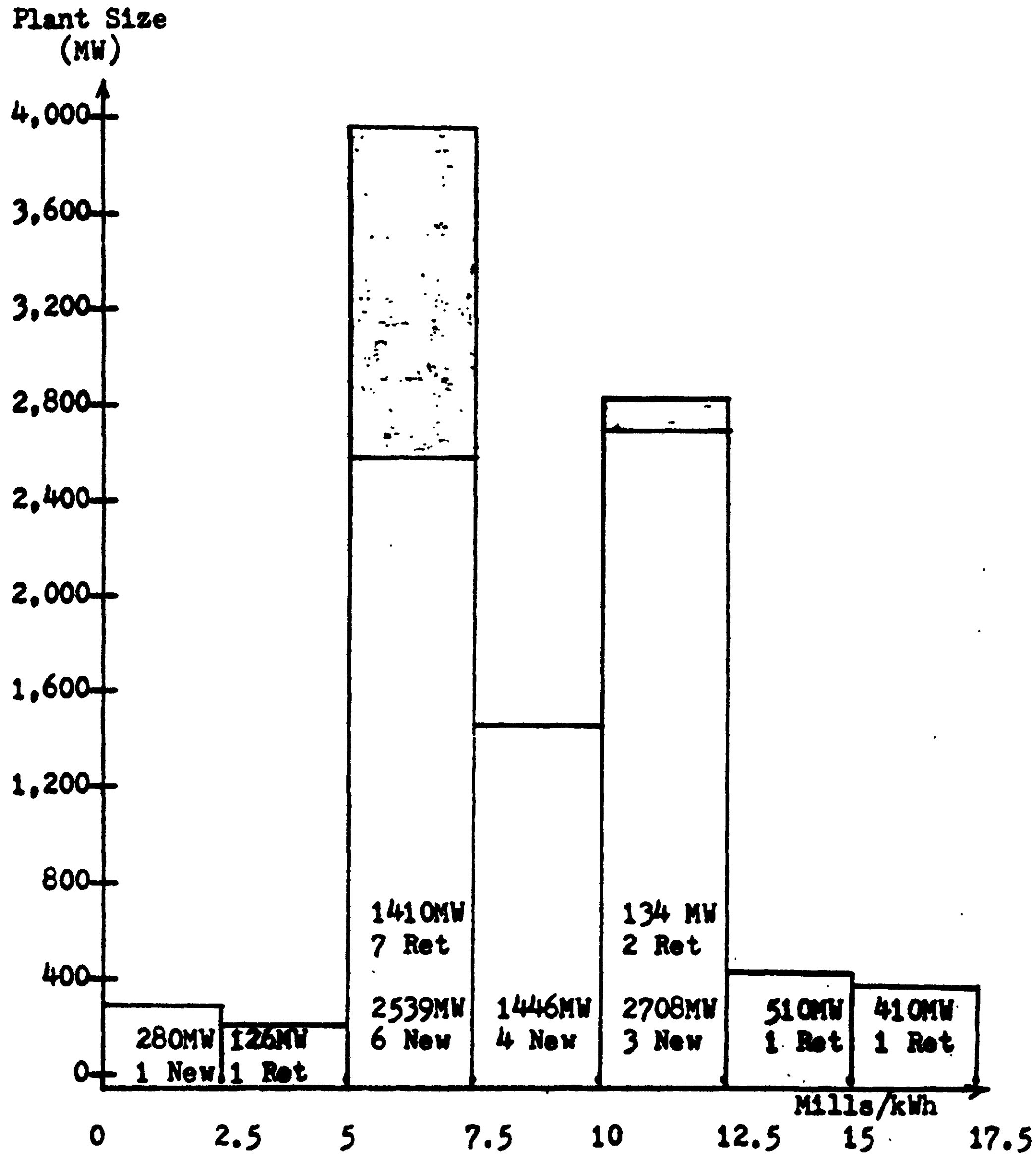
c. New/Retrofit FGD system.



No. of Plants	Average($/kWh)	Standard deviation
26 Group	130.12	20.62
14 New	124.83	19.6
12 Retrofit	144.4	45.6
6 NL	139.4	33.0
7 NLS	111.5	19.4
8 RL	153.2	58.9
2 RLS	143.8	80.3

Capital Costs Distribution

Figure 3.2



No. of Plants	Average(Mills/kWh)	Standard deviation
26 Group	8.7	1.7
14 New	8.4	1.8
12 Retrofit	9.6	3.1
6 NL	9.7	2.9
7 NLS	7.3	2.0
8 RL	11.3	4.5
2 RLS	6.8	3.6

Annual Costs Distribution

Figure 3.3

install a FGD system on an already existing plant than to build both a new scrubber and a new plant.

The numbers given in Table 3.2 indicate that there are 12 FGD retrofit systems with a total size of 2590 MW and 14 new FGD systems with a total size of 6973 MW. Therefore the average retrofit unit size is 216 MW whereas the average new unit size is 498 MW. As stated by the economic principle of economies of scale, the bigger the size of the unit, the less the capital cost will be. The following interpretation reinforces the former one. It is cheaper to design both a new plant and a new scrubber rather than trying to design a scrubber which will fit an old boiler "as well as possible".

The standard deviation is lower than average for the new plants, which means that the capital costs are about the same. On the other hand, the capital costs for retrofit systems are spread on a wide range, from \$62.80/kW for Hawthorn 3 and 4 to \$210.00 for Phillips 1-6.

The results by category show that the limestone process installed on new plants (NLS) has the lowest capital cost. The other results are not as meaningful since there is a very high standard deviation which cannot lead to a general interpretation.

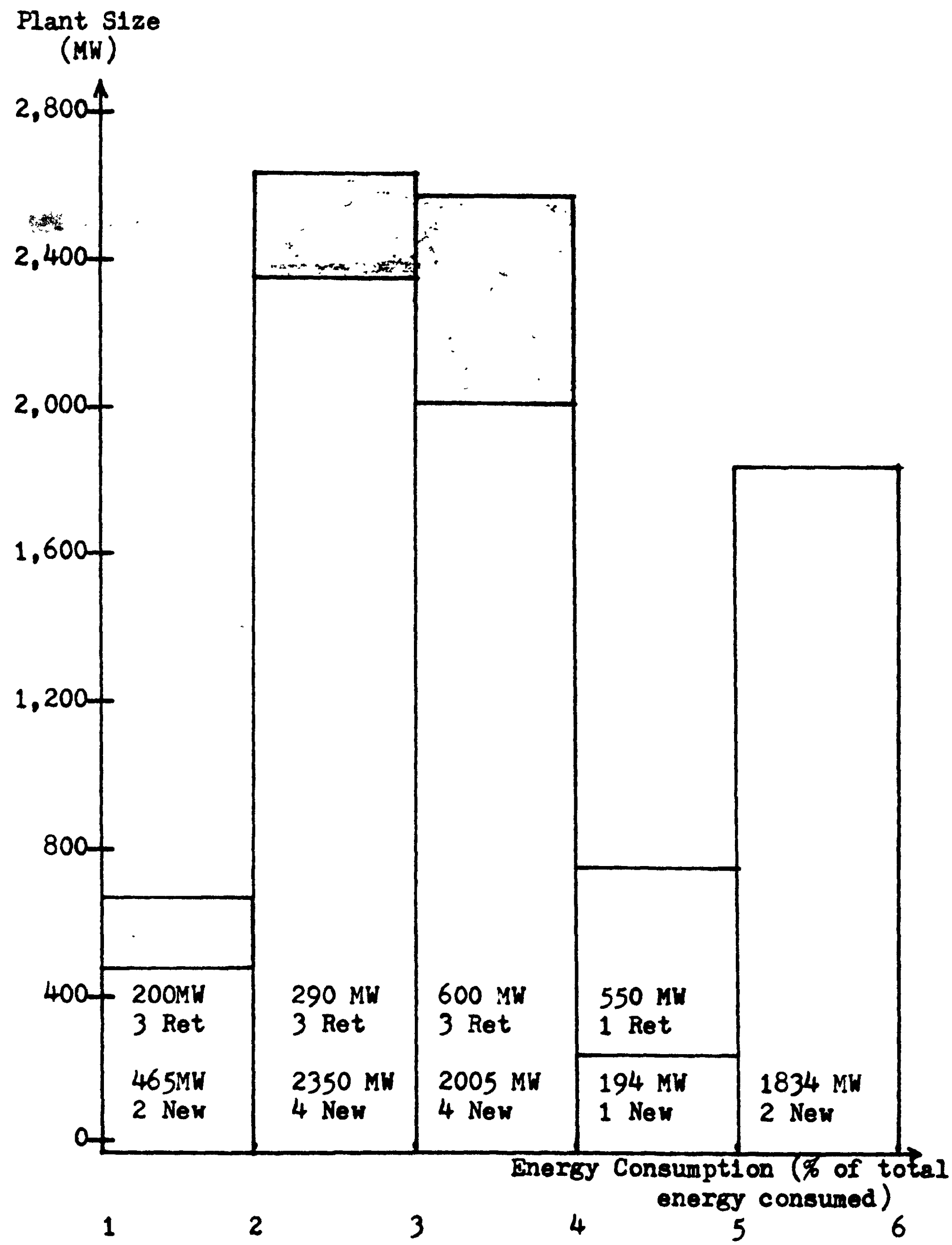
<u>Annual Costs:</u> The annual costs are again higher for retrofit plants and spread on a wide range from 4.8 mills/kWh for Cholla 1 to 17.6 mills/kWh for Phillips 1-6. The cheapest annual costs are obtained once again by the NLS cataegory. The RLS category is not considered because there were only 2 plants and the standard deviation was quite high. A possible explanation lies in the very cheap price of the limestone which was in 1980 about \$11.60 per ton versus a price of \$46.00 per ton for the

lime. This may also explain the curious shape of the distribution curve with two peaks: one between 5 and 7.5 mills/kWh, the other between 10 and 12.5 mills/kWh. Most of the lime processes are represented by the second peak whereas most of the limestone processes are represented by the first peak.

It is interesting to determine the relation between the annual cost and the design removal efficiency given in Table 3.2. This curve has been drawn on Figure 3.5. As expected, the greater the efficiency, the more expensive the annual cost is. The different points are not on a straight line. However the limits can be drawn. Between the upper limit and the lower one all the points can be found. The slope of the upper limit is greater, which means that the greater the efficiency, the larger the range of the annual cost.

3.3.3 Energy Consumption

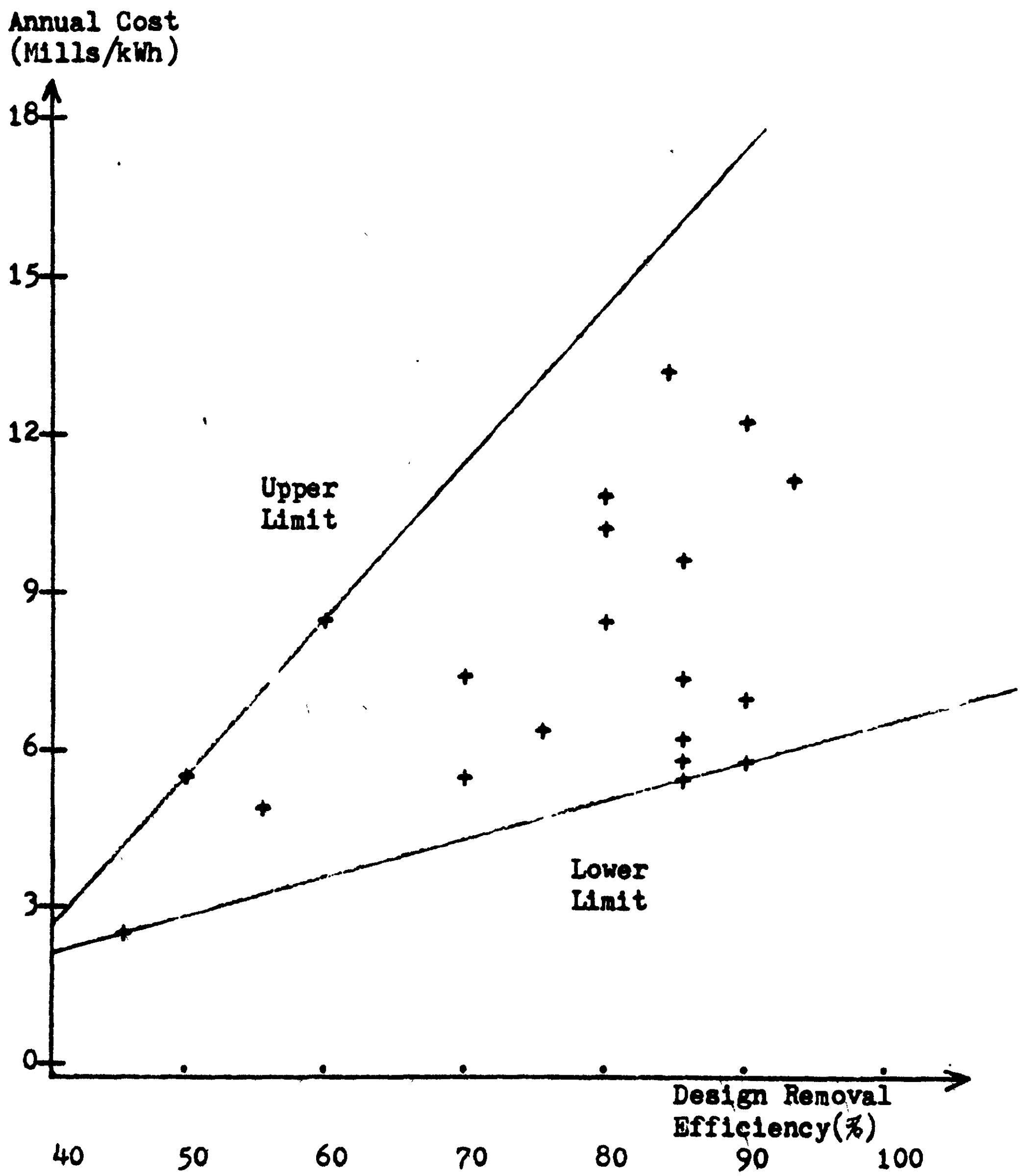
The distribution curve of the energy consumption expressed in percent of the total MW capacity has been drawn in Figure 3.4. The energy consumption is higher for new (3.7%) than for retrofit FGD systems (2.8%). The following explanation may be given. If an FGD system is retrofitted to an existing boiler the new electrical power demand of the FGD equipment will decrease the boiler net MW rating. Since the boiler was originally sized and designed to accomodate a certain grid demand, the utility may be forced to buy make-up power from the grid and/or increase the design capacity of planned boilers. Therefore the energy consumption for retrofit



No. of Plants	Average(%)	Standard deviation
23 Group	3.5	0.8
12 New	3.7	0.9
11 Retrofit	2.8	1.0
66 NL	4.9	1.7
7 NLS	2.8	0.5
8 RL	2.2	0.7
2 RLS	4.5	2.3

Energy Consumption Distribution

Figure 3.4



Annual Cost vs. Design Removal Efficiency

Figure 3.5

systems will be designed as low as possible.

For a new system the problem is not the same. The energy consumption required by the FGD system will be determined at the same time as the boiler size so that both work properly. The high price of energy will of course make it necessary to obtain a low energy consumption but it is not as imperative as for a retrofit system.

3.3.4 Impact on Consumer/Producer

The average annual cost of the FGD technology is about 9 mills per kWh (See Figure 3.3). It represents about 15% of the price of a kWh if we consider an average price of 60 mills for one kWh. This seems to confirm the claim that scrubbers would add at least $4 a month to the average home utility bill. (Dumanoski, 1982) The objective of this section is to determine the distribution of FGD cost between producer and consumer.

The study of electricity rates and more generally of the American electricity supply is very complicated. American electricity supply is decentralized into a patchwork of geographically separate operations. This is very well described by Wilcox and Shepherd. (Wilcox _et_. _al_., 1975)

To explore the behavior of regulated firms, a variant of the standard Averch-Johnson model (Anderson _et_. _al_., 1979) can be used. The standard Averch-Johnson model shows that a monopoly constrained in its decisions by a regulatory agency to earn a "fair rental" greater than the rental it would earn in a perfectly competitive market will use relatively more capital and less labor than cost minimization would require. As a hypothetical example, one might envision a regulated firm that employs excess capital in the form of pollution abatement equipment (See Section 4.3.3). The expanded capital stock would permit a higher absolute level of profits. (Silverman et. al., 1982)

The use of this model suggests that the FGD technology helps the electric utilities to increase their profits. Therefore the impact of FGD which can be reviewed as a tax (for each kWh produced, 15% of the cost is due to the scrubber) will be greater on the producer than on the consumer.

It confirms the fact that in a perfectly competitive case, the burden of the tax shifts from consumers to producers as we move from the short run to the long run for non-durable goods. (Mansfield, 1982) Whereas the demand for durable goods such as cars is characterized by a stock adjustment effect and therefore the long run demand curve will be more elastic than the short run demand curve because substitutes for electricity such as natural gas will become available.

