PB83-101329

Acid Rain Mitigation Study. Volume I
FGD Cost Estimates

Radian Corp.
Austin, TX

Prepared for

Industrial Environmental Research Lab.
Research Triangle Park, NC

Sep 82

U.S. DEPARTMENT OF COMMERCE
National Technical Information Service
NTIS®

EPA-600/2-82-070a
September 1982

PB83-101329

ACID RAIN MITIGATION STUDY
Volume I. FGD Cost Estimates
(Technical Report)

by

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EPA Contract No: 68-02-3171

Work Assignment 12

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Prepared for:

INDUSTRIAL ENVIRONMENTAL RESEARCH LABORATORY
OFFICE OF RESEARCH AND DEVELOPMENT
U.S. ENVIRONMENTAL PROTECTION AGENCY
RESEARCH TRIANGLE PARK, NC 27711

TECHNICAL REPORT DATA

(Please read Instructions on the reverse before completing)

1. REPORT NO.	2.	3. RECIPIENT'S ACCESSION NO.
EPA-600/2-82-070a		PB83 101329

4. TITLE AND SUBTITLE	5. REPORT DATE
Acid Rain Mitigation Study: Volume I. FGD Cost Estimates (Technical Report)	September 1982
	6. PERFORMING ORGANIZATION CODE

7. AUTHOR(S)	8. PERFORMING ORGANIZATION REPORT NO.
J. G. Ball and W. R. Menzies	DCN 81-203-001-12-23

9. PERFORMING ORGANIZATION NAME AND ADDRESS	10. PROGRAM ELEMENT NO.
Radian Corporation 8501 Mo-Pac Boulevard Austin, Texas 78766	11. CONTRACT/GRANT NO. 68-02-3171, Task 12

12. SPONSORING AGENCY NAME AND ADDRESS	13. TYPE OF REPORT AND PERIOD COVERED
EPA, Office of Research and Development Industrial Environmental Research Laboratory Research Triangle Park, NC 27711	Task Final; 2/80-2/81
	14. SPONSORING AGENCY CODE EPA/600/13

15. SUPPLEMENTARY NOTES IERL-RTP project officer William D. Baasel is no longer with EPA. For details, contact P. P. Turner, Mail Drop 62, 919/541-2826. Volume III is the industrial boiler technical report. Volume II contains the appendices.

16. ABSTRACT The report gives results of work to provide a consistent set of capital investment and operating costs for flue gas desulfurization (FGD) systems retrofitted to existing industrial boilers. The investigation of wet limestone scrubbers and lime spray drying FGD systems included: (1) the apparent discontinuities in both FGD system capital investment and operating costs; (2) FGD retrofit factors applied to existing boilers based on published reports; and (3) differences between PEDCo Environmental, Inc. and TVA cost estimates for utility boiler FGD systems. These costing issues were examined on the bases of design scope, costing factors (for equipment installation, indirect investment, etc.), year of costs, inherent strengths and weaknesses, and published data of actual system costs. Recommendations are made for the cost bases to use in further acid rain studies.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS		b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group	
Pollution	Calcium Carbonates	Pollution Control	13B	07B
Flue Gases	Limestone	Stationary Sources	21B	08G
Desulfurization	Calcium Oxides	Lime	07A,07D	
Cost Estimates	Rain	Acid Rain	05A,04A	04B
Boilers	Acidity		13A	
Industrial Processes			13H	

18. DISTRIBUTION STATEMENT	19. SECURITY CLASS (This Report)	21. NO. OF PAGES
Release to Public	Unclassified	164
	20. SECURITY CLASS (This page) Unclassified	22. PRICE

EPA Form 2220-1 (9-73)

NOTICE

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ABSTRACT

The U.S. EPA has initiated a multiphased study of the acid rain problem. As part of Phase I, Radian Corporation investigated SO_2 emissions and controls in the industrial sector. The primary objective of this work was to provide a consistent set of capital investment and operating costs for flue gas desulfurization (FGD) systems applied to both industrial and electric utility boilers. Retrofit factors as well as the cost for FGD systems applied to new boilers were addressed. Wet limestone scrubbing and lime spray drying FGD systems were evaluated.

In conducting the work to provide a consistent set of capital investment and operating costs for FGD systems retrofitted to existing boilers, the following issues were investigated:

- The apparent discontinuities in both FGD system capital investment and operating costs as a function of boiler capacity in the region between industrial boilers and small utility boilers,

- FGD retrofit factors applied to existing boilers based on published reports, and

- The differences between PEDCo Environmental, Inc. and TVA cost estimates for utility boiler FGD systems.

These costing issues were examined on the bases of design scope, costing factors (for equipment installation, indirect investment, etc.), year of costs, inherent strengths and weaknesses, and published data of actual system costs. Recommendations are made for the cost bases to use in further acid rain studies.

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SECTION 1

INTRODUCTION AND SUMMARY

1.1 INTRODUCTION

There is a growing concern about the acidity of precipitation in the northeastern United States and Canada. Acidic precipitation is thought by many scientists to kill aquatic and plant life, damage crop-growing soil, and accelerate erosion and damage to buildings. Although the mechanisms producing acid rain are not clearly understood, sulfur dioxide (SO_2) and oxides of nitrogen (NO_x) are thought to be the precursors of the chemicals that cause acid rain. Large quantities of SO_2 and NO_x are produced by various combustion and non-combustion processes in both the utility and industrial sectors.[1] Reducing these SO_2 and NO_x emissions to the atmosphere should reduce the potential for acid rain.

Because this concern is increasing, the United States Environmental Protection Agency (EPA) initiated a multi-phased study of the acid rain problem. As one part of Phase I, Radian Corporation investigated SO_2 emissions and controls in the industrial sector, while Teknekron, Inc. made a similar study of the utility sector. The results of these studies would provide direction for additional phases. The objectives of the later phases are to investigate SO_2 sources in more detail than Phase I, to investigate NO_x sources, and to model source/receptor relationships.

In support of the Phase I efforts, Radian Corporation was asked to provide a consistent set of capital investment and operating costs for flue gas desulfurization (FGD) systems applied to both industrial and electric utility boilers. Since existing SO_2 sources are the primary targets for reducing the impacts of acid rain, retrofit factors as well as the cost for

FGD systems applied to new boilers were addressed. This report summarizes the results of that cost work.

The cost estimates used as the basis for this study are:

- Utility boiler FGD systems by TVA and PEDCo Environmental, Inc., and
- Industrial boiler FGD systems by Radian Corporation.

Wet limestone scrubbing and lime spray drying FGD systems were evaluated. The U.S. EPA has recognized that there appear to be discrepancies in these published cost estimates in two areas:

- Utility boiler limestone FGD system costs prepared by TVA and PEDCo Environmental, Inc., and
- FGD system costs in the capacity transition from industrial boilers to small utility boilers.

To achieve the primary objective of the study (provide a consistent set of capital investment and operating costs for FGD systems retrofitted to existing boilers), the following issues were investigated:

- The apparent discontinuities in both FGD system capital investment and operating costs as a function of boiler capacity in the region between industrial boilers and small utility boilers,
- FGD retrofit factors applied to existing boilers based on published reports, and
- The differences between PEDCo Environmental, Inc. and TVA cost estimates for utility boiler FGD systems.

The above costing issues are examined on the bases of design scope, costing factors*, year of costs, inherent strengths and weaknesses, and published data of actual system costs. Recommendations are made for the cost bases to use in further acid rain studies.

This report contains two volumes. Volume I is divided into four major sections. Section 1 contains an introduction and summary of results. The three issues described above are addressed in Sections 2, 3, and 4, respectively. Volume II, Appendices, contains the technical support for the study.

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*For equipment installation, indirect investment, etc.

1.2 SUMMARY OF RESULTS

As discussed in the introduction, the primary objective of the study was attained by:

- resolving apparent discontinuities in both capital and operating cost estimates for FGD systems applied to new industrial and utility boilers,

- evaluating the retrofit factor studies and recommending retrofit factors to be used in the acid rain work, and

- comparing the FGD system cost estimates prepared by TVA and PEDCo Environmental, Inc. for utility boiler applications.

The results of the work in each area are summarized below. Each of the three issues identified above will be discussed separately.

1.2.1 Utility and Industrial Boiler FGD System Costs

Significant discontinuities in both the FGD system capital investment and operating cost areas as a function of boiler capacity have been observed in the capacity transition from industrial to small utility boiler systems. This study attempts to determine the causes of these discontinuities and to provide a consistent set of costs (capital and operating) for both types of FGD systems applied to new boilers. Cost estimates by TVA (for utility boilers) and Radian Corporation (for industrial boilers) were used for this analysis since these estimates are current and well-documented. In order to properly compare the TVA and Radian estimates, the costs were adjusted to the same economic and technical bases, which include:

- design scope made identical,
- same year of construction basis,
- same indirect investment algorithm basis, and
- same unit cost basis for labor, raw materials, utilities, etc.

In addition, major components of industrial boiler FGD systems are usually shop-fabricated whereas utility systems are field-erected. The capital and operating costs developed after accounting for the differences described above were compared to determine if the discontinuities were real or a result of inaccuracies in one or both sets of cost data.

Wet limestone scrubbing and lime spray drying FGD systems are the only processes evaluated in this study. For electric utility plants, wet lime and limestone systems dominate the operating units while wet lime/limestone scrubbing and lime spray drying processes are the prevalent systems being planned for future facilities. For industrial boilers, dual alkali and sodium (once-through) systems dominate operating and planned units, although spray drying systems are beginning to be applied. The dual alkali is more typical of the FGD system that will be applied to large industrial boilers. Sodium (once-through) will most likely be applied to small boilers where the high TDS (total dissolved solids) liquid waste can be easily disposed of (such as on steam generators used in oil field injection where the liquid waste can be disposed of by well injection or in evaporation ponds).

To simplify the basis of this and other studies, only the wet lime/limestone FGD costs are recommended for use in developing cost impacts of FGD control for acid rain mitigation. The reasons for this recommendation are:

- The capital and operating costs for wet limestone and dual alkali FGD systems are comparable for industrial boiler FGD applications over the capacity range of 30 - 200 x 10^6 Btu/hr. boiler heat input, and

- Due to the large amounts of data on existing utility boiler FGD systems, the cost estimates for limestone systems should be more accurate than for lime spray dryer systems. In addition, the cost estimates supplied by TVA for utility boiler spray dryer FGD systems were preliminary and had not been finalized prior to completing this report.

Only the costs for wet limestone FGD systems are presented and discussed in this summary. However, the analysis of spray drying in Chapter 2, Section 2 points out the major factors that affect the costs for these systems.

The capital and annual first year operating and maintenance (O&M)* costs for FGD systems applied to new industrial boilers are derived from the cost data developed by Radian Corporation. These costs are for limestone FGD systems, however, Radian found that dual alkali and limestone FGD costs were comparable (within 10 percent) for the capacity range evaluated. These cost data are part of the background information document which was developed to support new source performance standards for industrial boilers. Table 1.2.1-1 presents a complete breakdown of the capital investment costs (1980 dollars) for FGD systems applied to new industrial boilers ranging in capacity from 30 to 200 million Btu per hour. Table 1.2.1-2 shows the first year O&M costs for those same FGD systems. These costs are recommended for use in the acid rain study.

TVA has performed a similar cost analysis for limestone FGD systems applied to new utility boilers. Their costing work is part of an on-going program to develop detailed and accurate costs for utility-sized FGD systems. Table 1.2.1-3 presents the capital investment costs, while Table 1.2.1-4 shows the first year annual O&M costs. These costs are also recommended for use in the acid rain study.

The industrial and utility boiler FGD system capital investments, shown in Tables 1.2.1-1 and 1.2.1-3, respectively, should exhibit some discontinuity in the capacity transition from large industrial boilers to small utility boilers due to the following:

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*Includes raw materials, labor, maintenance, utilities, solid waste disposal (if applicable), and overhead. Does not include capital-related costs such as depreciation, income taxes, interest, return-on equity.

TABLE 1.2.1-1 INDUSTRIAL BOILER LIMESTONE FGD SYSTEM CAPITAL INVESTMENT

Boiler Heat Input Capacity, 10^6 Btu/hr	Capital Investment*, 10^3 $			
	30	75	150	200
Direct Investment				
Raw Materials Handling	59	99	147	171
SO_2 Scrubbing	149	244	368	401
Fans	20	40	69	76
Solids Separation	160	189	227	275
Utilities & Service	23	34	49	55
Total Direct Investment (TDI)	411	606	860	978
Indirect Investment				
Engineering	98	98	98	98
Construction & Field Expense	41	61	86	98
Construction Fees	41	61	86	98
Startup	8	12	17	19
Performance Test	4	6	9	10
Total Indirect Investment (TII)	192	238	296	323
Contingencies	121	169	231	260
Total Turnkey Investment (TTI)	724	1,013	1,387	1,561
Land	0.6	0.8	1	1
Working Capital	52	72	106	126
Total Cap. Investment (TCI) 1978 $	777	1,086	1,494	1,688
TCI x 1.21 = 1980 $	940	1,314	1,808	2,042
TCI (1980$) $10^3$$/10^6 Btu/hr	31.3	17.5	12.1	10.2

* Refer to Tables 2.1.2-4 and 2.1.2-5 for bases.

TABLE 1.2.1-2 INDUSTRIAL BOILER LIMESTONE FGD SYSTEM FIRST YEAR OPERATING AND MAINTENANCE COSTS

Boiler Heat Input Capacity, 10^6 Btu/hr	Annual O&M Cost, 10^3 \$/Yr (1978\$) 30	75	150	200
Direct Costs				
Raw Material				
Limestone	10	24	49	65
Conversion Costs				
Operating Labor	105	105	105	105
Supervision	21	21	21	21
Utilities				
Process Water	0.2	0.7	1	2
Power	7	18	36	42
Maintenance Labor & Materials	33	48	68	78
Solid Waste Disposal	28	71	143	190
TOTAL DIRECT COSTS	204	288	423	503
Indirect Costs				
Payroll Overhead	38	38	38	38
Plant Overhead	40	44	48	50
G&A	31	43	60	68
TOTAL INDIRECT COSTS	109	125	146	156
Total First Year O&M, 1978$	313	413	569	659
1981 \$ (1978 \$ x 1.285)	402	531	731	847
\$/10^6 Btu (1978\$)	1.99	1.05	0.72	0.63
\$/10^6 Btu (1981\$)	2.56	1.35	0.93	0.81

*Refer to Tables 2.1.2-4, 2.1.2-5, and 2.1.3-3 for bases.

TABLE 1.2.1-3 UTILITY BOILER LIMESTONE FGD SYSTEM CAPITAL INVESTMENT (1980$)

		Capital Investment,* 10^3 $			
Utility Boiler Capacity	MWe	100	250	500	1,000
Boiler Heat Input** (10^6 Btu/hr)		1,000	2,500	5,000	10,000
Direct Investment					
Raw Materials Handling		1,738	1,875	3,844	4,541
SO_2 Scrubbing		9,399	16,070	26,764	53,272
Waste Disposal		5,013	8,859	14,058	22,743
Total Direct Investment (TDI)		16,149	26,805	44,666	80,556
Indirect Investment (II)					
Engr. Design & Supv. plus Architectural & Engr. (A&E)		1,453	2,412	4,020	7,250
Construction Expenses		2,584	4,289	7,147	12,889
Contractor Fees		807	1,340	2,233	4,028
Contingency		4,199	6,969	11,613	20,945
Fixed Investment (TDI + II)		25,192	41,816	69,679	125,667
Other Capital Requirements					
Startup & Modifications		1,938	3,217	5,360	9,667
Interest During Construction		3,779	6,272	10,452	18,850
Land		634	1,247	2,107	3,573
Working Capital		820	1,388	2,349	4,270
Total Capital Investment (TCI)***		32,363	53,932	89,947	162,027
$/$KW_e$		323.6	215.7	179.9	162.0
10^3\$/10^6 Btu/hr**		32.4	21.6	18.0	16.2

*Refer to Tables 2.1.2-1 and 2.1.2-2 for bases.

**Assumes 10,000 Btu/kwh

***TCI = TDI + II + Other Capital Requirements.

TABLE 1.2.1-4 UTILITY BOILER LIMESTONE FGD SYSTEM FIRST YEAR OPERATING AND MAINTENANCE COSTS (1981$)

		Annual O&M Cost*, 10^3 $/Yr			
Boiler Capacity	MWe	100	250	500	1,000
Boiler Heat Input** (10^6 Btu/hr)		1,000	2,500	5,000	10,000
Direct Costs					
Raw Material					
Limestone		174	436	872	1,744
Conversion Costs					
Operating Labor & Supervision		172	260	356	486
Utilities					
Process Water		3	9	18	38
Electricity		264	604	1,201	2,343
Steam		166	414	829	1,657
Maintenance Labor & Materials		1,109	1,785	2,970	5,428
Analyses		52	52	78	104
TOTAL DIRECT COSTS		1,940	3,560	6,324	11,800
Indirect Costs					
Overheads					
Plant & Administrative		800	1,258	2,042	3,611
Total First Year O&M Costs***		2,740	4,818	8,366	15,411
Mills/Kwh		5.79	4.07	3.53	3.26
$/$10^6$ Btu****		0.58	0.41	0.35	0.33

*Refer to Tables 2.1.2-1, 2.1.2-2, and 2.1.3-1 for bases.

**Assumes 10,000 Btu/Kwh.

***Direct plus indirect costs.

****Based on Boiler heat input.

	Utility Boiler FGD System	Industrial Boiler FGD System
1. Design scope	Includes spare absorber modules, stack gas reheat, and on-site sludge disposal pond	Does not include spare absorbers, stack gas reheat, or an on-site pond.
2. Method of Installation	Field-erection	Shop-fabrication of major components
3. Indirect Investment plus other capital requirements	∿1.0 times direct investment	∿0.75 times direct investment

The analyses performed in Section 2 of this report illustrate that the three items listed above account for most of the discontinuity in the capital investment costs.

As with the capital investment costs, the industrial and utility boiler annual O&M costs presented in Tables 1.2.1-2 and 1.2.1-4, respectively, are also likely to exhibit some discontinuity due to the following:

	Utility Boiler FGD System	Industrial Boiler FGD System
1. Design scope	Stack gas reheat steam used; sludge disposed of in pond on-site	No stack gas reheat steam used; sludge disposed of by outside contractor at $15/ton
2. Unit costs for raw materials, labor, utilities, etc.	See Table 2.1.3-1	See Table 2.1.3-3
3. Capacity utilization factor	0.54	0.60

In addition to these factors, O&M costs that are estimated based on capital investment (such as maintenance and sometimes overhead) will be significantly different for the two systems because of factors which cause discontinuities in the capital investment (see previous discussion on capital investment). The analyses performed in Section 2 illustrate that the items identified above account for most of the cost discontinuity.

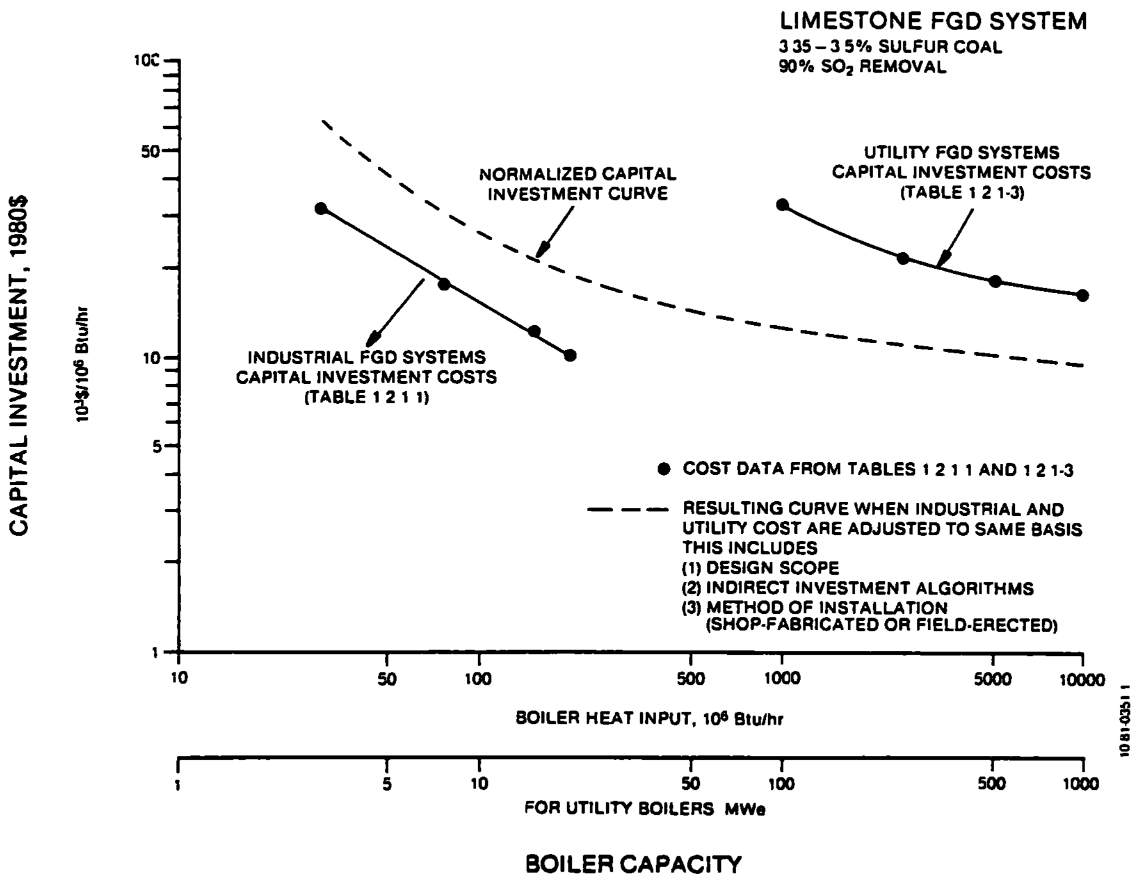
The discontinuities are shown graphically by plotting the data presented in Tables 1.2.1-1 through 1.2.1-4. Figure 1.2.1-1 shows a plot of the capital investment costs and Figure 1.2.1-2 shows a plot of the first year O&M costs. Also shown on these graphs is a plot of the normalized cost values which result from elimination of the differences in design scope, installation and indirect investment algorithms, capacity utilization factors, and unit costs mentioned above. The final normalized curves eliminate most of the discontinuities in both sets of data. The rationale for developing the normalized curve is discussed in detail in Section 2.

However, due to the environmental regulations and economy of scale, the design scope is likely to be considerably different for industrial and utility boiler FGD systems as discussed previously. Many components of industrial boiler FGD units are likely to be shop-fabricated, whereas, utility systems are field-erected. In addition, unit costs for raw materials, utilities, and solid waste disposal are likely to be considerably different due to volume or quantity considerations. Different capacity utilization factors may also be expected. The factors affecting capital investment and, therefore certain O&M costs (such as maintenance and overhead), are also important. Therefore, discontinuities in the capital investment and O&M curves similar to those shown in Figures 1.2.1-1 and 1.2.1-2 should be expected.

In summary, the annual O&M and capital investment cost estimates for wet limestone FGD systems presented in this study* should be considered as valid, consistent data. Therefore, it is recommended that the cost data shown in Tables 1.2.1-1 through 1.2.1-4 be used in later acid rain studies as the basis for assessing cost impacts for FGD controls.** Of course, adjustment to the bases (such as design scope, startup date, and site-specific unit costs for raw materials, utilities, etc.) may be required by a particular reader. The data in this report is documented so that these adjustments can be made, if desired.

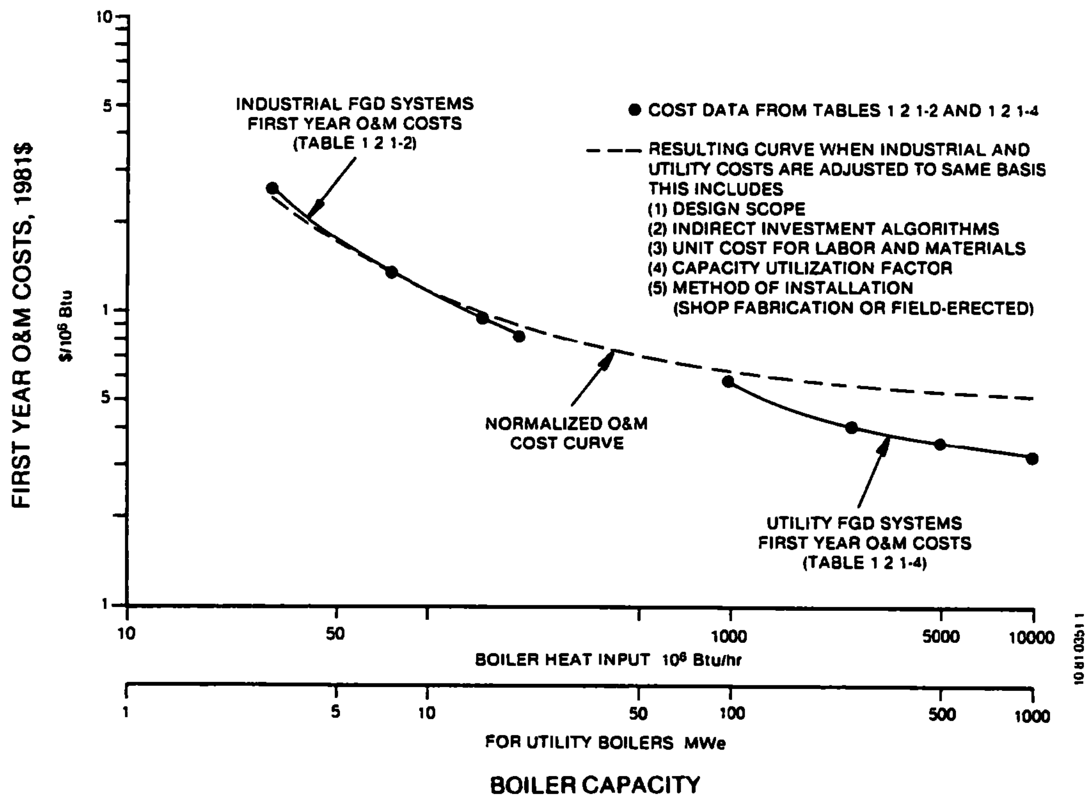
*For FGD systems applied to new industrial and utility boilers.

**Retrofit factors will have to be used to adjust these costs to reflect the costs of applying FGD systems to existing boilers.



NOTE: Utility boiler FGD unit investment estimates are provided for boiler capacities of 100-500 MWe and are expressed as dollars per 10^6 Btu/hr of capacity assuming a plant heat rate of 10,000 Btu/kwh. Industrial boiler FGD system estimates are also expressed as dollars per 10^6 Btu/hr of boiler capacity. The utility and industrial boiler investment and capacity scales are interchangeable if the same 10,000 Btu/kwh conversion factor is assumed. This is a close approximation of the heat rate for most utility plants.

Figure 1.2.1-1. Capital Investment for Industrial and Utility Boiler Wet Limestone FGD Systems.



NOTE: Utility boiler FGD unit annual O&M estimates are provided for boiler capacities of 100-500 MWe and are expressed as $\$/10^6$ Btu assuming a plant heat rate of 10,000 Btu/kwh. Industrial boiler FGD system estimates are provided for boiler heat input capacities of 30-200 x 10^6 Btu/hr and are expressed as $\$/10^6$ Btu. The utility and industrial boiler capacity scales are interchangeable if the same 10,000 Btu/kwh conversion factor is assumed. This is a close approximation of the heat rate for most utility plants.

Figure 1.2.1-2. First Year O&M Costs for Industrial and Utility Wet Limestone FGD Systems.

1.2.2 FGD System Retrofit Factor Evaluation

A retrofit factor is defined as the ratio of the capital investment or operating cost for installing a process in an existing plant to the capital investment or operating cost for the same process in a new installation. This factor is often applied to new installation costs to estimate the costs of putting the same basic equipment into an existing facility.

Retrofit factors were only evaluated for utility boilers because there was no published information on retrofit factors for industrial boilers. Therefore, there is no retrofit factor recommendation for industrial boiler FGD systems.

Capital Investment

Retrofit factor studies performed by TVA, PEDCo Environmental, Inc., M.W. Kellogg, and Radian Corporation were examined. Retrofit factors ranging from 0.9 to 3.0 were found in these studies. Space availability was identified as the principal factor affecting the capital investment associated with retrofitting FGD systems.

For a preliminary evaluation, a retrofit factor of 1.2 is recommended for "average" retrofits for boilers less than ten years old and with capacities greater than 200 Mw. A retrofit factor range of 1.1 to 1.4 is also recommended. The lower end of the range is applicable when installation of the FGD system is relatively uninvolved and when available space for FGD equipment is adequate. Retrofit factors in the upper range nearer 1.4 would be used when retrofitting is complex.

The retrofit factor 1.2 is recommended for use in a preliminary evaluation of FGD system retrofit costs for utility boilers. The reader should note that:

(1) Retrofit of FGD systems to some boilers will be infeasible.
(2) Retrofit factors greater than 1.4 are possible.

Only a site-specific evaluation of the factors associated with retrofit can accurately quantify the costs.

Annualized Costs

No retrofit factor for annualized costs is recommended. Increased annualized costs for retrofits compared to new systems are primarily associated with the higher capital investment. Therefore, an annualized cost retrofit factor would be a strong function of the capital investment retrofit factor, the load factor of the boiler, and the remaining useful life of the boiler.

1.2.3 TVA and PEDCo Environmental, Inc. FGD System Cost Comparison

Both TVA and PEDCo have developed cost estimating procedures for utility boiler FGD systems. In the past, estimates from the two organizations have shown significant differences. Cost estimates by TVA and PEDCo were evaluated to determine whether the differences are real or a function of such factors as design scope, indirect investment algorithms, unit cost for raw materials, utilities, and other economic parameters.

The results of the study are presented in Section 4 and show that capital investment and O&M costs for a lime wet scrubbing system prepared by both organizations are very similar when all bases (economical and technical) are made identical.

SECTION 2

FLUE GAS DESULFURIZATION SYSTEM COST COMPARISONS FOR INDUSTRIAL AND UTILITY BOILERS

Most operating flue gas desulfurization (FGD) units applied to utility boilers are lime or limestone systems. The majority of the planned systems are either wet lime/limestone or spray dryers. For industrial boilers, wet lime/limestone, dual alkali, spray dryers, and sodium scrubbing (once through) are the realistic alternatives for future FGD units.[9] Industrial boiler dual alkali and limestone costs (capital and operating) have been shown to be comparable for all boiler sizes.[9] In this report the costs for limestone and lime spray dryer FGD systems applied to new utility and industrial boilers are evaluated and compared. These costs should be representative of user costs for typical industrial and utility applications.*

Cost estimates were obtained from TVA and Radian Corporation for utility and industrial boiler FGD systems, respectively. Capital investment is expressed as \$/KWe and \$/10^6 Btu/hr (boiler heat input) for utility and industrial systems, respectively. First year O&M costs are expressed as mills/kwh and \$/10^6 Btu (boiler heat input). In order to compare the industrial and utility system costs, the utility boiler FGD unit costs can also be expressed as \$/10^6 Btu/hr and \$/10^6 Btu if a plant heat rate of 10,000 Btu/Kwh is assumed.

Limestone and lime spray dryer FGD system costs applied to new boiler installations are evaluated and compared in Sections 2.1 and 2.2. Retrofit costs are considered in Section 3.

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*The capital investment and annual operating costs are significant only to two figures; however, results are reported to the last whole significant figure to be consistent with other similar studies.

2.1 WET LIMESTONE FGD SYSTEM COST ESTIMATES

In this section, cost estimates (capital and operating) for utility and industrial boiler wet limestone FGD systems are presented and compared. In addition, reported costs for installed utility FGD systems are evaluated and compared to the TVA cost estimates.

2.1.1 Process Description

The wet limestone flue gas desulfurization process uses a slurry of calcium carbonate to absorb SO_2 in a wet scrubber. This process is commonly referred to as a "throwaway" process because the calcium sulfite and sulfate formed in the system are disposed of as waste solids.

The basic design of a wet limestone scrubbing system can be divided into the following process areas:

(1) Limestone Preparation,

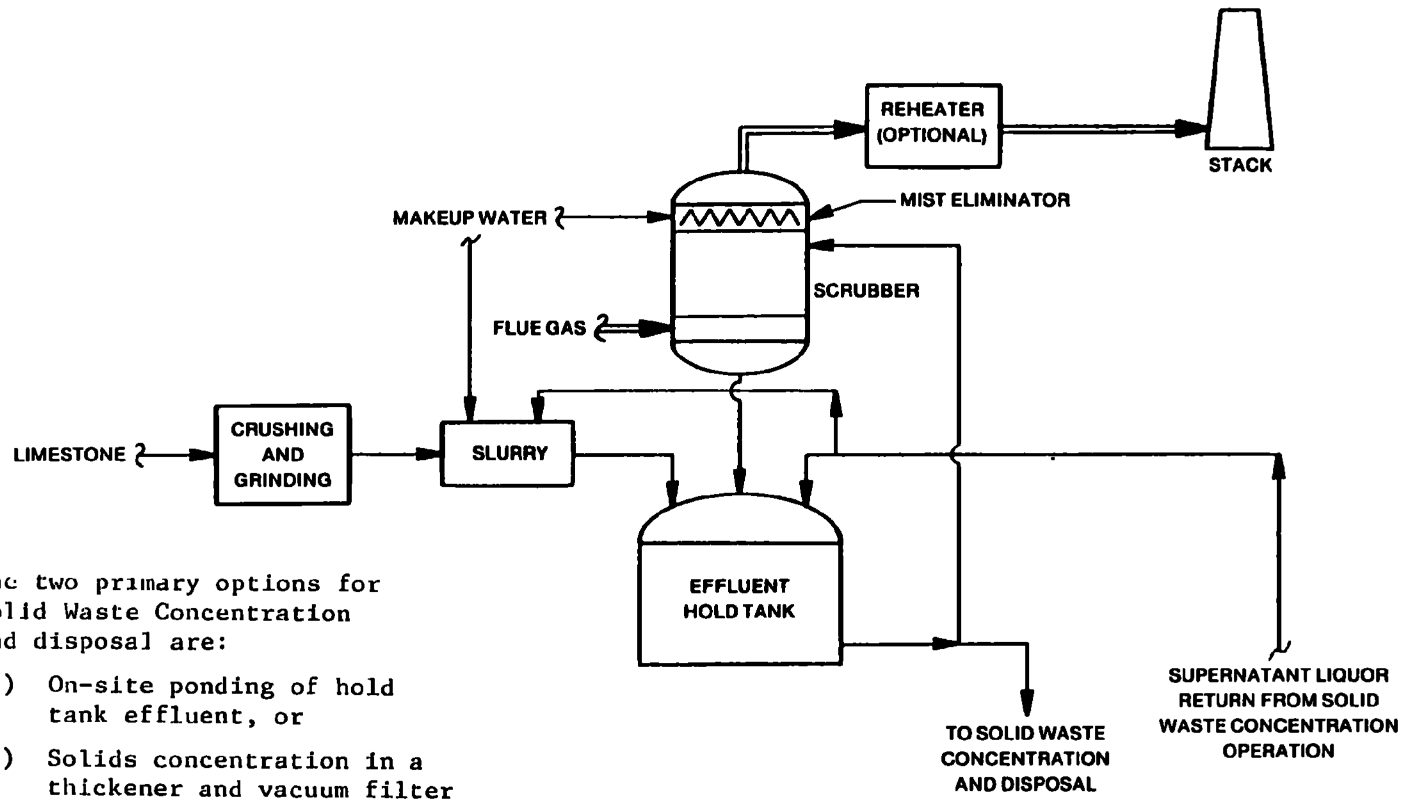
(2) SO_2 Absorption, and

(3) Solids Separation and Disposal.

Figure 2.1.1-1 presents a generalized process flow diagram.

Limestone Preparation

The raw material for a utility or industrial FGD system generally comes directly from the quarry, and is then reduced in size by crushing and grinding. For very small FGD applications, preground limestone would probably be purchased. The limestone is mixed with water to make a 25-60 percent solids slurry for feed to the effluent hold tank.



The two primary options for Solid Waste Concentration and disposal are:

(1) On-site ponding of hold tank effluent, or

(2) Solids concentration in a thickener and vacuum filter with the wastes trucked to off-site disposal

FIGURE 2.1.1-1 LIMESTONE FGD PROCESS FLOW DIAGRAM

SO_2 Absorption

Absorption of SO_2 takes place in a wet scrubber using limestone in a circulating slurry. Particulates can be removed in the SO_2 absorber or ahead of the absorber by an electrostatic precipitator, baghouse, or particulate scrubber. The selection of a method for particulate removal is based on economics and operational reliability. Removing particles in the SO_2 absorber increases the solids load in the SO_2 scrubbing system. It is also believed that some components of the fly ash catalyze the oxidation of sulfite to sulfate, thus increasing the potential for sulfate scaling.

The absorption of SO_2 from the flue gases by a limestone slurry constitutes a multiphase system involving gas, liquid, and several solids. The overall reaction of gaseous SO_2 with the alkaline slurry, yielding $CaSO_3 \cdot \frac{1}{2}H_2O$, follows:

$$SO_{2(g)} + CaCO_{3(s)} + \tfrac{1}{2}H_2O \rightarrow CaSO_3 \cdot \tfrac{1}{2}H_2O_{(s)} + CO_{2(g)}$$

The solid sulfite is only slightly soluble in the scrubbing liquor and thus will precipitate to form an inert solid for disposal.

In most cases, some oxygen will also be absorbed from the flue gas or surrounding atmosphere. This leads to oxidation of absorbed SO_2 and precipitation of solid $CaSO_4 \cdot 2H_2O$. The overall reaction for this step is as follows:

$$SO_{2(g)} + \tfrac{1}{2}O_{2(g)} + CaCO_{3(s)} + 2H_2O \rightarrow CaSO_4 \cdot 2H_2O_{(s)} + CO_{2(g)}$$

The extent of oxidation can vary considerably, normally ranging anywhere from almost zero to 40 percent. In some systems treating dilute SO_2 flue gas streams, sulfite oxidations as high as 90 percent have been observed. The actual mechanism for sulfite oxidation is not completely understood. However, the rate is known to be a strong function of oxygen concentration in the flue gas and liquor pH. It may also be increased by trace quantities of catalysts in fly ash entering the system.

Various types of gas-liquid contactors can be used as the SO_2 absorber. These differ in SO_2 removal efficiency as well as operating reliability. Four types of contactors are generally used for SO_2 removal:

- venturi scrubbers,
- spray towers (horizontal and vertical),
- grid towers, and
- mobile bed absorbers (such as marble bed and turbulent contact absorber [TCA]).

Simple impingement devices are placed downstream from the absorber to remove mist entrained in the flue gas.

The effluent hold tank receives the lime or limestone feed slurry and absorber effluent. The tank is equipped with an agitator for maintaining uniform composition. The volume of the hold tank is sized to allow adequate residence time for calcium sulfite and sulfate precipitation. Reaction time outside the scrubber is needed to allow the supersaturation caused by SO_2 sorption in the scrubber to dissipate and to permit limestone dissolution. Too little residence time in the hold tank can cause nucleation of calcium sulfite and sulfate solids in the scrubber, resulting in scaling.

Solids Separation and Disposal

A continuous slurry stream of 10-15 percent solids is recycled to the absorber from the effluent hold tank. In addition, a bleed stream is taken off to be dewatered. The dewatering step, which is needed to minimize the area needed for sludge disposal, varies depending on the application and type of disposal.

For systems with on-site pond disposal, solids may be pumped directly from the effluent hold tank to the pond area. Clear overflow liquor from the pond would then be returned to the system. Depending on the physical properties of the solids produced in the system, a thickening device such as a clarifier can be used to increase the solids content to a maximum of about 40 weight percent. Additional dewatering to 50-60 percent solids can sometimes be achieved by vacuum filtration. This type of processing may be selected if the waste solids must be transported offsite to disposal.

2.1.2 Limestone FGD System Capital Investment

Studies have shown that there can be large differences in capital investment per unit of capacity when comparing FGD systems for small industrial boilers to large utility boiler FGD systems.[1,2] A typical example of this difference is illustrated in Figure 2.1.2-1, which shows a very high capital investment per unit of capacity for very small industrial boilers, followed by a rapid drop as process size increases. The utility boiler FGD investment also shows a decrease in investment per unit of capacity as the process size is increased, but the rate of change is not as sharp as in the industrial case. However, a two to four times higher investment has been noted for utility boiler FGD systems as they approach the size of large industrial boiler FGD systems.[3] Some have claimed this is due to the fact that (1) industrial boiler FGD systems are shop-fabricated, while utility systems are field-erected and (2) that the design scope for industrial boiler FGD systems are considerably different than the scope for utility boiler FGD systems.[4] The question then becomes whether these differences are real or an artifact of the algorithms and assumptions used to calculate the FGD system investment. To answer this question, current capital investments were obtained for both utility and industrial limestone FGD systems. Then the assumptions and algorithms used to calculate the investments were carefully studied to determine if the differences could be caused by the use of different bases or methods of calculation.

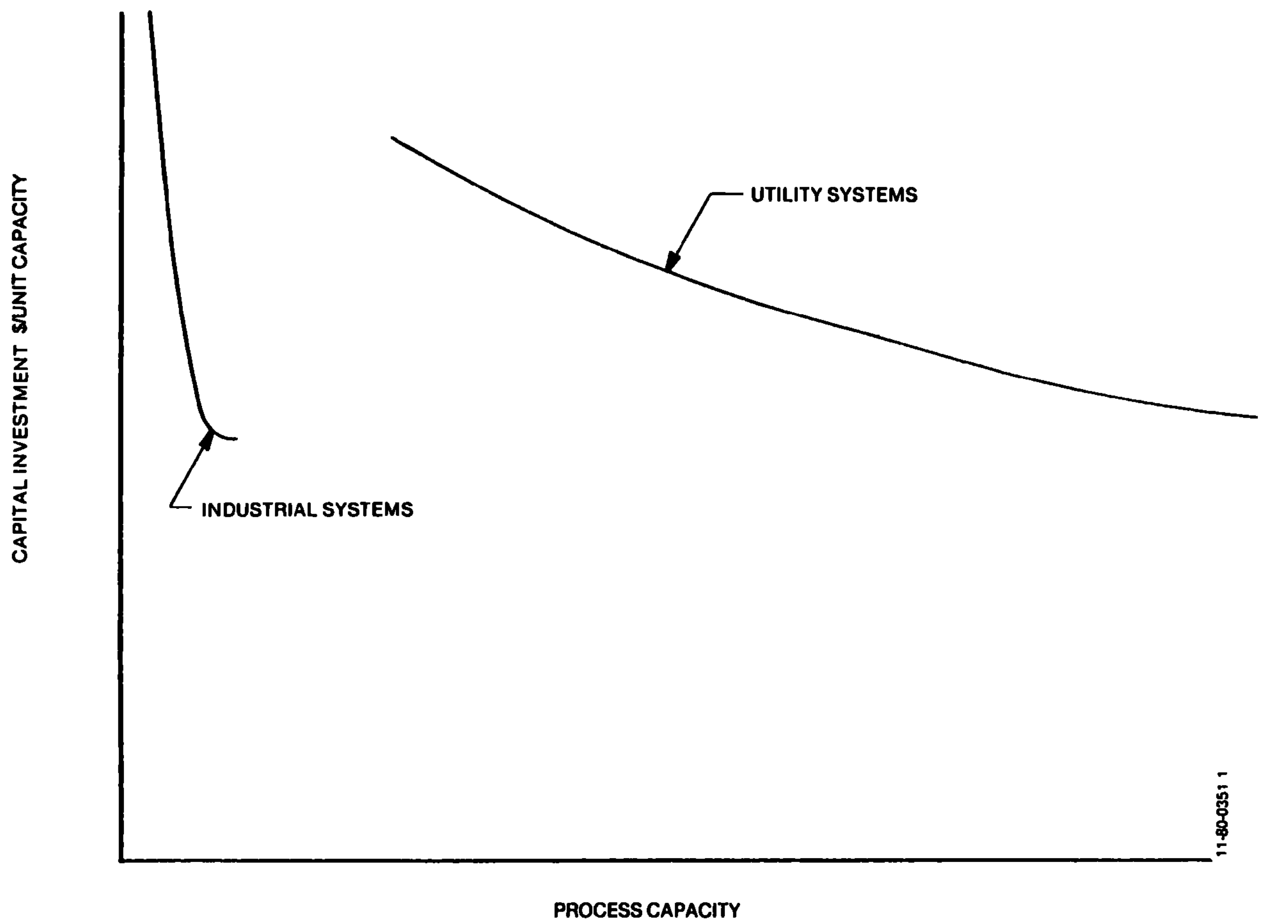


Figure 2.1.2-1. Comparison of Total Capital Investment for Small Industrial and Large Utility Boiler FGD Systems.

2.1.2.1 Utility Boiler FGD System Capital Investment Estimates

Utility boiler FGD system capital investment as a function of process size was estimated by the Technical and Economic Evaluation Section of the Tennessee Valley Authority by using their Shawnee Lime/Limestone Scrubbing Computerized Design/Cost-Estimate Model.[5,6] This model was updated in 1979 and 1980, and represents the most recent algorithm available for calculating lime and limestone FGD system capital investment and operating costs.[7] The economic bases and design scope are outlined in Tables 2.1.2-1 and 2.1.2-2, respectively, for a limestone FGD process achieving 90 percent SO_2 removal on a boiler firing 3.36 percent sulfur coal. The capital investment estimates are given in Table 2.1.2-3. Detailed assumptions, material balances, equipment lists and economic results for 100, 250, 500, and 1000 MWe FGD systems are given in Appendix A.

The capital investment results given in Table 2.1.2-3 illustrate the increase in investment/KWe that occurs as the size of the process decreases. The total capital investment/KWe doubles from $162 to $324 as the process size is reduced tenfold, from 1000 to 100 MWe. Estimates were not developed below 100 MWe because the computer program does not contain equipment costs for units smaller than 100 MWe. Computer extrapolation below this process size would result in an abnormally high investment/KWe, since some of the component equipment sizes and, therefore, costs would remain constant as the process size decreases. In fact, the capital estimates for 100 MWe systems are somewhat high due to the incorporation of some over-sized equipment.

The investment results include estimates for a new solid waste disposal pond which meets Resource Conservation and Recovery Act of 1976 (RCRA) requirements for disposal of nonhazardous wastes. Thus, a heavier dike, a security fence and lighting, costs for monitoring wells, and monitoring analytical costs for the life of the facility are included. Additional land is also provided for a wider perimeter of undisturbed land and topsoil storage than in previous models. These additional items increase the pond contruction direct investment by about 30 percent,[8] which in turn increases the total FGD system capital investment by approximately $12/KWe compared to the previous model.

TABLE 2.1.2-1 TVA UTILITY BOILER WET LIMESTONE FGD SYSTEM INVESTMENT BASES*

Investment	% of Total Direct Investment**(TDI)
1. Indirect Investment	
Engr. Design + A&E	9
Construction Expenses	16
Contractor Fees	5
Contingency***	26
2. Other Capital Requirements	
Startup and Modifications	12
Interest During Construction	23.4
Land	~3.9-4.7
Working Capital	~5.3

Plant Investment Indices

1978	218.8
1980	265.0****
1982	299.8

* Corresponds to the design scope described in Table 2.1.2-2.

** Total Direct Investment includes installed cost of all process equipment, disposal pond, foundations, structures, buildings, electrical, instrumentation and services.

*** Contingency is defined as 20 percent of (TDI plus engineering design plus construction expenses plus contractor fee).

**** Not in "official" TVA publications but used in limestone FGD study.

TABLE 2.1.2-2 TVA UTILITY BOILER WET LIMESTONE FGD SYSTEM DESIGN SCOPE

- Costs are for new limestone FGD systems applied to new utility boilers.
- Capital investment is expressed in 1980$.
- Coal contains 3.36 percent sulfur and has a heat content of 11,700 Btu/lb.
- SO_2 removal efficiency in the scrubber is 90 percent.
- Scrubber redundancy:

Size, MWe	100	250	500	1000
Operating absorbers	1	2	4	8
Spare absorbers	1	1	1	2

- Equipment components included in the design:
  - limestone handling and preparation
  - turbulent contact absorbers and associated process equipment
  - stack gas reheaters
  - induced draft (I.D.) fans and ductwork
  - pumps for slurry transport to pond and supernatant liquor return
- Onsite pond construction to meet RCRA requirements is included. Thickeners and vacuum filters are not included.
- Particulate matter control equipment is not included.
- Heat rate is 9500 Btu/KWH for all plants.

TABLE 2.1.2-3 UTILITY BOILER WET LIMESTONE FGD SYSTEM CAPITAL INVESTMENT (1980$)*

Utility Boiler Capacity	MWe	Capital Investment, 10^3 $ 100	250	500	1000
Direct Investment					
Raw Materials Handling		1,738	1,875	3,844	4,541
SO_2 Scrubbing		9,399	16,070	26,764	53,272
Waste Disposal		5,013	8,859	14,058	22,743
Total Direct Investment (TDI)		16,149	26,805	44,666	80,556
Indirect Investment (II)					
Engr. Design & Supv. + Architectural & Engr. (A&E)		1,453	2,412	4,020	7,250
Construction Expenses		2,584	4,289	7,147	12,889
Contractor Fees		807	1,340	2,233	4,028
Contingency		4,199	6,969	11,613	20,945
Fixed Investment (TDI + II)		25,192	41,816	69,679	125,667
Other Capital Requirements					
Startup & Modifications		1,938	3,217	5,360	9,667
Interest During Construction		3,779	6,272	10,452	18,850
Land		634	1,247	2,107	3,573
Working Capital		820	1,388	2,349	4,270
Total Capital Investment (TCI)**		32,363	53,932	89,947	162,027
$/KWe		323.6	215.7	179.9	162.0
10^3\$/10^6Btu/hr***		32.4	21.6	18.0	16.2

*Refer to Tables 2.1.2-1 and 2.1.2-2 for bases.
**TCI = TDI + II + Other Capital Requirements.
***Assumes a 10,000 Btu/kwh plant heat rate.

2.1.2.2 Industrial Boiler FGD System Capital Investment Estimates

Capital investment estimates for limestone wet scrubbing FGD systems for small industrial boilers (30 to 200 × 10^6 Btu/hr heat input capacity*) were developed by Radian Corporation as part of a series of technology assessment reports to assist in setting New Source Performance Standards (NSPS) for industrial boilers.[9] The bases and design scope used in estimating the investment are described in Tables 2.1.2-4 and 2.1.2-5, respectively. These factors, which are different from those used by TVA for utility boiler FGD systems, account for some of the differences between utility and industrial boiler FGD system cost estimates. Material balances and equipment lists used in estimating the direct investments for limestone FGD systems with 90 percent SO_2 removal for industrial boilers firing 3.5 percent sulfur coal are contained in Appendix B.

The capital investment estimates are given in Table 2.1.2-6. These costs are based on a higher solid separation investment than that used in the Industrial Technology Assessment Review (ITAR).[10] This investment component was revised by Radian after publication of the ITAR. The total capital investment has been updated to a 1980 cost basis from a 1978 basis by using Chemical Engineering Plant Cost Indices (265.0/218.8=1.21).

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* These boiler sizes would generate steam at about 20,000-140,000 lb/hr. Small utility boilers of comparable size would generate about 3-20 MWe of power, assuming a plant heat rate of 10,000 Btu/KWH.

TABLE 2.1.2-4 INDUSTRIAL BOILER WET LIMESTONE FGD SYSTEM INVESTMENT BASES*

Indirect Investment	% of Total Direct Investment** (TDI)
Engineering	***
Construction & Field Expense	10
Construction Fees	10
Startup	2
Performance Test	1
Total Indirect Investment (TII)	33
Other Capital Requirements* **	**Factor**
Contingency	20% × (TDI + TII)
Land	0.084 × TDI
Working Capital	25% × TDC****

* For the design scope and costs presented in Tables 2.1.2-5 and 2.1.2-6.

** Total Direct Investment includes installed cost of all process equipment, foundations, instrumentation, etc. Buildings and solid waste disposal areas are not included.

*** For this study, the engineering costs are assumed the same for all industrial boiler applications and are based on 10 percent of the Total Direct Investment (TDI) for the 200 x 10^6 Btu/hr boiler.

**** TDC = Total Direct Costs, which include a portion of the operating and maintenance annual costs, are defined in Section 2.1.3.2.

TABLE 2.1.2-5 RADIAN INDUSTRIAL BOILER WET LIMESTONE FGD SYSTEM DESIGN SCOPE

- Costs are for new limestone FGD systems applied to new industrial boilers.
- Capital investments were expressed in 1978 $ in the ITAR and are adjusted to 1980 $ in this report.
- Coal contains 3.5 percent sulfur and has a heat content of 11,800 Btu/lb.
- SO_2 removal efficiency in the scrubber is 90 percent.
- No spare scrubbers are incorporated into the cost estimate.
- Equipment components included in the design:
  - limestone handling
  - turbulent contact absorber and associated process equipment
  - forced draft (F.D.) fan
  - thickener, vacuum filter and associated equipment
- Solid waste disposal is performed by outside contractor. No capital investment is included beyond the vacuum filter.
- Stack gas reheat is not included.
- Particulate control equipment is not included.

TABLE 2.1.2-6 RADIAN INDUSTRIAL BOILER LIMESTONE FGD SYSTEM INVESTMENT*

Boiler Heat Input Capacity 10^6 Btu/hr	Capital Investment, 10^3 \$ 30	75	150	200
Direct Investment				
Raw Materials Handling	59	99	147	171
SO_2 Scrubbing	149	244	368	401
Fans	20	40	69	76
Solids Separation	160	189	227	275
Utilities & Service	23	34	49	55
Total Direct Invest. (TDI)	411	606	860	978
Indirect Investment				
Engineering	98	98	98	98
Construction & Field Expense	41	61	86	98
Construction Fees	41	61	86	98
Startup	8	12	17	19
Performance Test	4	6	9	10
Total Indirect Invest. (TII)	192	238	296	323
Contingencies	121	169	231	260
Total Turnkey Invest. (TTI) **	724	1,013	1,387	1,561
Land	0.6	0.8	1	1
Working Capital	52	72	106	126
Total Cap Invest. (TCI) 1978 \$	777	1,086	1,494	1,688
TCI x 1.21 = 1980 \$	940	1,314	1,808	2,042
TCI (1980 \$), 10^3 \$/10^6 Btu/hr	31.3	17.5	12.1	10.2

*Bases and design scope given in Tables 2.1.2-4 and 2.1.2-5.

**TTI = TDI plus TII plus contingencies.

2.1.2.3 Comparison and Integration of Utility and Industrial Boiler FGD System Capital Investment Estimates

Figure 2.1.2-2 illustrates the dramatic investment difference between FGD systems for utility and industrial boilers. The costs shown are those described in Sections 2.1.2.1 and 2.1.2.2. Three components of the bases used for the utility boiler FGD system and industrial boiler FGD system investment estimates account for most of this difference:

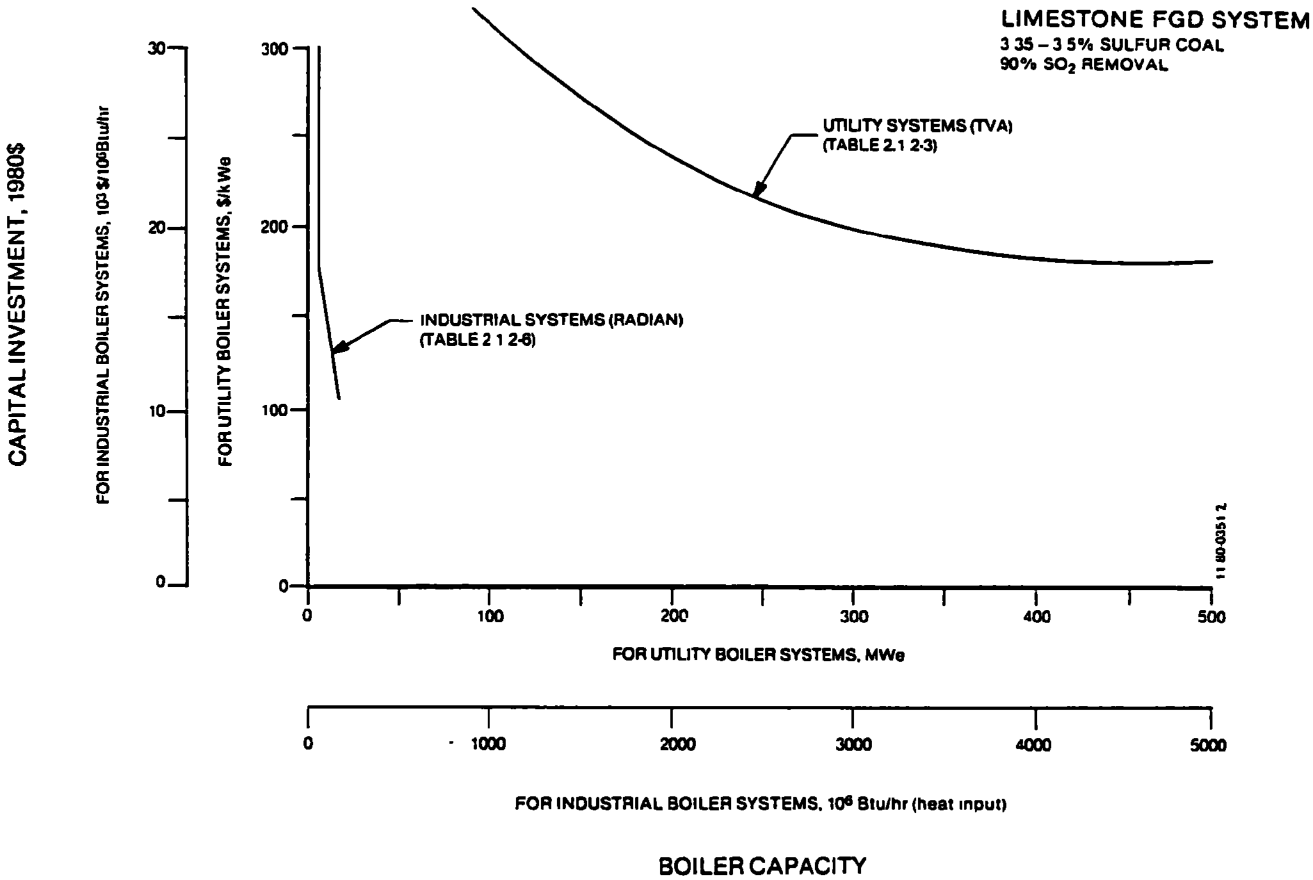
1. Equipment components (design scope),
2. Algorithms for estimating direct investment and other capital requirements, and
3. Equipment installation factors (shop-fabrication vs. field-erection)

The impacts of each of these components will be considered in comparing the utility and industrial boiler FGD system cost estimates. Investments for industrial and utility systems will be put on the same economic and technical bases to determine if the cost curves form a smooth transition through the FGD system size range. Smooth transition would indicate that the basic technical premises (including material and energy balances) and purchased equipment costs are comparable for the two system types.

The TVA utility boiler FGD system costs were developed for two different design scopes:

1) "Utility basis" - this design scope includes stack gas reheat, spare scrubbers, and an onsite pond for FGD sludge disposal. This scope is typical of many planned utility boiler FGD systems and was described in Table 2.1.2-2.

2) "Industrial basis" - this design scope includes a thickener and vacuum filter for waste solids concentration but does not include stack gas reheat, spare scrubbers, or an onsite



NOTE: Utility boiler FGD unit investment estimates are provided for boiler capacities of 100-500 MWe and are expressed as \$/KWe. Industrial boiler FGD system estimates are provided for boiler heat input capacities of 30-200 x 10^6 Btu/hr and are expressed as dollars per 10^6 Btu/hr of boiler capacity. The utility and industrial boiler investment and capacity scales are interchangeable if a 10,000 Btu/kwh conversion factor is assumed. This is a close approximation of the heat rate for most utility plants.

Figure 2.1.2-2. Difference in Capital Investment for Utility and Industrial Boiler Limestone FGD Systems.

pond. It is assumed that a contractor will haul the sludge to an offsite disposal area; the associated costs are considered as operating costs. Although large utility boiler FGD systems are not generally designed this way, the results are useful for comparison with industrial boiler FGD system costs, since these systems are typically designed in this manner.

As stated above, many industrial boiler FGD systems do not contain stack gas reheat, spare scrubbers, or an onsite disposal pond.

Table 2.1.2-7 presents the utility boiler FGD system capital investment for both design scopes discussed above. The difference in the capital investment for the two scopes ranges from $70/KWe to $170/KWe. The table shows that adding spare scrubbers for the smaller-sized units has the greatest impact on capital investment (+$88/KWe), while adding a waste disposal pond, rather than concentrating the slurry and transporting it away, has the greatest impact (+$32/KWe) on the larger units. A breakdown of the direct and indirect investments and other capital requirements for a utility FGD system on an "industrial basis" is given in Table 2.1.2-8. The detailed premises, material balances, equipment list, and investments and operating costs are given in Appendix C. Similar cost data for the "utility basis" FGD system were presented in Table 2.1.2-3 and Appendix A.

Figure 2.1.2-3 shows that even with the three major equipment components subtracted out to yield an "industrial basis" utility FGD system, there are still significant investment differences between comparable sizes of industrial boiler FGD systems and utility FGD systems on an "industrial basis." As stated previously, the algorithms used to calculate the indirect investment and other capital requirements for utility boiler FGD systems are different from those used for small industrial boiler FGD systems. In addition some of the indirect investment and other capital requirement categories are different for utility and industrial systems. The TVA algorithm results in a higher

TABLE 2.1.2-7 IMPACT OF DIFFERENT DESIGN SCOPE ON TVA UTILITY BOILER FGD SYSTEM CAPITAL INVESTMENT

Boiler Capacity	Capital Investment, 1980 $							
	100 MWe		250 MWe		500 MWe		1000 MWe	
	10^3 $	$/KWe	10^3 $	$/KWe	10^3 $	$/KWe	10^3 $	$/KWe
"Industrial Basis"**	15,441	154.4	27,093	108.4	50,696	101.4	90,608	90.6
+ Stack Gas Reheat	3,269	32.7	5,707	22.8	9,340	18.7	18,279	18.3
+ Scrubber System Spares	8,843	88.4	10,183	40.7	10,575	21.2	20,735	20.7
+ Pond*	4,810	48.1	10,949	43.8	19,346	38.7	32,405	32.4
"Utility Basis"	32,363	323.6	53,932	215.7	89,947	179.9	162,027	162.0

* This represents the difference between waste ponding vs. concentrating the waste for offsite disposal.

** "Industrial" basis denotes the removal of stack gas reheat, scrubbing system spares and onsite waste disposal pond. Clarifiers and vacuum filters are added so that the resulting sludge can be transported for offsite disposal.