However if we forget economics for a while and try to think simply about it, we guess that in the long run the consumer will eventually pay for it even if at the beginning the producers are obliged to pay for it because of the regulated price. The producers will notice a decrease of their profits due to the investment and use of scrubbers and will ask to raise the regulated price. Who will the victim be? The consumer, very likely!

3.3.5 Combination of Annual and Capital Costs or Net Present Value

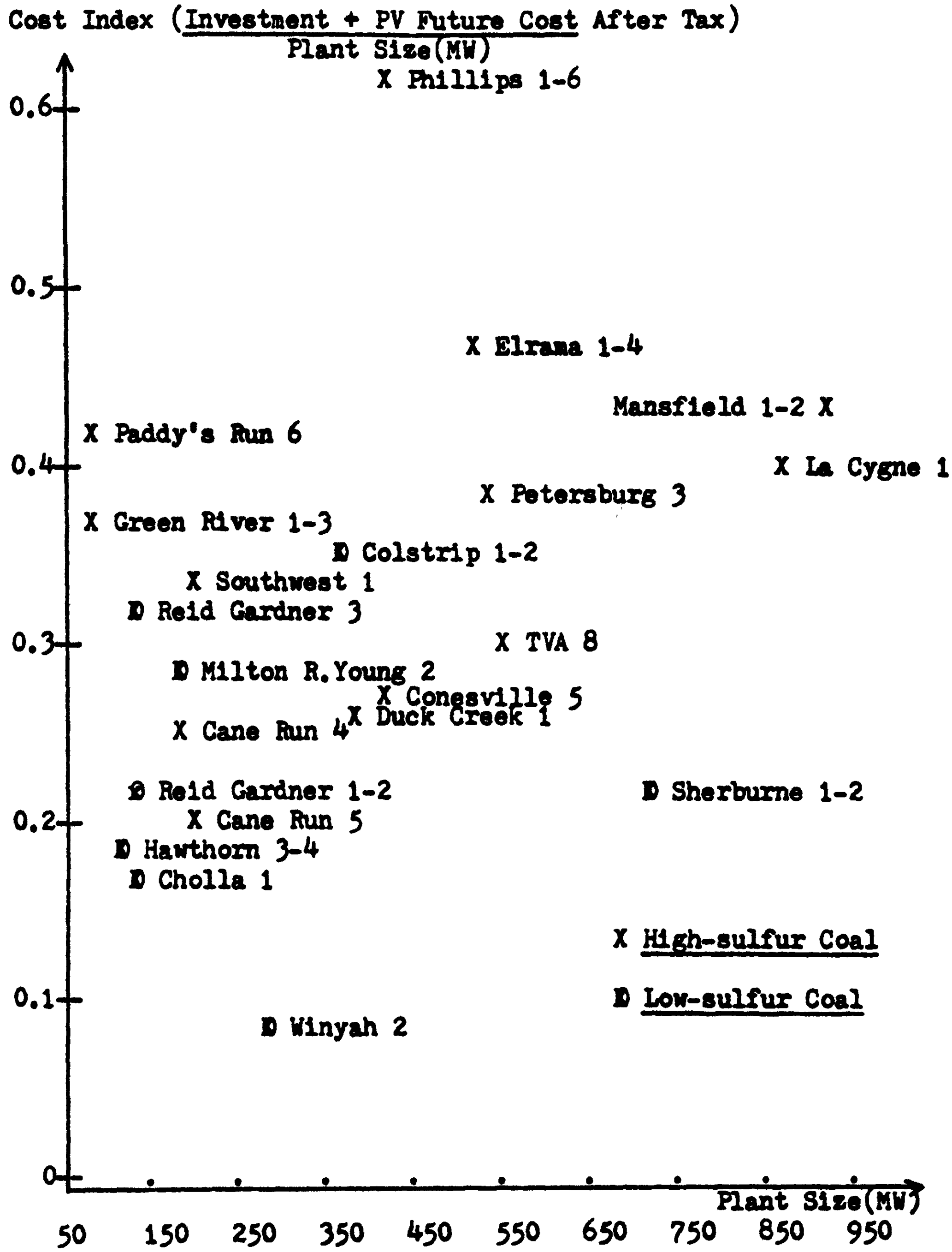
It would be very useful to compare these different plants with one index only. This index is the cost and investment ratio or the present value of forecasted future costs plus the initial investment divided by the size in MW. This index is almost the same as the profitability index (or benefit-cost ratio) described in corporate finance. (Brealey, et. al., 1981) However the benefits brought by the scrubbers are difficult to measure. it is always very difficult to measure the benefits brought by an air pollution control device.

On the other hand it is easier to calculate the annual cost and to add the present value of these future annual costs to the initial investment.

In order to calculate this index, the following assumptions were taken into account:

- The real opportunity cost of capital is 10 percent (assume a nominal opportunity cost of capital of 18 percent and an inflation rate of 7 percent)
- The useful life of retrofit scrubbers is 20 years whereas the useful life of new scrubbers is 30 years.
- The marginal tax rate for all plants is 0.46 and all plants are assumed to pay taxes.
- The investment tax credit is 10% and the depreciation tax shield has been calculated with the 1982 Accelerated Cost Recovery System (ACRS) on a 5-year basis.

The calculation of this index is shown in Table 3.3. and the classification of these plants according to this index is shown on Figure 3.6. As indicated in Table 3.3, some plants burn low-sulfur coal while others burn high-sulfur coal. The average index for low sulfur is 0.23 whereas the average index for high sulfur is 0.36. While the differences



Classification of the 26 Plants according to Size and Cost Index.

Figure 3.6

Table 3.3

Cost Index

Plant Name	Capital cost $/kW	Annual cost mills/ kWh	$1,000,000 Net Initial Investment (Tax included)	$1,000,000 Net Present Value of Cost	Index	(a)	(b)
Cholla 1	81.3	4.8	5.96	16.61	0.179	L	RLS
Duck Creek 1	132.2	5.8	29.05	66.68	0.253	H	NLS
Conesville 5	99.4	6.8	23.75	85.00	0.265	H	NL
Elrama 1-4	187.8	12.9	55.69	180.68	0.463	H	RL
Phillips 1-6	210.0	17.6	50.06	198.18	0.605	H	RL
Petersburg 3	162.1	9.7	50.14	156.94	0.389	H	RL
Hawthorn 3	62.8	5.2	4.02	15.71	0.179	L	RL
La Cygne 1	100.1	11.3	50.87	300.36	0.402	H	NLS
Green River 1-3	117.8	11.0	4.38	19.33	0.370	H	RL
Cane Run 4	115.2	6.2	12.73	32.35	0.237	H	RL
Cane Run 5	102.4	5.3	11.91	29.11	0.205	H	RL
Paddy's Run 6	133.0	12.2	5.41	23.45	0.412	H	RL
Milton Young 2	155.7	6.4	16.75	36.0	0.285	L	NLA
Colstrip 1	145.9	8.3	30.54	90.87	0.337	L	NLA
Colstrip 2							
Reid Gardner 1	87.1	5.8	6.33	19.91	0.210	L	RSC
Reid Gardner 2						L	
Reid Gardner 3	150.9	7.4	10.97	28.13	0.313	L	NSC
Sherburne 1	102.6	5.4	42.95	118.24	0.224	L	NLSA
Sherburne 2						L	
Mansfield 1	144.2	11.3	76.88	315.14	0.428	H	NL
Mansfield 2						H	
Winyah 2	47.0	1.8	7.65	15.33	0.082	L	NLS
Southwest 1	143.4	8.2	16.18	48.38	0.333	H	NLS
TVA 8	158.1	7.3	50.56	110.27	0.292	H	RLS

a. L means lowsulfur coal whereas H means highsulfur coal.
b. In this column are indicated the main processes:

RLS	Retrofit limestone
NLS	New limestone
RL	Retrofit lime
NL	New lime
NLA	New lime/Dual alkali
NLSA	New limestone/Dual alkali
RSC	Retrofit Sodium carbonate
NSC	New Sodium carbonate

between the new and retrofit scrubbers decrease with the cost index (because different useful lifes are considered), the limestone process still remains cheaper and it is cheaper to install a scrubber on a plant which burns low-sulfur coal than to install a scrubber on a plant which burns high-sulfur coal.

3.3.6 Conclusion

Several studies or forecasts of the cost of FGD technology were made within the last ten years. It is interesting to compare the results obtained with our results.

In 1973, the Sulfur Oxide Control Technology Assessment Panel (U.S. Environmental Protection Agency, 1973) estimated the costs of six different sulfur oxide control technologies. The investment per kilowatt of capacity ranged from $17 to $65, and the operating costs ranged from 0.6 mills to 3 mills per Kilowatt hour. At the time these costs were estimated, they represented a large fraction, ranging from 20 percent upward, of the total cost of electricity generation. These costs were estimates and were not based on actual data.

An attempt to produce a generalized cost function has been made by Burchard, (Burchard, 1972) who used data from a number of cost studies for sulfur dioxide scrubbing systems and developed equations to represent costs under a variety of conditions. Although it is not clear that Burchard's equation is actually fitted by regression techniques to the existing data, he does use his equation to reestimate the cost of actual facilities in his input data and finds that his cost estimates are within 15 percent of the original estimates.

A notable feature of Burchard's equation and data is the tremendous range in most of the cost variables, many of which vary by at least a factor of 2. The major contribution of this cost function is to reconcile the variety of cost estimates for different scrubbing installations, which vary enormously in parts because of the tremendously varied conditions of plant size, fuel sulfur content, byproduct, disposal costs, and a number of other factors.

Methods for sulfur dioxide removal from stack gases have been known in principle for some time, but only during the last decade have large-scale installations been made that can lead to the development of improvements and cost reductions in this technology. If policies are adopted that encourage or force the installation of large numbers of sulfur dioxide scrubbers over the future, it would be reasonable to expect that research and development would lead to substantial improvements in these processes. Maximum efficiencies should rise and costs should fall.

All this cost analysis is concerned by the tail-end treatment or removal of sulfur dioxide from stack gases. It is also possible to reduce sulfur dioxide emisions, by removing sulfur from the fuel before it is burned, by burning a low-sulfur fuel. Depending upon market conditons, in some cases it may be less expensive to purchase low-sulfur coal than it is to install stack gas scrubbers (See Section 1.2). Thus cost estimates based upon gas stack scrubbing alone are likely to overestimate actual costs incurred in a cost-minimizing abatement program for an area or a country.

4 FUNCTIONAL ANALYSIS OF PROVEN FGD

4.1 Introduction

The cost analysis described in Section 3 would not be sufficient without a functional analysis. One of our assumptions was a continuous operation of the boiler and a capacity factor of 65%. Therefore the prices calculated in Section 3 might not be realistic. A very high annual cost might result from a very low utilization of the scrubber. On the other hand, a very low annual cost might result from a very high utilization.

In order to remedy these drawbacks, we will study how well the FGD systems operate and what are the main reasons for failure.

Section 4.2 contains an overview of the proposed methodology. A definition of different viability indexes is given and the way these data are collected is explained.

In Section 4.3, the results obtained by applying this methodology are shown. The four main processes are compared with the set of indexes previously described. The evolution of one of these indexes, the operability, is shown. The different regulatory classes are presented and a study of the operablity limit shows how well the legislation is applied. After an analysis of the main reasons for failure, an interpretation of the applied results is given.

Section 4.4 constitutes a synthesis of the results obtained in Section 4 and Section 3. The definition of the operating cost is given. Then the average cost curve can be drawn.

Finally in Section 4.5 improvements of the viability of the FGD systems are suggested as well as other methods of sulfur removal.

4.2 Description of the Methodology

4.2.1 Definition of Different Viability Indexes

Several parameters have been developed to quantify the viability of FGD system technology. The operation of any FGD system during a given period can be accurately represented by the "availability," "reliability," "operability," and "utilization" indexes. These parameters are defined below and discussed briefly.

The availability index (A) is defined as the number of hours the FGD system is available for operation (whether operated or not) divided by the number of hours in period (8760 hrs for a year), expressed as a percentage:

$$A(\%) = \frac{\text{available FGD hrs}}{\text{hrs in period}} \times 100$$

This parameter tends to overestimate the viability of the FGD system because it does not penalize for election not to operate the system when it could have been operated. Boiler downtime may tend to increase the magnitude of the parameter because FGD failures generally cannot occur during such periods.

The reliability index (R) is defined as the number of hours the FGD system was operated divided by the number of hours the FGD system was called upon to operate, expressed as a percentage:

$$R(\%) = \frac{\text{actual FGD hrs}}{\text{Called upon FGD hrs}} \times 100.$$

This parameter has been developed in order not to penalize the FGD system for elected outages, periods when the FGD system could have been run but was not run because of chemical shortages, lack of manpower, short duration boiler operations, etc. The main problem in using this formula is the concise determination of whether the system was "called upon to operate" during a given time period. Moreover, an undefined value can result when the FGD system is not called upon to operate for a given period (for instance, turbine or boiler outage when the FGD system is available).

The operability index (O) is defined as the number of hours the FGD system was operated divided by the number of hours the boiler was operated, expressed as a percentage:

$$O(\%) = \frac{\text{actual FGD hrs}}{\text{actual boiler hrs}} \times 100$$

This parameter indicates the degree to which the FGD system is actually used, relative to boiler operating time. The parameter is penalized when options are exercised not to use the FGD system when the system is operable. In addition, an undefined value can result when the FGD system is not called upon to operate for a given period (for instance, turbine or boiler outage when the FGD system is available) (See reliability).

The utilization index (U) is defined as the number of hours the FGD system was operated divided by the number of hours in period (8760 hrs for a year), expressed as a percentage:

$$U(\%) = \frac{\text{actual FGD hrs}}{\text{hrs in period}} \times 100$$

This parameter is a relative stress factor for the FGD system. It is not a complete measure of the FGD system viability because the parameter can be strongly influenced by conditions that are external to the FGD system. Infrequent boiler operation will lower the value of the parameter although the FGD system may be highly dependable in its particular application.

4.2.2 Collection of the Data

The four indexes mentioned above have been reported monthly and supplied voluntarily by utility representatives, FGD system suppliers and designers, regulatory agencies and others. These FGD system design and performance data have been collected in a computerized data base known as the Flue Gas Desulfurization Information System (FGDIS). Neither the U.S. Environmental Protection Agency (EPA) nor the designated contractor warrants the accuracy or completeness of information contained in this data base.

The information provided for this thesis comes from a report which summarized the data from the data base. (Bruck et. al., 1981)

Among the four indexes reported, only the last two can be actually checked because both the number of actual FGD hours and the number of actual boiler hours are also reported. As a matter of fact, the reported operability and utilization indexes have not been taken into account. They were recalculated from the numbers of hours indicated.

The reliability and operability indexes can be easily compared since they only differ by the value of their denominator. It seems clear that when the boiler does not operate, the FGD system should not operate either. Therefore the number of hours the FGD system is called upon to operate should be less than the number of actual boiler hours, which means that the reliability should be greater than the operability. However, the contrary can be noticed for a few utilities. As mentioned above, it depends on the definition of "called upon to operate". Since the number of hours the FGD system was called upon to operate and since the number of available FGD hours are not recorded, the availability and reliability indexes cannot be trusted as much as the operability and utilization indexes.

It will also be noticed that for some other reasons such as strike or personnel change, the numbers recorded are either unavailable for a given period or not recorded the same way they were before.

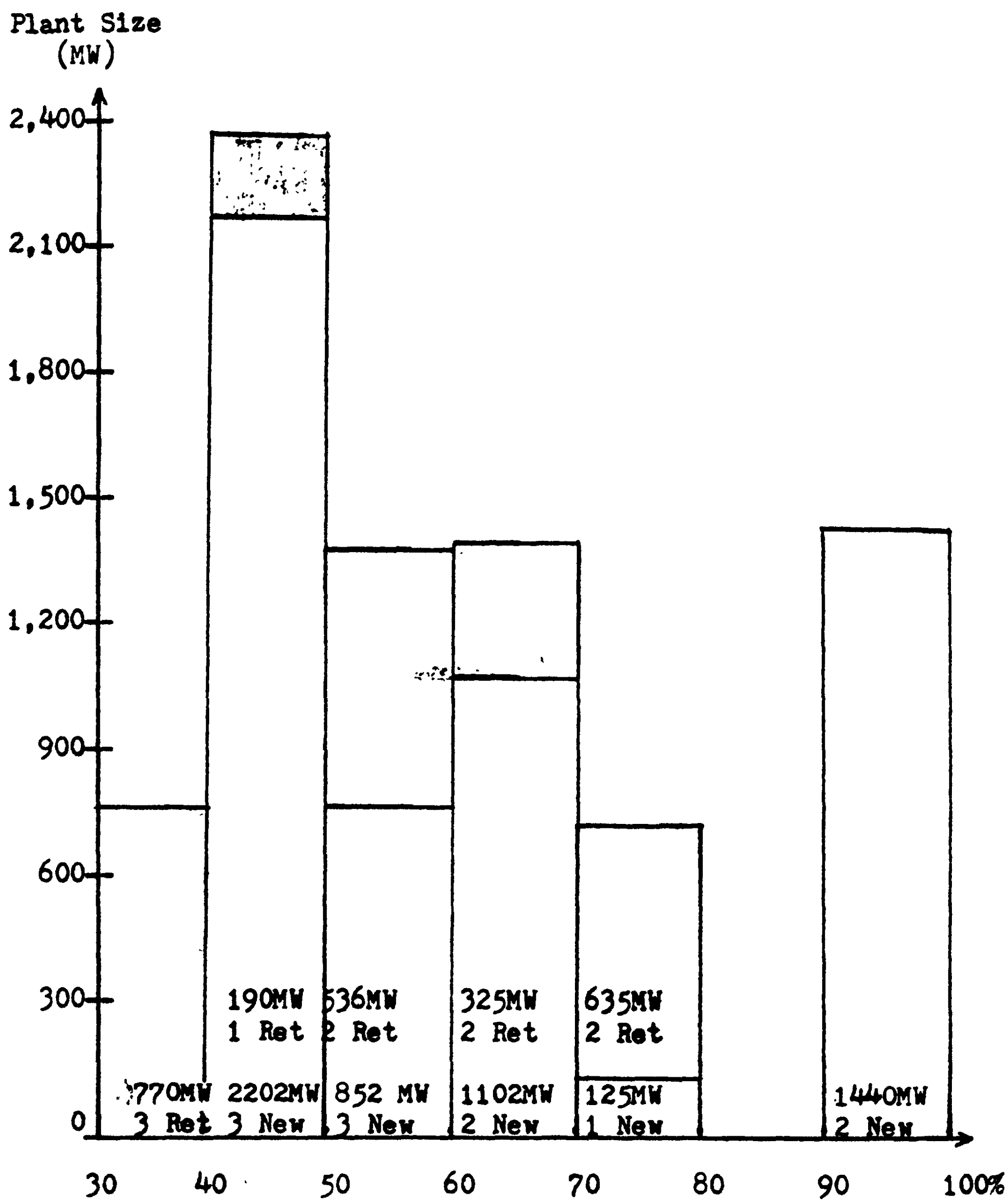
All these considerations have been taken into account so that the following analysis could be as reliable as possible.

4.3 Results and Interpretations

4.3.1 Comparison of the Different Viability Indexes in 1980 or 1981

The utilization, operability, reliability and availability were calculated for the group of plants already analyzed in Section 3. The method of calculation is explained in the Appendix. The results are presented in Table 4.1. The capacity factor is also included.

The distribution curve of the utilization index has been drawn on Figure 4.1. The retrofit scrubbers are not used as much (55%) as the new



No of Plants	Average(%)	Standard deviation
21 Group	61.1	11.3
11 New	63.9	13.0
10 Ret	54.8	12.8
4 NL	54.8	15.0
6 NLS	70.6	18.7
6 RL	58.9	18.9
2 RLS	39.9	13.6

<u>Utilization Index distribution</u>

<u>Figure 4.1</u>

Table 4.1

Viability Indexes in 1980 and 1981

Plant Name	New Ret	Start-Up Date	MW	Process	Utiliz	Operab	reliab	availab	cap Fact
Cholla 1	R	10/73	126	limestone	55.4	72.7	99.81	99.82	87.1
Duck Creek 1	N	7/76	378	limestone	52.5	72.7	82.0	58.9	62.9
Conesville 5	N	1/77	411	lime	49.6	88.9	93.1	82.2	83.3
Elrama 1-4	R	10/75	510	lime	72.2	78.7	94.2	95.4	49.0
Phillips 1-6	R	7/73	410	lime	58.5	64.3	73.5	74.6	50.5
Petersburg 3	N	12/77	532	limestone	NA	NA	NA	NA	NA
Hawthorn 3	R	11/72	110	lime	35.9	100	97.0	93.0	25.8
Hawthorn 4	R	8/72	110	lime	36.7	100	93.9	85.6	45.3
La Cygne 1	N	12/72	874	limestone	45.1	98.1	93.7	85.9	45.6
Green River 1-3	R	9/75	64	lime	NA	NA	NA	100	NA
Cane Run 4	R	8/76	190	lime	49.3	85.8	92.1	79.0	39.8
Cane Run 5	R	12/77	200	lime	60.0	90.8	94.3	86.1	45.2
Paddy's Run 6	R	4/73	70	lime	NA	NA	NA	100	NA
Milton R. Young 2	N	9/77	185	lime A	66.3	78.6	90.1	74.4	83.2
Colstrip 1	N	9/75	360	lime A	NA	NA	NA	89.3	NA
Colstrip 2	N	5/765	360	lime A	NA	NA	NA	88.4	NA
Reid Gardner 1	R	3/74	125	SC	76.5	93.3	93.1	93.6	96.8
Reid Garnder 2	R	4/74	125	SC	62.0	94.3	96.5	97.5	95.3
Reid Gardner 3	N	6/76	125	SC	70.4	98.2	95.4	87.2	88.5
Sherburne 1	N	3/67	720	limestone A	95.3	100	100	100	71.2
Sherburne 2	N	3/77	720	limestone A	96.3	100	100	100	72.6
Bruce Mansfield 1	N	12/75	917	lime	45.5	100	NA	77.8	NA
Bruce Mansfield 2	N	7/77	917	lime	63.9	100	NA	95.9	NA
Winyah 2	N	7/77	280	limestone A	58.5	93.5	94.0	85.9	69.8
Southwest 1	N	4/77	194	limestone A	51.2	74.5	85.7	63.3	63.3
TVA 8	R	5/77	550	limestone A	36.4	80.7	NA	90.6	41.0

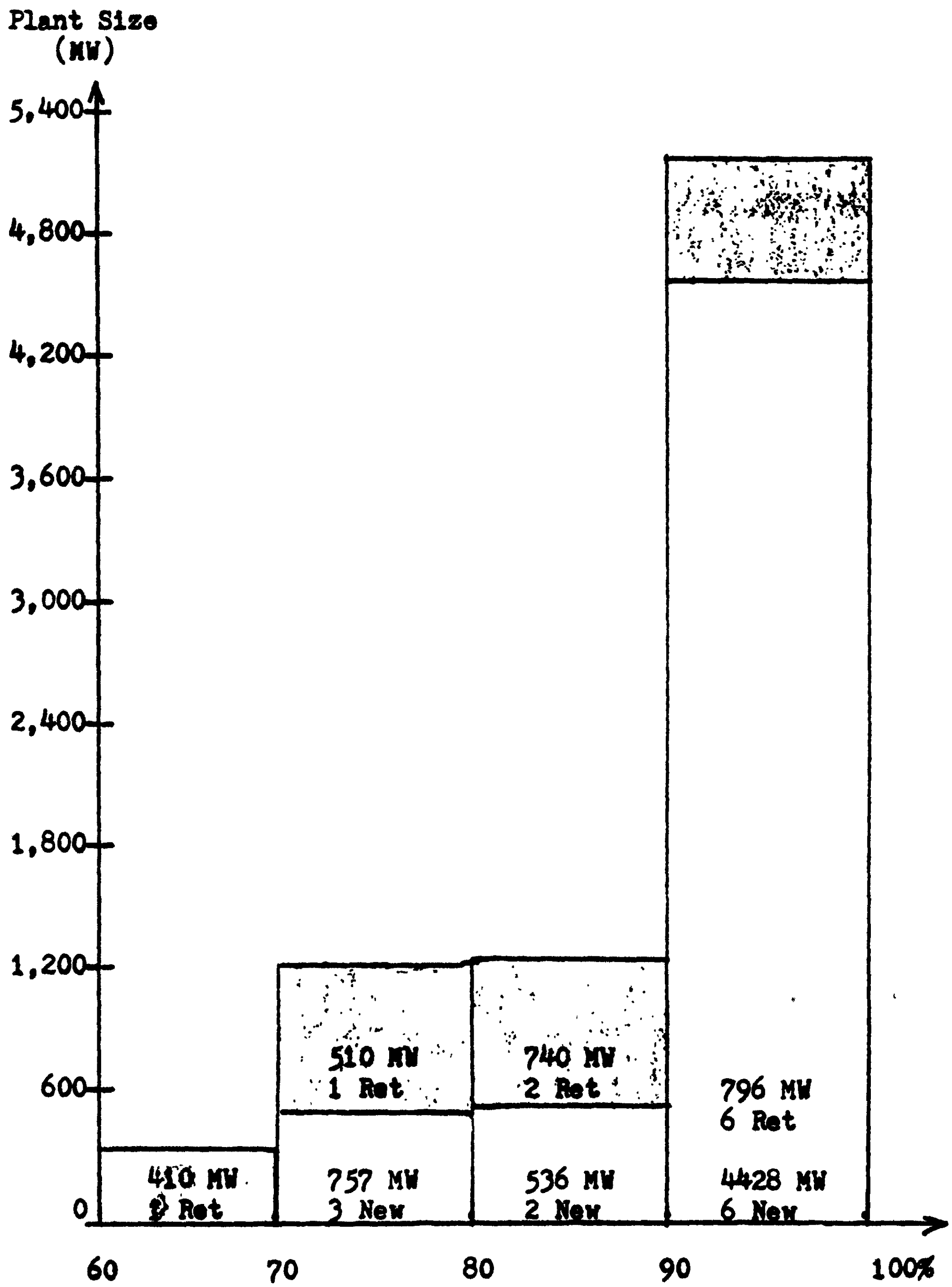
(NA = Not Available)

ones (64%). The limestone process installed on new plants (NLS) has a very high utilization index (70%). In Section 3, the same NLS category obtained the lowest annual cost in mills per kWh. However, as was explained in Section 4.2.1 this index can be strongly influenced by conditions that are external to the FGD system. This is the reason why we must consider the other indexes.

The distribution curve of the operability index has been drawn on Figure 4.2. The operability index is definitely higher (95%) for FGD systems installed on new plants than for FGD systems installed on old plants (83%). However the lime process installed on new plants has now the highest operability index. Nothing can really be concluded about the processes. Whereas the difference of operability between the new and retrofit scrubbers is high (more than 10%), the difference of operability between the lime and limestone processes, on either old or new plants is very low (2 or 3%). In section 4.3.3, an explanation of these results is given.

The distribution curve of the reliability index has been drawn on Figure 4.3. Only 18 plants gave values of reliability indexes. It mainly comes from the difficulty to define what is meant by "called upon to operate". The differences between new and retrofit scrubbers, as well as between lime and limestone processses are not very important.

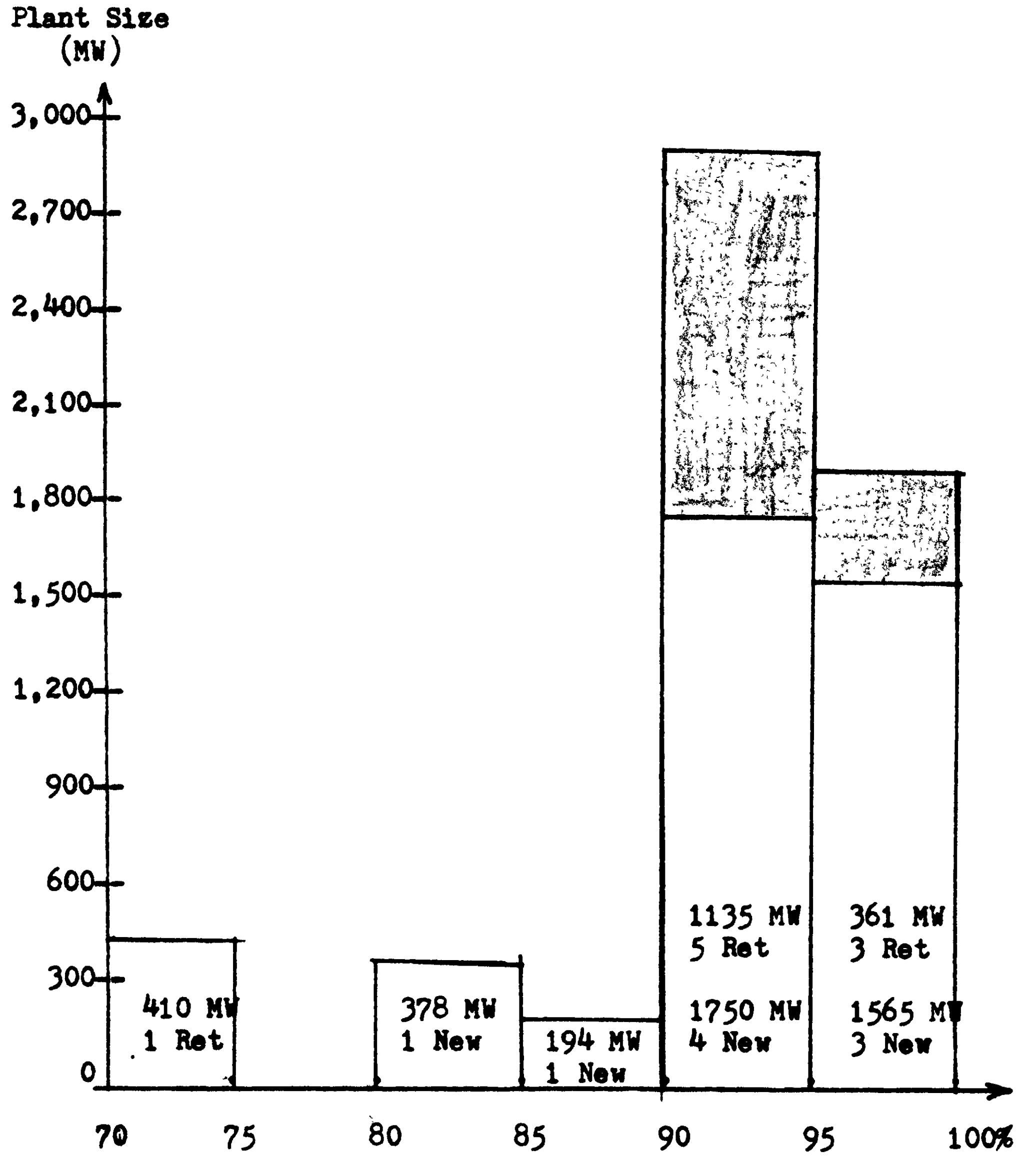
The reliability index is the highest of the four indexes. Its average value (93%) is also very high. For the lime processes installed on new plants (NL), the reliability is lower (92%) than the operability (97%). As mentioned in Section 4.2.2 the operability should be lower than the reliability. The contrary means that the FGD system was called upon to



No. of Plants	Average(%)	Standard deviation
21 Group	91.3	15.9
11 New	95.0	18.3
10 Retrofit	82.7	15.3
4 NL	96.5	28.0
6 NLS	94.1	21.4
6 RL	80.4	16.3
2 RLS	83.7	33.7

Operability Index distribution

Figure 4.2



No. of plants	Average(%)	Standard deviation
18 Group	93.0	16.7
9 New	94.3	19.8
9 Retr fit	90.1	18.6
2 NL	92.2	25.6
6 NLS	94.7	20.0
6 RL	88.6	21.0
1 RLS	99.8	0

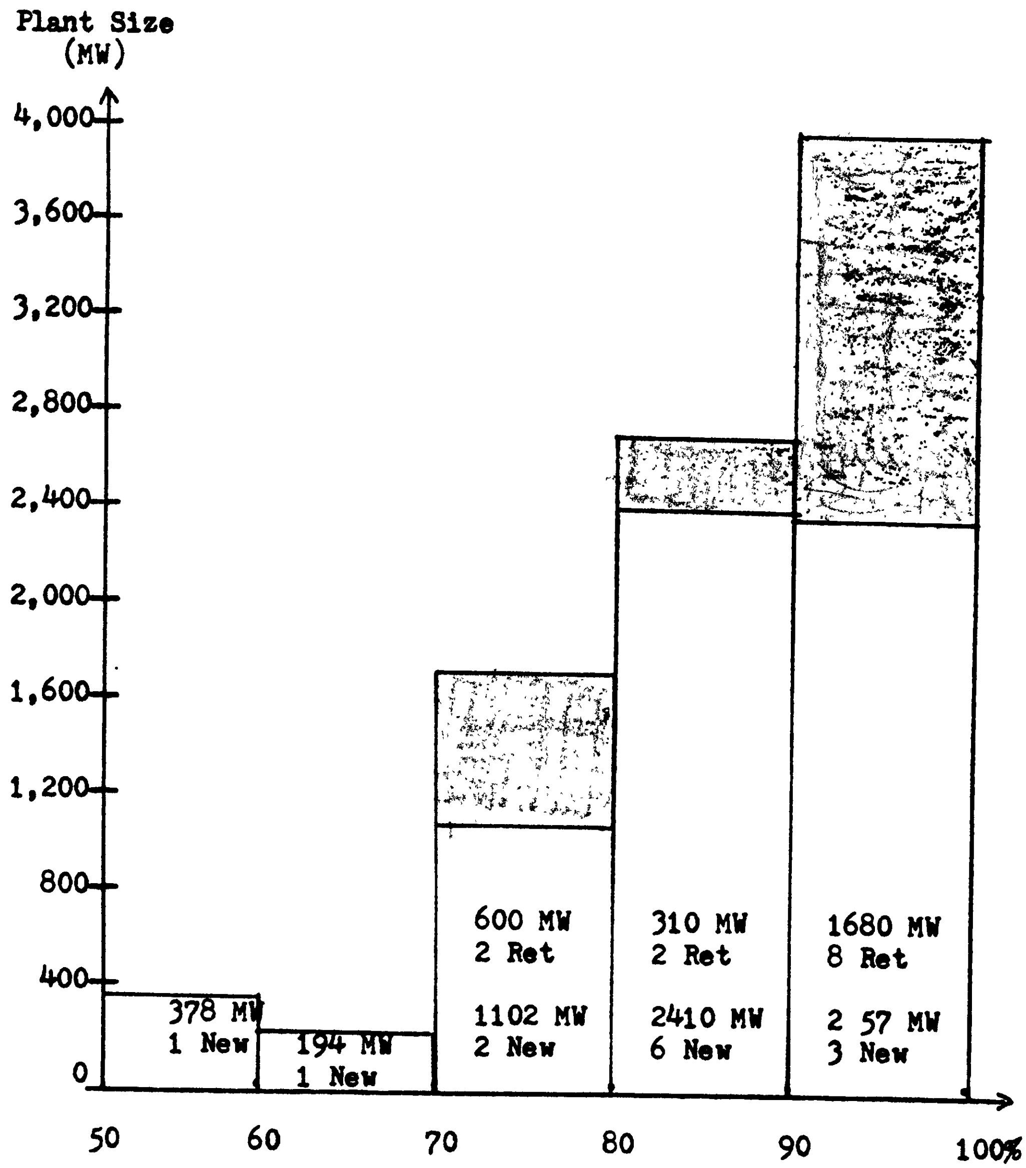
<u>**Reliability Index distribution**</u>

<u>**Figure 4.3**</u>

operate when the boiler was not operating. It might be a way of keeping the FGD system in operation in order to avoid the formation of sludges.