TABLE 2.1.2-8 UTILITY BOILER LIMESTONE FGD SYSTEM INVESTMENT ON AN INDUSTRIAL BASIS*

Utility Boiler Capacity, MWe	Capital Investment, 10^3 \$ 100	250	500	1000
Direct Investment				
Raw Materials Handling	1,753	1,866	3,845	4,492
SO_2 Scrubbing	4,283	9,636	19,033	37,643
Solids Separation (thickeners & filters)	1,767	2,199	2,780	3,746
Total Direct Investment	7,803	13,700	25,659	45,882
Indirect Investment				
Engr. Design & Supervision	702	1,233	2,309	4,129
Construction Expenses	1,249	2,192	4,105	7,341
Contractor Fees	390	685	1,283	2,294
Contingency	2,029	3,562	6,671	11,929
Fixed Investment	12,173	21,372	40,027	71,575
Other Capital Requirements				
Startup & Modifications	936	1,644	3,079	5,506
Interest During Construction	1,826	3,206	6,004	10,736
Land	15	19	27	42
Working Capital	491	852	1,549	2,749
Total Capital Investment (1980 \$)	15,441	27,093	50,686	90,608
\$/KWe	154.4	108.4	101.4	90.6
10^3\$/10^6 Btu/hr	15.4	10.8	10.1	9.1

*No spare scrubber
No stack gas reheat
Waste disposal pond replaced with clarifiers and filters

Bases
3.5% S Coal
90% SO_2 Removal
1980 $

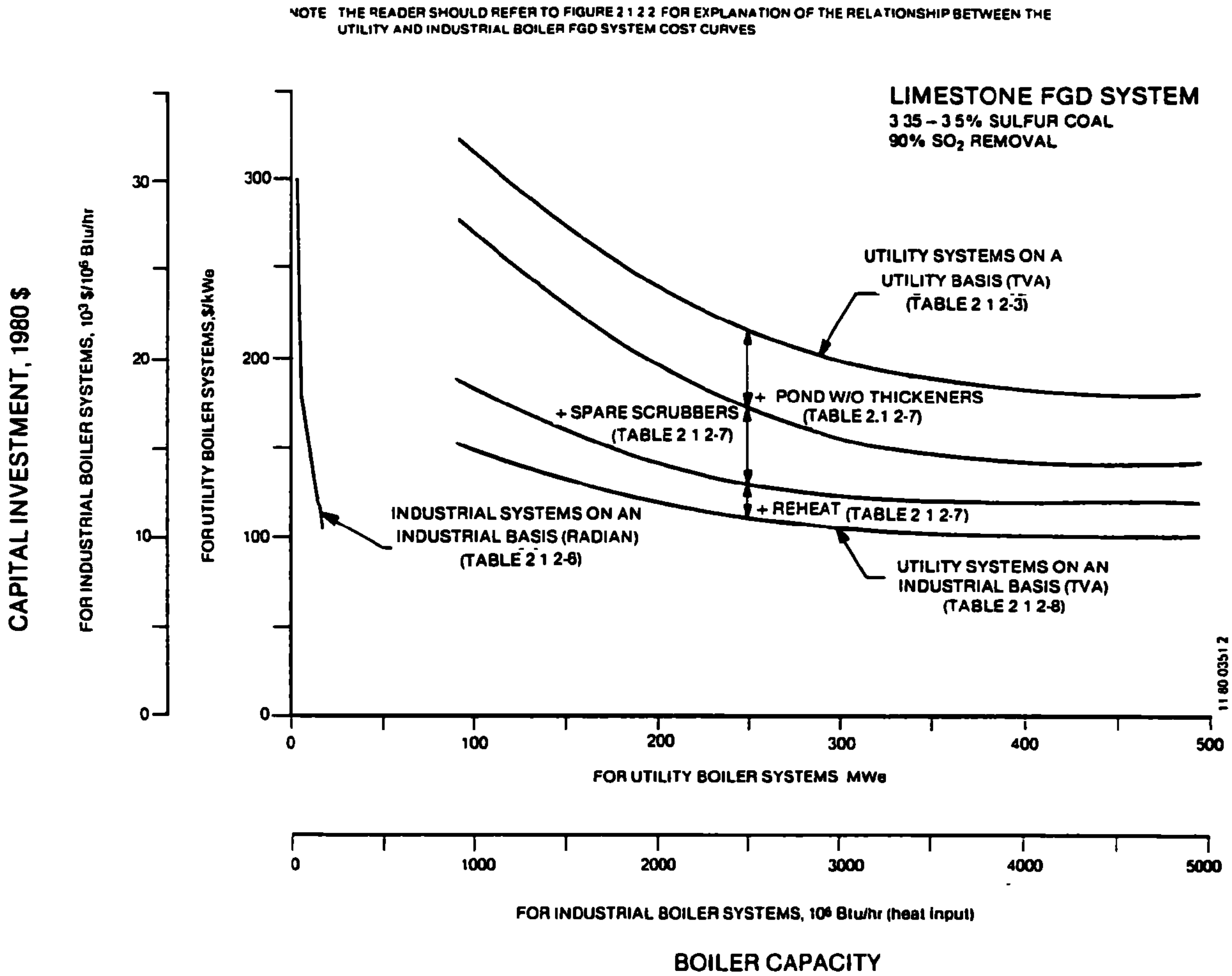


Figure 2.1.2-3. Impact of Major Equipment Components On Costs of Large Utility Boiler FGD Systems.

investment than the Radian algorithm. The total capital investment for a small industrial boiler FGD system (based on the Radian algorithms) can be approximated by multiplying the direct investment by 1.75; similarly, the capital investment for a utility boiler FGD system based on the TVA algorithms may be approximated by multiplying the direct investment by 2.0. Applying the utility indirect investment algorithm to the industrial direct investment will increase the total capital investment slightly, as shown in Table 2.1.2-9 and illustrated in Figure 2.1.2-4.

Finally, significant differences in equipment installation factors account for further differences in investment estimates. Installation factors are defined as the ratio of the direct investment (i.e., installed equipment investment) to the purchased equipment cost. In the Radian study on small industrial boiler FGD systems, installation factors were multiplied by purchased equipment costs to give installed, i.e., direct investment costs. In the TVA study on large utility boiler FGD systems and large utility boiler FGD systems on an "industrial basis," materials and installation labor were actually costed out. Thus, a more precise method of installation cost estimation was used in the TVA study. For purposes of comparison, installation factors for systems in the TVA study were calculated as follows:

$$IF = \frac{\text{Total Direct investment - Services and miscellaneous}}{\text{Purchased Equipment Cost}}$$

A comparison of the installation factors for small industrial boiler FGD systems versus large utility boiler FGD systems is given in Table 2.1.2-10. In general, the industrial boiler system installation factors are lower because the major components will be shop-fabricated, whereas utility boiler systems will be almost exclusively field-erected.

Application of these large FGD system installation factors to the purchased equipment costs of a small industrial boiler FGD system would dramatically increase the capital investment for the small industrial boiler FGD system. The results of these calculations are given in Table 2.1.2-11 and shown in Figure 2.1.2-5.

TABLE 2.1.2-9 INDUSTRIAL BOILER LIMESTONE FGD SYSTEM INVESTMENT USING INDUSTRIAL INSTALLATION FACTORS AND BASED ON TVA INDIRECT INVESTMENT ALGORITHM*

Boiler Heat Input Capacity, 10^6 Btu/hr	Capital Investment, 10^3 \$			
	30	75	150	200
Direct Investment				
Raw Material Handling	59	99	147	171
SO_2 Scrubbing	149	244	368	401
Fans	20	40	69	76
Solids Sep. (clarifiers & vacuum filters)	160	189	227	275
Utilities & Service	23	34	49	55
Total Direct Investment	411	606	860	978
Indirect Investment				
Engr. Design & Supervision	37	55	77	88
Construction Expenses	66	97	138	156
Contractor Fees	21	30	43	49
Contingency	107	158	224	254
Fixed Investment	642	946	1,342	1,525
Other Capital Requirements				
Startup & Modifications	49	73	103	117
Interest During Construction	96	142	201	229
Land	0.4	0.6	0.9	1
Working Capital	25	37	52	60
Total Capital Investment, 1978 \$	812	1,199	1,699	1,932
Total Capital Investment,** 1980 \$	983	1,451	2,056	2,338
TCI (1980 \$), 10^3 \$/10^6 Btu/hr	32.8	19.3	13.7	11.7

*3.5% S Coal
90% SO_2 Removal
**TCI (1980 $) = TCI (1978 $) x 1.21

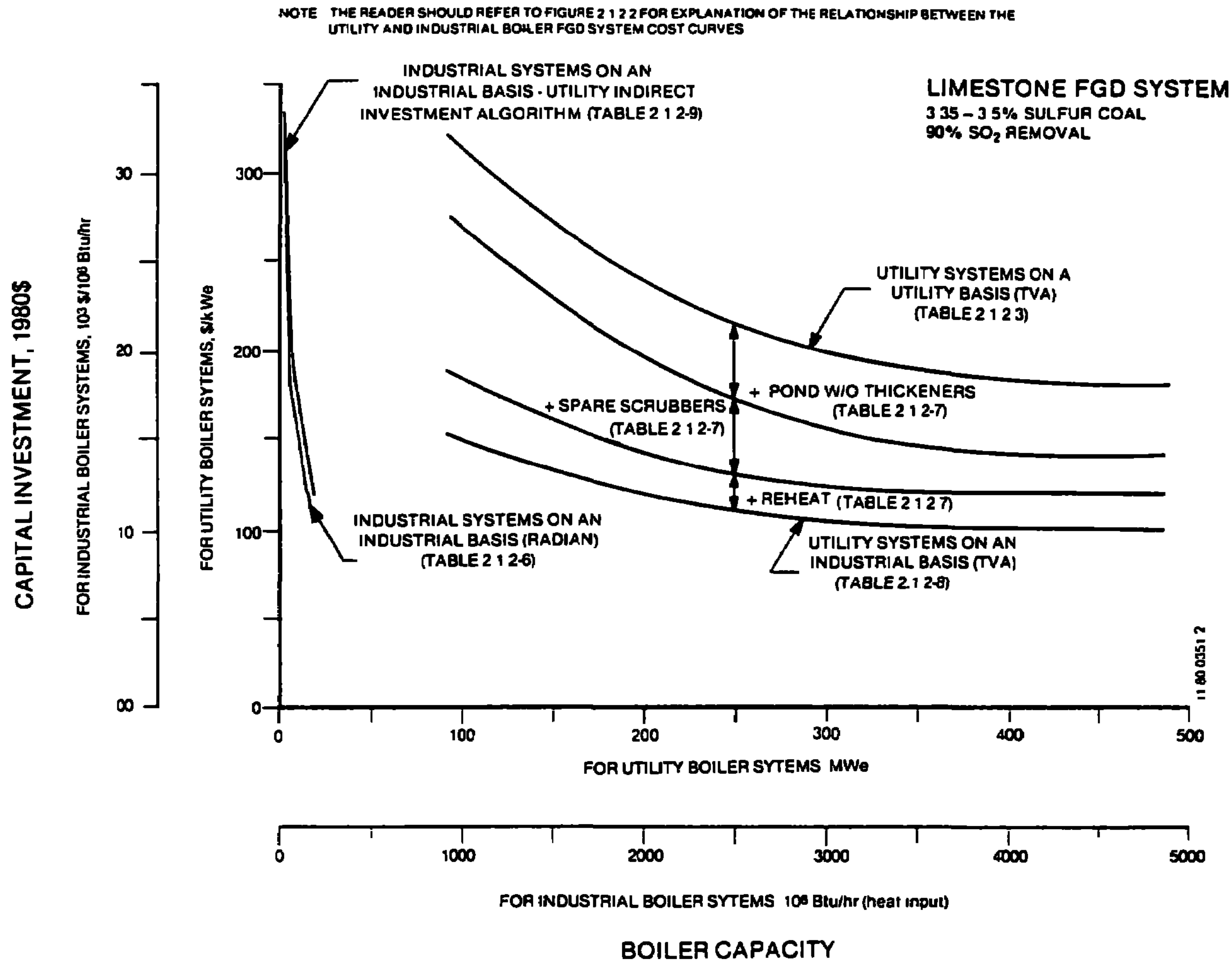


Figure 2.1.2-4. Impact of Using a Utility Indirect Investment Algorithm on Small Industrial Boiler FGD Systems.

TABLE 2.1.2-10 LIMESTONE WET SCRUBBING FGD SYSTEM INSTALLATION FACTORS

	SMALL INDUSTRIAL BOILER FGD SYSTEMS	LARGE UTILITY AND INDUSTRIAL BOILER FGD SYSTEMS			
Raw Material Handling	1.69		3.35*		
SO_2 Scrubbing	3.11		2.14*	(Includes Fans)	
Fans	2.29				
Solids Separation (Clarifiers and Vacuum Filters)	2.50	Boiler Capacity			
		10^6 Btu/hr	MW	IF	
			1000	3.81	TVA Factors
			500	4.22	TVA Factors
			250	4.75	TVA Factors
			100	5.82	TVA Factors
		200	20	7.0	Extrapolated
		30	3	7.4	Extrapolated

*Based on TVA estimates for 100 MW facilities.

TABLE 2.1.2-11 INDUSTRIAL BOILER LIMESTONE FGD SYSTEM INVESTMENT USING TVA COSTING ALGORITHM FOR BOTH EQUIPMENT INSTALLATION AND INDIRECT INVESTMENT*

Boiler Heat Input Capacity, 10^6 Btu/hr	Capital Investment, 10^3 \$ 30	75	150	200
Raw Materials Handling	117	196	291	340
Scrubbing & Fans	122	205	317	347
Solids Separation (clarifiers & vacuum filters)	477	551	645	769
Sub-Total	716	952	1,253	1,456
Utilities & Services	43	57	75	94
Total Direct Investment	759	1,009	1,328	1,550
Total Capital Investment, 1978 \$ (TCI = TDI x 1.977)	1,501	1,995	2,625	3,064
Total Capital Investment,** 1980 \$	1,816	2,414	3,176	3,708
TCI, 10^3 \$/10^6 Btu/hr	60.5	32.2	21.2	18.5

*3.5% S Coal
90% SO_2 Removal
**TCI (1980 \$) = TCI (1978 \$) x 1.21

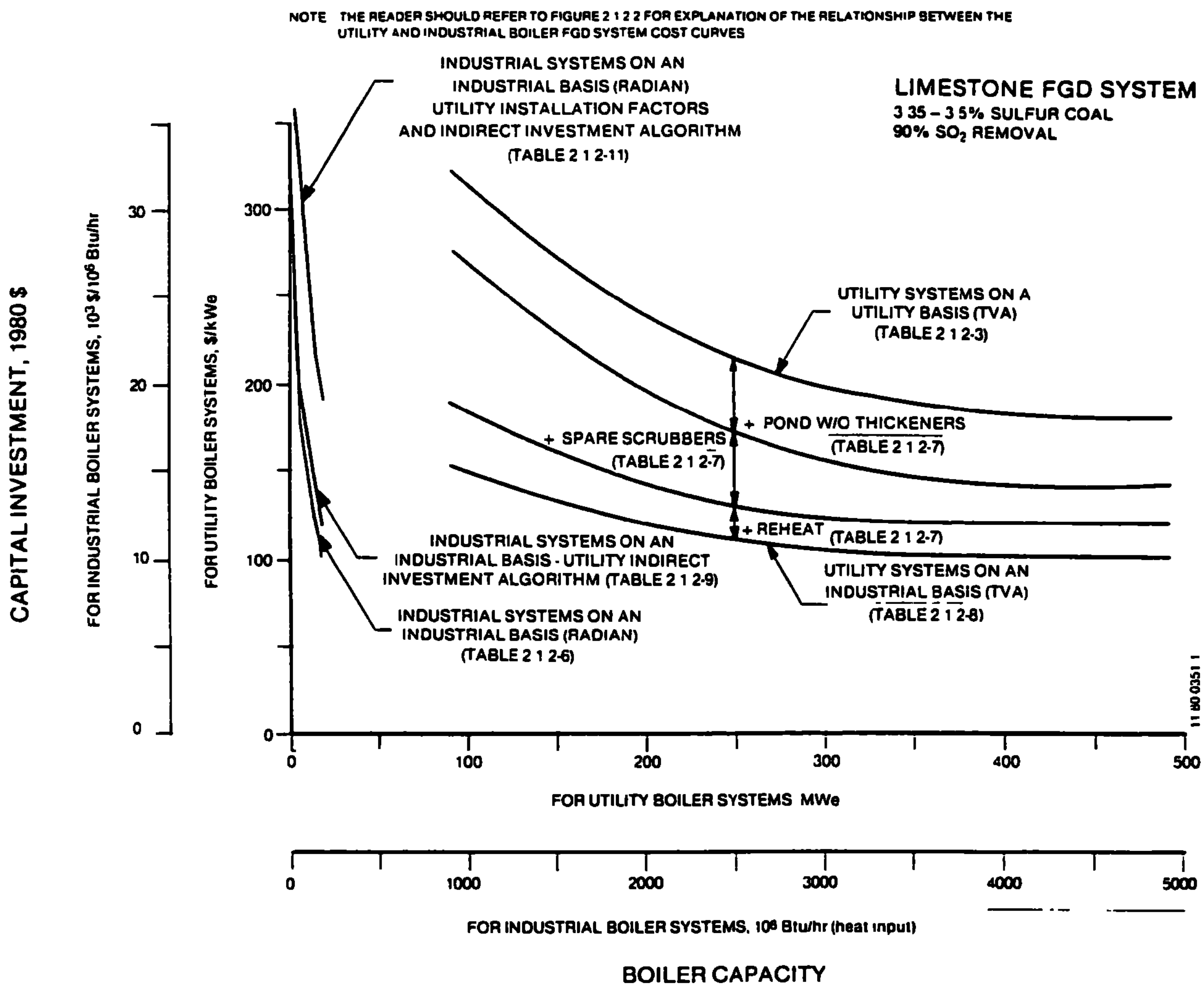


Figure 2.1.2-5. Impact of Using Large System Installation Factors and Utility Indirect Investment Algorithm on Small Industrial Boiler FGD Systems.

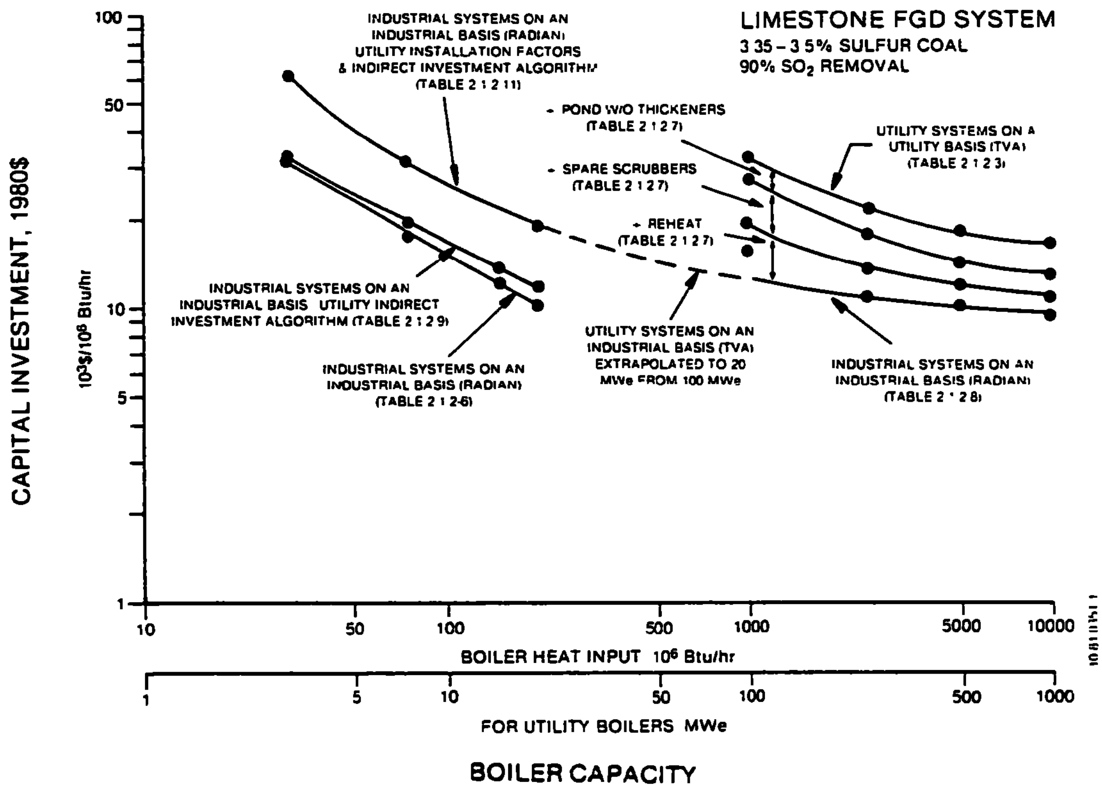
Figure 2.1.2-6 presents the seven curves shown in Figure 2.1.2-5 on a log-log plot. The consistency of the cost data can be best observed on this type of plot. Note also that each individual cost data point is also given in this figure. The dotted line connects the two curves (for the industrial and utility boiler FGD systems) that have been put on the same basis.

Figure 2.1.2-6 illustrates that a reasonably continuous capital investment curve as a function of boiler capacity can be obtained when the TVA utility and Radian industrial boiler FGD system estimates are put on the same basis (i.e., the following items made identical for both cases):

1) Design scope
2) Indirect investment algorithms
3) Equipment installation factors

The dotted line does not pass through the 100 MWe FGD cost data point. The TVA cost estimates are somewhat high for facilities in the 100 MWe capacity range because some pieces of process equipment are oversized for the 100 MWe scrubber case. This occurs primarily in the raw materials handling and SO_2 absorber areas where the smallest capacity process equipment (for which cost estimates are known) are larger than required. No attempt was made to analyze the magnitude of this overestimate but it is expected that the difference is comparable to that shown in Figure 2.1.2-6.

The above discussion shows that the basic material and energy balances and purchased equipment costs are reasonably consistent for the utility and industrial boiler FGD systems. However, any or all of the factors listed above are likely to be legitimately different for industrial and utility boiler FGD systems. First, environmental regulations and economy of scale will likely cause the two systems to be designed differently. Second, the indirect investments for the two types of systems will be different, especially for interest during construction and construction expenses. Finally, shop-fabrication of many components of industrial systems will



NOTE: Utility boiler FGD unit investment estimates are provided for boiler capacities of 100-500 MWe and are expressed as dollars per 10^6 Btu/hr of capacity assuming a plant heat rate of 10,000 Btu/kwh. Industrial boiler FGD system estimates are also expressed as dollars per 10^6 Btu/hr of boiler capacity. The utility and industrial boiler investment and capacity scales are interchangeable if the same 10,000 Btu/kwh conversion factor is assumed. This is a close approximation of the heat rate for most utility plants.

Figure 2.1.2-6 Comparison of All Cases for Limestone Wet Scrubbing FGD System Investment.

result in lower installation costs for these systems compared to the field-erection costs for utility systems. Therefore, capital investments for industrial and utility boiler FGD systems are not expected to yield a continuous curve throughout the boiler capacity range.

2.1.2.4 Comparison of TVA Utility Boiler FGD System Capital Investment Estimates with Actual Installed FGD System Investment

Capital investment estimate results for large utility boiler FGD systems (Table 2.1.2-3) were compared with costs for actual installed systems. Recently, PEDCo[11] analyzed the capital investment for installed utility FGD systems where economic data were available. These results were adjusted by PEDCo where possible so that they would be on a comparable basis, i.e., so that the same type of equipment is considered and the indirect investment charges are calculated in the same manner and contain the same components. Four new installations were found that were comparable to the model used in the TVA capital investment study (i.e., limestone wet scrubbing, 3.5% sulfur coal, and 90% SO_2 removal). Comparison of PEDCo's results with the TVA estimates shows that the PEDCo results were about 36 percent lower than those predicted by the TVA model (see Table 2.1.2-12).

However, the Utility FGD Survey[12] shows that these installations are not on the same equipment basis as the TVA study, i.e. some systems do not have stack gas reheat, none have spare scrubbers, and all were permitted before the RCRA regulations were passed. In addition, it will be shown in Section 4 that the PEDCo indirect investment algorithm yields a lower total capital investment than the TVA algorithm by a factor of 2.0/1.8, or 11 percent.

Thus the PEDCo results required further adjustments to put them on the same basis as the TVA study; i.e., costs for additional equipment and more sophisticated disposal pond design were added where necessary, and the indirect investment component was adjusted. This was accomplished by using the TVA study (Table 2.1.2-7) to add to the total investment for the "missing" equipment components and increasing the total capital investment of the PEDCo results by 11 percent. For example, TVA estimated that their "new pond" design capital investment is about $12/KW higher than for the previous pond designs. Results of these adjustments (Table 2.1.2-13) show an average deviation of about one percent with a maximum deviation of about ± 10 percent.

TABLE 2.1.2-12 COMPARISON OF PEDCo ADJUSTED CAPITAL INVESTMENT WITH TVA ESTIMATES FOR COMPARABLE OPERATING FGD SYSTEMS

					Investment, $/KWe, 1980 $		
Plant Description	Boiler Capacity, MWe	New or Retrofit	Coal Sulfur Content Wt.%	SO_2 Removal	PEDCo Adjusted Estimate	TVA Estimate*	Δ,%
Central Illinois Light Duck Creek 1	378	N	3.30	85	115	185	-37.8
Indianapolis Power & Light Petersburg 3	532	N	3.25	85	148	180	-17.8
Springfield City Utilities Southwest 1	194	N	3.50	80	134	240	-44.1
Southern Illinois Power Corp Marion 4	184	N	3.50	89	140	247	-43.3
						Avg Δ	-35.8%

*Table 2.1.2-3 and Figure 2.1.2-3

TABLE 2.1.2-13 COMPARISON OF FINAL ADJUSTED PEDCo CAPITAL INVESTMENT TO TVA ESTIMATES FOR SIMILAR OPERATING FGD SYSTEMS

Plant Description	MWe	New or Retrofit	Coal, % S	SO_2 Removal, %	Investment, $/KWe, 1980 $: PEDCo Adjustment***	Indirect Investment* Adjustment	+ Spare Scrubber	+ Reheat	+ New Pond**	= Total	TVA Estimate	Δ,%
Central Illinois Light Duck Creek 1	378	N	3.30	85	115	128	25	19	12	184	185	0
Indianapolis Power & Light Petersburg 3	532	N	3.25	85	148	164	21	-	12	197	180	+9.4
Springfield City Utilities Southwest 1	194	N	3.50	80	134	149	57	-	12	218	240	-9.2
Southern Illinois Power Corp. Marion 4	184	N	3.50	89	140	156	60	24	12	252	247	+2.0
											Avg Δ	+0.6%

*Adjustment = PEDCo Adjustment × $\frac{2.0}{1.8}$

**All four facilities have waste disposal ponds. The $12/KWe adjustment represents the increased cost of RCRA-approved ponds compared to previous pond designs as reflected by the current TVA pond model ("new pond") compared to previous models.

***From Table 2.1.2-12.

These results suggest that the TVA estimating program can closely predict actual installed investment, when actual installations are put on the same equipment basis and the TVA indirect investment algorithm is used. However, this conclusion is based only on a study of four installations and a capacity range of 184 to 532 MWe.

2.1.2.5 Equipment on Actual Installed FGD Systems

Since the previous section showed that all utility FGD systems do not contain the same equipment, the sixty-two operational utility FGD systems[13] were surveyed to determine (1) how many systems have scrubbing spares and reheat, (2) the type of waste disposal used, and (3) whether the included equipment is a function of FGD system size. The results of this survey are shown in Table 2.1.2-14 and Figure 2.1.2-7. An estimated thirty percent of the systems have spare scrubbers, while no units less than 250 MWe have spares. Most of the units have stack gas reheat. About 66 percent of the units pond the waste, and 34 percent landfill. About half of the units pump the waste to disposal, and one-third truck the waste; the remaining 20 percent did not specify waste transportation procedures. However, for planned facilities, the pond/landfill ratio shifts from 66/34 to 42/58. In future utility boiler FGD unit economic studies, these results should be used as a guide for selecting the FGD system design scope as a function of capacity.

TABLE 2.1.2-14 EQUIPMENT SUMMARY FOR 62 OPERATIONAL UTILITY FGD SYSTEMS

Spare Scrubbers

	No.	Percent	
Yes	12	19	
No	33	54	
Unsure			→ 30% with spare scrubbers
Probably Yes	7	11	
Probably No	10	16	
	62	100	

Reheat

	No.	Percent	
Yes	53	85	
No	3	5	→ Almost all reheat
DNA*	6	10	
	62	100	

Waste Disposal (By site)

- Operational Units (No./Percent)

	Pump	Truck	Unknown	Total
Landfill	2/6%	8/23%	2/6%	12/34%
Pond	15/43%	3/9%	5/14%	23/66%
TOTAL	17/49%	11/31%	7/20%	35/100%

- Planned Units

	No.	Percent	
Landfill			
On-site	4	13	} 58
Off-site	6	19	
Unknown	8	26	
Pond	13	42	
	31	100	

* Data Not Available

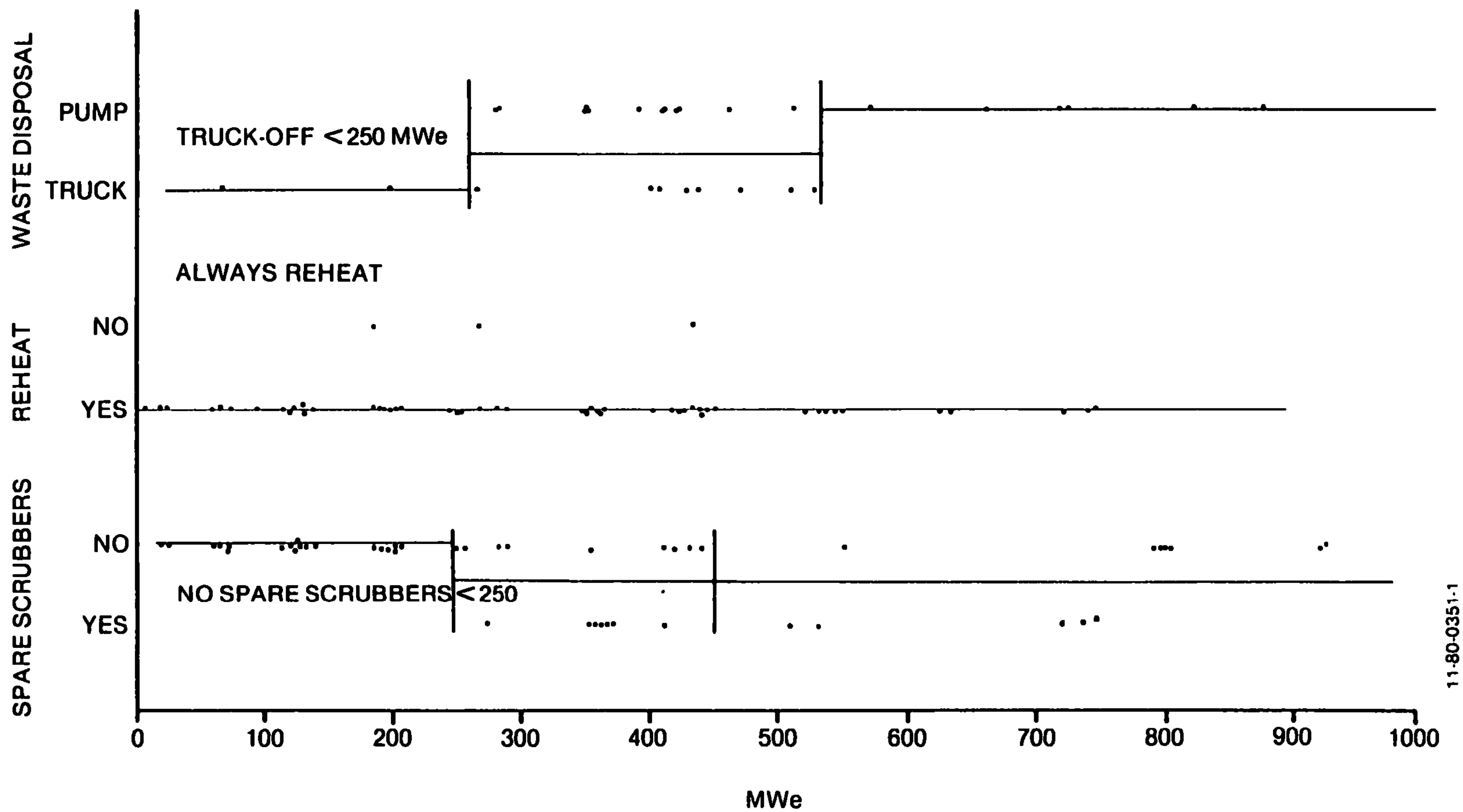


Figure 2.1.2-7. Equipment on 62 Operational Utility Boiler FGD Systems.

2.1.3 Limestone FGD System Annual Operating Cost Estimates

An evaluation of utility and industrial boiler FGD system annual operating costs was performed in a manner similar to the analysis of capital investment in Section 2.1.2.

2.1.3.1 Utility Boiler FGD System Annual Operating and Maintenance Cost Estimates

At the same time that the capital investment for utility boiler FGD systems was being developed, TVA also estimated annual operating and maintenance (O&M) costs.* The economic assumptions for a limestone FGD system with 90 percent SO_2 removal from a boiler firing 3.36 percent sulfur coal are outlined in Table 2.1.3-1, while the system design scope is described in Table 2.1.2-2. First year operating and maintenance (O&M) costs are given in Table 2.1.3-2 and illustrated in Figure 2.1.3-1. Detailed assumptions, material balances, equipment lists, and economic results are given in Appendix A.