The distribution curve of the availability index has been drawn on Figure 4.4. Contrary to the three former indexes, the availability of the retrofit scrubbers is greater than the availability of the new scrubbers. This result is only surprising in appearance. If the boiler does not operate most of the time, the risk of FGD failure is very low and therefore the availability of the system is very high. This is the reason why we must also consider the utilization index when we look at the availability. We already saw that the utilization index is a lot lower for retrofit scrubbers than for new scrubbers and this is the reason why we observe this amazing result.

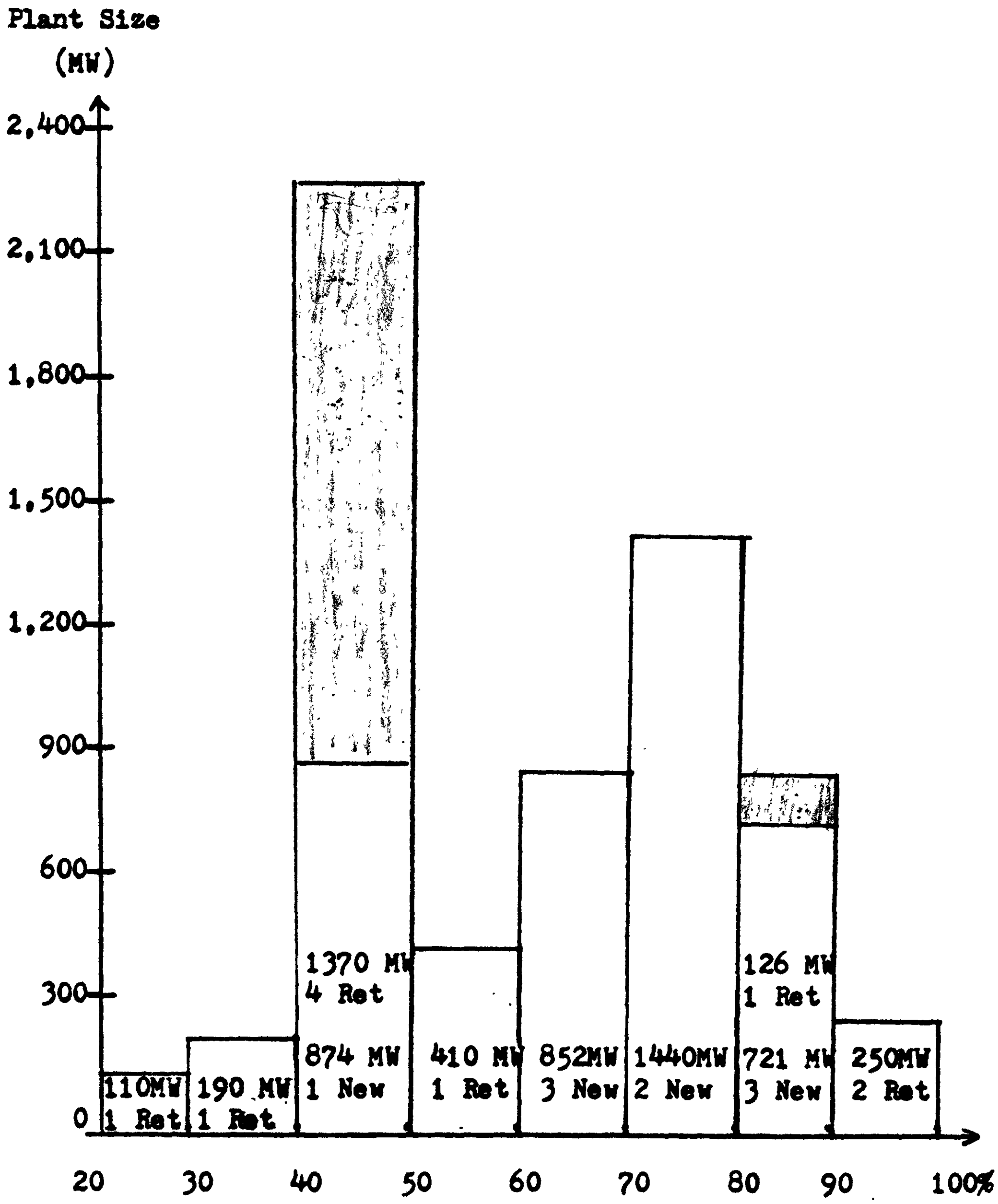
Finally the distribution curve of the capacity factor has been drawn on Figure 4.5. This capacity factor is the capacity factor of the boiler and does not measure the viability of the FGD system. However a comparison of this curve with the FGD utilization curve can be made. The average capacity factor is the same as the average utilization factor - 61%. Whereas the capacity factor of a new boiler (67%) is greater than the utilization factor of a new scrubber (64%), the capacity factor of an old boiler (52%) is less than the utilization factor of a retrofit scrubber (55%). Nothing can be concluded from this comparison because these two indexes are really independent.



No. of Plants	Average(%)	Standard deviation
25 Group	87.5	13.8
13 New	86.7	15.1
12 Retrofit	89.1	19.7
6 NL	86.0	20.0
6 NLS	87.7	20.9
8 RL	86.8	23.3
2 RLS	92.3	39.0

Availability Index distribution

Figure 4.4



No. of Plants	Average(%)	Standard deviation
19 Group	61.1	9.7
9 New	66.8	11.7
10 Retrofit	52.0	9.2
2 NL	83.3	22.4
6 NLS	62.9	12.0
6 RL	45.8	13.2
2 RLS	49.6	12.1

Capacity Factor distribution

Figure 4.5

4.3.2 Evolution of the Operability

Among the four viability indexes described in Section 4.2.1, the operability seems the most reliable since the number of hours the FGD system is operated is recorded by the utility as well as the number of boiler hours. It also gives an accurate measure of the viability of the FGD system. That is the reason why this index has been chosen to analyze the viability of the FGD systems through the years.

The results are shown in Table 4.2. The years of FGD operation begin only after the commercial start-up. Four plants, Hawthorn 3 & 4, La Cygne 1 and Paddy's Run 6 have been operating for nine years. The value 0 was given to the operability whenever both the number of boiler hours and FGD hours were equal to zero, which was a case of indetermination.

The average operability has been calculated for every year and drawn on Figure 4.6. During the first three years the operability stays at a low level of about 60% before jumping at the fourth year and reaching during the following years an asymptotic level of about 95%.

The average operability was also calculated for the four different categories of processes, new lime, new limestone, retrofit lime, and retrofit limestone scrubbing. It is interesting to look at the curve of the NL category. The shape is about the same as the average operability. However the level of the first years is lower at about 30% and the asymptotic level is lower at about 80%. The precipitation of calcium sulfate or gypsum can explain this low level of operability.

The shape of the average operability curve can be compared to the S-shaped curve of the spread of innovation described by many economists.

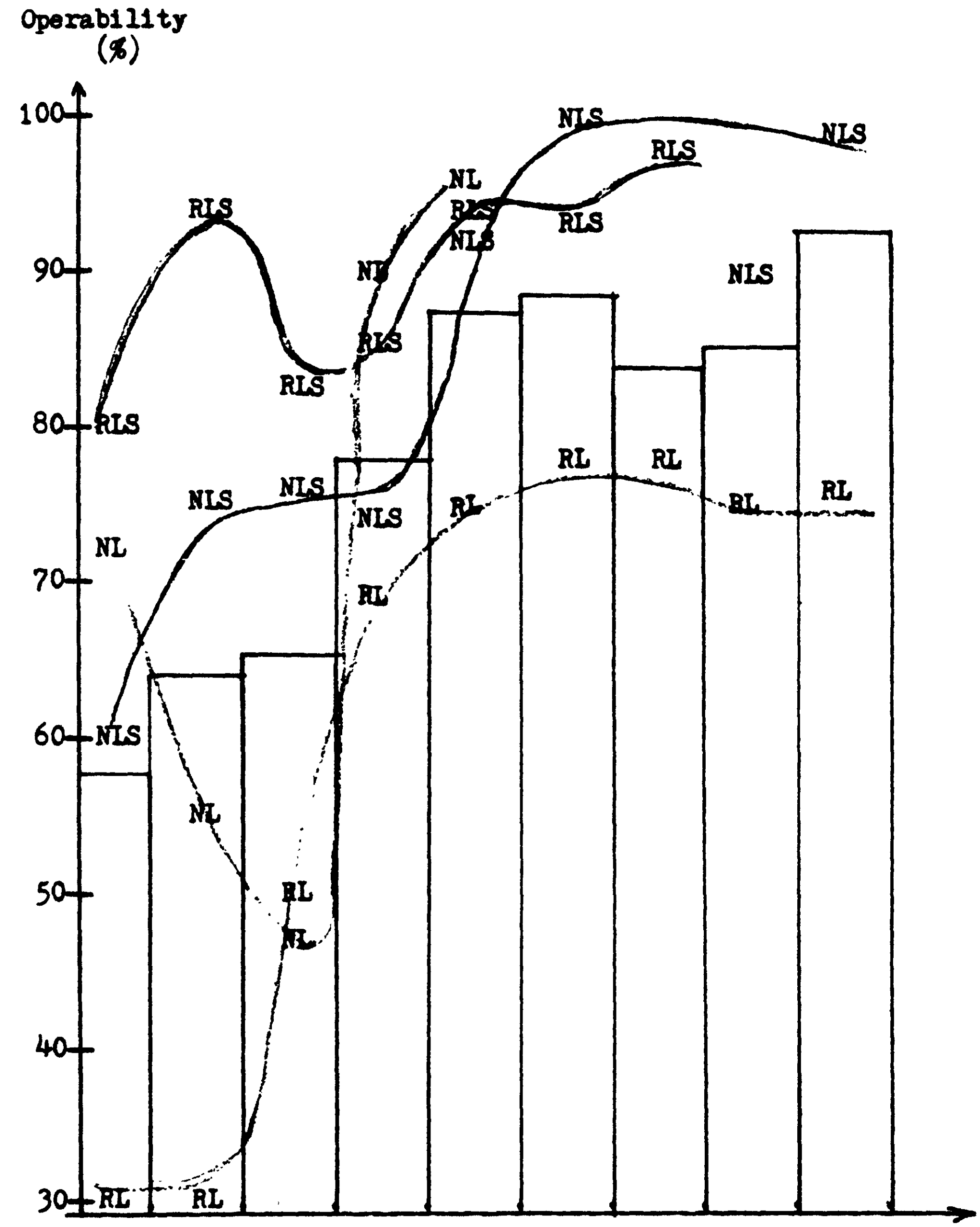
Table 4.2

Evolution of the Operability (%)

	year 0 (a)	year 1	year 2	year 3	year 4	year 5	year 6	year 7	year 8
Cholla 1	2 months	(74) 65.1	84.7	88.7	84.8	96.0	92.5	96.9	N.A.
Duck Creek 1	25 months	(78) 30.0	43.7	68.3	72.7	--	--	--	--
Conesville 5	1 month	(77) 35.4	41.0	34.1	75.6	88.9	--	--	--
Elrama 1-4	0 month	(76) 0	0	46.7	64.9	98.6	78.7	--	--
Phillips 1-6	11 months	(74) 28	28	28	67.6	49.1	68.9	71.5	64.3
Petersburg 3	0 month	(78) NA	NA	NA	NA	--	--	--	--
Hawthorn 3	0 month	(73) 0	0	37.3	28.4	74.1	82.5	100	78.9
Hawthorn 4	0 month	(73) 0	0	41.5	32	69.6	100	100	100
La Cygne 1	6 months	(73) 60.7	77.2	NA	NA	NA	NA	NA	89.0
Green River 1-3	9 months	(76) 86.7	87.3	58.7	99.5	0	0	--	--
Cane Run 4	12 months	(77) 84.4	78.4	71.0	85.9	85.8	--	--	--
Cane Run 5	7 months	(78) 80.9	80	82.7	90.8	--	--	--	--
Paddy's Run 6	0 month	(73) 55.0	62.5	97.5	90.1	78.6	99.7	36.3	89.80
Milton R. Young 2	9 months	(78) 56.3	45.1	60.3	78.0	--	--	--	--
Colstrip 1	2 months	(76) NA	NA	NA	NA	NA	NA	--	--
Colstrip 2	5 months	(76) NA	NA	NA	NA	NA	NA	--	--
Reid Gardner 1	1 month	(74) 0	63.3	77.4	47.6	89.6	88.7	93.3	87.1
Reid Garnder 2	0 month	(74) 0	87.5	74.9	69.6	85.4	92.7	4.3	94.4
Reid Gardner 3	1 month	(76) 54.9	75.3	92.6	87.8	89.2	97.1	--	--
Sherburne 1	2 months	(76) 86.9	88.1	83.6	NA	NA	100	--	--
Sherburne 2	1 month	(77) 87.4	84.5	NA	NA	100	--	--	--
Bruce Mansfield 1	6 months	(76) 79.8	63.5	NA	NA	100	NA	--	--
Bruce Mansfield 2	3 months	(77) 83.8	NA	NA	100	NA	--	--	--
Winyah 2	0 month	(77) 0	94.0	97.5	99.1	93.5	--	--	--
Southwest 1	5 months	(77) 0	30.1	35.3	40.9	74.5	--	--	--
TVA 8	8 months	(78) 83.7	96.3	80.7	NA	--	--	--	--

(NA = Not Available)

a. This column does not give an operability index but the number of months between the start-up and the end of the year



Average Operabil.	Y1	Y2	Y3	Y4	Y5	Y6	Y7	Y8	Y9
Group	57.6	63.3	64.7	77.6	87.8	87.9	81.7	83.8	92.6
NL	72.0	55.1	47.0	90.8	96.6	-	-	-	-
NLS	60.0	75.9	76.4	74.1	94.3	100.0	-	89.0	98.1
RL	31.9	31.5	50.8	68.9	73.8	79.2	77.7	74.8	75.9
RLS	80.2	94.1	82.2	84.8	96.0	92.5	96.9		

<u>Evolution of the Operability</u>

<u>Figure 4.6</u>

(Kennedy <u>et</u>. <u>al</u>., 1972) This curve shows that most innovations exhibit a slow initial acceptance, a period during which many firms adopt the innovation and a final stage in which adoption ceases (at perhaps less than 100%). The meaning is slightly different. The percent of firms adopting the FGD technology does not change since we are studying our 26 utility plants. However it represents the evolution of technical progress and shows how fast the utilities master the FGD technology.

4.3.3 <u>Regulatory Classes and Operability Limit</u>

The sulfur emissions are regulated by standards set up by the Environmental Protection Agency (EPA) and called the New Source Performance Standards (NSPS). These standards, promulgated in December 1971 and in June 1979, are more stringent for new plants than for old plants. Depending on the plant location and the quality of coal used, the plant belongs to one of the following categories:

- A The unit is subject to NSPS promulgated in June 1979.
- B The unit is subject to NSPS promulgated in December 1971.
- C The unit is subject to standards more stringent than 79 NSPS.
- D The unit is subject to standards more stringent than 71 NSPS, but no more stringent than 79 NSPS.
- E The unit is subject to standards equal to or less stringent than 71 NSPS.