Annual revenue requirement, i.e. annual O&M costs plus capital-related costs (such as depreciation, interest-on-debt, return-on-equity) is not evaluated in this section due to the many different procedures for annualizing capital investment. However, TVA estimates for annual revenue requirements (ARR) for each FGD case are presented in the appropriate appendices.

TVA procedures for developing the ARR are summarized below:

1. Obtain first year annual O&M costs.

---

* Includes raw material, labor, supervision, utilities, maintenance, chemical analyses, and overhead costs. Does not include capital-related costs.

Table 2.1.3-1 TVA UTILITY BOILER LIMESTONE FGD SYSTEM ECONOMIC PREMISES AND ASSUMPTIONS

1. Limestone — \$8/ton

2. Operating Labor and Supervision — \$12.50/hr

3. Utilities

   - Process Water — \$0.12/ 10^3gal
   - Electricity — \$0.029/Kwh
   - Steam — \$2.00/ 10^6 Btu

4. Maintenance Labor and Material — 8% of TDI

5. Chemical Analyses — \$17/hr *

6. FGD Capacity, MW

FGD Capacity, MW	100	250	500	1000
No. of Analysts	2	2	3	4

7. Solid Waste Disposal

   "Utility Basis" - On-site disposal

   "Industrial Basis" - \$15/ton paid to outside contractor

8. Plant & Administrative Overhead — 60% × (Conversion Cost** minus Utilities)

9. Plant Material Cost Indices

1978	240.6
1980	286.1
1981	309.3
1982	333.7

10. First year costs expressed in 1981 \$.

11. Capacity Utilization Factor is 0.54.

* Annual Cost for chemical analyses =

$$2080 \frac{\text{hours}}{\text{analyst} \cdot \text{year}} \times \sqrt{\text{Capacity Factor}} \times \frac{\$17}{\text{hour}} \times \text{No. of Analysts}$$

**Conversion Costs include labor, utilities, maintenance, and analyses.

TABLE 2.1.3-2 UTILITY BOILER LIMESTONE FGD SYSTEM FIRST YEAR OPERATING AND MAINTENANCE COSTS*

		Annual O&M Cost, 10^3 $/Yr		
Boiler Capacity MWe	100	250	500	1000
Direct Costs				
Raw Material				
Limestone	174	436	872	1,744
Conversion Costs				
Op. Labor & Supervision	172	260	356	486
Utilities				
Process Water	3	9	18	38
Electricity	264	604	1,201	2,343
Steam	166	414	829	1,657
Maintenance Labor & Materials	1,109	1,785	2,970	5,428
Analyses	52	52	78	104
TOTAL DIRECT COSTS	1,940	3,560	6,324	11,800
Indirect Costs				
Overheads				
Plant & Administrative	800	1,258	2,042	3,611
Total 1st Yr O&M Costs**	2,740	4,818	8,366	15,411
Mills/Kwh	5.79	4.07	3.53	3.26
$/10^6$ Btu***	0.58	0.41	0.35	0.33

* 1981 $

3.5% S Coal

90% SO_2 Removal

0.54 Capacity Factor = $\frac{\text{Annual Use}}{\text{Potential Annual Use at Maximum Capacity}}$

**Direct plus Indirect Costs

***Assuming a plant heat rate of 10,000 Btu/kwh.

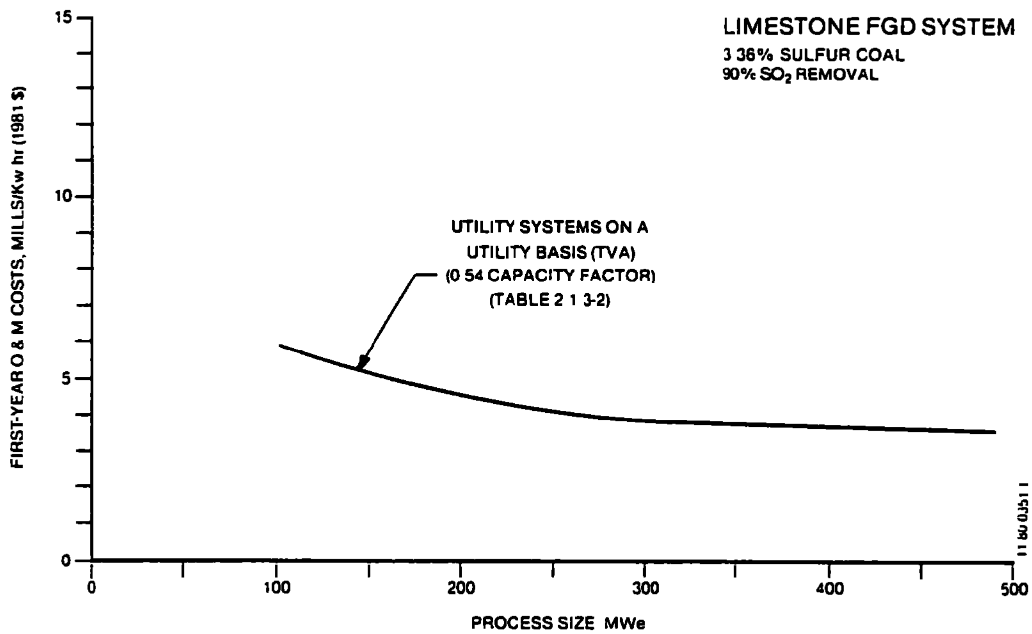


Figure 2.1.3-1. Utility Boiler Limestone FGD System First-Year Operating and Maintenance Costs.

2. Levelized O&M costs equal first year annual O&M × levelization factor.*

3. Levelized annual capital-related charges equal 14.7 percent of the total capital investment.

4. Levelized annual revenue requirement equals the sum of items 2 and 3 above.

* For the cases in Appendices A and C, the levelizing factor is 1.886. This factor is based on a 30-year equipment life, 6 percent annual inflation and a discount rate of 10 percent. Levelizing factors for other economic assumptions can be calculated by the algorithm shown in EPRI's Technical Assessment Guide.[14]

2.1.3.2 Industrial Boiler FGD System Annual Operating and Maintenance Cost Estimates

The annual O&M costs* for limestone FGD systems on small industrial boilers (30 to 200 x 10^6 Btu/hr) were estimated in the FGD ITAR.[15] The assumptions used in the calculations are given in Table 2.1.3-3. As in the capital investment comparison, these assumptions are different from those used by TVA for large utility boiler FGD systems. These assumptions lead to differences in utility and industrial FGD system O&M cost estimates for comparably sized FGD systems.

The first year costs given in Table 2.1.3-4 and shown in Figure 2.1.3-2 are different from those reported in the ITAR.[16] The maintenance labor and material plus the general and administrative overhead (G&A), both percentages of the investment, are higher because of the adjusted capital investment, as described in Section 2.1.2. In addition, the solid waste disposal cost was reduced to $15/ton from $40/ton as reported in the ITAR. A recent study[17] showed this lower figure to be more realistic.

* Includes raw material, labor, supervision, utilities, maintenance, solid waste disposal, and overhead costs. Does not include capital-related costs.

TABLE 2.1.3-3 RADIAN INDUSTRIAL BOILER LIMESTONE FGD SYSTEM ECONOMIC ASSUMPTIONS

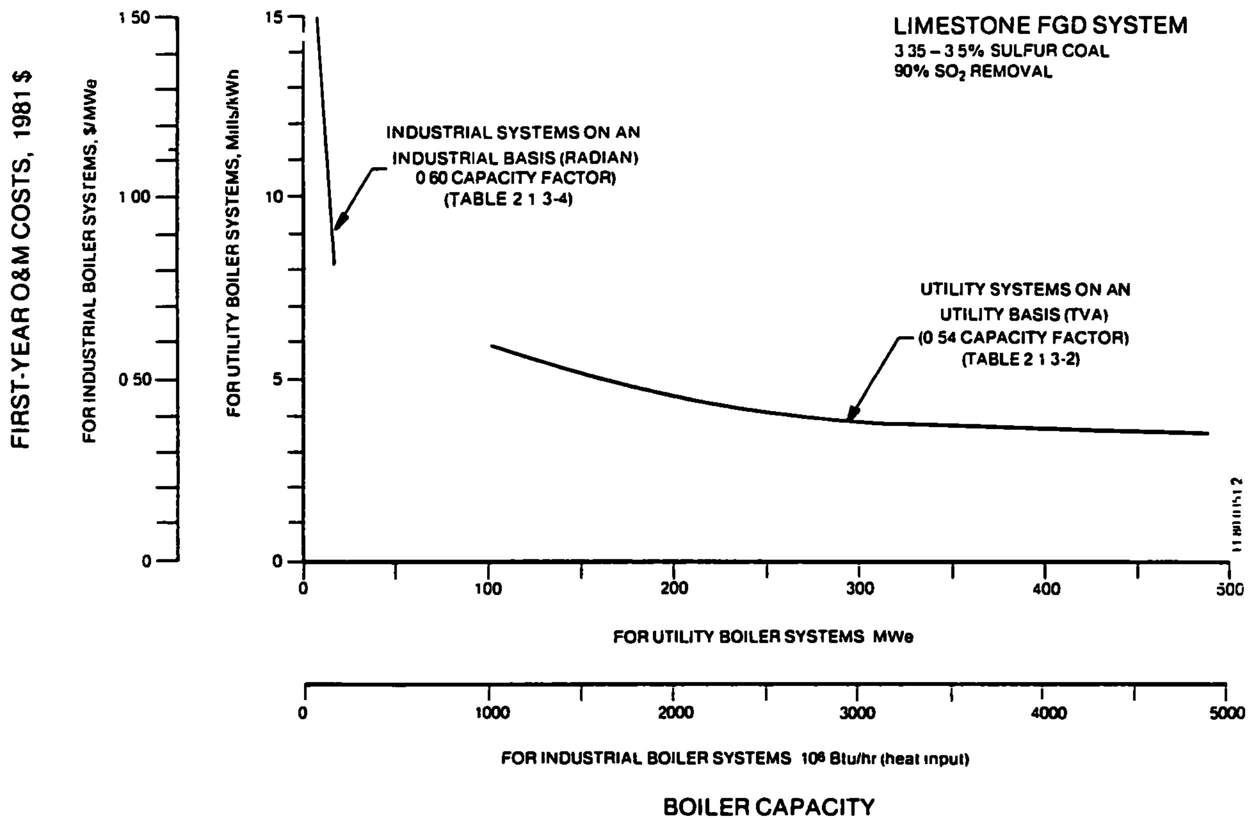
1.	Crushed Limestone	\$13/ton
2.	Operating Labor & Supervision	\$12.02/hr
3.	Utilities	
	Process water	\$0.15/ 10^3 gal
	Electricity	\$0.0258/kwh
4.	Maintenance Labor & Material	8% × TDI*
5.	Chemical Analyses	None
6.	Solid Waste Disposal	\$15/ton (wet) paid to outside contractor
7.	Overhead	
	Payroll Overhead	30% × (Operating Labor & Supervision
	Plant Overhead	26% × (Operating Labor & Supervision plus Maintenance Labor and Materials)
	G&A	4% × TDI*
8.	First year O&M costs are expressed in 1978 \$ and 1981 \$.	
9.	Capacity Utilization Factor is 0.60.	

*TDI = Total Direct Investment

TABLE 2.1.3-4 INDUSTRIAL BOILER LIMESTONE FGD SYSTEM FIRST YEAR OPERATING AND MAINTENANCE COSTS USING RADIAN MATERIAL AND OPERATING COSTS AND OVERHEAD ALGORITHM*

	Annual Cost, 10^3 $/Yr			
Boiler Heat Input Capacity 10^6 Btu/hr	30	75	150	200
Direct Costs				
Raw Material				
Limestone	10	24	49	65
Conversion Costs				
Operating Labor	105	105	105	105
Supervision	21	21	21	21
Utilities				
Process Water	0.2	0.7	1	2
Power	7	18	36	42
Maint. Labor & Materials	33	48	68	78
Solid Waste Disposal	28	71	143	190
TOTAL DIRECT COSTS	204	288	423	503
Indirect Costs				
Payroll	38	38	38	38
Plant	40	44	48	50
G&A	31	43	60	68
TOTAL INDIRECT COSTS	109	125	146	156
Total 1st Yr. O&M	313	413	569	659
$/$10^6$ Btu (1978$)	1.99	1.05	0.72	0.63
$/$10^6$ Btu (1981$)	2.56	1.35	0.93	0.81

*1981$ = 1978$ x 1.285
0.60 Capacity Utilization Factor
3.5% S Coal
90% SO_2 Removal



NOTE: Utility boiler FGD unit annual O&M estimates are provided for boiler capacities of 100-500 MWe and are expressed as mills/kwh. Industrial boiler FGD system estimates are provided for boiler heat input capacities of 30-200 x 10^6 Btu/hr and are expressed as $\$/10^6$ Btu. The utility and insutrial boiler annual O&M and capacity scales are interchangeable if a 10,000 Btu/kwh conversion factor is assumed. This is a close approximation of the heat rate for most utility plants.

Figure 2.1.3-2. Differences in First-Year Operating and Maintenance Costs for Utility and Industrial Boiler FGD Systems.

2.1.3.3 Comparison and Integration of Utility and Industrial Boiler FGD System Annual O&M Cost Estimates

Annual O&M cost estimates were evaluated using the same methods as those used for comparing capital investment; i.e., small industrial and large utility FGD system cost estimates were put on the same economic and financial bases to determine if the cost curves form a smooth transition through the FGD system size range. Smooth transition of the cost curves would indicate that the basic technical premises (including material and energy balances and manpower required to operate the system) for the two system types are comparable.

In Figure 2.1.3-2, visual extrapolation of the cost curve for utility systems to the industrial boiler system cost curve gives a possible smooth transition from 100 MWe to 20 MWe. As discussed previously (Section 2.1.2.3), TVA estimated the "industrial basis" for large utility boiler FGD systems by subtracting costs for spare scrubbers and stack gas reheat, and replacing the waste disposal pond with a solids concentration and trucking system. Solid waste disposal costs were taken as $15/ton (the same as in Radian's industrial boiler system study). The annual operating and maintenance costs for this industrial-based design scope are given in Table 2.1.3-5 and illustrated in Figure 2.1.3-3. Visual extrapolation of the industrial-based curve for large utility boiler FGD systems shows a marked difference in annual costs between large utility and small industrial boiler FGD systems.

Tables 2.1.3-1 and 2.1.3-3 show some differences in raw material prices, labor rates, utility prices, and algorithms used to calculate maintenance labor and material overheads. However, in most cases these differences are not large. The industrial boiler FGD system was put on the same cost basis as that in the TVA study by (1) using raw material prices, labor rates, and utility prices from the TVA study, and (2) using the TVA algorithm to calculate maintenance labor, material, and overhead costs. Material balances and operating labor hours were the same as those used in Radian's analysis of

TABLE 2.1.3-5 UTILITY BOILER LIMESTONE FGD SYSTEM* FIRST YEAR OPERATING AND MAINTENANCE COSTS ON AN INDUSTRIAL BASIS**

	First Year Annual O&M Cost, 10^3 \$/Yr			
Boiler Capacity, MWe	100	250	500	1000
Direct Costs				
Raw Material				
Limestone	194	484	969	1,937
Conversion Costs				
Op. Labor & Supervision	342	435	536	674
Utilities				
Process Water	5	12	24	47
Electricity	287	653	1,294	2,520
Maintenance				
Labor & Materials	624	1,096	2,053	3,671
Analyses	55	55	82	110
Sludge Disposal (\$15/wet ton)	951	2,375	4,751	9,502
TOTAL DIRECT COSTS	2,458	5,109	9,708	18,459
Indirect Costs				
Overheads				
Plant & Admin.	1,183	2,376	4,453	8,373
Total First Year O&M	3,641	7,486	14,161	26,833
Mills/Kwh	6.93	5.70	5.39	5.11
\$/10^6 Btu	0.69	0.57	0.54	0.51

*3.5% Sulfur Coal
90% SO_2 Removal
0.60 Capacity Factor
1981 \$

**No space scrubbers
No stack gas reheat
No waste disposal pond

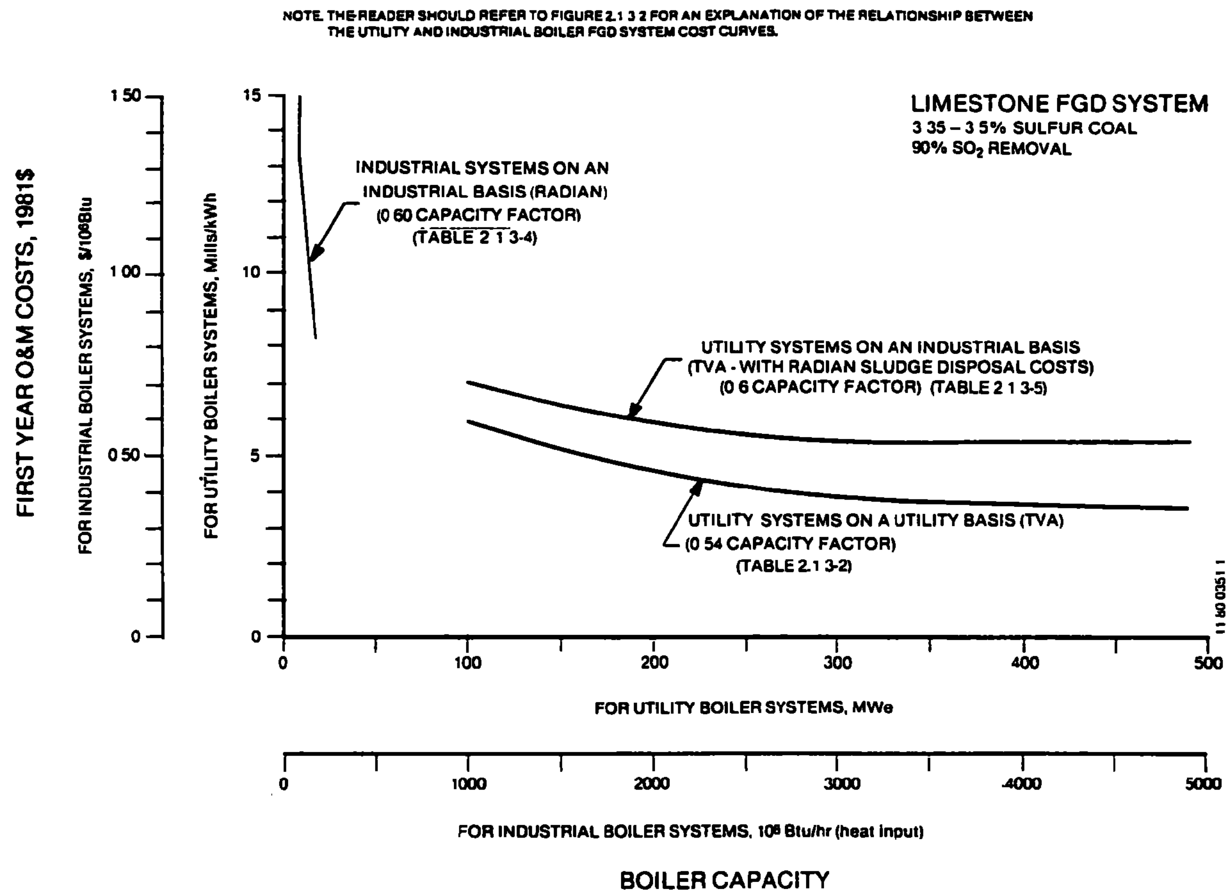


Figure 2.1.3-3. Impact of Putting Large Utility Boiler FGD Systems on an Industrial Basis.

small boiler FGD systems. The results are given in Table 2.1.3-6 and illustrated as Figure 2.1.3-4. The curve for this data is lower than the curve for the industrial data only. Visual extrapolation shows a large discontinuity between the curve for industrial boiler system using the TVA cost basis and utility boiler system using the Radian industrial design scope.

Further examination shows that the maintenance labor, material and overhead costs are a significant portion of the O&M costs. Maintenance costs are generally estimated as a percentage of investment. Overhead costs are based on direct costs (which include maintenance), thus making O&M costs very sensitive to investment. The maintenance costs for an industrial boiler FGD system (Table 2.1.3-6) were calculated with the utility indirect investment algorithm and using investment on an industrial boiler basis design scope (see Table 2.1.2-9) but not including the higher installation costs for field-fabrication/erection (Table 2.1.2-11). Using these investment figures (Table 2.1.2-11) to calculate maintenance costs, significantly higher costs are obtained for the small industrial boiler FGD systems. These results are given in Table 2.1.3-7 and illustrated in Figure 2.1.3-5.

Figure 2.1.3-6 presents the five curves shown in Figure 2.1.3-5 on a log-log plot. The consistency of the cost data can best be observed on this type of plot. Note also that each individual cost data point is also given in the figure. The dotted line connects the two curves (for the industrial and utility boiler FGD system) that have been put on the same basis.

Figure 2.1.3-6 illustrates that a reasonably continuous first year O&M cost curve as a function of FGD capacity can be obtained when utility and industrial boiler FGD systems are put on the same basis (i.e., the following items are made identical for both cases):

(1) Design scope
(2) Indirect investment algorithms
(3) Equipment installation factors
(4) Unit costs for raw materials, labor, utilities, solid waste disposal, etc.

TABLE 2.1.3-6 INDUSTRIAL BOILER LIMESTONE FGD SYSTEM FIRST YEAR OPERATING AND MAINTENANCE COSTS USING TVA MATERIAL AND OPERATING COSTS PLUS OVERHEAD ALGORITHM (RADIAN INVESTMENT BASIS)

Boiler Heat Input Capacity 10^6 Btu/hr	Annual O&M Cost, 10^3 \$/Yr 30	75	150	200
Direct Costs				
Raw Material				
Limestone	6	15	30	40
Conversion Costs				
Operating Labor & Supervision	126	126	126	126
Utilities				
Process Water	0.2	0.6	0.8	1.6
Electricity	8	20	40	47
Maintenance Labor & Materials	40	59	83	95
Analyses	7	14	21	27
Sludge Disposal	28	71	143	190
TOTAL DIRECT COSTS	215	288	444	527
Indirect Costs				
Overheads				
Plant & Admin.	121	151	224	263
Total First Year O&M	336	439	668	790
\$/10^6 Btu	2.13	1.11	0.85	0.75

Bases

1981 \$
3.5% Sulfur Coal
90% SO_2 Removal
0.60 Capacity Utilization Factor

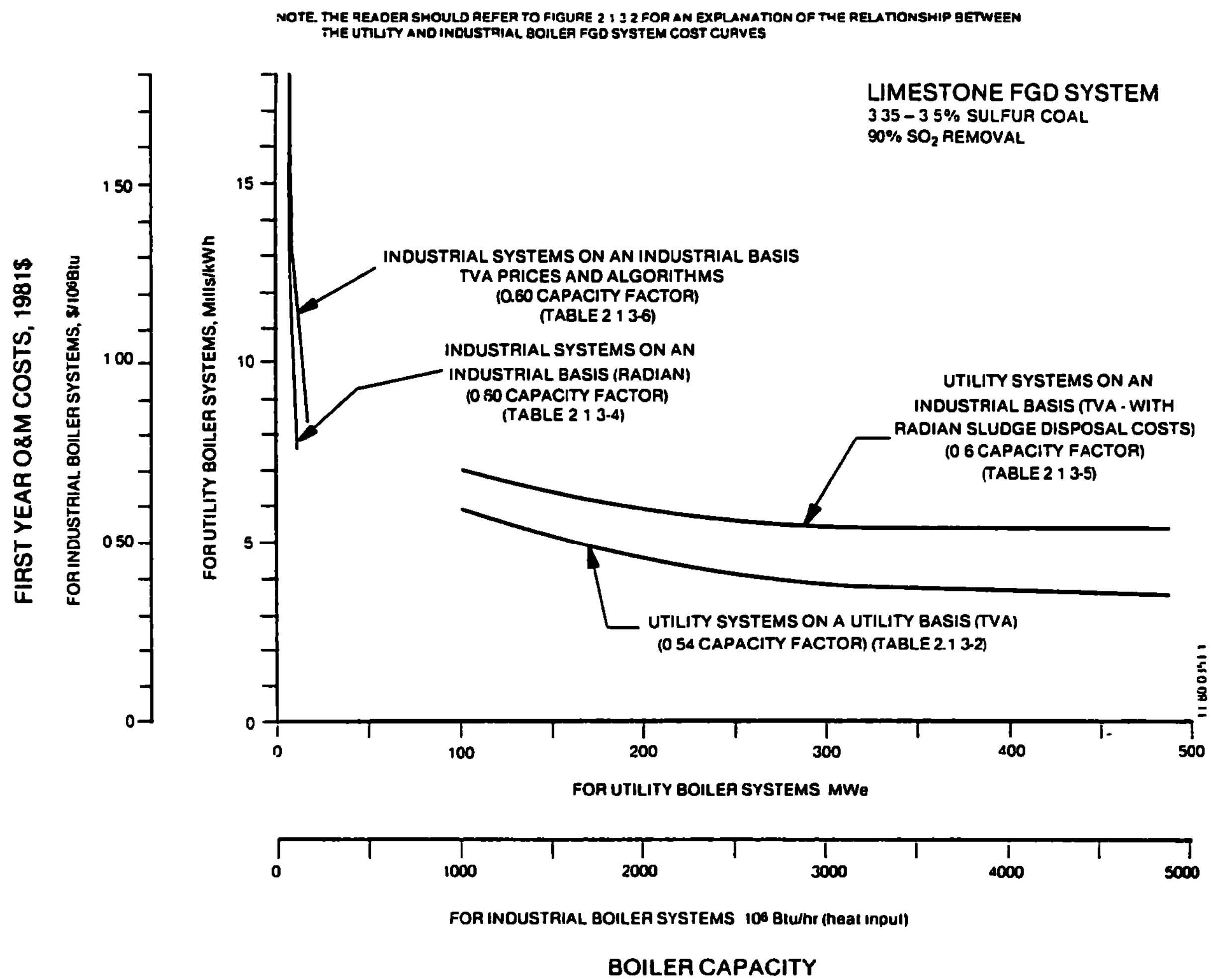


Figure 2.1.3-4. Impact of Putting Small Industrial Boiler FGD Systems on a Large Utility Boiler FGD System Basis.

TABLE 2.1.3-7 INDUSTRIAL BOILER LIMESTONE FGD SYSTEM FIRST YEAR OPERATING AND MAINTENANCE COSTS USING TVA MATERIAL AND OPERATING COSTS PLUS OVERHEAD ALGORITHM (TVA INVESTMENT BASIS, i.e. INSTALLATION FACTORS)

Boiler Heat Input Capacity 10^6 Btu/hr	First Year Annual O&M Cost, 10^3 \$/Yr			
	30	75	150	200
Direct Costs				
Raw Material				
Limestone	6	15	30	40
Conversion Costs				
Operating Labor & Supervision	126	126	126	126
Utilities				
Process Water	0.2	0.6	0.8	1.6
Electricity	8	20	40	47
Maintenance Labor & Materials	73	98	129	160
Analyses	7	14	21	27
Sludge Disposal	28	71	143	190
TOTAL DIRECT COSTS	248	345	490	592
Indirect Costs				
Overheads				
Plant & Administration	140	185	251	301
Total First Year O&M	388	530	741	893
\$/10^6 Btu	2.46	1.34	0.94	0.85

Bases

1981 \$
3.5% Sulfur Coal
90% SO_2 Removal
0.60 Capacity Utilization Factor

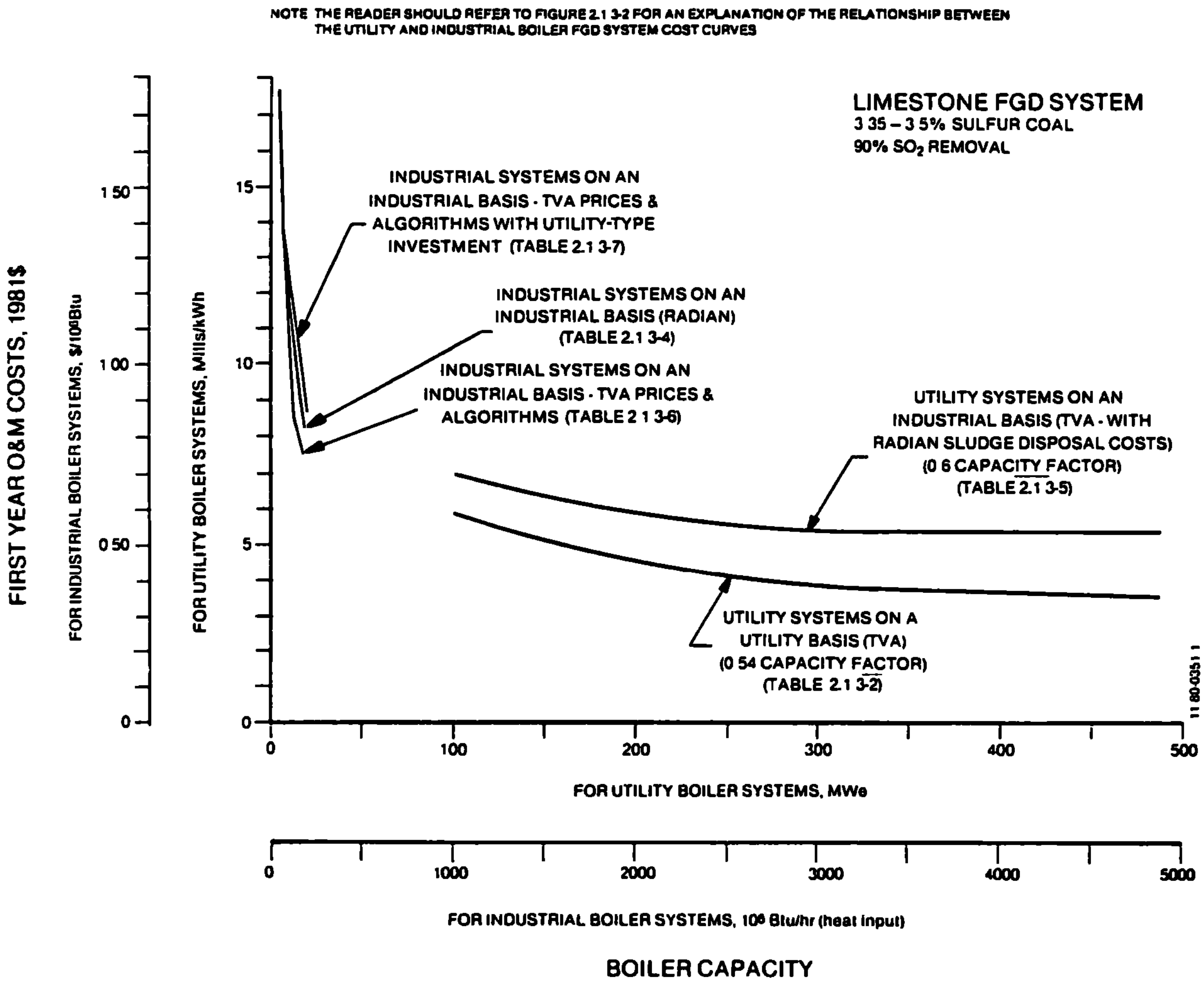
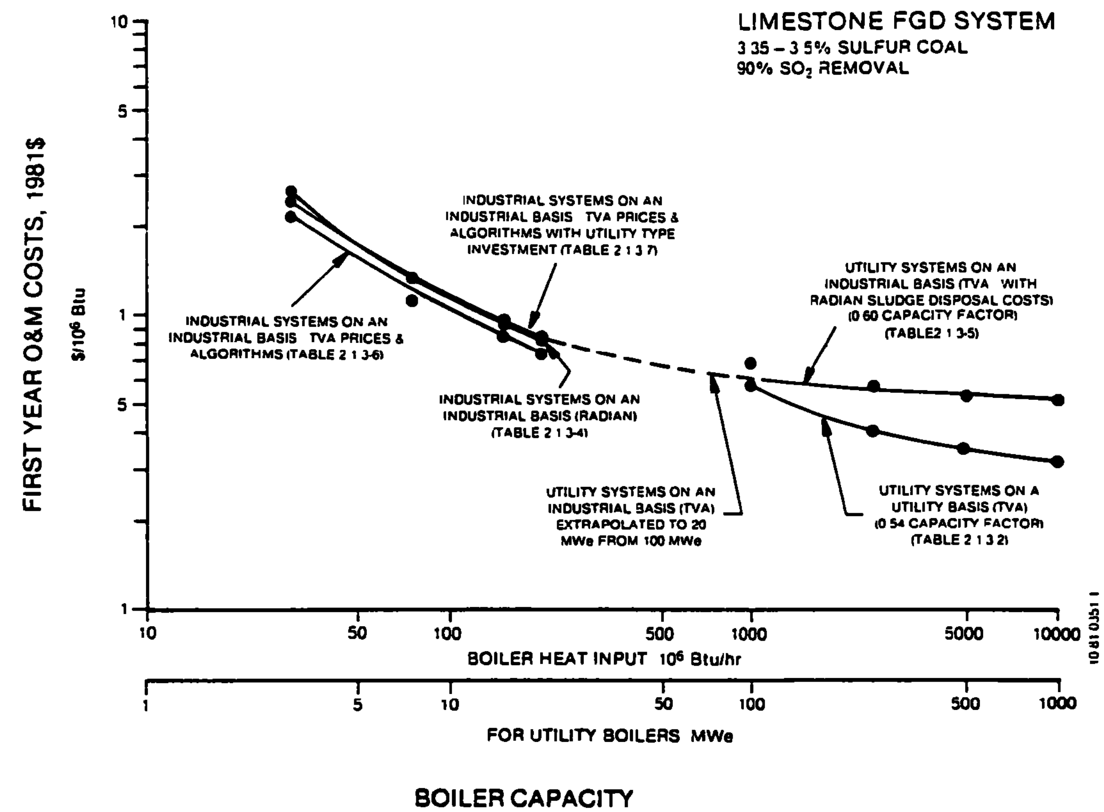


Figure 2.1.3-5. Impact of Putting Small Industrial Boiler FGD Systems on a Large Utility Boiler FGD System Basis, Including Investment.



NOTE: Utility boiler FGD unit annual O&M estimates are provided for boiler capacities of 100-500 MWe and are expressed as $\$/10^6$ Btu assuming a plant heat rate of 10,000 Btu/kwh. Industrial boiler FGD system estimates are provided for boiler heat input capacities of 30-200 x 10^6 Btu/hr and are expressed as $\$/10^6$ Btu. The utility and industrial boiler capacity scales are interchangeable if the same 10,000 Btu/kwh conversion factor is assumed. This is a close approximation of the heat rate for most utility plants.

Figure 2.1.3-6. Comparison of All Cases for Wet Limestone Scrubbing FGD System First-Year Operating and Maintenance Costs.

However, any or all of these factors are likely to be significantly different for industrial and utility boiler FGD systems. First, environmental regulations and economy of scale will likely cause the two systems to be designed differently. Second, the indirect investments for the two types of systems will be different, especially for interest during construction and construction expenses. Third, shop-fabrication of many components of industrial systems will result in lower installation costs for these systems compared to the field-erected costs for utility systems. Finally, unit costs for raw materials and solid waste disposal will be different due to significant volume differences. Utilities and labor costs may also be different for utility and industrial applications. Therefore, a continuous function for industrial and utility boiler FGD system O&M costs should not be expected throughout the capacity range.

As with the capital investment curve, the dotted line does not pass through the 100 MWe cost data point. The TVA cost program estimates high for capital investment for this fairly low capacity FGD system. The reasons were explained in Section 2.1.2.3. Therefore the O&M costs for the 100 MWe system are expected to be high based on the costs that are directly related to capital investment (such as maintenance and overhead).

2.1.4 Use of the Cost Estimate Results

Sections 2.1.2 and 2.1.3 have provided capital investment and O&M cost estimates developed on different bases. No one single estimate is "correct"; rather, the appropriate estimate is dependent on the applicable basis. Table 2.1.4-1 outlines the various investment and cost bases and appropriate table for reference.

In additional acid rain studies it is recommended that the FGD capital investment costs* applied to new utility boilers in Table 2.1.2-3 and industrial boilers in Table 2.1.2-6 be used as the basis for assessing costs of FGD controls for acid rain abatement. Although these costs show discontinuities (as depicted in Figure 2.1.2-2), they do represent likely situations for FGD units of comparable size. The difference between industrial and utility boiler FGD systems can be primarily attributed to the design scope, method of installation, and indirect investment factors as discussed in the previous section.

With the capital investment costs, it is recommended that the first year O&M costs* for utility boiler FGD units in Table 2.1.3-2 and for industrial boiler FGD units in Table 2.1.3-4 be used to assess FGD system cost impacts. These O&M costs are consistent with the investment costs recommended above.

*These costs are for FGD systems applied to new boilers. Retrofit factors will have to be used to estimate costs for FGD systems applied to existing boilers.

TABLE 2.1.4-1 SUMMARY OF LIMESTONE FGD SYSTEM COST STUDIES

Case	Investment Basis	Investment Table Number	O&M Cost Basis	O&M Cost Table Number
1	100-1000 MWe FGD Systems with Reheat, Spare Scrubbers and a Waste Disposal Pond based on current TVA estimation procedure	2.1.2-3	TVA Raw Material, Labor & Utility Costs and TVA Indirect Cost Algorithm (0.54 Capacity Factor)	2.1.3-2
2	100-1000 MWe FGD Systems without Reheat, Spare Scrubber or a Waste Disposal Pond (Clarifiers/Thickeners added) using the TVA Indirect Investment Algorithm	2.1.2-8	TVA Raw Material, Labor & Utility Costs with Radian Solid Waste Disposal Costs and TVA Indirect Cost Algorithm (0.6 Capacity Factor)	2.1.3-5
3	30-200 x 10^6 Btu/hr Industrial Boiler FGD Systems with Field-Erected Installation Factors, without Reheat, Spare Scrubbing or a Waste Disposal Pond and using the TVA Indirect Investment Algorithm	2.1.2-11	TVA Raw Material, Labor & Utility Costs with Radian Solid Waste Disposal Costs and TVA Indirect Cost Algorithm (0.6 Capacity Factor)	2.1.3-7
4	30-200 x 10^6 Btu/hr Industrial Boiler FGD Systems with Shop-Fabricated Installation Factors, without Reheat, Spare Scrubbers, or a Waste Disposal Pond and using the TVA Indirect Investment Algorithm	2.1.2-9	TVA Raw Material, Labor & Utility Costs with Radian Solid Waste Dispoal Costs and TVA Indirect Cost Algorithm (0.6 Capacity Factor)	2.1.3-6
5	30-200 x 10^6 Btu/hr Industrial Boiler FGD Systems with Shop-Fabricated Installation Factors, without Reheat, Spare Scrubbers or a Waste Disposal Pond and using the Radian Indirect Investment Algorithm	2.1.2-6	Radian Raw Material, Labor & Utility Costs with Radian Solid Waste Disposal Costs and Radian Indirect Cost Algorithm (0.6 Capacity Factor)	2.1.3-4

* Maintenance Costs are based on capital investment defined to the left.

2.2 Lime Spray Dryer FGD System Cost Estimates

Dry scrubbing FGD systems are those processes which involve contacting a sulfur oxide-containing flue gas with an alkaline material for SO_2 removal and generating a dry solid waste product. Three major types of dry scrubbing FGD systems are currently being developed: spray drying, dry injection, and combustion of fuel/lime mixtures. Of these three types, spray drying is the only one being extensively developed on a commercial scale. In this report, cost estimates (capital and operating) for utility and industrial boiler spray dryer systems are presented. The most widely-used sorbents for spray drying are sodium carbonate and lime. Sodium carbonate, being very water-soluble, is the most reactive. This increased solubility can, however, lead to waste disposal problems. Therefore, only lime spray dryers are considered here.

2.2.1 Process Description

Flue gas at air preheater outlet temperatures (generally 250 to 400^oF) is contacted with a lime slurry in a spray dryer with 5 to 10 seconds residence time. The flue gas is adiabatically humidified to within 20 to 50^oF of its saturation temperature by the water evaporated from the slurry. As the slurry or solution is evaporated, liquid phase salts are precipitated and these salts and unreacted sorbent are dried to generally less than one percent free moisture. These solids, along with fly ash, are entrained in the flue gas and carried out of the dryer to a particulate collection device. Reaction between the alkaline material and flue gas SO_2 occurs both during and following the drying process. A generalized flow diagram of a lime spray dryer is presented in Figure 2.2.1-1.

With set conditions for inlet flue gas temperature and humidity and for a specified approach to saturation temperature, the amount of water which can be evaporated into the flue gas is specified by energy balance considerations. Liquid-to-gas ratios are generally in the range of 0.2 to 0.3 gal/10^3 cf.

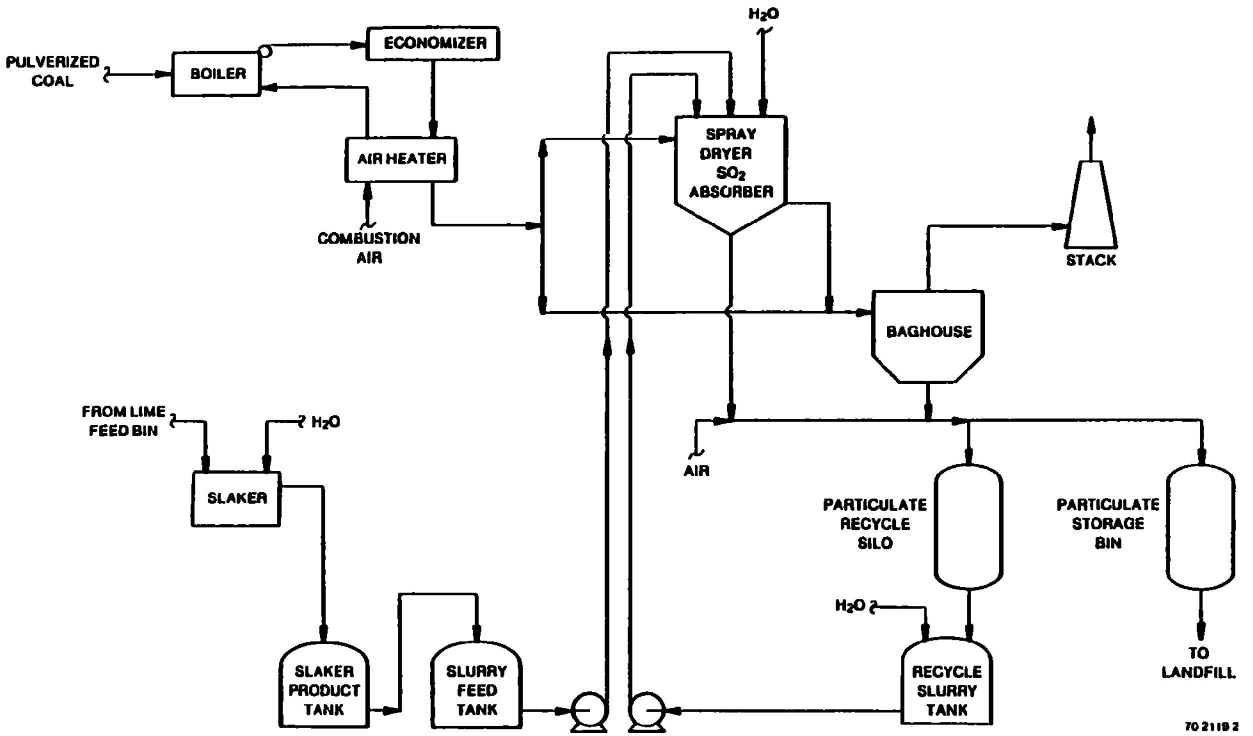


FIGURE 2.2.1-1 LIME SPRAY DRYER PROCESS FLOW DIAGRAM

The sorbent stoichiometry is varied by raising or lowering the weight percent solids of a slurry containing this set amount of water. While holding other parameters such as temperature constant, the obvious way to increase SO_2 removal is to increase sorbent stoichiometry. However, as sorbent stoichiometry is increased to raise the level of SO_2 removal, two limiting factors are approached:

(1) Sorbent utilization decreases, increasing sorbent and disposal costs.

(2) An upper limit is reached on the weight percent of sorbent solids in the slurry.

There are at least two methods of circumventing these limitations. One method is to initiate sorbent recycle, either using the solids dropped out in the spray dryer or the particulate collection device catch. This has the advantage of increasing the sorbent utilization, as well as increasing tne opportunity for utilizing any alkalinity in the fly ash.

The second method of avoiding the above limitations on SO_2 removal is to operate the spray dryer at a lower outlet temperature, that is, at a closer approach to saturation. Operating the spray dryer outlet at a closer approach to saturation has the effect of both increasing the residence time of the liquid droplets and increasing the residual moisture level in the dried solids. As the approach to saturation is narrowed, SO_2-removal rates and sorbent utilization generally increase dramatically. Since the mechanisms for SO_2 removal are not clearly defined, it is not obvious whether it is the increase in liquid phase (droplet) residence time, the increase in residual moisture in the solids, or both which account for the increased removal.

The approach to saturation at the spray dryer outlet is set by either the requirement for a margin of safety to avoid condensation in downstream equipment or restrictions on stack temperature. The spray dryer outlet can be operated at temperatures lower than these restrictions would otherwise allow if some flue gas is bypassed around the spray dryer and used to reheat the dryer outlet gas. Warm gas (downstream of the boiler air heater) can be used at no energy penalty, but the amount of untreated gas involved in reheating begins to limit overall SO_2 removal efficiencies. Significantly less hot gas (upstream of the air heater) is required to heat, but an energy penalty, associated with the decrease in energy available for air preheat, comes with using this higher temperature gas. Figure 2.2.1-1 illustrates the warm gas "reheat" option.

The spray dryer design can be affected by the choice of particulate collection device. Bag collectors have an inherent advantage in that unreacted alkalinity in the collected waste on the bag surface can react with remaining SO_2 in the flue gas. Some process developers have reported SO_2 removal on bag surfaces on the order of 10 percent of total removal. Because the fabric is somewhat sensitive to wetting, a margin above saturation temperature must be maintained for bag protection. ESP collectors have not been demonstrated to achieve significant incremental SO_2 removal. However, some vendors claim that the ESP is less sensitive to condensation and hence the spray dryer can be operated closer to saturation (about $20^{\circ}F$ approach), resulting in increased SO_2 removal in the spray dryer.

The choice between sorbent types, (sodium- or calcium-based), use of recycle, use of warm or hot gas bypass (if at all), and the type of particulate collection device tends to be rather site specific. Vendor and customer preferences, system performance requirements, and site-specific economic factors dictate the system design for each individual application.

2.2.2 Lime Spray Dryer FGD System Capital Investment

There are apparent large differences in capital investment per unit capacity when comparing small industrial boiler lime dry scrubbing FGD systems with large utility boiler lime dry scrubbing FGD systems. To resolve these differences, the same approach as that used in comparing the limestone FGD system cost estimates will be used to compare lime dry scrubbing FGD system costs. Large utility and small industrial boiler lime dry scrubbing FGD systems will be put on the same basis to determine if cost differences are real or an artifact of the algorithms and assumptions used to calculate the investments and costs.*

The estimates provided by TVA for utility boiler FGD systems should be considered "preliminary." These estimates were provided on a quick response basis by TVA and, since no full scale systems are in operation currently, these estimates cannot be considered as accurate as the limestone FGD system estimates presented in Section 2.1. Prior to using these estimates the reader should obtain updated TVA information.

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*All costs in this section are for lime dry scrubbing FGD systems applied to new boilers.

2.2.2.1 Utility Boiler Lime Spray Dryer Capital Investment Estimates

Although economic evaluations of dry scrubbing FGD systems for large utility boilers are very limited, TVA has conducted an economic evaluation of a 70 percent SO_2 removal lime dry scrubbing FGD system for a 500 MWe boiler firing 0.7 percent sulfur western coal.[1] This work was recently updated and also extended to include an FGD system on a 500 MWe boiler burning 0.7 percent sulfur eastern coal with 70 percent SO_2 removal, and a 500 MWe boiler firing 3.5 percent sulfur eastern coal with 90 percent SO_2 removal.[2] The economic assumptions for the FGD system on the boiler firing 0.7 percent sulfur western coal with 70 percent removal, and for the system on the boiler firing 3.5 percent sulfur eastern coal with 90 percent removal are given in Appendix D. It should be noted again that these results are preliminary and have not been approved by TVA or EPA. A reader should obtain up-to-date TVA information before using these cost estimates.

These results were modified and extended to meet the needs of this study. The TVA investment estimates were based on a 1982 construction schedule rather than a 1980 schedule as needed for this study. Thus, uninstalled material costs were adjusted to 1980 rates by multiplying the projected 1982 material costs by the ratio of 1980 and 1982 Chemical Engineering Material Costs Indices (1980/1982=286.1/333.7=0.857). Next, installation factors for each operating area were derived by dividing the 1982 area installed direct investment by the 1982 material costs. Then, the 1980 area material costs were multiplied by the appropriate area installation factors to give the 1980 area direct investment. (1982 material costs and installation factors are given in Appendix D.) The algorithms used to calculate indirect investment and other capital requirements in the limestone FGD study (Table 2.1.2-1) were applied to the direct investment results to give a total capital investment.

These studies provided estimates for a 500 MWe system only. To estimate the investment for units of other sizes, scale factors were used. For the raw material handling area:

250 MWe 1980 Raw Material Handling Direct Investment =

$$\left(\frac{\text{Lime feed rate @ 250 MWe}}{\text{Lime feed rate @ 500 MWe}}\right)^{0.89} \times \begin{array}{l}\text{500 MWe 1980 Raw Material}\\ \text{Handling Direct Investment}\end{array}$$

The scale factors were obtained from TVA and used to estimate costs for 250 MWe and 1000 MWe systems.[20] The scale factors for the eight principal operation areas are given in Appendix D. The algorithms used to calculate indirect investment and other capital requirements in the limestone FGD study (Table 2.1.2-1) were applied to the total direct investment to obtain the total capital investment.

The capital investment results from these calculations are shown in Table 2.2.2-1. These results cannot be compared directly to the limestone FGD investment results in previous sections of this report because a particulate collection system (baghouse) was not included in the wet scrubbing system study but was included in the dry scrubbing system study.

Several other differences are also apparent. The capital investment for the SO_2 absorption equipment (spray dryers) is much less than for the limestone system. Also the cost for the landfill area construction is estimated to be much less than for the limestone system onsite. Each of these observations should be analyzed carefully before using these costs for other studies.

TABLE 2.2.2-1 UTILITY BOILER LIME SPRAY DRYER FGD SYSTEM CAPITAL INVESTMENT *

	Capital Investment, 10^3\$, 1980 \$					
	0.7% S Western Coal-70% Removal			3.5% S Eastern Coal-90% Removal		
Direct Investment MWe	250	500	1000	250	500	1000
Material Handling	756	1399	2597	2144	3973	7363
Feed Preparation	355	526	783	796	1181	1754
Gas Handling	5065	8115	13002	5612	8990	14406
SO_2 Absorption	3873	6077	9536	4753	7458	11701
Particulate Removal	4780	9559	19119	4647	9293	18587
Particulate Handling & Recycle **	726	1189	1943	333	544	892
Solids Disposal (trucks, etc)	222	381	888	337	577	1348
Services, Utilities & Misc	947	1635	2872	1117	1921	3363
Landfill Construction	1005	1799	4020	1800	3599	7198
TOTAL DIRECT INVESTMENT	17729	30680	54760	21539	37536	66612
Indirect Investment						
Engr. Design & Supv+A&E	1596	2761	4928	1939	3378	5995
Construction Expenses	2837	4909	8762	3446	6006	10658
Construction Fees	886	1534	2738	1077	1877	3331
Contingency	4610	7977	14238	5600	9759	17319
FIXED INVESTMENT	27658	47861	85426	33601	58556	103915
Other Capital Requirements						
Startup & Modifications	2127	3682	6571	2585	4504	7993
Interest During Construction	4149	7179	12814	5040	8783	15587
Land	833	1441	2574	1012	1764	3131
Working Capital	940	1626	2902	1142	1989	3530
TOTAL CAPITAL INVESTMENT	35707	61789	110287	43380	75596	134156
\$/KWe	142.8	123.6	110.3	173.5	151.2	134 2

*The design scope is described in Appendix D.

**Recycle is not employed for the 3.5% S case.

2.2.2.2 Industrial Boiler FGD System Capital Investment Estimates

The capital investment for lime dry scrubbing FGD systems on small industrial boilers (approximately 75 to 400 x 10^6 Btu/hr heat input) has been estimated by Radian Corporation as part of a series of technology assessment reports to provide EPA with technical background for use in setting New Source Performance Standards (NSPS) for industrial boilers.[21] Material balances and an equipment list for FGD systems on boilers firing 0.6 percent sulfur coal with 70 percent SO_2 removal and 2.3 percent sulfur coal with 70 percent SO_2 removal are given in Appendix E. The assumptions used in calculating the indirect investment, which are different from those used by TVA for utility boiler FGD systems, are the same as those used in the industrial boiler limestone FGD system study (Table 2.1.2-4).

The capital investment results are given in Table 2.2.2-2. These results were corrected for higher particulate removal (baghouse) investment than that contained in the Industrial Technology Assessment Review (ITAR).[22] In addition, the total capital investment was updated from a 1978 dollar basis to a 1980 basis by using the Chemical Engineering Plant Cost Index (265.0/218.8 = 1.21).

TABLE 2.2.2-2 RADIAN INDUSTRIAL BOILER LIME DRY SCRUBBING FGD SYSTEM CAPITAL INVESTMENT ESTIMATES

Boiler Heat Input Capacity 10^6 Btu/hr	Capital Investment,* 10^3\$			
	0.6% S-70% Removal		2.3% S-70% Removal	
	150	400	75	400
Direct Investment				
Raw Material Handling	75	116	87	179
SO_2 Scrubbing	230	337	171	349
Fans	66	124	41	126
Solids Separation	713	1310	440	1344
Utilities & Service	65	113	44	120
TOTAL DIRECT INVESTMENT (TDI)	1149	1898	783	2118
Indirect Investment				
Engineering	117	190	117	212
Const. & Field Expense	115	190	78	212
Construction Fees	115	190	78	212
Startup	23	38	16	42
Performance Test	11	19	8	21
TOTAL INDIRECT INVESTMENT (TII)	381	627	297	699
Contingencies	306	505	216	563
TOTAL TURNKEY INVESTMENT (TTI)	1836	3030	1296	3380
Land	1	2	1	2
Working Capital	66	98	60	139
TOTAL CAPITAL INVESTMENT (TCI) 1978 \$	1903	3130	1357	3521
TCI x 1.21 = 1980 \$	2303	3787	1642	4260
TCI (1980 \$), 10^3 \$/10^6 Btu/hr	15.35	9.47	21.89	10.65

*Based on Radian estimates (both equipment installation factors and indirect investment algorithm.

2.2.2.3 Comparison and Integration of Utility and Industrial Boiler FGD System Capital Investment Estimates

A comparison of utility and industrial boiler dry scrubbing FGD system capital investment estimates is shown in Figure 2.2.2-1. As is the case with wet scrubbing FGD systems, there are three primary differences in the bases of the utility and industrial boiler FGD system investment estimates:

1. Equipment components (design scope)
2. Algorithms to calculate indirect investment and other capital requirements
3. Equipment installation factors

The differences in the design scope makes a major impact on capital investment estimates. Most industrial boiler systems do not include spare scrubbers, solids disposal equipment, particulate handling and recycle, or landfill area. Subtracting the cost for these items from the utility boiler FGD investment for the 0.7 percent S western coal, 70 percent SO_2 removal can yield a \$20/KWe to \$30/KWe lower capital investment (Table 2.2.2-3 and Figure 2.2.2-2).

Figure 2.2.2-2 illustrates that even with the investment of the above equipment components subtracted from utility FGD system investment, there are still significant differences in investment for comparably sized industrial boiler FGD systems and utility boiler FGD systems on an "industrial basis." As discussed in the wet scrubbing section (Section 2.1.2.3), the algorithms used to calculate the indirect investment and other capital requirements for utility boiler FGD systems are different from those used for small industrial boiler FGD systems. Using the TVA indirect investment algorithm (i.e., total capital investment equals $\sim$2.0 x total direct investment) to calculate investment results in a higher investment estimate than using the Radian indirect investment algorithm. Thus, applying the utility

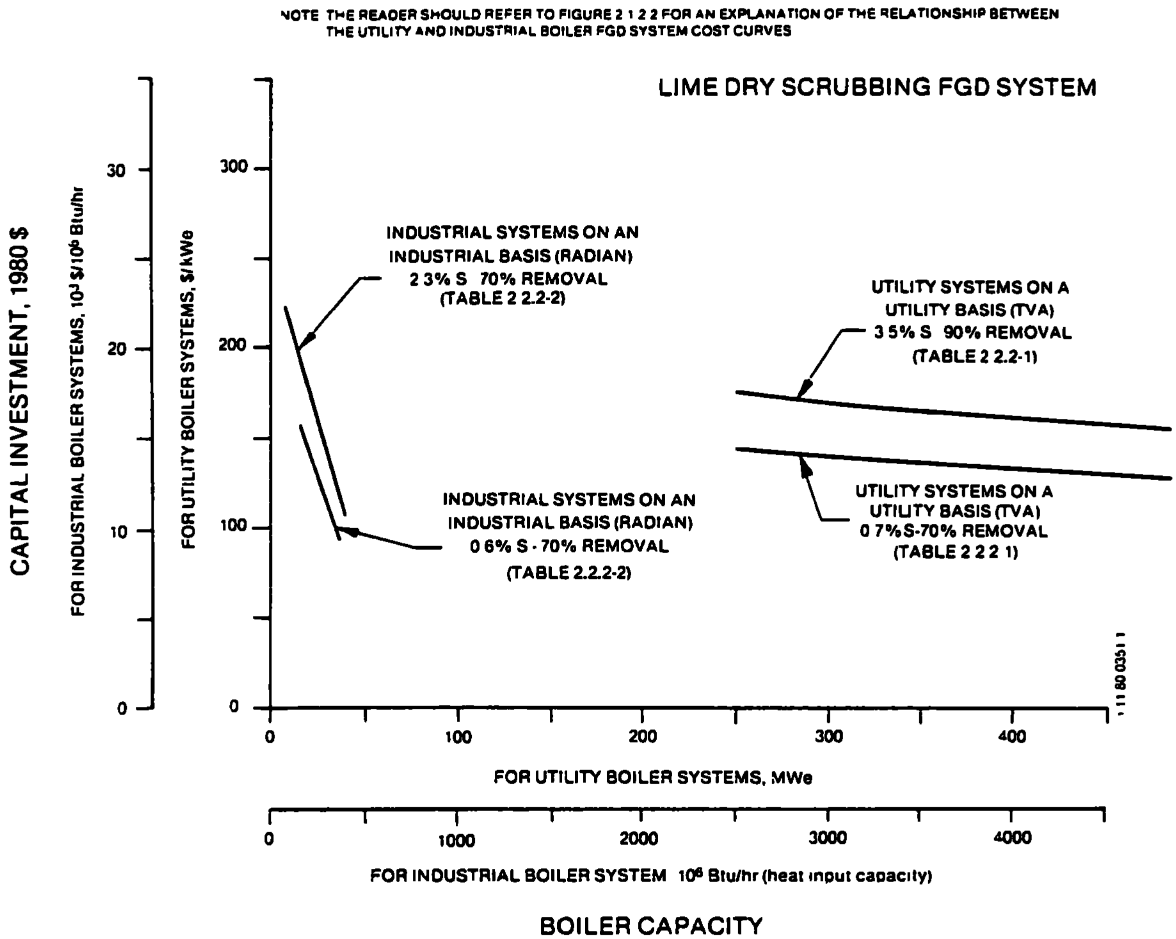


Figure 2.2.2-1. Differences in Capital Investment for Utility and Industrial Boiler FGD Systems.

TABLE 2.2.2-3. UTILITY BOILER LIME DRY SCRUBBING FGD SYSTEM CAPITAL INVESTMENT ON AN INDUSTRIAL BASIS*

	Capital Investment, 10^3\$		
Boiler Capacity, MWe	250	500	1000
10^6 Btu/hr	2,500	5,000	10,000
Direct Investment			
Raw Material Handling	756	1399	2597
Feed Preparation	355	526	783
Gas Handling	5065	8115	13002
SO_2 Absorption	2595	4558	7154
Particulate Removal	4780	9559	19119
Services, Utilities & Misc.	813	1449	2559
TOTAL DIRECT INVESTMENT	14364	25606	45214
Indirect Investment			
Engr. Design & Supv. + A&E	1293	2305	4069
Construction Expenses	2298	4097	7234
Contractor Fees	718	1280	2261
Contingency	3735	6658	11756
TOTAL FIXED INVESTMENT	22408	39946	70534
Other Capital Requirements			
Startup & Modifications	1724	3073	5426
Investment During Construction	3361	5992	10580
Land	14	26	45
Working Capital	876	1562	2758
TOTAL CAPITAL INVESTMENT	28383	50599	89343
\$/KWe	113.5	101.2	89.3
10^3 \$/10^6 Btu/hr**	11.4	10.1	8.9

*No Onsite Solids Disposal or landfill area preparation
No Spare Scrubbers
No Particulate Handling and Recycle

**Assuming a plant heat rate of 10,000 Btu/kwh

Bases
1980\$
70 % SO_2 Removal
0.7% S Coal

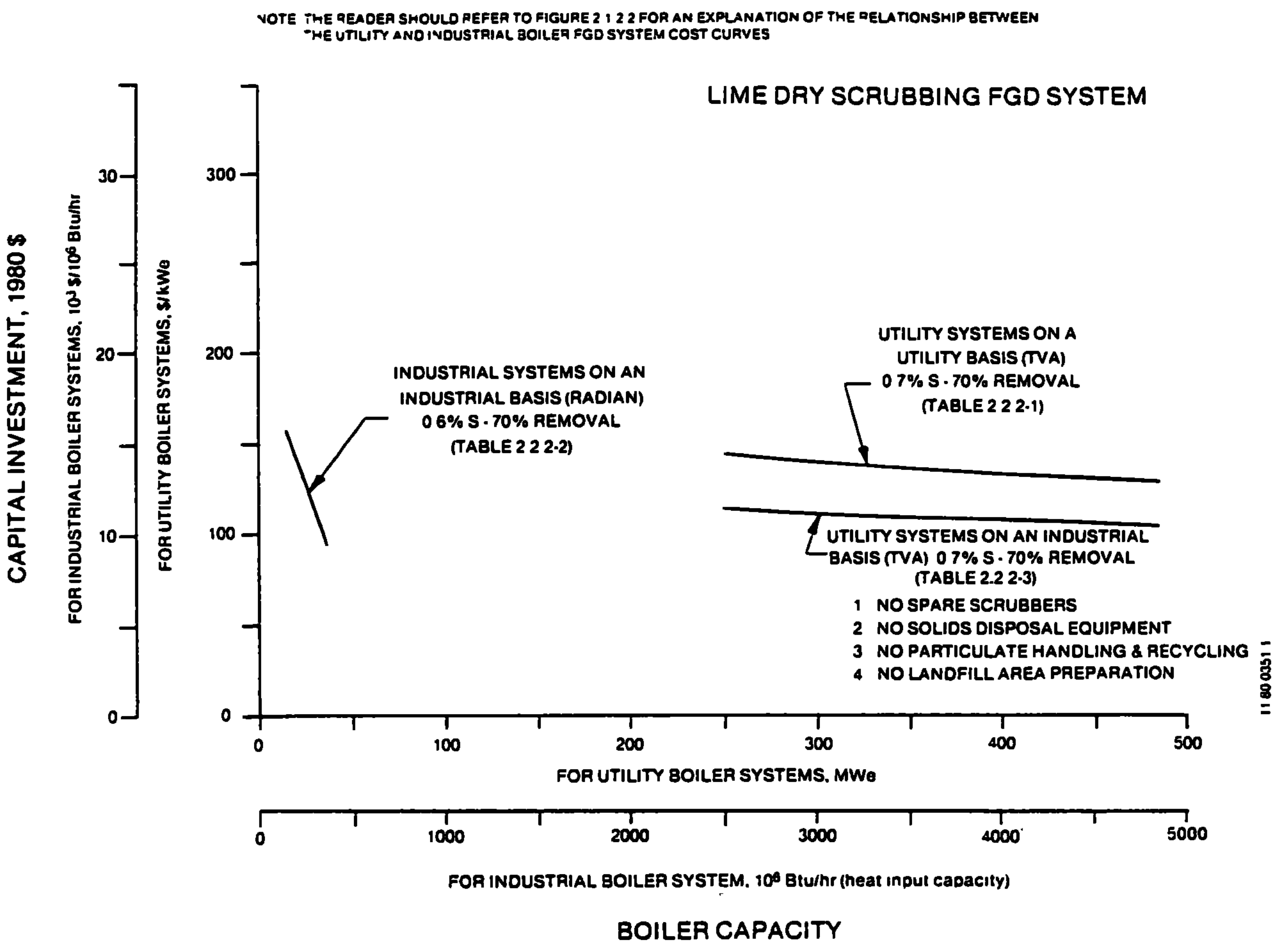


Figure 2.2.2-2. Impact of Major Equipment Components on Costs of Large Utility Boiler FGD Systems.

indirect investment algorithm to the industrial boiler system direct investment increases the capital investment, as shown in Table 2.2.2-4 and illustrated in Figure 2.2.2-3.