These categories are shown on Table 4.3. These data were provided by PEDCo. For each plant are given both the regulatory classification and the

Table 4.3

Regulatory Classes and Operability Limit

Plant Name	Start-Up Date	Process	Size (MW)	Regulatory Classification	$\times 10^9$ g/J SO_2 emission limitation	Operability limit
Cholla 1	10/73	RLS	126	C	430	0
Duck Creek 1	7/76	NLS	378	B	516	74.2
Conesville 5	1/77	NL	411	D	516	80.6
Elrama 1-4	10/75	RL	510	D	258	79.7
Phillips 1-6	7/73	RL	410	D	258	79.7
Petersburg 3	12/77	NLS	532	B	516	70.9
Hawthorn 3	11/72	RL	110	D	258	2.8
Hawthorn 4	8/72	RL	110	D	258	2.8
La Cygne 1	12/71	NLS	874	E	1290	59.6
Green River 1-3	9/75	RL	64	E	387	72.9
Cane Run 4	8/76	RL	190	D	516	74.3
Cane Run 5	12/77	RL	200	D	516	74.3
Paddy's Run 6	4/73	RL	70	E	516	70.4
Milton R. Young 2	9/77	NLA	185	D	516	0
Colstrip 1	9/75	NLA	360	B	516	0
Colstrip 2	5/76	NLA	360	B	516	0
Reid Gardner 1	3/74	RSC	125	B	516	0
Reid Garnder 2	4/74	RSC	125	B	516	0
Reid Gardner 3	6/76	NSC	125	B	516	0
Sherburne 1	3/67	NLSA	720	D	413	0
Sherburne 2	3/77	NLSA	720	D	413	0
Bruce Mansfield 1	12/75	NL	917	D	258	83.6
Bruce Mansfield 2	7/77	NL	917	D	258	83.6
Winyah 2	7/77	NLS	280	B	516	0
Southwest 1	4/77	NLS	194	B	516	75.7
TVA 8	5/77	RLS	550	E	516	96.5

emission limitation expressed in Nanograms (10^{-9} g) per Joule.

The operability limit is defined as the minimum operability necessary so that the FGD system meets the requirements of the plant regulatory classification.

The quantity of sulfur emitted, expressed in Ng/J, is defined as the ratio of the sulfur content over the heat content of the coal used by the utility, and given in Table 3.3.

$$\text{Quantity emitted} = \frac{\text{Aver sulfur content (\%)}}{\text{Aver heat content (j/g)}} \times 10^{9}$$

The quantity of sulfur which must be removed by the scrubber is equal to the difference between the quantity emitted and the emission limitation, given in Table 4.3:

$$\text{quantity removed} = \text{quantity emitted} - \text{emission limitation} \qquad (1)$$

We also know that this quantity removed is equal to the quantity emitted multiplied by the scrubber removal efficiency given in Table 3.2 and by the operability limit OL:

$$\text{quantity removed} = \text{quantity emitted} \times \text{scrubber efficiency} \times \text{OL} \qquad (2)$$

Therefore combining equations (1) and (2), we obtain the value of the operability limit OL:

$$\text{OL} = 1 - \frac{\text{emission limitation}}{\text{quantity emitted}} \times \frac{1}{\text{scrubber efficiency}}$$

This operability limit was calculated for the 26 plants and is shown in Table 4.3. The operability limit distribution is shown below in Figure 4.7.

No. of plants	Average	OL	Standard Deviation σ
26	Group	50.7	12.8
14	New	45.7	14.8
12	Retrofit	63.9	23.5
6	NL	59.2	26.7
7	NLS	35.8	13.9
8	RL	67.16	24.1
2	RLS	78.5	55.5

Figure 4.7: Operability Limit Distribution

The first interesting result is the great number of zeros. It simply means that the scrubber is useless and that on the average the quantity of sulfur emitted is below the limitation. One can therefore wonder why these people bothered investing so much money for nothing. The answer is some concern with the future when new, more stringent standards might be promulgated and when the regulatory classification might be changed. Another answer is the overcapitalization under the form of pollution abatement equipment due to regulatory constraints known as the Averch-Johnson effect, described in Section 3.3.4.

The average operability limit is 50.7, below the average operability of the learning curve (57.6) shown in Figure 4.6. These results are apparently good, However, a closer look is necessary. When not zero, the operability limit is included between 70 and 95%, numbers usually reached by the fourth year of utilization (See Figure 4.6). Moreover the RL category whose learning curve is well below the average learning curve (-20%) has one of the highest operability limits (67.6). In 1981, 5 FGD systems representing 25% of the MW capacity had operability indexes below their operability limits. The conclusion is quite disappointing. Whenever the scrubbers are useless the present operability is very high whereas whenever the emission limitations depend on the operability, this index is generally below the limit.

4.3.4 Main Reasons for Failure

The main reasons for failure are the freeze of the make-up solution, the plugging of the lines and the corrosion of different parts of the FGD system. (Chem Systems International Ltd., 1976)

In the winter months, when the weather conditions are particularly bad, a utility experiences some problems due to frozen pipes. Although it does not endanger the scrubber nor its components, the freeze decreases the level of operability and is difficult to prevent. That is the reason why the operability index does not go over 92%. Moreover the capacity factor of the plant is generally the highest during these winter conditions because the demand for electricity reaches its peak. While the scrubber cannot operate because of the weather, the boiler operates much more than usual and thus a bigger quantity of sulfur is emmitted to the atmosphere.

The plugging of the lines has been reported by almost all the utilities which operate a FGD system. This generally occurs during the first years of operation. While the firm moves along the learning curve, these problems are progressively solved.

A certain level of solids must be maintained in the slurry. Thus the precipitation of gypsum and the calcium sulfite/sulfate solid solution occurs. However the system must be kept below the critical level of saturation with respect to gypsum.

Another parameter, the pH, has an important impact on scaling. A high pH promotes the formation of scale whereas a low PH reduces the sulfur dioxide removal. Optimum levels of 8 for lime and 6 for limestone have been determined by operating experience.

Corrosion seems to be a very important problem in the FGD systems. Even if in the short therm it does not cause a decrease of the operability index, it will on a longterm basis. Sulfurs containing acids and chlorides are the main agents of corrosion. Elimination of scale in the system reduces potential sites for locally high concentrations of chloride ion. The scrubber shells are now made of stainless steel instead of carbon steel because of its superior resistance to corrosion.

Although the scaling and corrosion problems are solved when the utility moves along the operating curve, the freeze problem still remains. Dry scrubbing may be a solution.

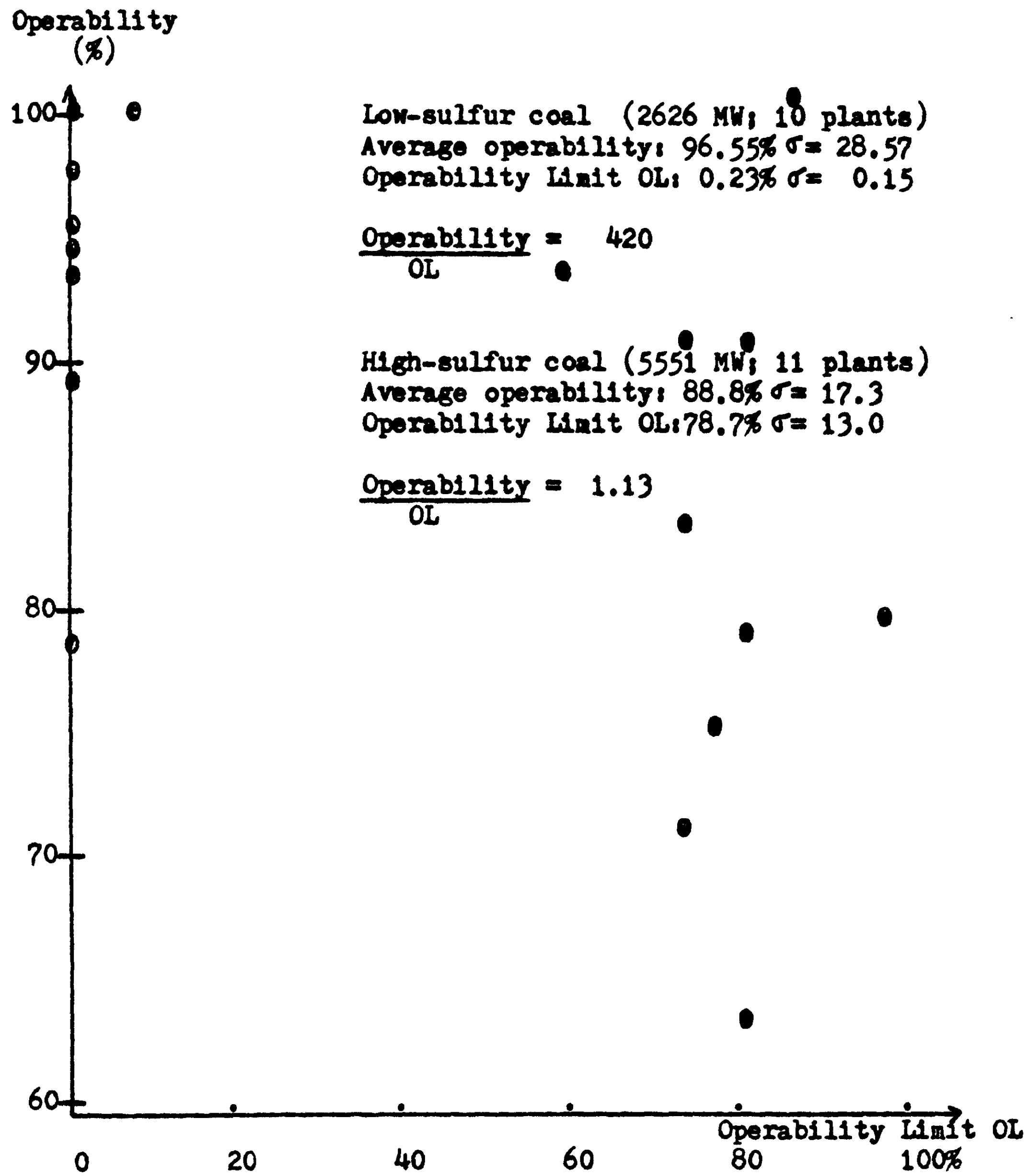
4.3.5 Other Performance Indexes

A good way of comparing the performance of our plants is to plot the operability versus the operability limit, as shown in Figure 4.8. The average operability of the points situated on the left side of this Figure is 96.55 for an average operability limit of 0.23 which gives a very high ratio of 420. On the right side of the Figure the points represent an average operability of 88.8 and an average operability limit of 78.7 which gives a low ratio of 1.13. Fortunately this last ratio is greater than 1 which tends to show that the regulations are met on the average even for high-sulfur coal.

Another way of looking at the performance is to calculate a performance index that considers SO_2 removal efficiency, operability and capacity factor. A similar index has been described by Yeager. (Yeager, 1978) This index has been calculated in Table 4.5. Figure 4.9 shows a classification of these plants according to this index.

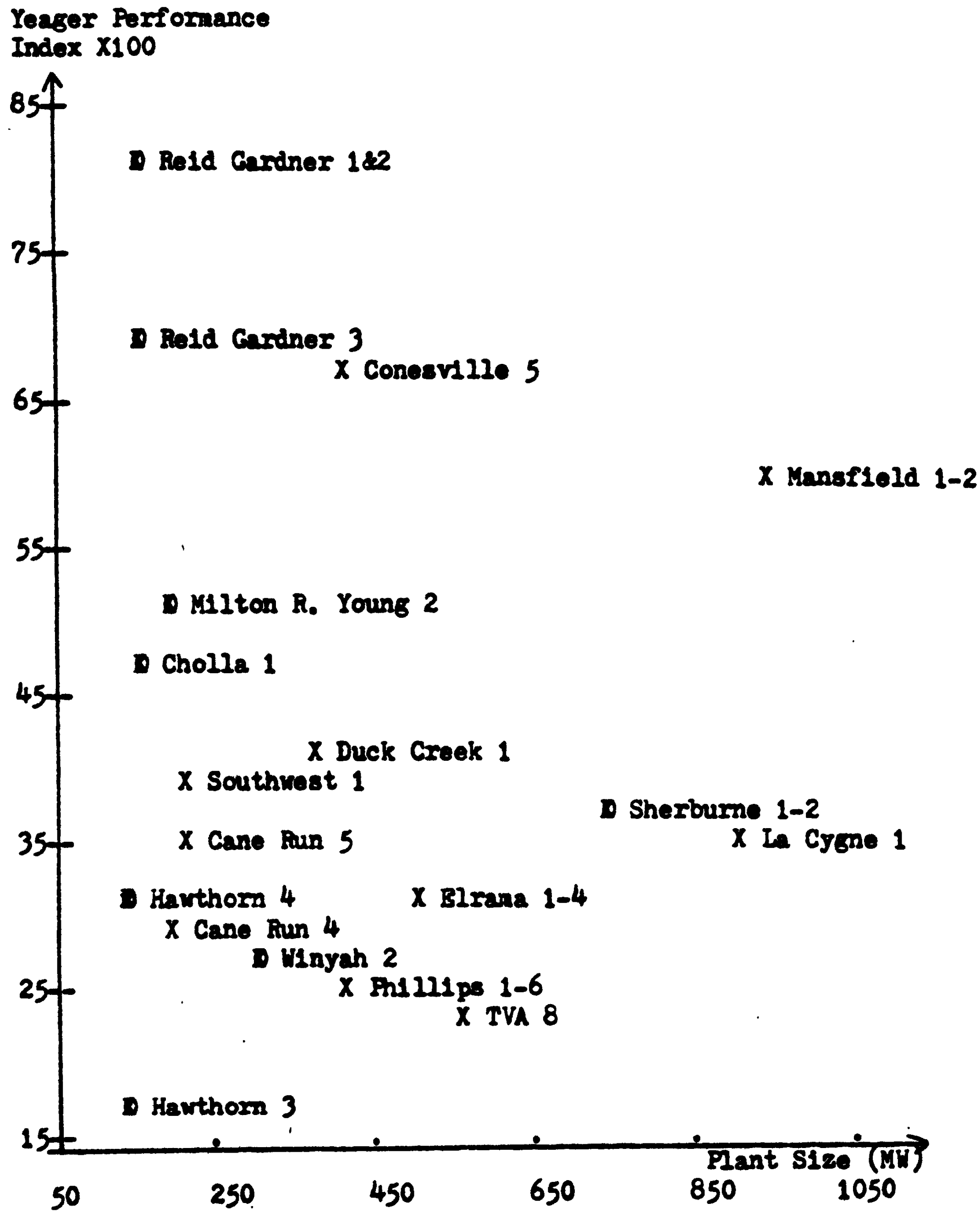
The results are very different from Yeager's analysis, although the same plants are considerd. However Yeager plotted the performance index vs the start-up date which probably means that the FGD availability and capacity factor are average, calculated since the beginning whereas mine are just calculated for the year 1981. It can also be noticed that my index is slightly different since I used the operability instead of the availability. Section 4.2.1 explained the flaws linked with the use of the availability.

The distinction between high-sulfur coal and low-sulfur coal brings opposite results. The average performance index for plants burning high-



Scrubber performance: Low-sulfur vs. High-sulfur coal

Figure 4.8



X High-sulfur coal; Average Index= 47.76 (σ= 10.77)

D Low-sulfur Coal ; Average Index= 41.67 (σ= 9.53)

<u>Classification of the 21 Plants according to Size and Yeager Index</u>

<u>Figure 4.9</u>

sulfur coal is 48 whereas it is only 42 for plants burning low sulfur coal. This suggests a major flaw in the perfomance index. In fact the sulfur removal efficiency as well the plant capacity factor are factors which influence the quantity of sulfur removed but not the performance of the scrubber. The perfomance of the scrubber can be better described by one of the four indexes described in Section 4.2.1. The Yeager index tries to unify two incompatible factors: the quantity of sulfur removed and the actual performance of the scrubber. That is why the Yeager index overestimates the actual performance of scrubbers from high-sulfur plants and underestimates the actual performance of scrubbers from low-sulfur plants.