As with wet scrubbing FGD systems, differences in installation factors between utility and industrial boiler dry FGD systems were noted. However, these differences occur in only two operating areas -- material handling and fans. The quotes originally obtained in the ITAR for the industrial boiler scrubber and solids separator are given on an installed basis; thus, they accurately reflect the true installed costs of the equipment in those two areas. In this case, both the utility and industrial FGD scrubbers are field-fabricated and erected. Air velocities in wet scrubbers are about 10 ft/sec, but in spray dryers the velocity is about 3 ft/sec. Thus, spray dryers are much larger in diameter than wet scrubbers of a comparable process size and typically require field fabrication/erection, except for very small units. (Field fabrication is required for diameters greater than ∿12 ft because of road hauling restrictions on vehicle widths. Larger units are sometimes shop-fabricated if they can be shipped by barge.[23]) Applying the utility installation factors (Table 2.1.2-10) to the material handling and fan costs for an industrial boiler FGD system (0.6 percent S Coal - 70 percent SO_2 removal) gives the results shown in Table 2.2.2-5 and Figure 2.2.2-4.

Figure 2.2.2-5 presents the five curves shown in Figure 2.2.2-4 on a log-log plot. The consistency of the cost data can best be observed on this type of plot. Note also that each individual cost data point is also given in this figure. The dotted line connects the two curves (for the industrial and utility boiler FGD systems) that have been put on the same basis.

Figure 2.2.2-5 illustrates that a reasonably continuous capital investment curve as a function of boiler capacity can be obtained when utility and industrial boiler FGD systems are put on the same basis (i.e., the following items made identical for both cases):

TABLE 2.2.2-4. INDUSTRIAL BOILER LIME DRY SCRUBBING FGD SYSTEM INVESTMENT CALCULATED USING INDUSTRIAL INSTALLATION FACTORS (RADIAN) AND TVA INDIRECT INVESTMENT ALGORITHM

Boiler Heat Input Capacity, 10^6 Btu/hr	Capital Investment, 10^3\$			
	0.6% S Coal		2.3% S Coal	
	150	400	75	400
Direct Investment				
Material Handling	79	116	87	179
Scrubbing	230	337	171	349
Fans	66	124	41	126
Solids Separation	713	1310	440	1344
Utilities & Services	65	113	44	120
Total Direct Invest	1153	2000	783	2118
Indirect Investment				
Engr. Design & Supv+A&E	104	180	70	191
Construction Expenses	184	320	125	339
Contractor Fees	58	100	39	106
Contingency	300	520	204	551
Fixed Invest	1799	3120	1221	3305
Other Capital Charges				
Startup & Modification	138	240	94	254
Interest During Construction	270	468	183	496
Land	1	2	1	2
Working Capital	70	122	48	129
Total Capital Invest, 1978\$	2278	3952	1547	4186
Total Capital Invest, 1980\$ (TCI 1980\$≐TCI 1978\$ x 1.21)	2756	4782	1872	5065
10^3\$/10^6 Btu/hr	18.4	12.0	25.0	12.7

Basis

70 percent SO_2 Removal

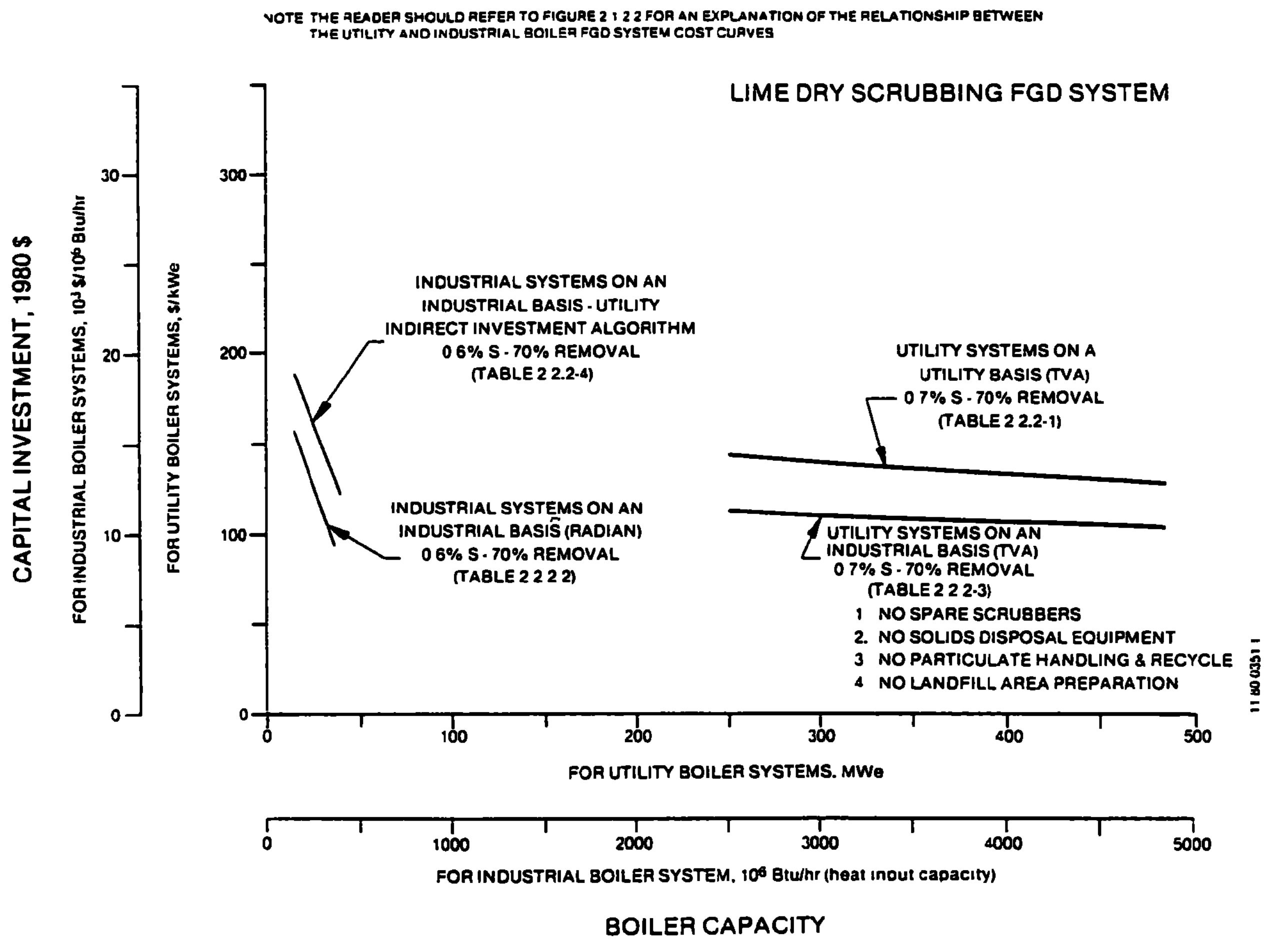


Figure 2.2.2-3. Impact of Using Utility Indirect Algorithm on Small Industrial Boiler FGD Systems.

TABLE 2.2.2-5. INDUSTRIAL BOILER LIME DRY SCRUBBING FGD SYSTEM INVESTMENT USING TVA COSTING ALGORITHMS FOR BOTH EQUIPMENT INSTALLATION AND INDIRECT INVESTMENT

Boiler Heat Input Capacity, 10^6 Btu/hr	Capital Investment, 10^3\$	
	150	400
Direct Investment		
Raw Material Handling	199	291
Scrubbing	230	337
Fans	126	226
Solids Separation	713	1310
Utilities & Services	76	133
TOTAL DIRECT INVESTMENT	1340	2343
TOTAL CAPITAL INVESTMENT, 1978\$ (TCI = TDI x 1.977)	2649	4632
TOTAL CAPITAL INVESTMENT, 1980\$ (TCI 1980 = TCI 1978 \$ x 1.21)	3205	5605
10^3\$/10^6 Btu/hr	21.4	14.0

Bases

0.6 percent S Coal

70 percent SO_2 Removal

NOTE: THE READER SHOULD REFER TO FIGURE 2.1.2.2 FOR AN EXPLANATION OF THE RELATIONSHIP BETWEEN THE UTILITY AND INDUSTRIAL BOILER FGD SYSTEM COST CURVES

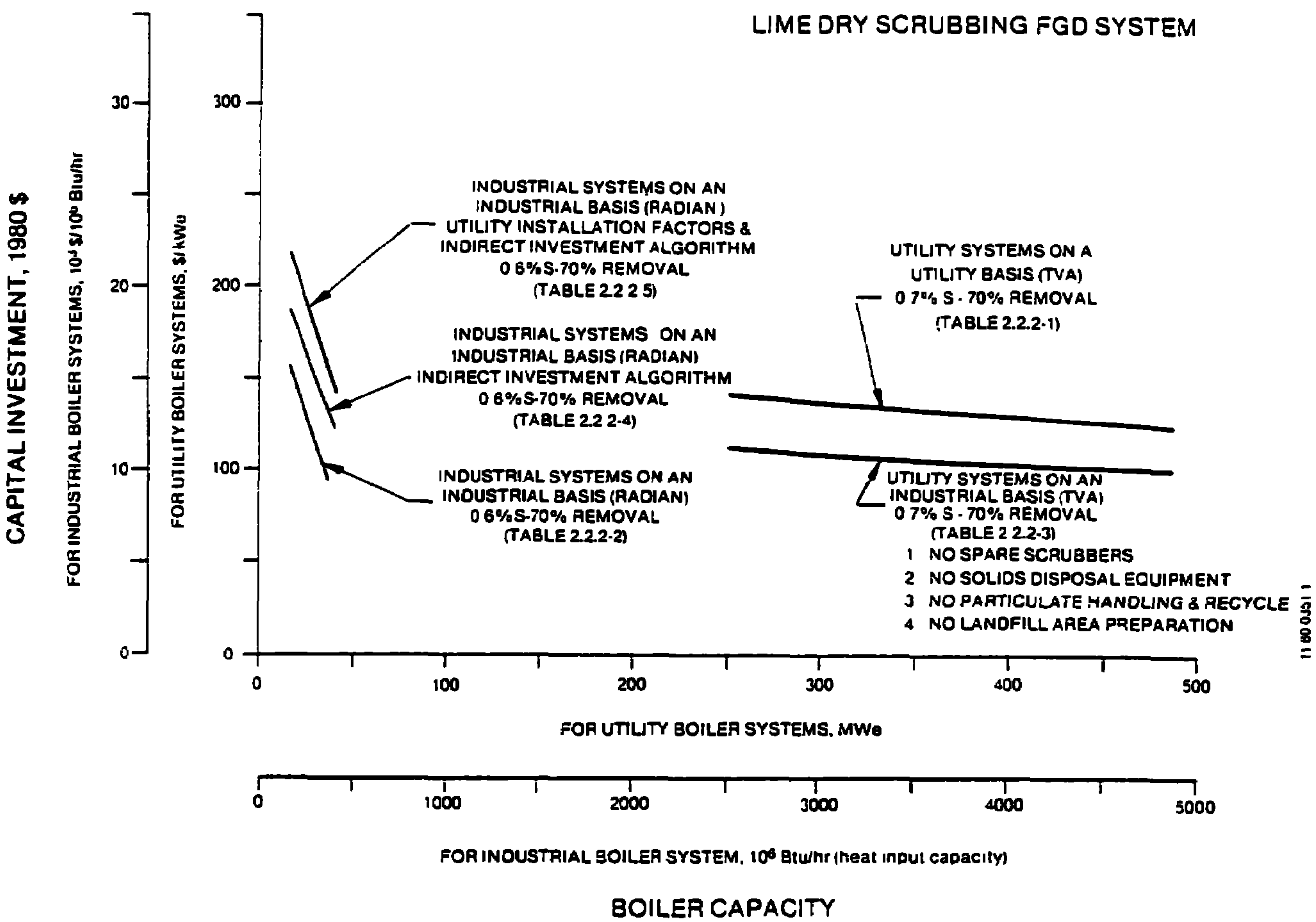
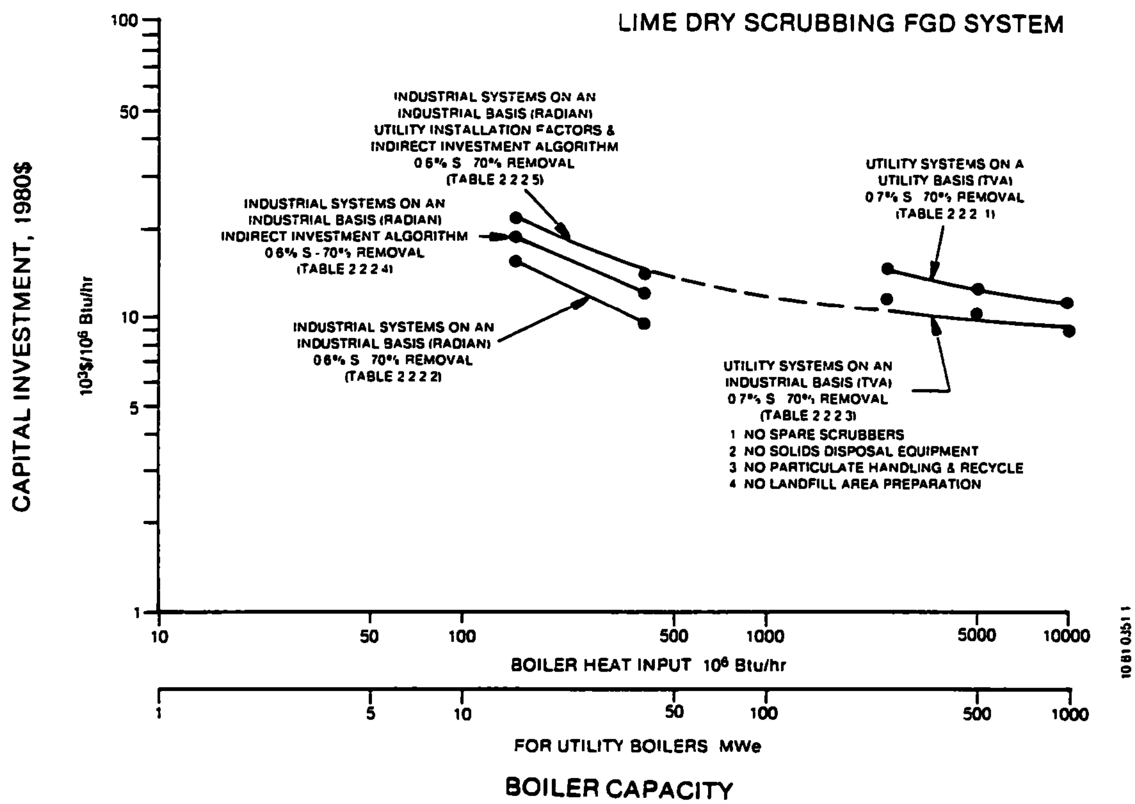


Figure 2.2.2-4. Impact of Using Large System Installation Factors and a Utility Indirect Investment Algorithm on Small Industrial Boiler FGD Systems.



NOTE: Utility boiler FGD unit investment estimates are provided for boiler capacities of 100-500 MWe and are expressed as dollars per 10^6 Btu/hr of capacity assuming a plant heat rate of 10,000 Btu/kwh. Industrial boiler FGD system estimates are also expressed as dollars per 10^6 Btu/hr of boiler capacity. The utility and industrial boiler investment and capacity scales are interchangeable if the same 10,000 Btu/kwh conversion factor is assumed. This is a close approximation of the heat rate for most utility plants.

Figure 2.2.2-5. Comparison for All Low Sulfur Cases for Lime Dry Scrubbing FGD System Investment

1. Design scope
2. Indirect investment algorithms
3. Equipment installation factors

However, any or all of these factors are likely to be different for industrial and utility boiler FGD systems. First, environmental regulations and economy of scale will likely cause the two systems to be designed differently. Second, the indirect investments for the two types of systems should be different, especially for interest during construction and construction expenses. Finally, shop-fabrication of some components of industrial systems will result in lower installation factors for these systems compared to the field-erection costs for utility systems. Therefore, a continuous curve for capital investment as a function of boiler size for both utility and industrial boiler FGD systems should not be expected.

The results of the study show that the basic material and energy balances and purchased equipment costs for the TVA and Radian estimates are reasonably consistent for the full capacity range evaluated. Most of the discontinuity is the result of the three factors listed above. However, this study requires some qualifications. It should be noted that the process equipment costs for two of the utility cases are based on extrapolating the results from the single process capacity, i.e., 500 MWe. Additionally, the reader should remember that the results provided by TVA are preliminary. The reader should obtain updated information before using these costs. As a result, there is less confidence in these capital investment estimates than in the wet scrubbing study. Therefore, this dry scrubbing study should be used to illustrate trends rather than to provide precise results.

2.2.3 Dry Scrubbing FGD System Annual O&M Cost Estimates

An evaluation of utility and industrial boiler FGD system annual O&M costs was performed in a manner similar to the analysis of capital investment in Section 2.2.2.

2.2.3.1 Utility Boiler FGD System Annual O&M Cost Estimates

Annual O&M costs* were estimated** for an FGD system achieving 70 percent SO_2 removal on a 500 MWe boiler firing 0.7 percent sulfur coal and for an FGD system attaining 90 percent SO_2 removal on a 500 MWe boiler firing 3.5 percent sulfur coal. These O&M estimates reflect 1984 costs. The annual costs were put on a 1981 dollar basis by using the raw material, operating labor and supervision, and utilities unit costs employed in the wet scrubbing study (Table 2.1.3-1). Operating labor and maintenance costs specific to the dry scrubbing study are presented in Table 2.2.3-1.

Because TVA prepared estimates only for 500 MWe capacity boilers, assumptions were made so that costs for 250 and 1000 MWe plants could be estimated. Raw material, utility, and waste disposal costs were assumed to be proportional to the size of the unit. For example, the amount of lime used for a 250 MWe size unit would be 1/2 that for the 500 MWe unit. In addition, operating labor requirements were estimated using the limestone system estimates as a guide. First year O&M costs (1981$) are given in Table 2.2.3-2 and illustrated in Figure 2.2.3-1. These costs include the disposal of dry solid waste by trucking it to an onsite landfill, rather than hiring a contractor to dispose of the waste.

*Includes raw materials, utilities, maintenance, chemical analyses, and waste disposal but no capital-related charges such as depreciation, interest-on-debt, return on equity, and local, state, and federal taxes.

**By TVA.

TABLE 2.2.3-1 TVA UTILITY BOILER DRY SCRUBBING FGD SYSTEM ECONOMIC PREMISES AND ASSUMPTIONS*

---

1. Raw Materials

   Lime $60/ton

2. Maintenance Labor and Material

   6 percent of (TDI - Landfill DI) + 3 percent of Landfill DI

3. Sludge Disposal - Onsite in landfill

4. Cost given in 1981 $

---

*See Table 2.1.3-1 for additional information.

TABLE 2.2.3-2 UTILITY BOILER LIME DRY SCRUBBING FGD SYSTEM FIRST-YEAR OPERATING AND MAINTENANCE COSTS

	Annual O&M Cost, 10³$/Yr					
	0.7% S Western Coal-70% Removal			3 5% S Eastern Coal-90% Removal		
MWe	250	500	1000	250	500	1000
Direct Costs						
Raw Material - Lime	303	606	1212	2583	5166	10332
Conversion Costs						
Operating Labor & Supv	232	318	434	266	364	498
Utilities						
Water	5	9	18	8	16	32
Electricity	571	1142	2284	604	1207	2414
Steam				138	275	550
Maintenance						
Labor & Material	1033	1787	3165	1238	2144	3781
Analyses	71	71	107	71	71	107
Waste Disposal						
Labor	124	247	494	89	354	708
Operation	9	18	36	21	42	84
TOTAL CONV COSTS	2045	3592	6538	2435	4473	8174
TOTAL DIRECT COSTS	2348	4198	7750	5018	9639	18506
Indirect Costs						
Overheads - Plant & Admin	881	1465	2542	1011	1785	3107
Total First Year O&M	3229	5663	10292	6029	11424	21613
Mills/Kwh	2 34	2 05	1 86	4 37	4 14	3 92

Bases
0 63 Capacity Factor
1981 $

The design scope is described in Appendix D.

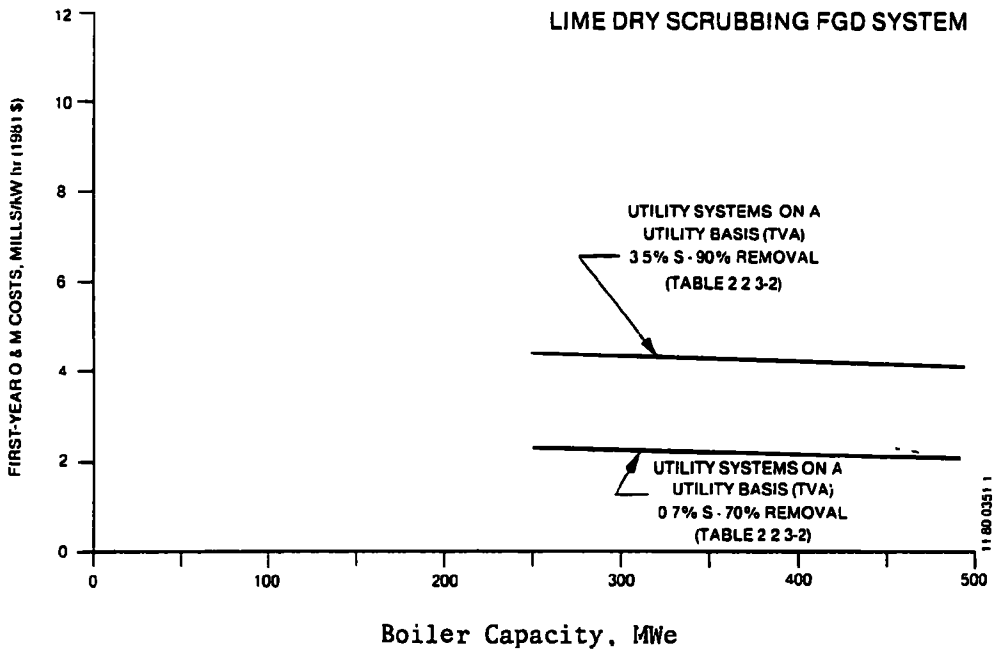


Figure 2.2.3-1. Utility Boiler FGD System First-Year Operating and Maintenance Costs.

2.2.3.2 Industrial Boiler FGD System Annual O&M Cost Estimates

The annual operating costs for lime dry scrubbing FGD systems on small industrial boilers (75 to 400 x 10^6 Btu/hr) have been estimated in the FGD ITAR.[24] The assumptions used in these estimates are the same as in the industrial boiler limestone FGD system analysis (Table 2.1.3-3). In addition, lime costs are $35/ton. As in the capital investment comparison, these assumptions are different from those used by TVA for large boilers, and lead to differences in utility and industrial cost estimates for comparably sized FGD systems.

These first-year cost estimates for all systems are given in Table 2.2.3-3 and shown in Figure 2.2.3-2. The data reported in the ITAR have been adjusted. The maintenance labor and material plus the general and administrative overhead (G&A), both percentages of the investment, are higher because of the adjusted capital investment, as discussed in Section 2.2.2.2. In addition, the solid waste disposal cost was reduced from the $40/ton reported in the ITAR to $15/ton. A recent study[25] shows this lower cost to be more realistic.

TABLE 2.2.3-3 INDUSTRIAL BOILER LIME DRY SCRUBBING FGD SYSTEM FIRST YEAR OPERATING AND MAINTENANCE COSTS USING RADIAN MATERIAL AND OPERATING COSTS AND OVERHEAD ALGORITHM

	Annual Cost, 10^3 $/Yr			
	0.6% S Coal		2.3% S Coal	
Boiler Heat Input Capacity, 10^6 Btu/hr	150	400	75	400
Direct Costs				
Raw Materials				
Lime	17	46	24	128
Conversion Costs				
Operating Labor	105	105	105	105
Supervision	21	21	21	21
Utilities				
Process Water	1	2	0.5	2
Power	12	27	8	28
Maint. Labor & Materials	92	152	62	170
Solid Waste Disposal	14	37	20	102
TOTAL DIRECT COSTS	262	390	241	556
Indirect Costs				
Payroll OH	41	41	41	41
Plant OH	57	72	49	77
G&A	76	125	54	141
TOTAL INDIRECT COSTS	174	238	144	259
Total First-Year O&M	436	628	385	815
$/$10^6$ Btu (1978 $)	0.55	0.30	0.98	0.39
$/$10^6$ Btu (1981 $)	0.71	0.39	1.26	0.50

Bases

0.60 Capacity Factor
1981 $ = 1978 $ x 1.285
70 percent SO_2 Removal

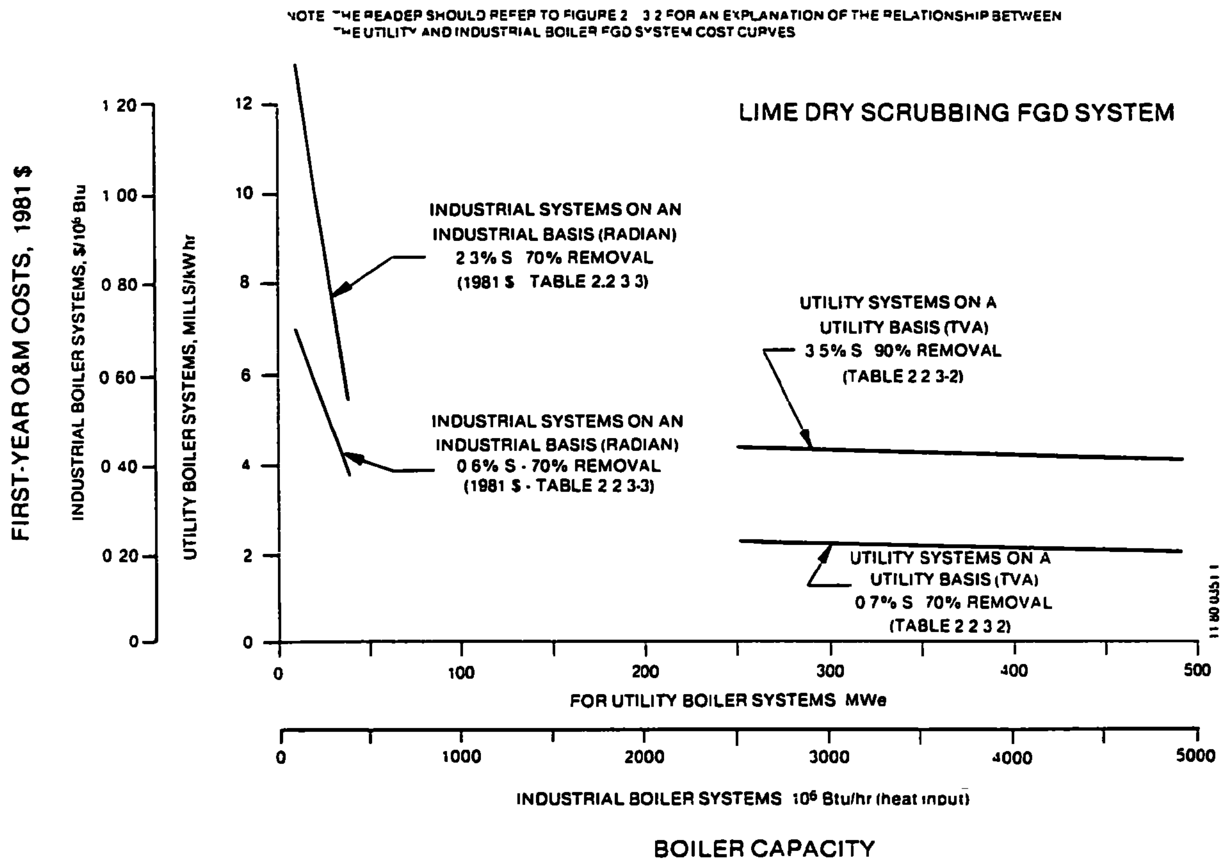


Figure 2.2.3-2. Difference in First-Year Operating and Maintenance Costs for Utility and Industrial Boiler FGD Systems.

2.2.3.3 Comparison and Integration of Utility and Industrial Boiler FGD System Annual Cost Estimates

This section will follow the same organization as the section on capital investment for dry scrubbing FGD systems (Section 2.2.2.3). The same economic assumptions will be used for small industrial boiler FGD systems and large utility boiler FGD systems to determine if the small industrial FGD system cost curves form a smooth transition with the utility FGD system cost curves for a comparable FGD system size and design scope. Smooth transition of the cost curves would indicate that the basic technical premises for the two types of systems are comparable. These premises include material and energy balances, manpower required to operate the system and other factors previously described.

The industrial and utility boiler FGD system cost data shown in Figure 2.2.3-2 for low sulfur coal are not on comparable bases. TVA estimated the costs for dry scrubbing FGD systems on the "industrial basis" (i.e., without the spare scrubbers, solids disposal equipment, particulate handling and recycle equipment, and onsite landfill area preparation). Small industrial boiler FGD system solid waste disposal costs ($15/ton) were used to estimate the large system solid waste disposal costs. The resulting costs are given in Table 2.2.3-4 and illustrated in Figure 2.2.3-3.

Examination of Tables 2.1.3-3 and 2.2.3-1 shows significant differences in raw material prices, labor rates, utility prices, and algorithms used to calculate maintenance labor and material and overheads for the two types of systems. Therefore, the small industrial boiler FGD system was put on the same cost basis as that used by TVA. The material balances, labor hours, and quantities of utilities for the small industrial boiler FGD system were considered, but TVA raw material prices, labor rates and utility prices were used. In addition, the TVA algorithms used to calculate maintenance labor and material and overheads were applied to the small industrial case. The results are given in Table 2.2.3-5 and illustrated in Figure 2.2.3-4.