In order to compare cost and operability the cost index calculated in Section 3.3.4 can be plotted versus the operability as shown in Figure 4.10. Although these points are very dispersed, they can be correlated by a regression whose coefficient of correlation is -0.45 and whose equation is:

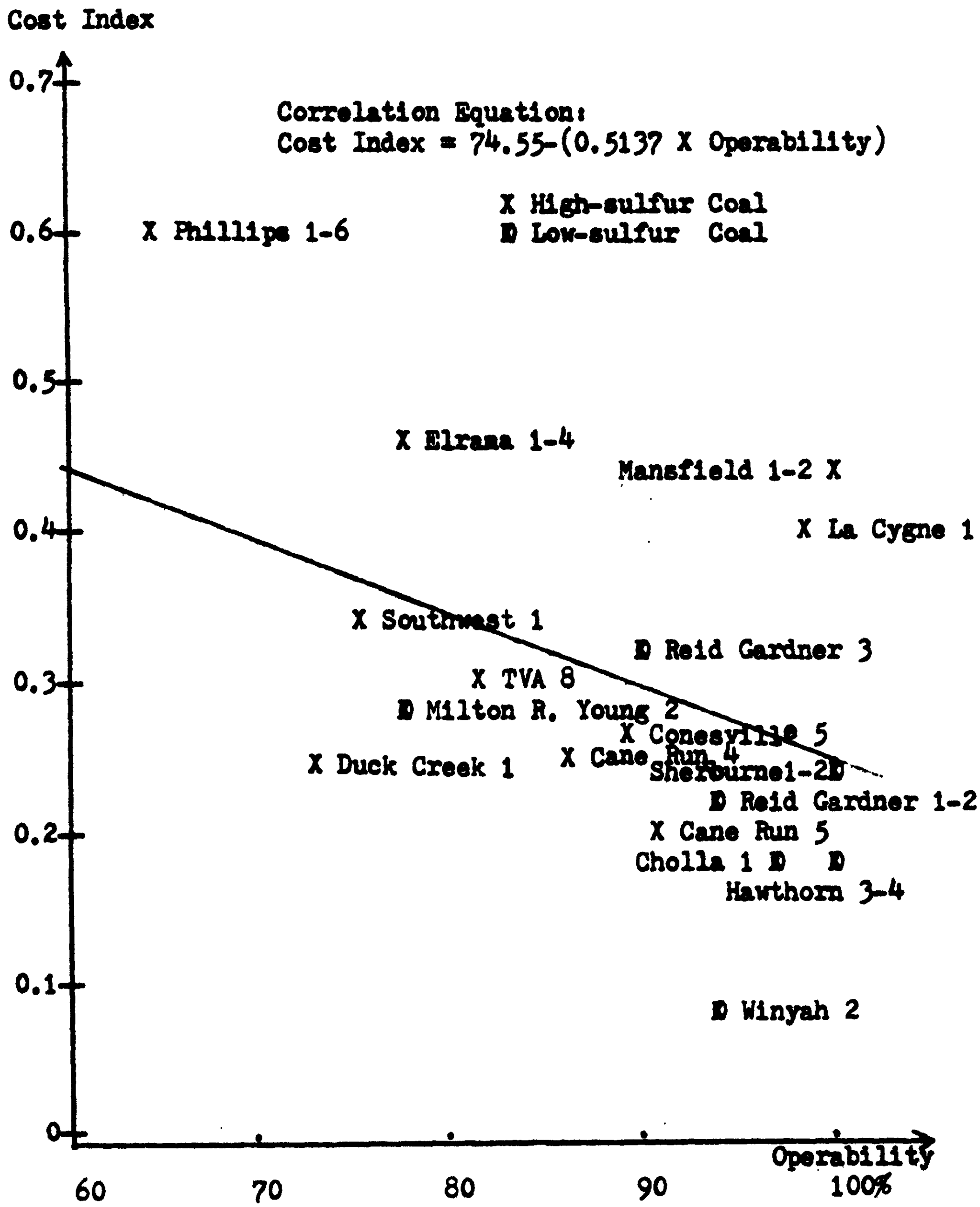
$$\text{Cost Index} = 74.55 - (0.5137 \times \text{operability})$$

The Figure simply means that the greater the operability is, the lower the cost is. This represents an introduction to Section 4.4 where the relation between operating cost and operability is described.

4.4 Relation Between Operability and Cost

4.4.1 Definition of the Operating Cost

The operating cost represents the direct cost portion of the annual



Cost Index vs. Operability

Figure 4.10

Table 4.4

The Operating Cost

Plant Name	Start-Up Date	Size MW	Process	Operating Cost (%)
Cholla 1	10/73	126	RLS	43.6
Duck Creek 1	7/76	378	NLS	63.6
Conesville 5	1/77	411	NL	48.5
Elrama 1-4	10/75	510	RL	37.8
Phillips 1-6	7/73	410	RL	39.7
Petersburg 3	12/77	532	NLS	45.8
Hawthorn 3	11/72	110	RL	50.1
Hawthorn 4	8/72	110	RL	50.1
La Cygne 1	12/71	874	NLS	53.9
Green River 1-3	9/75	64	RL	53.8
Cane Run 4	8/76	190	RL	39.9
Cane Run 5	12/77	200	RL	35.5
Paddy's Run 6	4/73	70	RL	49.8
Milton R. Young 2	9/77	185	NLA	16.6
Colstrip 1	9/75	360	NLA	33.9
Colstrip 2	5/76	360	NLA	33.9
Reid Gardner 1	3/74	125	RSC	41.0
Reid Garnder 2	4/74	125	RSC	41.0
Reid Gardner 3	6/76	125	NSC	28.3
Sherburne 1	3/67	720	NLSA	32.2
Sherburne 2	3/77	720	NLSA	32.2
Bruce Mansfield 1	12/75	917	NL	51.0
Bruce Mansfield 2	7/77	917	NL	51.0
Winyah 2	7/77	280	NLS	22.3
Southwest 1	4/77	194	NLS	33.9
TVA 8	5/77	550	RLS	24.0

No. of Plants	Category	Average	Standard Deviation σ
26	Group	41.4	7.2
14	New	42.9	8.2
12	Retrofit	37.5	6.7
6	NL	44.7	13.3
7	NLS	41.8	9.1
8	RL	41.0	9.5
2	RLS	27.7	8.1

cost as described in Section 3.2.2. This operating cost includes the cost of raw materials such as lime or limestone, the cost of utilities such as water and electricity as well as the cost of operating labor, supervision, maintenance, and repairs.

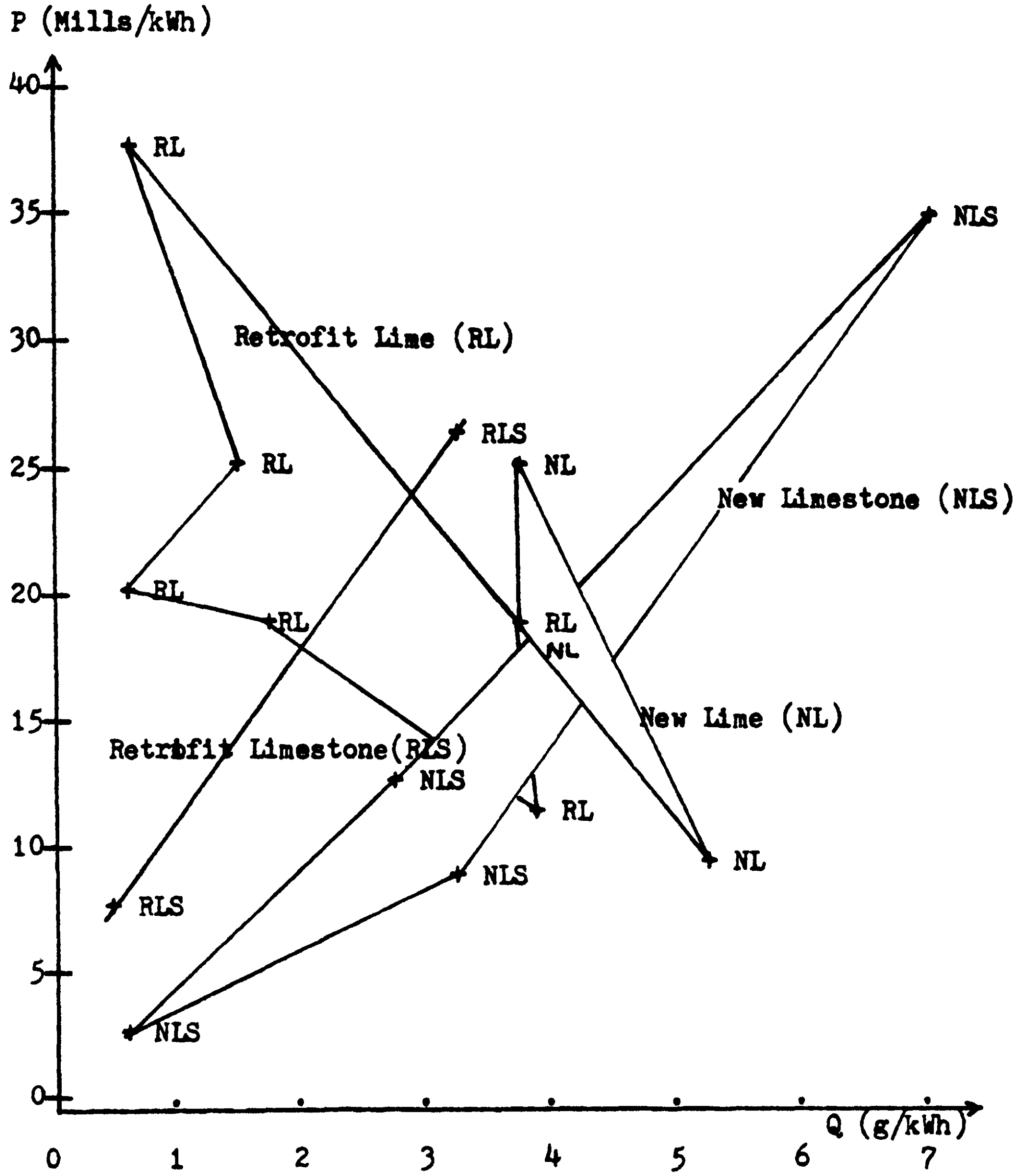
In Table 4.4 the operating cost has been calculated for each plant of the group as a percentage of the total annual cost. The average operating cost represents 41% of the total annual cost.

If the FGD system does not operate during the year the operating cost will be zero and so will the operability. Therefore the total annual cost will decrease. On the other hand, the utility which burns coal without removing sulfur might be obliged to pay a fine. In order to avoid this a clever strategy can be adopted. A simulation of failures can be performed and as we saw in Section 4.3 it will be difficult to detect it.

4.4.2 Average Cost Curve

In the former section we saw how the operating cost influences the operability. The operability directly affects the quantity of sulfur removed and is thus linked with the price necessary to remove this quantity by a relation known as the average cost curve.

The average cost curve drawn on Figure 4.11 represents the annual cost in mills/kWh versus the annual quantity of sufur removed in kg/kWh. However, this annual cost will be different from the annual cost calculated in Table 3.2; an average 65% capacity factor and a continuous operation of the boiler (8760 hrs) were assumed.



Average Cost Curve

Figure 4.11

From the data given by PEDCo, (Bruck et. al., 1981) actual capacity factors and actual numbers of boiler hours were calculated. The results are shown in Table 4.5. For five plants, the number of boiler hours is zero. The demand was too low and the utility did not produce any elctricity. The capacity factor varies within a range from 25% for Hawthron 3 to 95% for Reid Gardner 2.

The new price P is calculated as folows;

$$P\ (\text{mills/kWh}) = \frac{P_0\,(\text{mills/kWh}) \times 0.65 \times 8760}{\text{capacity factor }(\%) \times \text{number of boiler hours (hrs)}}$$

The average operability index was calculated for 1981. The same PEDCo survey shows the average sulfur content (in percent) and the average heat content (in J/g) of the coal utilized, and the sulfur design removal efficiency (in percent) ranging from 45 to 92. These data are listed in Table 4.5

The quantity of sulfur removed is calculated as follows:

$$Q(\text{g/KWh}) = \frac{\text{FGD operability }(\%) \times \text{average sulf. cont.} \times \text{sulf. eff.}}{\text{average heat cont. (J/g)} \times 278\ 10^{-9}}$$

Two observations can be made from this curve:

- The limestone scrubbing processes have increasing average costs whereas the lime scrubbing processes have decreasing average costs.
- The curves for new processes, both limestone and lime are situated on the right side of the Figure, whereas the curves for retrofit processes are situated on the left side.

The decreasing average cost for the limestone process can be explained

Table 4.5

Quantity Removed and Readjusted Price P

Plant name	Process	Sulfur removal effic. %	Aver. Sulfur cont. %	Aver. heat cont. (J/g)	oper. %	Q g/kWh
Cholla 1	RLS	55	.5	23609	96.9	0.41
Duck Creek 1	NLS	85.3	3.4	24181	72.7	3.14
Conesville 5	NL	89.5	4.67	25237	88.9	5.3
Elrama 1-4	RL	83	2.05	26907	78.7	1.79
Phillips 1-6	RL	83	2.05	26907	64.3	1.47
Petersburg 3	NLS	85	3.25	25004	N.A.	N.A.
Hawthorn 3	RL	70	.6	22795	100	0.66
Hawthorn 4	RL	70	.6	22795	100	0.66
La Cygne 1	NLS	80	5.39	21864	98.1	6.97
Green River 1-3	RL	80	2.5	26935	N.A.	N.A.
Cane Run 4	RL	85	3.75	26749	85.8	3.68
Cane Run 5	RL	85	3.75	26749	90.8	3.90
Paddy's Run 6	RL	90	3.70	26284	N.A.	N.A.
Milton R. Young 2	NLA	78	.6	15119	78.6	0.87
Colstrip 1	NLA	60	.78	20569	N.A.	N.A.
Colstrip 2	NLA	60	.78	20569	N.A.	N.A.
Reid Gardner 1	RSC	90	.5	28959	93.3	0.52
Reid Garnder 2	RSC	90	.5	28959	94.3	0.53
Reid Gardner 3	NSC	85	.5	28959	89.2	0.47
Sherburne 1	NLSA	50	.8	19771	100	0.73
Sherburne 2	NLSA	50	.8	19771	100	0.73
Bruce Mansfield 1	NL	92.1	3	26749	100	3.72
Bruce Mansfield 2	NL	92.1	3	26749	100	3.72
Winyah 2	NLS	45	1.1	26749	93.5	0.63
Southwest 1	NLS	80	3.5	26749	74.5	2.81
TVA 8	RLS	70	3.7	23260	80.7	3.24

Table 4.5

Plant name	Average capacity factor %	Boiler hours	p mills/ kWH	Performance Index Yeager	Low & High Sulfur
Cholla 1	87.1	5,005	6.27	46.4	LS
Duck Creek 1	62.9	6,327	8.3	39.0	HS
Conesville 5	83.3	4,884	9.52	66.3	HS
Elrama 1-4	49	8,039	18.65	32.0	HS
Phillips 1-6	50.5	7,968	24.91	26.9	HS
Petersburg 3	N.A.	N.A.	N.A.	--	--
Hawthorn 3	25.8	3,146	36.47	18.1	LS
Hawthorn 4	45.3	3,212	20.35	31.7	LS
La Cygne 1	45.6	4,023	35.07	35.8	HS
Green River 1-3	N.A.	N.A.	N.A.	--	--
Cane Run 4	39.8	5,028	17.64	29.0	HS
Cane Run 5	45.2	5,789	12.53	34.9	HS
Paddy's Run 6	N.A.	N.A.	N.A.	--	--
Milton R. Young 2	83.2	7,386	5.93	51.0	LS
Colstrip 1	N.A.	N.A.	N.A.	--	--
Colstrip 2	N.A.	N.A.	N.A.	--	--
Reid Gardner 1	96.8	7,180	4.75	81.3	LS
Reid Garnder 2	95.3	5,764	6.01	80.9	LS
Reid Gardner 3	88.5	6,911	6.89	67.1	LS
Sherburne 1	71.2	8,349	5.17	35.6	LS
Sherburne 2	72.6	8,432	5.02	36.3	LS
Bruce Mansfield 1	N.A.	3,984	24.85	59.5	HS
Bruce Mansfield 2	65 assumed	5.600	17.68		
Winyah 2	69.8	5,481	2.68	29.4	LS
Southwest 1	63.3	6,020	12.25	37.7	HS
TVA 8	41	3,953	25.65	23.2	HS

by economies of scale. This economic principle, however, does not seem to be valid for the lime process, probably because the price of lime is four times as much as the price of limestone.

The second observation can be interpreted as follows. For the same price, the quantity of sulfur removed for new processes is greater than for retrofit processes which means that the design of new scrubbers makes them more efficient than the retrofit ones.

To obtain these data, different plants were looked at one point in time, the year 1981. We assumed that these different firms were similar, once the differences of capacity factor, operability and number of boiler hours were removed. The principal difficulty is that the firms may not be sufficiently similar and that the data collected may more correctly represent "interutility" differences rather than reflecting a simple relationship between quantity removed and costs. (Johnson, 1960)

Another method would have been to look at the quantity of sulfur removed and cost data for a particular plant in different time periods. (See Section 5) The difficulty with this method is that prices of inputs may change over time. Such price changes will obviously affect costs independently of how a utility's quantity of sulfur removed is changing. (Nicholson, 1978)

The reason why this method was not used in this section is that many data were missing for most of the utilities. Therefore I was not able to derive these curves for all the plants of my survey. However, these curves have been derived for the four utilities listed in the case studies in Section 5.

It will be also noticed that the capital cost is not included in this annual cost, contrary to an usual average cost curve.

4.5 Conclusion

As the FGD technology moves along the learning curve, considerable progress is made in resolving major problems that plague the initial FGD installations. More work needs to be done, however, to optimize system design and reduce cost and system energy demand without impairing reliability and efficiency.

The design of the mist eliminators should be improved because of the plugging of the lines due to precipitation of gypsum.

The instrumentation and process control strategies must be improved as well as the construction materials used in FGD systems and related equipment. The problem of corrosion is a very important one and reduces the life of the scrubber and its components.