TABLE 2.2.3-4 UTILITY BOILER LIME DRY SCRUBBING FGD SYSTEM FIRST-YEAR OPERATING AND MAINTENANCE COSTS ON AN INDUSTRIAL BASIS*

	Annual O&M Cost, 10^3 \$/Yr.		
Boiler Capacity, MWe	250	500	1,000
Direct Costs			
Raw Material			
Lime	288	577	1,154
Conversion Costs			
Operating Labor & Supervision	221	303	413
Utilities			
Process Water	5	9	17
Electricity	544	1,087	2,174
Maintenance			
Labor and Materials	862	1,536	2,713
Analysis	71	71	107
Waste Disposal	921	1,842	3,684
TOTAL CONV. COSTS	2,624	4,848	9,108
TOTAL DIRECT COSTS	2,912	5,425	10,262
Indirect Costs			
Overheads			
Plant and Administration	1,245	2,251	4,150
Total First Year O&M	4,157	7,676	14,412
Mills/Kwh	3.16	2.92	2.74
\$/10^6 Btu **	0.32	0.29	0.27

*No on-site solids disposal
No spare scrubber
No particulate handling and recycle
No landfill area preparation

**Assuming a plant heat rate of 10,000 Btu/kwh

Bases
1981 \$
0.60 Capacity Factor
0.7% S Coal
70% SO_2 Removal

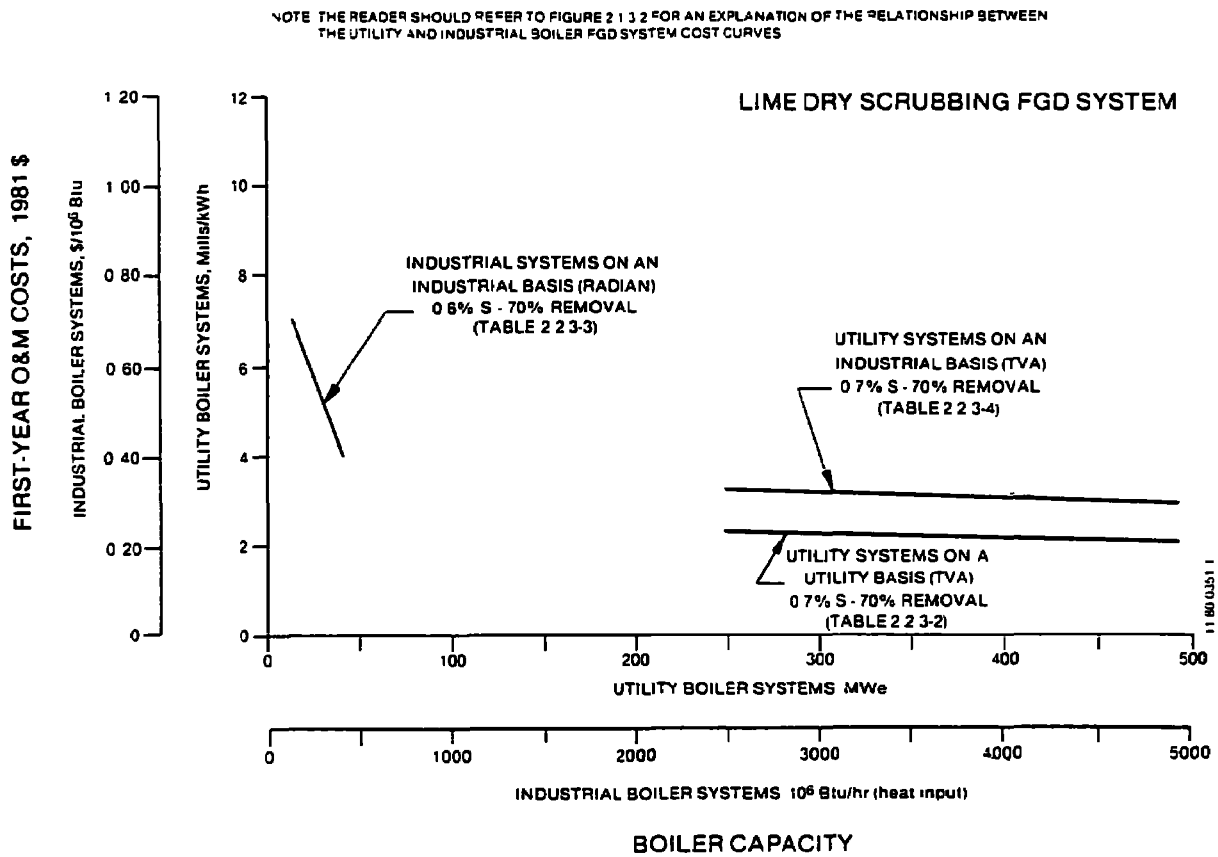


Figure 2.2.3-3. Impact of Putting Large Utility Boiler FGD Systems on an Industrial Basis

TABLE 2.2.3-5 INDUSTRIAL BOILER LIME DRY SCRUBBING FGD SYSTEM FIRST-YEAR OPERATING & MAINTENANCE COSTS USING TVA MATERIAL & OPERATING COSTS PLUS OVERHEAD ALGORITHM (RADIAN INVESTMENT BASIS)

	Annual Cost, 10^3 \$/Yr.	
Boiler Heat Input Capacity, 10^6 Btu/hr	150	400
Direct Costs		
Raw Material		
Lime	29	79
Conversion Costs		
Operating Labor and Supplies	126	126
Utilities		
Process Water	1	2
Electricity	13	30
Maintenance		
Labor and Materials	84	145
Analyses	21	56
Waste Disposal	14	39
TOTAL CONV. COSTS	259	398
TOTAL DIRECT COSTS	288	477
Indirect Costs		
Overheads		
Plant and Administration	147	220
Total First Year O&M	435	697
\$/10^6 Btu	0.55	0.33

Bases

1981 \$
0.6 Capacity Factor
0.6 % S Coal
70% SO_2 Removal

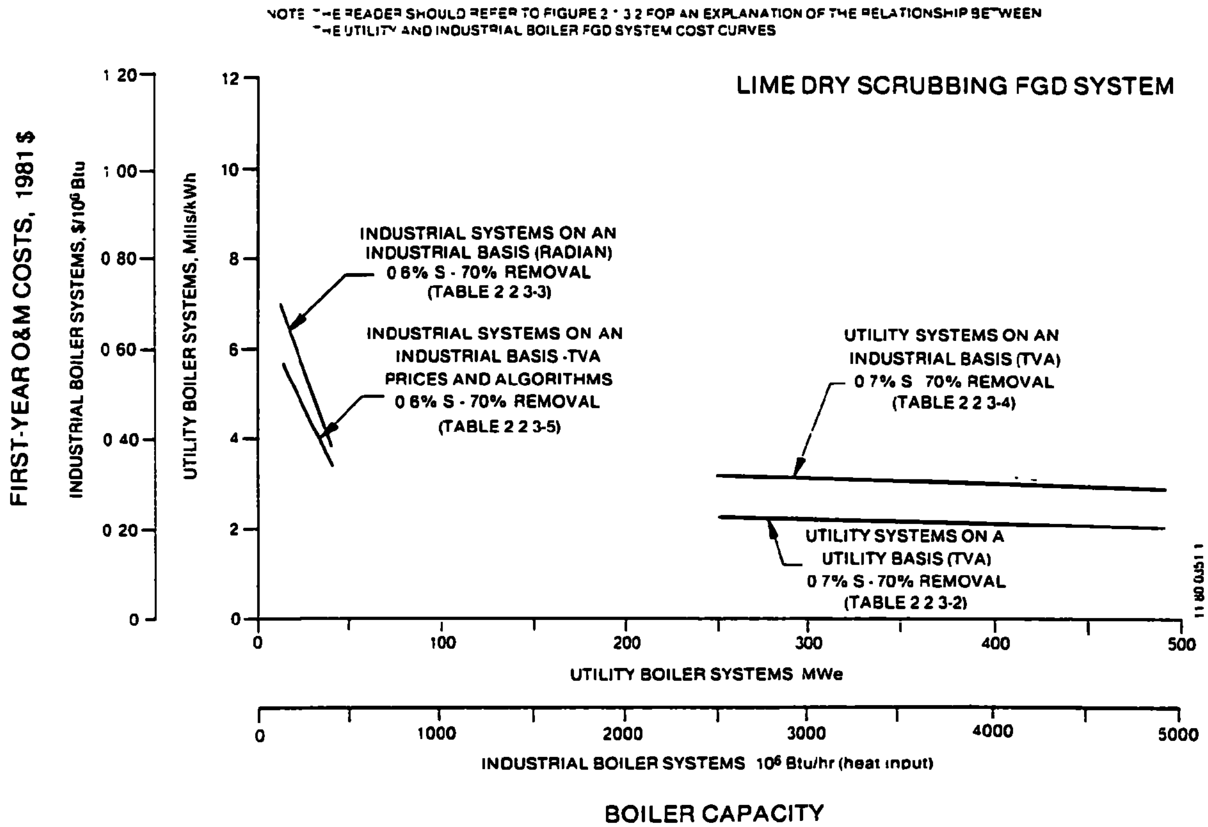


Figure 2.2.3-4. Impact of Putting Small Industrial Boiler FGD Systems on a Large Utility System Basis.

Further examination shows that the maintenance labor and material, and overhead costs are a significant portion of the O&M costs. Maintenance costs are calculated as a percentage of investment. Overhead costs are based on direct costs (which include maintenance), thus making O&M costs very sensitive to investment. The maintenance costs in Table 2.2.3-5 were calculated by using investment on an industrial basis (Radian basis) with the utility indirect investment algorithm (Table 2.2.2-4), but do not incorporate the higher installation costs for field-fabrication/erection (which are shown in Table 2.2.2-5). Using these investment figures (Table 2.2.2-5)* to calculate maintenance costs (and thereby increasing direct costs, overhead and, therefore, total O&M) results in slightly higher O&M costs for the FGD systems on small industrial boilers. These results are given in Table 2.2.3-6 and illustrated in Figure 2.2.3-5.

Figure 2.2.3-6 presents the five curves shown in Figure 2.2.3-5 on a log-log plot. The consistency of the cost data can best be observed on this type of plot. Note also that each individual cost data point is also given in the figure. The dotted line connects the two curves (for the industrial and utility boiler FGD systems) that have been put on the same basis.

Figure 2.2.3-6 illustrates that a reasonably continuous first year O&M cost curve as a function of FGD capacity is obtained when utility and industrial boiler FGD systems are put on the same basis (i.e., the following items are made identical for both cases):

1. Design scope
2. Indirect investment algorithms
3. Equipment installation factors
4. Unit costs for raw materials, labor, utilities, solid waste disposal, etc.

*Small industrial boiler FGD system costs using field erected installation factors.

TABLE 2.2.3-6 INDUSTRIAL BOILER LIME DRY SCRUBBING FGD SYSTEM FIRST YEAR OPERATING & MAINTENANCE COSTS USING TVA MATERIAL & OPERATING COSTS PLUS OVERHEAD ALGORITHMS (TVA INVESTMENT BASIS, i.e., INSTALLATION FACTORS)

	Annual Cost, 10^3 $/Yr.	
Boiler Heat Input Capacity, 10^6 Btu/hr	150	400
Direct Costs		
Raw Material		
Lime	29	79
Conversion Costs		
Operating Labor and Supervision	126	126
Utilities		
Process Water	1	2
Electricity	13	30
Maintenance		
Labor and Materials	97	170
Analyses	21	56
Waste Disposal	14	39
TOTAL CONV. COSTS	272	423
TOTAL DIRECT COSTS	301	502
Indirect Costs		
Overheads		
Plant and Administration	155	235
Total First Year O&M	456	737
$/$10^6$ Btu	0.58	0.35

Bases

1981 $
0.60 Capacity Factor
0.6% S Coal
70% SO_2 Removal

NOTE THE READER SHOULD REFER TO FIGURE 2 · 3 2 FOR AN EXPLANATION OF THE RELATIONSHIP BETWEEN THE UTILITY AND INDUSTRIAL BOILER FGD SYSTEM COST CURVES

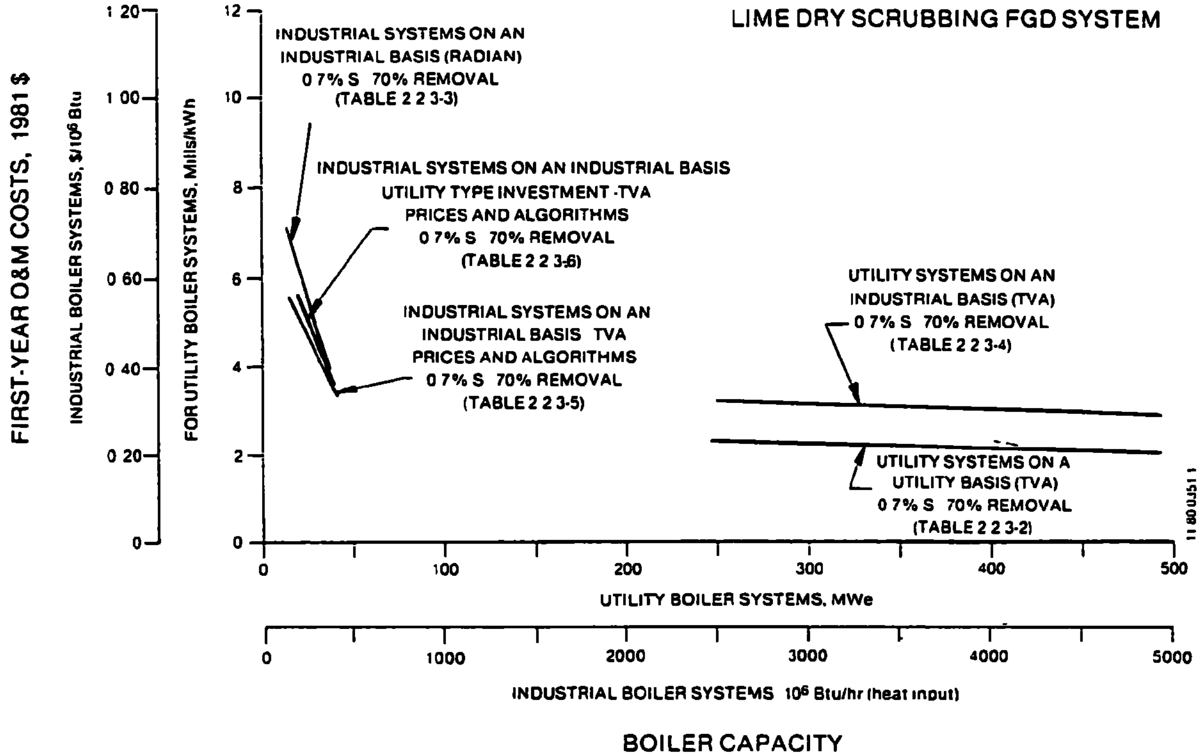
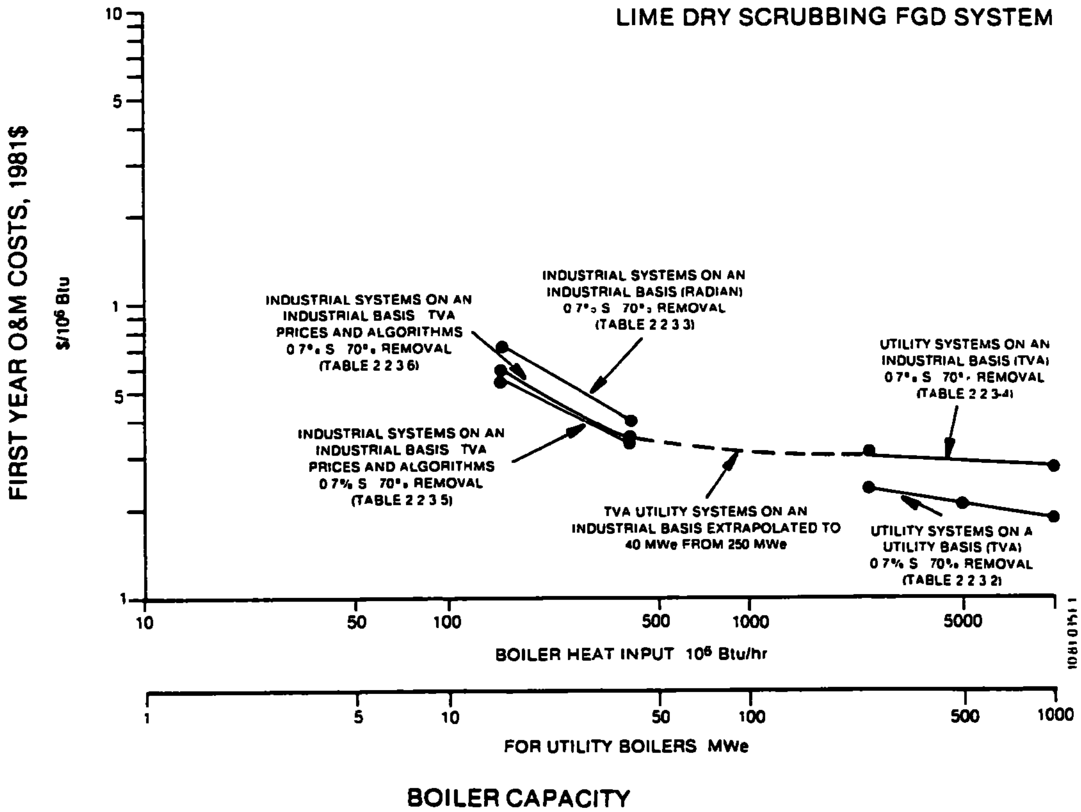


Figure 2.2.3-5. Impact of Putting Small Industrial Boiler FGD Systems on a Large Utility Boiler FGD System Basis, Including Investment.



NOTE: Utility boiler FGD unit annual O&M estimates are provided for boiler capacities of 100-500 MWe and are expressed as $\$/10^6$ Btu assuming a plant heat rate of 10,000 Btu/kwh. Industrial boiler FGD system estimates are provided for boiler heat input capacities of 150-400 x 10^6 Btu/hr and are expressed as $\$/10^6$ Btu. The utility and industrial boiler capacity scales are interchangeable if the same 10,000 Btu/kwh conversion factor is assumed. This is a close approximation of the heat rate for most utility plants.

Figure 2.2.3-6. Comparison of all Low Sulfur Cases for Lime Dry Scrubbing FGD System First Year Operating and Maintenance Costs.

However, any or all of these factors are likely to be significantly different for industrial and utility boiler FGD systems. First, environmental regulations and economy of scale will likely cause the two systems to be designed differently. Second, the indirect investments for the two types of FGD processes will be different, especially for interest during construction and construction expenses. Third, shop fabrication of many components of industrial units will result in low installation costs compared to field-erected costs for utility boiler systems. Finally, unit costs for raw materials and solid waste disposal will be different due to significant volume requirement differences. Utilities and labor costs may also vary for the two types of systems. Therefore, a continuous function for industrial and utility boiler FGD process costs should not be expected.

The results of the study show that the basic material and energy balances and operating labor requirements for the TVA and Radian estimates are reasonably consistent for the full capacity range evaluated. Much of the discontinuity is the result of the four factors listed above. However, this study requires some qualifications. It should be noted that the process equipment costs for two of the utility cases are based on extrapolating the results from a single process capacity, i.e., 500 MWe. Additionally, the reader should remember that the results provided by TVA are preliminiary. The reader should obtain updated TVA information before using these costs. As a result, there is less confidence in these first year O&M estimates than in the wet scrubbing study. Therefore, this dry scrubbing study should be used to illustrate trends rather than provide precise results.

2.2.4 Use of the Cost Estimate Results

Sections 2.2.2 and 2.2.3 have provided capital investment and O&M cost estimates on several different bases. No one single estimate is "correct"; rather the appropriate estimate is dependent on the applicable basis. Table 2.2.3-7 outlines the various investment and cost bases and appropriate tables for reference.

Because the cost estimates for the lime spray drying systems were not as accurate as the wet limestone FGD systems, lime spray drying costs are not recommended for further assessments in acid rain studies. At the time of this report TVA had just begun its investigation of lime spray drying costs. Once those TVA costs become final they could be incorporated into the report to assess cost impacts with reasonable accuracy. However, at this time only the wet limestone FGD costs are recommended to be used in cost impact analyses.

TABLE 2.2.3-7 SUMMARY OF LIME DRY SCRUBBING FGD COST STUDIES

Case	Investment Basis	Investment Table #	O&M Cost Basis	O&M Cost Table #
1	250-1000 MWe FGD Systems with Spare Scrubbers, Solids Disposal Equipment, Particulate Handling & Recycle and Landfill Area Based on Current TVA Estimation Procedures.	2.2.2-1	TVA Raw Material, Labor and Utility Costs and TVA Indirect Cost Algorithm (0.63 Capacity Factor)	2.2.3-2
2	250-1000 MWe FGD Systems without Spare Scrubbers, Solids Disposal Equipment, Particulate Handling & Recycle and Landfill Area Using the TVA Indirect Investment Algorithm.	2.2.2-3	TVA Raw Material, Labor & Utility Costs with Radian Solid Waste Disposal Costs and TVA Indirect Cost Algorithm (0.6 Capacity Factor)	2.2.3-4
3	25-400 x 10^6 Btu/hr Industrial Boiler FGD Systems with Field-Erected Installation Factors, without Spare Scrubbers, Solids Disposal Equipment, Particulate Handling & Recycle & Landfill Area Using the TVA Indirect Investment Algorithm.	2.2.2-5	TVA Raw Material, Labor & Utility Costs with Radian Solid Waste Disposal Costs and TVA Indirect Cost Algorithm (0.6 Capacity Factor)	2.2.3-6
4	75-400 x 10^6 Btu/hr Industrial Boiler FGD Systems with Shop-Fabricated Installation Factors, without Spare Scrubbers, Solids Disposal Equipment, Particulate Handling & Recycle, & Landfill Area and Using the TVA Indirect Investment Algorithm.	2.2.2-4	TVA Raw Material, Labor & Utility Costs with Radian Solid Waste Disposal Costs and TVA Indirect Cost Algorithm (0.6 Capacity Factor)	2.2.3-5
5	75-400 x 10^6 Btu/hr Industrial Boiler FGD Systems with Shop-Fabricated Installation Factors except for Scrubbers & Baghouse which have Actual Installation Costs & without Spare Scrubbers, Solids Disposal Equipment, Particulate Handling & Recycle, & Landfill Area Using the Radian Indirect Investment Algorithm.	2.2.2-2	Radian Raw Material, Labor & Utility Costs with Radian Solid Waste Disposal Costs & Radian Indirect Cost Algorithm (0.6 Capacity Factor)	2.2.3-3

*In each case the maintenance component in the annual O&M cost is based on the capital investment to the immediate left.

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SECTION 3

FLUE GAS DESULFURIZATION SYSTEM RETROFIT COST ESTIMATES FOR UTILITY BOILERS

The costs for installing an FGD unit on new boilers (industrial and utility) were evaluated in Section 2. In this section, FGD system retrofit considerations are discussed. Adding a new process to an existing plant is typically more expensive than originally designing the plant to include the process. This is true for many boilers because adequate space was not provided for FGD system installation when the boiler was originally installed.

Retrofit factor is defined as the ratio of the capital investment cost for installing a process in an existing plant to the capital investment cost for the same process in a new installation. This factor is often applied to new installation costs to estimate the costs of putting the same basic equipment into an existing facility. Retrofit factors for FGD systems have been reported from as low as 0.9 to as high as 3.0. A study was conducted to understand these differences and determine if a factor or set of factors, as a function of a number of significant variables, could be developed.

Section 3.1 briefly summarizes some of the existing studies on retrofit factors. Section 3.2 presents an analysis for two utility boiler FGD system retrofits. Section 3.3 presents retrofit factor recommendations for use in the acid rain work.

Although there is no retrofit factor for operating costs, annualized cost will increase because the capital investment is increased. Other operating costs such as labor, materials and utilities will be approximately the same for new and retrofit facilities.

3.1 REVIEW OF EXISTING STUDIES

A study by M.W. Kellogg in 1972[1] showed that 79 percent of 103 utility plants evaluated had adequate space to install SO_2 scrubbers. Each plant was surveyed, and a total capital investment retrofit factor was estimated qualitatively for each boiler. This retrofit factor compared the retrofit investment to the investment for installing the same system in a new plant. Considerations such as space availability and extent of plant modification required were addressed. These factors ranged from 1.0 for installing an FGD unit on a new plant to 3.0 for a complex retrofit installation. The results of the study are presented in Table 3.1-1. The study indicated trends toward higher factors with older, smaller power plants. The average factor for units more than 20 years old with capacities of less than 100 MWe was 3.0, while that for units less than ten years old with capacities of less than 500 MWe was 2.0. The average investment retrofit factor (weighted for capacity) was 1.69.

Detailed engineering studies were not performed in the Kellogg program. Retrofit factors of 1.0, 1.5, 2.0, 2.5 and 3.0 were qualitatively assigned to the various boilers based primarily on site observations. The prime consideration in estimating the retrofit factor was the difficulty in installing the scrubber. The relative ease or difficulty of installing the solids handling and waste disposal systems was apparently not considered. For example, the complexity in retrofitting the scrubber might be 2.0, while the complexity in retrofitting the balance of the control system might be 1.0. If the investment for each portion is equal, the total system retrofit factor should be 1.5, whereas it appears that 2.0 was indicated in the study. A cost analysis by Kellogg of these same installations showed that the incremental annual revenue requirement* would be 2.5 - 3.5 mills/kwh higher than for a new installation. Most of the increase is the result of higher capital-related charges.

* Annual O&M costs plus capital-related charges.

TABLE 3.1-1 1972 M.W. KELLOGG FGD SYSTEM RETROFIT STUDY[1]

Complexity Factor	Surveyed Generating Capacity, MW	Percent	Cumulative Percent
1.0	1,037	1.17	1.17
1.5	26,853	30.34	31.51
2.0	9,333	10.54	42.05
2.5	16,012	18.10	60.15
3.0	16,477	18.61	78.76
*	18,538	21.24	100.00
	88,250		

Total Capacity Surveyed = 88,250 MW

Total U.S. Oil & Coal Generation Capacity at Time of Survey = 212,943 MW

[1]Reference 1.

*Retrofit of FGD system was considered infeasible.

Radian performed a study in 1973[2], using some of the Kellogg information. It was concluded that 87 percent of the units less than ten years old and 85 percent of the units with capacities of greater than 500 MW have sufficient space to be retrofitted. As shown in all studies, the key for the ability to retrofit is availability of space to install the absorbers.

As part of this study, Radian estimated capital investment retrofit factors of 1.30 and 1.23 for two relatively new coal-fired installations. Large differences in annualized costs between retrofit and new installations were also noted. However, the major factor contributing to the higher operating costs was related to the higher capital investment coupled with a shorter operating life at low capacity factors.

McGlamery et al.[3] studied the impact of retrofitting FGD systems and found that long duct runs and higher installation costs were the major factors contributing to higher investment/operating costs. However, retrofit factors of less than 1.0 were found because of differences assumed in the methods of reheat and particulate removal requirements. When a comparison between installing an FGD system on an existing plant and on a new plant was made on the same basis, the ratio of direct investment (retrofit costs divided by new plant costs) over the range of 200 to 1000 MW was about 1.22 for a limestone slurry process and 1.25 for a lime slurry process (Table 3.1-2).

In addition, a difference of six percent in indirect investment (design, field expenses, contractor's fees and contingency) as a function of direct investment for a retrofit installation was considered realistic. Thus, the total capital investment retrofit factor increased to 1.28 for a limestone slurry process and to 1.31 for a lime slurry process. Differences in annualized costs between retrofit and new installations were due almost entirely to higher capital-related charges when both processes were put on an equivalent equipment basis.

TABLE 3.1-2 RETROFIT FACTORS FROM TVA ANALYSIS (3.5% S Coal, 90% SO_2 Removal, On-Site Solids Disposal)[1]

		Direct Investment, 10^3 \$, Mid-1974 \$						
		Existing Plant			New Plant			Ratio
Process	Boiler Size, MW	Total	Noncommon* Equipment	Net	Total	Noncommon* Equipment	Net	Net Existing / Net New
Limestone Slurry	200	6,608	1,696	4,912	7,911	3,899	4,012	1.22
	500	14,116	3,934	10,182	16,069	7,682	8,387	1.21
	1000	21,947	5,999	15,948	24,637	11,563	13,074	1.22
Lime Slurry	200	7,594	3,595	3,999	7,133	3,958	3,175	1.26
	500	15,913	7,919	7,994	14,318	7,915	6,403	1.25
	1000	23,821	11,918	11,903	21,397	11,898	9,499	1.26

[1] Reference 3.

*Noncommon equipment = particulate scrubbers (new facility only), stack gas reheat, calcium solids disposal. For example, the reheaters were direct oil-fired units for the retrofit and were indirect steam units for the new facility.

In a PEDCo study[4] of 238 utility boilers, each boiler was inspected and FGD system capital investment was estimated for retrofit to the existing plant and for a comparable new plant (Table 3.1-3). Details of these comparisons are not available to determine if the retrofit and new installations were compared on the same installed equipment basis. The results of the PEDCo analysis are:

Average retrofit factor = 1.21

Range = 1.00 to 1.99

Mean = 1.16, Mode = 1.16*

No comparisons were made for operating and maintenance costs.

Ponder _et al._[5] and Dickerman _et al._[6] indicate that retrofit investment can be signficantly higher due to the following factors:

	Percent Increase in Capital Investment
Long duct runs	4-7
Tight space	1-18
Delayed construction	5-15
Hilly terrain	0-10
New stack	6-20

Uhl[7] recommends an investment retrofit factor of 1.3 x Fixed Investment.

More recently, Pullman-Kellogg carried out another retrofit study.[8] TVA reviewed these results and reported that the retrofit factors were excessively high.[9]

*Mean and mode are based on a tabulation of the retrofit factors presented in Table 3.1-3.

TABLE 3.1-3 PEDCo POWER PLANT FGD CAPITAL INVESTMENT RETROFIT FACTORS [1].

Plant Name	Boiler No.	Investment Retrofit Factor	Capital Investment ($/kW) Jan. 1975*	On-Site Ponding	Trucking Distance to Disposal Site, Miles
Albany	1	1.560	95.91	x	
	2	1.560			
	3	1.560			
	4	1.560			
Amos	1	1.158	N.A.		N.A.
	2	1.158			
	3	1.226			
B.L. England	1	1.264	112.20	x	
	2	1.264			
Big Bend	1	1.113	58.49	x	
	2	1.113			
	3	1.113			
Big Sandy	1	1.160	N.A.	x	
	2	1.160			
Brayton Point	1	1.410	52.27		10
	2	1.310			
	3	1.084			
Cabin Creek	81	1.452	N.A.		N.A.
	82	1.452			
	91	1.565			
	92	1.565			
Chesterfield	1	1.090	N.A.		N.A.
	2	1.158			
	3	1.158			
	4	1.158			
	5	1.158			
	6	1.158			
Colbert	1	1.070	74.60		N.A.
	2	1.070			
	3	1.080			
	4	1.070			
	5	1.090			
Cooper	1	1.181	N.A.		N.A.
	2	1.181			

[1]Reference 4.
*Capital investment is for limestone FGD, combined for all boilers.

N.A. = not available

(Continued)

TABLE 3.1-3 PEDCo POWER PLANT FGD CAPITAL INVESTMENT RETROFIT FACTORS[1] (Cont.)

Plant Name	Boiler No.	Investment Retrofit Factor	Capital Investment ($/kW) Jan. 1975*	On-Site Ponding	Trucking Distance to Disposal Site, Miles
Crist	4	1.140	65.87		N.A.
	5	1.140			
	6	1.160			
	7	1.160			
Crystal River	1	1.000	99.05	x	
	2	1.000			
Crane	1	1.640	102.45		15
	2	1.500			
Cumberland	1	1.140	80.78		N.A.
	2	1.140			
Dale	1	1.150	80.61		N.A.
	2	1.110			
	3	1.090			
	4	1.090			
Danskammer	1	1.391	89.94		15
	2	1.520			
	3	1.390			
	4	1.150			
Delaware City	1	1.036	96.16	x	
	2	1.036			
	3	1.036			
	4	1.110			
Des Moines	6	1.339	N.A.**	x	
	7	1.339	66.00		
	8	1.226			
	9	1.226			
	10	1.339			
	11	1.226			
Edge Moor	1	1.110	78.27	x	
	2	1.110			
	3	1.110			
	4	1.188			
Gould Street	3	1.475	106.48		15
Fort Martin	1	1.113	67.77		N.A.
	2	1.113			

[1] Reference 4.
*Capital investment is for limestone FGD, combined for all boilers.
**Capital investment for Boiler 6 is not available.
N.A. = not available.

(Continued)

TABLE 3.1-3 PEDCo POWER PLANT FGD CAPITAL INVESTMENT RETROFIT FACTORS[1] (Cont.)

Power Plant	Boiler No.	Investment Retrofit Factor	Capital Investment ($/kW) Jan. 1975*	On-Site Ponding	Trucking Distance to Disposal Site, Miles
Gallatin	1	1.080	93.96	x	
	2	1.080			
	3	1.070			
	4	1.070			
Gannon	1	1.070	57.66		2
	2	1.060			
	3	1.060			
	4	1.070			
	5	1.140			
	6	1.170			
Green River	1	1.045		x	
	2	1.045			
	3	1.045			
	4	1.100			
	5	1.100			
Hammond	1	1.140	114.12	x	
	2	1.140			
	3	1.140			
	4	1.140			
Harrison	1	1.384	74.94		N.A.
	2	1.384			
	3	1.384			
Hawthorn	1	1.339	78.00	x	
	2	1.339			
	3	1.339			
	4	1.339	N.A.**	x	
	5	1.226			
James River	1	1.452	107.82	x	
	2	1.339			
	3	1.339			
	4	1.452			
	5	1.339			
Jeffries	1	1.165	86.58	x	
	2	1.165			
	3	1.339			
	4	1.339			

[1]Reference 4.
*Capital investment is for limestone FGD, combined for all boilers.
**Capital investment for Boiler 4 is not available.
N.A. = not available.