The study of the average cost curve shows a very big difference between the adjusted cost P_0 of 5.2 mills/kWh and a real cost P of 36.5 mills/kWh, which represents about 60% of the price of a kWh! However for sodium carbonate and dual alkali processes this difference is smaller (P is even smaller than P_0).

Hence other methods of sulfur removal should be considered. The dry collection processes should be investigated. A substantial amount of work has already been done to verify process design using lime and sodium carbonate reagents for low to medium sulfur coal applications. The feasibility of dry collection for medium to high sulfur coal applications could prove beneficial.

5. CASE STUDIES

5.1 Introduction

In Section 3 and Section 4 we looked at a group of plants and we used a statistical analysis to calculate the cost and to study the operation of the FGD systems installed in the utilities.

In Section 5 we analyze the FGD systems as case studies. For each category previously considered (New/Retrofit Limestone and New/Retrofit Lime Scrubbing) one plant is selected. The criteria of selection are a large unit capacity (125 MW), a good operability index (70%) and a good set of data concerning the operation of the scrubber since its initial start up.

Section 5.2.1, 5.3.1, 5.4.1, 5.5.1 contain descriptions and an analysis of the evolution of the operability along the years for each of the plants selected. The variations are explained and a comparison is conducted between the FGD system and the category which it belongs to.

In Sections 5.2.2, 5.3.2, 5.4.2, 5.5.2 the evolution of costs is described. Actually it would be more accurate to say that we consider the evolution of the annual cost per kWh produced, since the capacity factor of the plant and the number of boiler hours are the variables which determine the cost. The average cost curves for each plant are drawn, using the evolution of cost and operability previously studied.

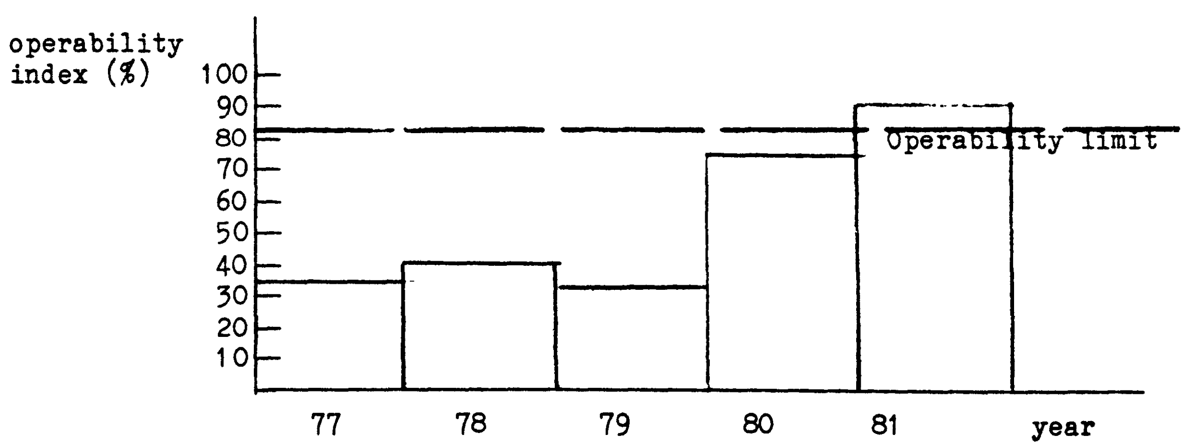
Section 5.2.3, 5.3.3, 5.4.3, 5.5.3 summarize the problems encountered in the case study.

Finally in Section 5.6 a comparison between the FGD system and the category which it belongs to is performed. An attempt is made to explain the differences observed between the average cost curves drawn for the case studies and the general average cost curves drawn in Section 4.4.2.

5.2 New Lime Scrubbing, Conesville 5

5.2.1 Evolution of the Operability

The evolution of the operability is shown in Figure 5.1. The operability limit is very high (80.6%) and is reached only in the fifth year of use, which means that, during the first four years of scrubber operation, the regulations standards were not met. The jump of the operability index at the end of the third year form 34.1 to 75.6 is a characteristic of the learning curve described in Section 4.



Evolution of the Operability - Conesville 5

Figure 5.1

5.2.2 Evolution of the Cost

In 1981, a price P_o of 6.8 mills/kWh was calculated in Section 3 with the data given by PEDCo and the assumption of a continuous operation and a capacity factor of 65%. The actual number of boiler hours and capacity factor have been calculated from 1977 until 1981 and are shown in Table 5.1.

Table 5.1 FGD hours, Boiler hours and Capacity Factor for Conesville 5

year	1977	1978	1979	1980	1981
FGD hours	2351	2704	1932	5392	4342
Boiler hours	6650	6600	5663	7130	4884
Operability (%)	35.4	41.0	34.1	75.6	88.9
Capacity factor (%)	NA	NA	NA	58.1	83.3

The price P_o calculated in 1981 was probably lower in 1977 because of inflation. However, in order to compare the costs and the quantity of sulfur removed, we must keep a constant dollar basis, which will be P_o. The price P will be calculated a follows:

$$P = \frac{Po \times 8760 \times 0.65}{\text{Boiler hours} \times \text{Capacity factor}}$$

When the capacity factor is not available, the usual 65% capacity factor is assumed.

The quantity Q of sulfur removed was calculated with the equation gien in Section 4. The results are shown below in Table 5.2.

Table 5.2

Annual Cost and Quantity of Sulfur Removes

year	1977	1978	1979	1980	1981
mills/kWh P	8.96	9.03	10.52	9.35	9.52
g/kWh Q	2.1	2.4	2.0	4.5	5.3

These results are drawn in Figure 5.5. The average cost curve obtained is very flat, which means that the price is almost constant, whatever the quantity of sulfur removed is.

5.2.3 Problems Encountered

After a fire which delayed the unit start up for one month, the early operations began in January 1977 and were marked by cold weather and related problems such as frozen lines. In April 1977, some plugging occurred in the tube thickeners. Rocks up to five inches in diameter were detected. It was decided to install mechanical separators and metal detectors at the lime shipment facility. Many modifications and repairs were made to the unit instrumentation system, to the absorber liner and to the piping so that the FGD system was most often closed until the end of 1977. The operability for 1977 was 35.4%, which is well below the average operability for the first year of operation, 57.6% calculated in Section 4. We will also notice that the first year operability for the new lime scrubbing category is 72.0%!

In 1978, the operability remained about the same for the same reasons. In April 1978, the FGD system was down due to an excess of flocculant in the thickener. This excess yielded a high solids level in the overflow and resulted in plugging problems in the absorber modules. Finally, in May, the thickener was emptied in order to restore a proper flocculant balance. In July and August outage time was due to plugging in the mist eliminator.

In 1979, the operability index was the lowest since the start up. During January and February, the scrubber did not work because of severe winter weather. In March and April, module B did not operate because of severe corrosion at the inlet presaturator duct. In May and June, the pH lines were plugged. During the first three years of "operation", the FGD system experienced all the problems listed in Section 4.

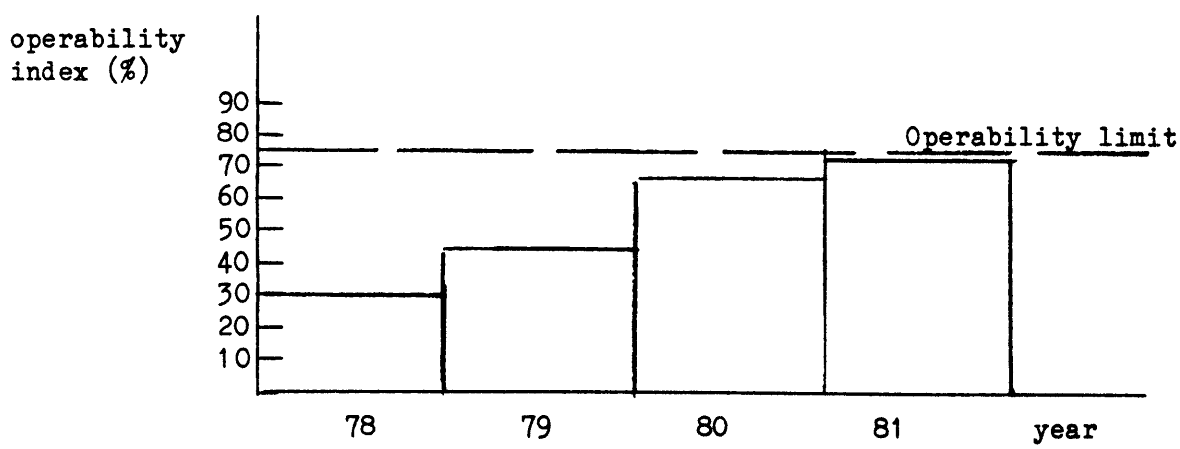
The problems encountered in 1980 were minor problems and therefore the operability finally increased. The instrumentation and mist eliminator nozzle plugging caused some FGD system outage time.

In 1981, the operability was above the operability limit. The FGD system finally met the regulation standards. Other problems appeared, however corrosion was the main one. Pump failure was another one. These problems can reduce the useful life of the system but they do not decrease the operability very much.

5.3 New Limestone Scrubbing - Duck Creek 1

5.3.1 Evolution of the Operability

The evolution of the operability is shown in Figure 5.2. The operability limit is again very high (74.2%) and is never reached during the first four years of use. We can observe again the jump of the index at the end of the second year from 43.7 to 68.3. This jump appears earlier than usual. We must remember that the start-up of the scrubber occurred in July of 1976. No data are given for the period between the start-up time and 1978, which actually postpones the jump one year and a half.



Evolution of the Operability - Duck Creek 1

Figure 5.2

5.3.2 Evolution of the Cost

In 1981, a price P_o of 5.8 mills/kWh was calculated in Section 3, with the data given by PEDCo and the assumption of a continuous operation and a capacity factor of 65%. The actual number of boiler hours and capacity factor have been calculated from 1978 until 1981 and are shown in Table 5.3

Table 5.3 FGD hours, Boiler hours and Capacity Factor for Duck Creek 1

year	1978	1979	1980	1981
FGD hours	959	3131	5319	4599
Boiler hours	3198	7162	7787	6327
Operability (%)	30.0	43.7	68.3	72.7
Capacity factor (%)	60.3	62.6	69.1	62.9

The price P and quantity Q of sulfur removed for each year have been calculated with the formulas used in Section 5.2. The results are shown below in Table 5.4.

These results are drawn in Figure 5.5. The average cost curve shows decreasing costs. We will notice that we have only four points and whereas three of them are in the same area, the other one which gives this curve a negative slope is in a remote place. Therefore these results must be considered with caution.

Table 5.4 Annual Cost and Quantity of Sulfur Removed

year	1978	1979	1980	1981
mills/kWh P	17.13	7.37	6.14	8.30
g/kWh Q	1.30	1.90	.90	3.10

5.3.3 Problems Encountered

The major problem area during the second half of 1976 after the start-up was a massive scale development on the mist eliminators. A fresh water wash system was installed for the mist eliminator. Different modifications (additional spray header and additional mixer) were made at the beginning of 1977. The utility fired low sulfur coals until the entire 4-module scrubber plant was ready for service in August 1978. That is why we don't see any record of the operability between the start-up and 1978.

During the last part of 1978, the major causes for downtime were valve leaks. This resulted in contamination of the recycle pump gland seal water system. A new valve system was installed and the operating pressures were changed to prevent recurrence of the contamination. An excessive limestone carryover to the mist eliminator was also noted. The top rod deck was removed to improve gas flow and eliminate the carryover problem.

In the early months of 1979, frozen line problems were experienced. Freezing problems continued to hamper FGD operations during March. In the last three quarters of the year two major problems were encountered: the mist eliminator was plugged (already a start-up problem three years ago) and storage pump leaks were reported as well as recycle pump failures.

In 1980, the operability almost reached 70%, still below the operability limit. The main problems encountered are due to leaks and repairs because of aging materials. Among replacements were the replacement of the limestone storage tank mixer motor and of the ball mill motor.

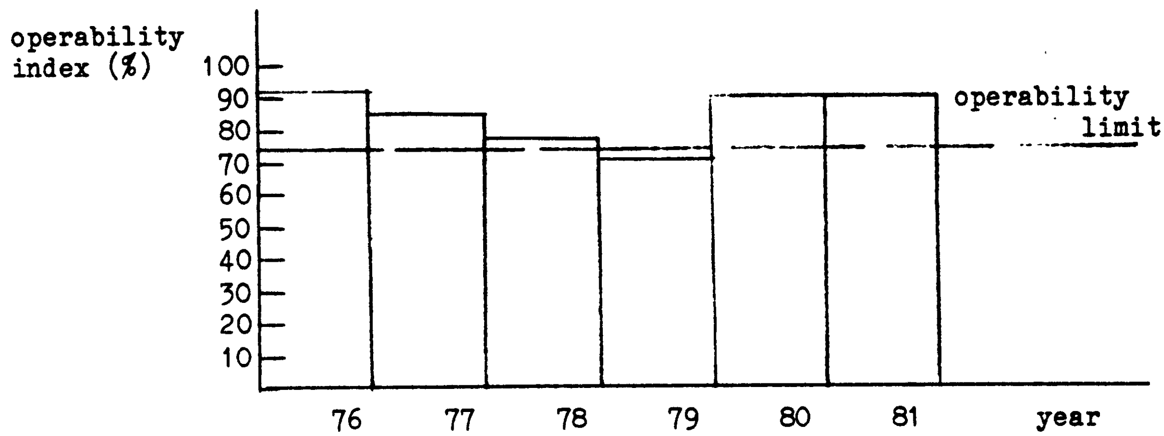
The operability reached its maximum in 1981 at 72.7%. However the major problem of Duck Creek 1, plugging, is not yet solved. This is the main reason why the operability did not reach 100%. Extensive plugging was observed at the beginning of April, resulting in the need for extensive maintenance, cleaning, repairs, and upgrading of each module.

Clearly, at the end of 1981, the plugging problem remained at Duck Creek 1. This problem caused outage time which resulted in a low availability of the system and consequently a quicker deterioration of the main parts of the equipment (lines, pumps, fans,...).

5.4 Retrofit Lime Scrubbing - Cane Run 4

5.4.1 Evolution of the Operability

Whereas the two former case studies, Conesville 5 and Duck Creek 1, had operability indexes well below the average and sometimes below their operability limit, Cane Run 4 has a very high and quite bizarre evolution of the operability. We saw in Section 4 that the Retrofit lime scrubbing systems had a learning curve well below the average, as shown in Figure 5.3. Although the operability limit (74.3%) is the same as Duck Creek 1, only in 1979, the operability index was below its limit.



Evolution of the Operability - Cane Run 5

Figure 5.3

5.4.2 Evolution of the Cost

The actual number of boiler hours and capacity factor have been calculated from 1978 until 1981 and are shown in Table 5.5.

In 1981, a price P_o of 6.2 mills/kWh was calculated in Section 3. For each year, the new price P and the quantity Q of sulfur removed have been calculated with the formulas described in Section 5.2 and with the data displayed in Table 5.5. The results are shown below in Table 5.6.

Table 5.5 FGD hours, Boiler hours and Capacity Factor for Cane Rune 4

year	1976	1977	1978	1979	1980	1981
FGD hours	2962	4208	3813	2136	5259	4316
Boiler hours	3258	4985	4862	3010	6122	5028
Operability (%)	90.9	84.4	78.4	71.0	85.9	85.8
Capacity factor (%)	57.2	49.0	47.6	49.8	49.6	39.8

Table 5.6 Annual Cost and Quantity of Sulfur Removed

year	1976	1977	1978	1979	1980	1981
mills/kWh P	18.94	14.45	15.25	23.55	11.63	17.64
g/kWh Q	3.90	3.60	3.40	3.00	3.70	3.68

The results are drawn in Figure 5.5. The average cost curve is very inelastic. The price varies a lot whereas the quantity of sulfur removed remains about the same. This high inelasticity is due to the evolution of the operability which is almost constant. Actually this average cost curve represents the product of the number of boiler hours times the capacity factor versus the operability, since the reference price P_o remains constant as well as the scrubber design removal efficiency, the coal heat content and the coal sulfur content.

5.4.3 Problems Encountered

The problems are quite different from the problems encountered during the two previous case studies because of the high level of operability. In 1976, there were some minor problems with the spray nozzles in the mobile bed contactor. The plastic expanded due to the high operating temperatures and blocked the slurry feed. These nozzles were replaced with ceramic constructed components.

At the beginning of 1977, the FGD system was taking off line, as usual, because of the freezing problem. The reason for Cane Run 4 is linked to the supply of Lime which ceased because the barges could not come due to the Ohio River freeze up. No real problem was encountered later on. A few modifications were completed. For instance, a new spray header was added to increase the liquid gas ratio. In September 1977 the FGD system was officially proved to have achieved compliance.

In 1978, the operability index decreased from 84.4% to 78.4%, mainly because of severe winter weather.

The scrubber was off line during the month of September 1979, due to a mechanical failure with the damper gates. This is the reason why the operability index is the lowest (71.0%).