(Continued)

TABLE 3.1-3 PEDCo POWER PLANT FGD CAPITAL INVESTMENT RETROFIT FACTORS [1] (Cont.)

Power Plant	Boiler No.	Investment Retrofit Factor	Capital Investment ($/kW) Jan. 1975*	On-Site Ponding	Trucking Distance to Disposal Site, Miles
John Sevier	1	1.045	52.70	x	
	2	1.045			
	3	1.045			
	4	1.045			
Johnsonville	1	1.230	76.38	x	
	2	1.230			
	3	1.230			
	4	1.230			
	5	1.160			
	6	1.160			
	7	1.160			
	8	1.160			
	9	1.110			
	10	1.110			
Kammer	1	1.134	82.70		N.A.
	2	1.134			
	3	1.134			
Kanawha	1	1.791	N.A.		N.A.
	2	1.339			
Kaw	1	1.294	95.40		3
	2	1.226			
	3	1.084			
Kennedy	6	1.045	N.A.	x	
	9	1.045			
	10	1.045			
Lawrence	2	1.384	N.A.	x	
	3	1.384			
	4	1.384			
	5	1.113			
McManus	1	1.113	N.A.		N.A.
	2	1.113			
McWilliams	1	1.113	N.A.	x	
	2	1.113			
	3	1.113			
Mt. Tom	1	1.068	64.11	x	
Maynard	9	N.A.	N.A.		N.A.
	10	N.A.			
	11	N.A.			
	12	N.A.			
	14	N.A.			

[1]Reference 4.
*Capital investment is for limestone FGD, combined for all boilers.
N.A. = not available.

(Continued)

TABLE 3.1-3 PEDCo POWER PLANT FGD CAPITAL INVESTMENT RETROFIT FACTORS[1] (Cont.)

Power Plant	Boiler No.	Investment Retrofit Factor	Capital Investment ($/kW) Jan. 1975*	On-Site Ponding	Trucking Distance to Disposal Site, Miles
Mitchell	1	1.384	84.80		N.A.
	2	1.384			
Morgantown	1	1.110	73.60		6
	2	1.110			
Municipal	5	1.086	N.A.		N.A.
	6	1.110			
Northside	1	1.057	N.A.	x	
	2	1.057			
	3	1.023			
Neal	1	1.339	N.A.	x	
	2	1.452			
Owensboro	1	1.068	N.A.	x	2
	2	1.068			
	3	1.068			
	4	1.110			
Paradise	1	1.158	77.30	x	
	2	1.158			
	3	1.158			
Portsmouth	1	1.068	N.A.		N.A.
	2	1.068			
	3	1.068			
	4	1.068			
Port Wentworth	1	1.113	N.A.	x	
	2	1.113			
	3	1.113			
Quindaro 2	17	1.158	N.A.		N.A.
	18	1.158			
	19	1.158			
	20	1.158			
	21	1.158			
	22	1.158			
Quindaro 3	1	1.110	68.19		3
	2	1.061			
Riverside	1	1.332	152.61		15
	2	1.181			
St. Clair	1	1.339	79.33	x	

[1]Reference 4.
*Capital investment is for limestone FGD, combined for all boilers.
N.A. = not available.

(Continued)

TABLE 3.1-3 PEDCo POWER PLANT FGD CAPITAL INVESTMENT RETROFIT FACTORS[1] (Cont.)

Power Plant	Boiler No.	Investment Retrofit Factor	Capital Investment ($/kW) Jan. 1975*	On-Site Ponding	Trucking Distance to Disposal Site, Miles
Salem Harbor	1	1.990	104.19		25
	2	1.933			
	3	1.886			
Schiller	1	1.023	N.A.		N.A.
	2	1.023			
	3	1.023			
	4	1.023			
	5	1.023			
Shawnee	1	1.136	68.64	x	
	2	1.136			
	3	1.136			
	4	1.136			
	5	1.136			
	6	1.136			
	7	1.136			
	8	1.136			
	9	1.136			
	10	1.136			
Sheldon	1	1.050	59.46	x	
	2	1.070			
Somerset	1	1.111	81.24		25
	2	1.156			
Southside	1	1.160	N.A.		N.A.
	2	1.160			
	3	1.160			
	4	1.160			
	5	1.160			
South Street	1	1.197	101.73		6
	2	1.197			
Sutherland	1	1.384	N.A.		N.A.
	2	1.384			
	3	1.113			
Sutton	1	1.158		x	
	2	1.158			
	3	1.339			
Tecumseh	7	1.294	N.A.		N.A.
	8	1.294			
	9	1.294			
	10	1.294			

[1]Reference 4.
*Capital Investment is for limestone FGD, combined for all boilers.
N.A. = not available.

(Continued)

TABLE 3.1-3 PEDCo POWER PLANT FGD CAPITAL INVESTMENT RETROFIT FACTORS[1] (Cont.)

Power Plant	Boiler No.	Investment Retrofit Factor	Capital Investment ($/kW) Jan. 1975*	On-Site Ponding	Trucking Distance to Disposal Site, Miles
Wabash	1	N.A.	N.A.	x	
	2	N.A.			
	3	N.A.			
	4	N.A.			
	5	N.A.			
	6	N.A.			
Wagnor	1	1.097	89.66	x	
	2	1.097			
Watson	1	1.230	N.A.	x	
	2	1.230			
	3	1.230			
Waukegan	1	1.283	71.96	x	
	2	1.283			
	3	1.283			
Weston	1	1.791	111.37	x	
	2	1.791			
West Springfield	1	1.283	71.96	x	
	2	1.283			
	3	1.283			
Winnetka	4	1.562	N.A.		N.A.
	5	1.520			
	6	1.520			
	7	1.407			
	8	1.407			
Yorktown	1	1.271	N.A.		8
	2	1.271			
Zuni	1	1.339	104.00		15
	2	N.A.	N.A.**		
	3	1.113			

[1]Reference 4.
*Capital investment is for limestone FGD, combined for all boilers.
**Capital investment for Boiler 1 is not available, investment shown is for Boiler 1 and 3.
N.A. = not available.

3.2 CURRENT STUDIES

As described in Section 2.1.2-4, PEDCO has analyzed the capital investment for utility FGD systems where data are available.[10] Two retrofit installations were found to be comparable to the limestone FGD system used in the economic studies in this report, i.e. a boiler firing 3.5 percent sulfur coal with an FGD system providing 90 percent SO_2 removal. As in Section 2.1.2-4, these PEDCo-adjusted numbers were further modified to put them on the same equipment and indirect investment bases as the TVA cost estimates provided in this report. An investment retrofit factor was then derived by comparing the investment for these actual retrofit installations to the calculated investment using the TVA procedures for a new FGD installation with the same capacity. These results are shown in Table 3.2-1. A retrofit factor of 1.08 was calculated for Widows Creek, and 1.15 was calculated for Powerton.

TABLE 3.2-1 INVESTMENT RETROFIT FACTOR EVALUATION[1]

Plant Description	MWe	New or Retrofit	Coal Sulfur, Wt. %	% SO_2 Removal	PEDCo Investment Adjustment	Indirect Investment Adjustment*	Spare Scrubbers	+ Reheat	+ New Pond**	= Total	TVA Estimate	Retrofit Factor
TVA Widows Creek 8	550	R	3.70	70	145	161	21	-	12	194	180	1.08
Commonwealth Edison Powerton 51	450	R	3.60	74	138	153	42 (2 spares)	-	12	207	180	1.15

[1] Bases

1980$

Investment is expressed as $/KWe

* Indirect investment adjustment adjusts the PEDCo investment estimate to the same investment bases as the TVA.

** Each of these units were installed prior to RCRA regulations. The $12/KWe is TVA's estimate for the incremental cost of their new pond design relative to the pre-RCRA pond design.

3.3 RECOMMENDED FLUE GAS DESULFURIZATION RETROFIT FACTORS

3.3.1 Utility Boilers

It is recommended that a capital investment retrofit factor of

RF = 1.1 to 1.4 x Direct Investment

be used for boilers greater than or equal to 200 MWe. (Direct investment is defined in Table 3.3-1.) A factor of 1.1 would be used for installations that have sufficient space for equipment and that appear to require straightforward installation; a factor of 1.4 would be used for difficult retrofits. A factor of 1.2 would be used for "average" retrofits for boilers less than 10 years old and with capacities greater than 200 MWe.

These recommendations should only be used for a "preliminary" evaluation of the costs of retrofitting FGD systems to utility boilers. As discussed previously, some boilers do not have adequate space for retrofit and therefore either cannot accommodate an FGD system or the costs would be exorbitant. An engineering evaluation following a site inspection would be necessary to provide a reasonable cost estimate for a specific retrofit.

No retrofit factor for annualized costs is recommended. There would probably be some slight increase in operating cost due to greater pressure drops in longer duct runs, etc. However, this cost increase may be negligible compared to the increase in capital-related costs due to the higher capital investment for retrofit installations. Of course, the remaining life of the boiler and the projected capacity utilization factor will influence these capital-related costs significantly. Definition of these factors by the boiler operator will be required before meaningful costs (in mills/kwh) can be estimated.

TABLE 3.3-1 CAPITAL INVESTMENT COMPONENTS

Direct Investment

All installed equipment, foundations, structural components, instrumentation and buildings.

\+ Indirect Investment

Engineering design and supervision, construction expenses, contractor fees and contingency - usually calculated as a percent of Direct Investment.

Subtotal = Fixed Investment

\+ Allowance for Startup and Modifications

\+ Interest During Construction

\+ Land

+ Working Capital

Total = Capital Investment

3.3.2 Industrial Boilers

No studies for industrial boiler FGD system retrofits were located. Therefore, no retrofit factor is recommended for industrial boiler FGD systems. The same types of considerations discussed in Section 3.3.1 on utility boilers will be applicable for these systems.

REFERENCES

1. Kellogg (MW) Company. Applicability of SO_2 - Control Processes to Power Plants, NTIS PB 213 421, November 1973.

2. Radian Corporation. Factors Affecting Ability to Retrofit Flue Gas Desulfurization Systems, EPA-450/3-74-015, December 1973.

3. McGlamery, G.G., R.L. Torstrick, W.J. Broadfoot, J.P. Simpson, L.J. Hensen, S.V. Tomlinson, and J.F. Young. Detailed Cost Estimates for Advanced Effluent Desulfurization Processes, EPA-600/2-75-006, January 1975.

4. Ponder, T.C. (PEDCo) to R.L. Torstrick (TVA). Power Plant Retrofit Factors, February 25, 1976.

5. Ponder, T.C., L.V. Yerino, U. Katari, Y. Shah, and T.W. Devitt. Simplified Procedures for Estimating Flue Gas Desulfurization System Costs, EPA-600/2-76-150, June 1976.

6. Dickerman, J.C. and K.L. Johnson. Technology Assessment Report for Industrial Boilers, EPA-600/7-79-178i, November 1979.

7. Uhl, V.W. A Standard Procedure for Cost Analysis of Pollution Control Operations; Vol. II, Appendices, EPA-600/8-79-0186, June 1979.

8. Pullman-Kellogg Company. Proposed Guidelines for Determining Best Available Retrofit Technology for Coal-Fired Power Plants and Other Major Stationary Sources, EPA-450/3-80-609a, March 1980

9. Torstrick, R.L. (TVA) to Michael A. Maxwell (EPA/IERL/RTP). June 12, 1980.

10. Preliminary Results of FGD Cost Analysis for Lime/Limestone Processes (Preliminary unvalidated data), PEDCo Environmental, Inc., Cincinnati, OH, June 1980.

SECTION 4

COMPARISON OF TENNESSEE VALLEY AUTHORITY AND PEDCO ENVIRONMENTAL, INC. CAPITAL INVESTMENT AND ANNUAL COST ALGORITHMS FOR UTILITY BOILER FGD SYSTEMS

TVA and PEDCo Environmental, Inc. have both developed algorithms to estimate FGD system capital investment and annualized costs. Studies show, however, that there are many differences in the final results of their work. One study by PEDCo[1], comparing their algorithm with TVA's, highlights some of these differences. A major difference pointed out by PEDCo was in the equipment bases used in calculating capital investment and annualized costs; i.e., the two studies assumed different equipment configurations. However, all of the differences were not resolved. Therefore, the objective of this section is to determine the differences between TVA and PEDCo capital investment and annualized cost estimates for comparable FGD systems. First, the equipment basis of the two algorithms are determined. Next, the investment/cost calculational algorithms are compared and differences noted. Then the impact of the different equipment bases and calculational algorithms on investment and annualized costs are estimated. Finally, both the TVA and PEDCo studies are put on the same base to determine if the investment/cost results are equivalent.

4.1 EQUIPMENT CONFIGURATION BASIS

One of the difficulties in this study was that the equipment bases and financial algorithms for both TVA and PEDCo have changed with time. For the initial comparison, the latest update by TVA was used[2], along with a study recommended by PEDCo Environmental, Inc.[3] However, the PEDCo study was not the most current available; differences between this older study and more current ones have been noted.[4,5]

A comparison of the equipment bases and operating conditions for several studies for both TVA and PEDCo is shown in Table 4.1-1. The impacts of the numerous differences are discussed in Section 4.4.

4.2 ECONOMIC PREMISES

The economic premises used by TVA and PEDCo for several studies are shown in Table 4.2-1. TVA gives a detailed description of the basis for annual capital-related charges (e.g., the cost of capital, etc.) in their reports. PEDCo, however, does not provide such a detailed description. Each reference used in obtaining PEDCo information specified different components for the annual capital-related charges. A description of the costing methodology for TVA and PEDCo is presented in Appendix F.

4.3 CAPITAL INVESTMENT ALGORITHMS

The capital investment algorithms used by TVA and PEDCo are given in Table 4.3-1. A comparison of the components that make up total capital investment (TCI) shows many differences between the TVA and PEDCo methodology. The key point, however, is that the TCI can be estimated by multiplying the direct investment (DI) by 2.0 for TVA and 1.8 for PEDCo.

4.4 COMPARISON OF TVA AND PEDCO CAPITAL INVESTMENT

PEDCo has published an economic study of the installation of a 500 MWe lime slurry FGD system.[5] This study, based on firing 3.5 percent sulfur coal with 90 percent SO_2 removal, was put on a 1980 investment dollar basis. TVA then conducted a similar study for this report, using their latest basis, which is detailed in Table 4.3-1. The pertinent design bases for these studies, extracted from Tables 4.1-1 and 4.2-1 are presented in Table 4.4-1.

TABLE 4.1-1 COMPARISON OF TVA AND PEDCo EQUIPMENT CONFIGURATION AND OPERATING CONDITIONS

	TVA*	PEDCo**
Boiler		
Location	East Central	Midwest-East North Central
Size, MW	200, 500, 1000 can be utilized down to 100	25, 100, 200, 500, 1000 [500]
Life (Years)		
New	30	35 {30}
Retrofit	20	- {20}
Capacity Factor, %	Year 1-5 50 + 4 × Age Year 6-15 70 Year 16-30 115 - 3 × Age Levelized = 63% (10% discount factor)	65
Heat Rate, Btu/Kwh	500 MW - 9,500	25 MW - 10,000 100 MW - 9,500 200 MW - 9,200 500 MW - 9,000 1,000 MW - 8,700
Fuel (coal)		
Sulfur Variability	Not taken into account directly.	24-hour average sulfur content is higher than long term average by up to 47%.
% S → SO_x	92% eastern bituminous 85% western subbituminous	Not specified.

	TVA Coal Analysis (Wet Basis) % S Total	% S Pyrite	% Ash	Heat Content Btu/lb	PEDCo Coal Analysis (Wet Basis) % S Total	% S Pyrite	% Ash	Heat Content Btu/lb
Bituminous	4.80	3.17	15.1	11,700	6.39	4.6	14.0	12,000
Bituminous	3.36	2.21	15.1	11,700	3.48	2.49	14.0	12,000
Bituminous	1.92	1.25	15.1	11,700	-	-	-	-
Subbituminous	0.59	0.20	9.7	9,700	0.8	-	8.0	10,000 [10,500]
Lignite	-	-	-	-	0.4	-	6.0	8,000 [7,900]
Anthracite	-	-	-	-	0.8	-	6.0	13,500

	TVA*	PEDCo**
Flue Gas Entering Scrubber		
Temperature, °F	300	310
Flow rate,*** acfm/MWe	3375 for 2.5% S Coal 3568 for 0.7% S Coal	25 MW - 3,500 100 MW - 3,350 200 MW - 3,175 500 MW - 3,080 1000 MW - 3,000

(Continued)

* Reference 2

** Reference 1 except that information in [ ] is from Reference 3 and information in { } is from Reference 4.

*** Actual cubic feet per minute.

TABLE 4.1-1 COMPARISON OF TVA AND PEDCo EQUIPMENT CONFIGURATIONS AND OPERATING CONDITIONS (Continued)

	TVA*	PEDCo**
FGD System		
Removal	Variable	Variable
# Operating/Spare module	200 MW 2/1 500 MW 4/1 1000 MW 8/2	25 MW 1/0 100 MW 1/1 200 MW 2/1 500 MW 4/1 1000 MW 8/1
FGD Module Availability, %	85	25 MW 99 50 MW 99 100 MW 99 200 MW 97 350 MW 95 500 MW 92 750 MW 89 1000 MW 82 (based on 90% for each scrubber module)
Reheat		
Type	Indirect Steam	Not specified.
Temperature, °F	175	175
Solids Disposal		
On-Site	Yes - 1 mile from scrubber	Yes
Type	Ponding (nonstabilized) "old" & "new" basis and Landfill disposal	Ponding (stabilized)

* Reference 2

** Reference 1 except information in [ ] is from Reference 3 and in { } is from Reference 4.

TABLE 4.2-1 COMPARISON OF TVA AND PEDCo ECONOMIC PREMISES

	TVA*		PEDCo**
Capital Structure, %	Common Stock	35	DNA[1]
	Preferred Stock	15	
	Long Term Debt	50	
Cost of Capital, %	Common Stock	11.4	DNA
	Preferred Stock	10.0	
	Long Term Debt	9.0	
	Average	10.0	
Discount Rate, %	10		DNA
Investment Tax Credit, %	10		DNA
Federal and State Income Tax, %	50		DNA
Property Tax and Insurance, %	2.5		DNA
Annual Inflation Rate, %	6		7.5
Depreciation, yrs (new)	30		20
Annual Capital-Related Charges:			
Capital Recovery Factor	TCI[2] x 10.61		See Note
Interim Replacements	TCI x 0.56		
Insurance and Property Taxes	TCI x 2.50		
Levelized Income Tax	TCI x 4.31		
Investment Credit	TCI x (1.92)[3]		
Accelerated Depreciation	TCI x (1.36)[3]		
Total	TCI X 14.70		

Note: Each of the PEDCo references has different annual capital charge factors. These range from 0.16 x TCI (Reference 3) to 0.231 x TCI (Reference 1). These capital charge factors varied depending on assumptions concerning income tax rate, debt/equity, local taxes and insurance, etc.

* Reference 2

** Reference 1

[1]DNA - Data Not Available

[2]TCI - Total Capital Investment

[3]( ) - Denotes a Credit

TABLE 4.3-1 COMPARISON OF TVA AND PEDCo CAPITAL INVESTMENT ALGORITHMS

	TVA*	PEDCo**
Cash Flow	25% 1st year of construction 50% 2nd year of construction 25% 3rd year of construction	Not Specified
Total Process Capital (TPC)	1979 equipment cost x CE index (Installed basis)	mid-1976 cost x 7.5%/yr (Installed basis)
Services & Miscellaneous	6% x TPC (4-8%)	Not broken out separately
Direct Investment (DI)	TDI = TPC + Services and miscellaneous	TDI = TPC
Indirect Investment (II)		
Engineering design & supervision	7% x DI (6-8%)	10% (DI - sludge pond) (10% x DI)
Arch & engineering contractor	2% x DI (1-3%)	
Construction field expense	16% x DI (14-18%)	10% x DI
Contractor fees***	5% x DI (4-6%)	6% (DI + II) (5% x DI)
Contingency***	20% (DI plus above II) = 26% x DI	20% (DI + II)
Freight	Included with DI	1.25% (DI - sludge pond) (None)
Off-site expenditure	--	3.0% x DI (None)
Taxes	--	1.50% (DI - sludge pond) (2% x DI)
Fixed Investment (FI)	156% x DI	
Other Capital Requirements (OCR)		
Allowance for Start-up****	12% x FI	5.0% x DI
Interest during construction****	15.6% x FI	10% x DI
Royalties	0.5% x DI	--
Working Capital		
Raw material	1 month supply	1% (DI - sludge pond) (None)
Conversion cost	1.5 x monthly cost	--
Overhead	1.5 x monthly cost	--
Spares, accounts receivables	3% x DI	0.4% x DI (1% x DI)
Land, $/acre	5000	2000
Total Capital Investment (TCI)	~ 2.0 x DI	~ 1.8 x DI

* Reference 2

** Reference 1 except information in [ ] is from reference 3 and information in ( ) is from reference 4.

*** Not a part of II with PEDCo method.

**** Part of II in PEDCo method

NOTE. Direct Investment includes all installed equipment, pond, electrical, buildings, instrumentation, etc

TABLE 4.4-1 DESIGN BASES FOR TVA AND PEDCo TOTAL CAPITAL INVESTMENT COMPARISON

	TVA	PEDCo
Boiler Data		
Size, MWe	500	500
Life, Years	30	35
Capacity Factor, %	63	65
Heat rate, Btu/Kwh	9500	9000
Fuel		
Composition (wet basis)		
S, %	3.36	3.48
Pyrite, %	2.21	2.49
Ash, %	15.1	14.0
Heat Context, Btu/lb	11,700	12,000
Flue Gas		
Temperature, °F	300	310
Flow rate, acfm/MWe	3375	3080
FGD Scrubbers		
Type	wet lime	wet lime
Operating Units	4	4
Spares	1	1
Reheat		
Type	Indirect steam	Type not specified
Flue gas		
Temperature, °F	175	175
Solids Disposal		
Type	Nonstabilized pond ("new" basis)	Stabilized pond

The results of the two studies are given in Table 4.4-2. The total direct investment (TDI) in the PEDCo study is 93 percent that of the TVA study, with the largest absolute difference in the waste disposal area. This is not unexpected since the TVA study assumes the use of TVA's "new pond" model.* Using TVA's "old pond" model to calculate TDI for TVA brought the TDI of the two studies within two percent of one another.

A close examination of the components that make up indirect investment (II) and other capital requirements (OCR) shows that TVA includes freight and off-site expenditures in calculating TDI, whereas PEDCo does not. Adding these two components into TDI for PEDCo increases the PEDCo TDI to one percent higher than that of TVA. Thus, the TVA and PEDCo algorithms give almost the same TDI (including the TDI components) when the equipment basis and components that make up the TDI are the same.

As shown in Table 4.3-1, the TVA and PEDCo algorithms used to calculate II and OCR are different. Of course, when the same II and OCR algorithm is used, the TVA and PEDCo models give nearly the same total capital investment (TCI), since nearly the same TDI is used. This is illustrated in Table 4.4-2, where a TVA TDI of $40,593,000 gives a TCI of $81,186,000, whereas a PEDCo TDI of $41,199,000 gives a TCI of $82,398,000, using the TVA approximation of TCI = 2.0 x TDI. Details of these calculations are given in Appendix G.

4.5 ANNUAL OPERATING COST AND REVENUE ALGORITHMS

The algorithms used to calculate direct operating costs, indirect operating costs, and annual capital-related charges for both TVA and PEDCo are given in Table 4.5-1. Comparing the two algorithms shows that even with the same technical basis (i.e., equipment configuration, material and energy balances, etc.) there are significant differences in annual operating costs and annual revenue requirement.

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*Described in Section 2.1.2

TABLE 4.4-2 500 MWe LIME SLURRY FGD SYSTEM CAPITAL INVESTMENT (3.5% S Coal, 90% SO_2 Removal, 1980$)

	Investment, 10^3 $, 1980 $					
	TVA		PEDCo		PEDCo/TVA	
Direct Investment (DI)	--					
Raw Material Handling & Preparation	3,261		2,253		0.69	
SO_2 Scrubbing	26,803		27,945		1.04	
Waste Disposal (including pond)	12,380	(10,529)[1]	9,418		0.76	(0.98)
TOTAL DIRECT INVESTMENT (TDI)	42,444	(40,593)[1] (40,593)[1]	39,616	 (41,199)[4]	0.93	(0.98) (1.01)
Indirect Investment (II) & Other Capital Requirements (OCR)						
Engineering Design & Supervision Architecture & Engineering Contractor	3,820		3,163		0.83	
Construction Field Expense	6,791		3,962		0.58	
Contractor Fees	2,122		3,313		1.56	
Contingency	11,035		11,044		1.00	
Freight	-		395	→ (41,199)[4]	-	
Off-Site Expenditure	-		1,188	→ (41,199)[4]	-	
Taxes	-		474		-	
Allowance for Start Up	5,093		1,996		0.39	
Interest During Construction	9,932		3,962		0.40	
Working Capital	2,390		462[2]		0.19	
Land	1,815		154		0.08	
TOTAL II & OCR	42,998	(40,593)[1,3] (40,593)[1,3]	30,113	(28,530)[4] (41,199)[3,4]	0.70	(0.66) (1.01)
Capital Investment						
TOTAL	85,442	(81,186)[1,3] (81,186)[1,3]	69,729	(69,729) (82,398)[3,4]	0.82	(0.86) (1.01)
$/KWe	171	(163)[1,3] (163)[1,3]	139	139 (165)[3,4]	-	

[1]"Old" pond model.
[2]Spares + raw material only.
[3]Total II + OCR = 1.0 x TDI.
[4]Freight and off-site expenditures included in TDI.

TABLE 4.5-1 COMPARISON OF TVA AND PEDCo ANNUAL OPERATING COST AND REVENUE ALGORITHMS

	TVA	PEDCo
Capacity Factor	0.63 (5500 hrs/yr)	0.65
Direct Costs		
Raw Material	Current Costs	Current Costs
Operating Labor & Supervision	Current Costs	Labor - Current Costs Supv. - 15% x Direct Labor
Utilities	Current Costs	Current Costs
Maintenance Labor & Materials	8% x DI	Labor & Mat. - 4.35% x TCI Supplies - 15% x Labor & Materials
Analyses	Current Costs	None
Indirect Costs		
Plant & Administrative OH	60% of Direct costs - raw mat. - utilities)	50% x (Operating Labor & Maint.)
Payroll OH	Included in Plant and Administrative OH	20% x Operating Labor
Annual Capital-Related Charges	14.77%	23.1%

4.6 COMPARISON OF TVA AND PEDCo ANNUAL OPERATING COST AND ANNUAL REVENUE REQUIREMENT

Table 4.6-1 shows the results of the TVA and PEDCo economic study. The unit costs in Table 4.6-1 were used with the algorithms in Table 4.5-1 to calculate the operating cost and annual revenue requirements. Although the annual revenue requirement is approximately the same for the two studies, very large differences in the components are evident.

The annual O&M and capital-related costs are put on the same basis in Table 4.6-2. Specifically, the same unit costs and algorithms were applied to both the TVA and PEDCo material balances, energy balances, and labor and supervision assumptions. Both the algorithm and unit costs used were the latest TVA figures. The capital investments used in the maintenance algorithm are shown in Table 4.4-2.

As Table 4.6-2 shows, both the operating costs and the annual revenue requirements are comparable for the two studies. The components that make up the costs are also comparable, illustrating that the basic inputs (i.e., material and energy balances and labor and supervision assumptions) for the two studies are also comparable. The major cost difference is in the electricity consumption. The limited investigation by this study could not resolve this large difference. Details of the cost calculations are given in Appendix G.

4.7 SUMMARY

The basic objective of this section was to determine the sources of differences in capital investment and annual costs between TVA and PEDCo algorithms and to determine the impact of these differences. It was found that, with the exception of the waste pond model, the basic equipment configurations of the latest TVA and PEDCo studies are the same. Major differences in capital investment for the two studies are due to different indirect investment and other capital requirement algorithms. Similarly, it was found that the basic material and energy balances and labor and

TABLE 4.6-1 500 MWe LIME SLURRY FGD ANNUAL COSTS AND REVENUE (3.5% S Coal, 90% SO_2 Removal)

	TVA* Unit Cost	TVA* Annual Quantity	TVA* Annual Cost, 10^3 \$	PEDCo Unit Cost	PEDCo Annual Quantity	PEDCo Annual Cost, 10^3 \$
Direct Costs						
Raw Material						
Lime	\$40/ton	60K tons	2,405	\$50/ton	64K tons	3,219
Fixation Chemicals				\$20/ton	26K tons	527
Conversion Costs						
Labor						
Op. Labor	\$12.50/hr	28.5K hr	356	\$10/hr	27.7K hrs	277
Supv.				15% x Direct Labor		42
Utilities						
Steam	\$2.00/MBTU	438×10^6 BTU	876	\$1.25/MBTU	92 MBTU/hr	542
Process H_2O	\$0.12/Kgal	146×10^6 gal	18	\$0.20/Kgal	592 gpm	32
Electricity	\$0.029/Kwh	39.5×10^6 Kwh	1,146	\$0.025/Kwh (Calculations show utilities based on 4555 hr/yr = 0.52 cap. factor)	76.1×10^6 Kwh	1,903
Maintenance						
Labor & Materials	8% x TDI		2,875	4.35% x TCI		2,889
Supplies				15% x Labor & Mat.		433
Analyses	\$17/hr	4590 hr	78			-
Sludge Handling			-	\$2/ton-mile	264K ton-mile	528
DIRECT COSTS			7,753			10,374
Indirect Costs						
Overhead						
Plant	60% (Conv. Cost - Utilities		1,985	50% x Op. Labor & Maint.		1,821
Administration				20% x Op. Labor & Supv.		64
INDIRECT COSTS			1,985			1,885
1st YEAR OP & MAINTENANCE			9,738			12,259
Fixed Charges						
Depreciation				equivalent to 23.1% x TCI		1,206
Taxes						4,708
Insurance						253
Capital Costs	14.7% x TCI		12,560			9,336
TOTAL FIXED CHARGES			12,560			16,103
TOTAL ANNUAL REVENUE			22,298			28,362
Mills/Kwh			9.43			9.96

* This particular study used a 0.54 capacity factor

K = thousand, M = million

TABLE 4.6-2. 500 MWe LIME SLURRY FGD ANNUAL COSTS ON SAME UNIT COST AND OPERATING BASIS (3.5% S Coal, 90% SO_2 Removal, 0.63 Capacity Factor)

		TVA		PEDCo	
	Unit Cost	Annual Quantity	Annual Cost, $10^3$$	Annual Quantity	Annual Cost, $10^3$$
Direct Costs					
Raw Material					
Lime	$40/ton	70K tons	2,800	63K tons	2,520
Conversion Costs					
Op. Labor & Supv.	$12.50/hr	33.3K hrs	416	26.8 hrs	335
Utilities					
Steam	$2.00/MBTU	511 MBTU	1,022	508 MBTU	1,016
Process H_2O	$0.12/Kgal	170 Mgal	20	196 Mgal	24
Electricity	$0.029/Kwh	46M Kwh	1,334	92M Kwh	2,668
Maint. Labor & Supv.	8% x TDI		3,396		3,296
Analyses	$17/hr	4590 hours	78		
TOTAL COSTS			9,066		9,859
Overhead					
60% (Conv. Costs - Utility)			2,334		2,179
1st YEAR O&M COSTS			11,400		12,038
Mills/Kwh			4.13		4.37
Fixed Charges - 14.7% x TCI			11,934*		12,192**
ANNUAL REVENUE REQUIREMENT			23,334		24,230
Mills/Kwh			8.45		8.78

* Using TCI = 2.0 x TDI

** Using TDI = 81,186,000 (Table 4-5)

K = Thousand, M = Million

supervision assumptions are comparable for the two studies. Major differences in annual O&M cost and annual revenue requirements are due to different calculational algorithms, electricity usage, and unit costs.

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6. Torstrick, et al., op cit.

7. Gibbs, et al., op cit.