In 1980, the operability increased again due to mild winter weather, in spite of several failures which occurred during the last months of 1980. Different failures (spray pump, valves, ductwork and mist eliminators) caused some outage time. This is part of the maintenance necessary to repair a material which becomes old.

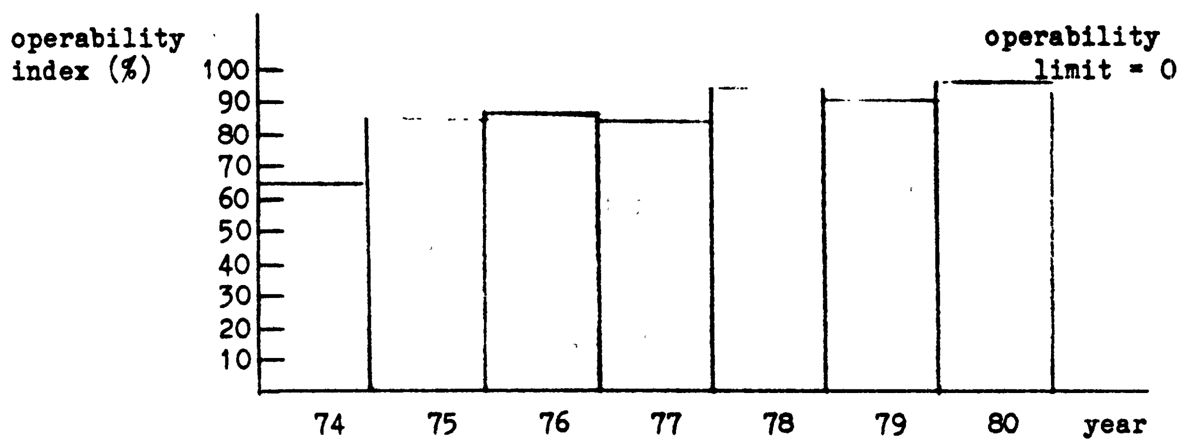
No major problems were encountered during 1981. However, in August 1981 the traditional FGD problem, plugging, appeared in the absorber module and caused some outage time.

This FGD system is very unusual. The learning curve does not appear and thus no major problems wer encountered. The only reason why the operability does not reach 100% is a problem of lime supply during the winter. How can it be solved? Papermills which receive wood through the rivers begin stocking a bigger pile of wood during the summer and the fall in order not to be stopped because of the river freeze up. Cane Run 4 has probably already considered this eventuality but the investment necessary to overstock the lime might be too high. Another solution would be to buy lime from another producer during the winter. Once again, the problem can be solved but the real question is: Is it worth spending extra money just to decrease sulfur emissions since the EPA has officially approved the scrubber?

5.5 Retrofit Limestone Scrubbing - Cholla 1

5.5.1 Evolution of the Operability

The operability limit for Cholla 1 is 0. Therefore a low operability index is expected. These expectations are different from reality. A traditional learning curve is observed with an early jump at the end of the first year from 65.1% to 84.7%. Although the data for 1981 were not available, seven years (74-80) of data have been recorded and the 1980 operability index is 96.9%.



Evolution of the Operability - Cholla 1

Figure 5.4

5.5.2 Evolution of the Cost

The actual number of boiler hours and capacity factor have been calculated from 1974 until 1980 and are shown in Table 5.7.

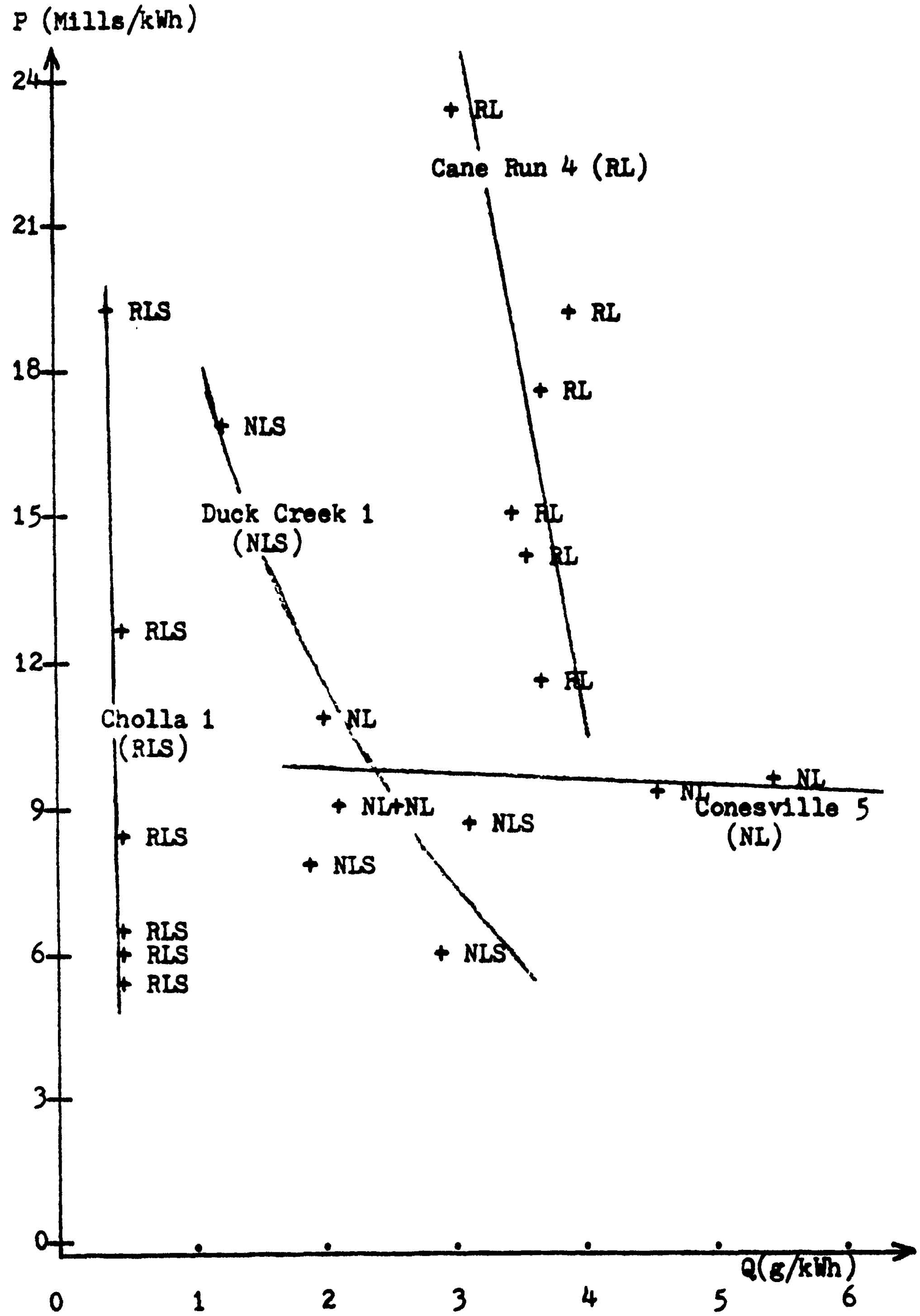
In 1981, a price P_0 of 4.8 mills/kWh was calculated in Section 3. For each year, the new price P and the Quantity Q of sulfur removed have been calculated with the formulas described in Section 5.2 and with the data displayed in Table 5.7. The results are shown in Table 5.8.

Table 5.7 FGD Hours, Boiler Hours and Capacity Factor for Cholla 1

year	1974	1975	1976	1977	1978	1979	1980
FGD hours	1453	6575	2967	6178	6486	6378	4869
Boiler hours	2232	7760	3345	7284	7811	6894	5005
Operability (%)	65.1	84.7	88.7	84.8	96.0	93.5	96.9
Capacity factor %	NA	NA	NA	NA	NA	NA	87.1

Table 5.8 Annual Cost and Quantity of Sulfur Removed

year	1974	1975	1976	1977	1978	1979	1980
mills/kWh P	18.84	5.42	12.57	5.77	5.38	6.10	8.40
g/kWh Q	0.28	0.36	0.38	0.36	0.41	0.39	0.41



<u>**Case Studies - Average Cost Curves**</u>

<u>**Figure 5.5**</u>

The results are drawn in Figure 5.5. The average cost curve is similar to the Cane Run 4 case. Since the operability is very high and almost constant, the quantity of sulfur removed remains constant whereas the price varies following the number of boiler hour fluctuations. The quantity of sulfur removed per kWh is very small. This is due to the low sulfur content of the coal used by Cholla 1 and a consequence of the zero operability limit.

5.5.3 Problems Encountered

The main problem which occurred after the commercial startup in December 1973 was a vibration problem. The difference in the size of the main duct and reheated transition duct caused the gas flow to produce harmonic vibrations in the reheater. The installation of baffles partially dampened the vibrations.

The two other problems which appeared are classical FGD problems: corrosion and plugging. One of the reheater bundles was badly corroded by acid that condensed in the uninsulated duct upstream of the reheaters. The tube bundle was replaced, a baffle was installed to divert condensed acid from reheater tubes and the duct upstream of the reheater was insulated.

When the system operated at low flow rates, some lines plugged, solids settled out in standby pumps and excessive fan vibrations occurred because of an accumulation of scale buildup when the unit was idle. To solve these problems the piping was modified to eliminate stagnant pockets, the pumps were flushed immediately after removal from service and the fan was sandblasted.

Operation of the system throughout 1975 and 1976 was accompanied by a number of minor problem areas related to plugging and corrosion. the operability was very high during these two years at about 85%. As a consequence of the corrosion/erosion problem, many leaks were discovered at sensitive points of the scrubber. The last 15% necessary to reach 100% were due to intensive repairs and maintenance caused by these multiple minor problems. The weather in the winter did not seem to be a problem.

During 1977, routine maintenance was required. In December, the overhaul period began. Therefore the boiler and scrubbing system were out of service. Evidence of chloride attack was found in the liquid gas centrifugal separator shell and on the reheater tubes. Extensive corrosion was also discovered in the ductwork. Although the utility had recoated different parts, the problem was not fully resolved.

During 1978, 1979, and 1980, no major problems were reported. A very high operability index (around 95%) means that the only outage time was due to routine maintenance.

It is amazing to see how busy people can be trying to improve the operability level when they know that the operability limit is zero and that the scrubber is not necessary. Usually utilities with a zero operability limit have a very high operability index. An explanation could be the following: the utilities which have a zero operability limit have not much sulfur to remove from their coal. Therefore the usual plugging and corrosion problems have not the same gravity as for a utility with a high operability limit.

5.6. Conclusion

The comparison of the average cost curves obtained for each of these case studies with the curves obtained in Section 4 for the corresponding category is interesting. Striking differences can be observed and explained by the two following considerations.

As we saw in this section, each case study is not really a good representative of the category which it belongs to. Therefore the average cost curves drawn in Figure 5.5 give only a partial view of what the real curves look like.

We must also consider the fact that the curves drawn in Figure 5.5. are drawn with data given for a period ranging from 4 to 7 years, whereas the curves drawn in Figure 4.8 are drawn for the year 1981 only. Therefore these later curves can be viewed as short run curves, while the former ones can be viewed as long run curves, which are the aggregate of different short run curves.

6 CONCLUSIONS AND RECOMMENDATIONS

6.1 Conclusions

The cost analysis shows that the limestone wet scrubbing process is the cheapest of all FGD processes. It is also cheaper to install a scrubber on a plant which uses low-sulfur coal than on a plant which uses high-sulfur coal. The financial analysis which takes into account capital and annual costs reduces the gap between retrofit and new scrubbers. The overall result is that scrubbing raises utility capital requirements by 25 percent and electricity bills by at least 15 percent if we assume that the burden of the FGD technology is totally shifted onto the consumer.

Our functional analysis shows that the scrubber becomes operational only three years after the start-up date, which corresponds to a move along the learning curve. However the scrubber works well when it removes almost no sulfur (low-sulfur coal) whereas problems of plugging and corrosion prevent a good performance of the scrubber which "tries" to remove a lot of sulfur (high-sulfur coal).

Moreover the operability limit defined as the minimum operability necessary to meet the regulations is too high for high-sulfur coals, and in most cases even after five or more years the regulations are still not met. On the other hand, scrubbers controlling the emissions from plants burning low-sulfur coal have a zero operability limit, which means that the regulations are met even without scrubbers. It is a result of the New Source Performance Standards which require every new plant to install a scrubber. Ironically, these low-sulfur scrubbers do not have many problems. This is logical since they do not remove much sulfur.

6.2 Recommendations

Therefore the legislation should be changed. A mandate such as "All new plants must install scrubbers" must be avoided and replaced by the "Best available Technology" introduced in the Clean Air Act of 1970. For existing scrubbers, the operability limit should be the same, whatever the location or the type of coal used. It means that the standards should become more stringent for low-sulfur coals (in order to increase the operability limit) and less stringent for high-sulfur coals (in order to reduce the operability limit). However we know from the past that the solution chosen differs from the rational solution. In this particular problem a consensus must be found between the different stakeholders who are the environmentalists, the utilities, the Department of Energy, the coal miners and the FGD system designers.

In addition to its economic, energy and environmental impacts, the United States' decision on whether and how to implement control strategies could have international implications. At a November 1980 conference on acid precipitation in Portland, Maine, the Parliamentary Secretary of the Canadian Ministry of the Environment made his government's position clear:

> "The official position of the government of Canada is that we cannot wait for a perfect understanding of the acid precipitation phenomenon before moving to control it."

However the legislator cannot be blamed for the poor performance of the scrubber. Research and Development must be pursued in order to optimize system design and reduce cost and system energy demand. Improvement of mist elimination and instrumentation as well as optimization of construction materials will reduce the plugging and corrosion problems.

Investigation of other processes like dry collection should be conducted. A substantial amount of work has already been made to verify process design using lime and sodium carbonate reagents for low to medium sulfur coal applications. The feasibility of dry collection for medium to high sulfur coal applications could prove beneficial and shoud be investigated. Also R&D on "in-combustion" sulfur removal, (e.g. lime injected multistage burner (LIMB) should be further increased.

Finally a constant enforcement pressure might improve the operability! Today, inspection visits are few and far between. The regulators rely on the polluters themselves to supply data on their scrubbing efficiency and thus regulators are unable to distinguish reliable from unreliable information. Unqualified utility employees are sent to the scrubbing operation. We know that scrubbers constantly demand creative tending when they become clogged or corroded. Therefore a conscientious and highly competent staff is an absolute requirement. Why, for instance, is there such a difference between the Japanese and American operability of scrubbers? People believe that the successful use of scrubbers in Japan is due to the strength of the Japanese enforcement program. The Japanese operate control research centers that are usually linked directly, via telemetry, to stations monitoring emissions from a major source.

It is therefore important for the EPA to create an administrative infrastructure equal to the challenge of enforcement.

APPENDIX

Definition of the Average and of the Standard Deviation

This appendix will briefly review some of the statistical methods which have been used in this thesis. Two main quantities, the average and the standard deviation have been calculated for different sets of data including capital and annual costs as well as viability indexes.

Average

The average is a weighted average which takes into account the capacity of the plant expressed in Megawatts (MW). For instance, the average operability $\overline{O}$ of a group of N plants, each of size si and of operability Oi, can be expressed as follows:

$$\overline{O} = \sum_{i=1}^{N} \frac{Oi\ si}{\sum_{i=1}^{N} si} = \frac{\sum_{i=1}^{N} Oi\ si}{\sum_{i=1}^{N} si}$$

This weighted average has been used as often as possible. As a matter of fact, the different annual viability indexes for instance, given in Table 4.1 and 4.2 are weighted averages of monthly viability indexes provided by PEDCo. Environmental.

Standard Deviation

The standard deviation which measures the variability or dispersion of the data has also been calculated as a "weighted standard deviation." The standard deviation called σ and calculated for the above example can be expressed as follows:

$$\sigma^2 = \sum_{i=1}^{N} \frac{Oi\ si}{\sum_{i=1}^{N} si} - \overline{\frac{O}{N}}^{\,2}$$

$$\text{or} \quad \sigma = \frac{1}{N} \times \frac{1}{\sum_{i=1}^{N} si} \times \sum_{i=1}^{N} (Oi\ si - \sum_{i=1}^{N} Oi\ si)^2$$

$$\sigma = \frac{1}{N} \times \frac{1}{\sum_{i=1}^{N} si} \times \sum_{i=1}^{N} (\sum_{\substack{j=1 \\ j\neq i}}^{N} Oi\ si)^2$$

It will be noticed that the standard deviation has been calculated with the population parameter taken to be N, the sample taken being a population.

Warning

A 95% confidence interval is an interval around the average such that we are 95% sure that the interval contains the true average. If σ represents the standard deviation of a normally distributed set of data, then such an interval has the following limits:

average - 1.96 σ and average + 1.96 σ.

This confidence interval however cannot be constructed if we don't have a normal distribution. Another analysis should be done to construct such intervals in case for instance of exponential or t-distributions.

The standard deviation can always be calculated and measure the variability or the dispersion of the data (it is called risk in finance). However only in the case of a normal distribution can it be interpreted as the boundary of a confidence interval.

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