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FEASIBILITY OF INSTALLING SULFUR DIOXIDE SCRUBBERS ON STATIONARY SOURCES IN THE SOUTH COAST AIR BASIN OF CALIFORNIA
VOLUME II: TECHNICAL DISCUSSION

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ABSTRACT

The feasibility and costs of flue gas scrubbing were determined for retrofitting eight selected oil-fired power plants and five industrial sources of sulfur dioxide (SO_2) emissions in the Los Angeles area. Sulfur dioxide scrubbing to achieve the equivalent of 0.05-percent sulfur oil (90 percent SO_2 removal from 0.5 percent sulfur oil) for the utility installations and the removal of approximately 90 percent SO_2 from the other sources were evaluated. The major emphasis on feasibility in this study was for physical installation of the scrubbers.

The power plants selected within the scope of this study represent approximately 80 percent of the fossil fuel-fired power plant generating capacity in the South Coast Air Basin. The SO_2 emissions from the five other sources studied are typical of boilers burning carbon monoxide in flue gas from fluid catalytic cracker units, petroleum coke calcining kilns, and sulfuric acid plants. They currently produce SO_2 emissions equivalent to approximately 18 percent of the emissions now being emitted from the eight power plants.

Technical feasibility for SO_2 removal was established on the basis of the lime-limestone nonregenerable scrubber technology demonstrated in Japan and on units currently being installed and operated in the United States. Other factors such as compatibility with facility operations, space requirements, waste handling, and disposal were examined. Power, water, and flue gas reheating requirements were also addressed.

It was concluded that all of the sites studied can be retrofitted with wet nonregenerable scrubbers capable of removing SO_2 to the levels specified. The degree of difficulty of the scrubber installations varied considerably. Some plants have relatively open areas near the stack, whereas others involve a difficult siting problem. Disposal of scrubber wastes produced from the scrubbers does not appear to present a significant handling problem or impact on existing Class I landfill disposal sites in Los Angeles County.

Capital investment estimates reflecting a range of retrofit complexity and redundancy factors are provided. Corresponding annualized charges in terms of mills per kilowatt hour, dollars per ton SO_2 removed, and dollars per ton product, as appropriate, are reported. The credit resulting from the burning of 0.5 percent sulfur oil by the utilities rather than the 0.25 percent currently in use is also identified.

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Contributions in the form of operating information and site data were provided by the Los Angeles Department of Water and Power, Southern California Edison, Chevron, USA, Inc., Collier Carbon, Inc., Great Lakes Carbon, Inc., Martin Marietta Carbon, Inc., and Stauffer Chemical, Inc.

Sulfur dioxide scrubber information was provided by the Chemico Division of Envirotech, FMC Corporation, Peabody Process Systems, Pullman Kellogg, Research-Cottrell, and Air Correction Division of UOP, Inc.

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Appreciation is extended to all the contributors. However, assembly of the data, assessments, and conclusions drawn are the responsibility of the authors.

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1. INTRODUCTION

The State of California Air Resources Board is evaluating the potential for reducing sulfur dioxide (SO_2) emissions from oil-fired utility power plants and other SO_2 sources in the Los Angeles area. This study has involved assessing the feasibility and cost of retrofitting flue gas scrubbers on utility boilers to achieve SO_2 removal equivalent to use of 0.05 percent sulfur oil (90 percent SO_2 removal from the burning of fuel oil containing 0.5 percent sulfur) and the reduction of SO_2 by approximately 90 percent from existing levels for other sources which include boilers burning carbon monoxide (CO) in the flue gas from fluid catalytic cracker regenerators, petroleum coke calcining kilns, and sulfuric acid units. These objectives are summarized in Table 1.

TABLE 1. SULFUR DIOXIDE REMOVAL OBJECTIVES

Source	Objective
Utility boilers	90 percent removal from combustion of fuel oil with 0.5 percent sulfur
Fluid catalytic cracker carbon monoxide boiler	50 ppm maximum
Petroleum coke calcining kilns	1.5 lb/short ton of coke charged into kiln
Sulfuric acid units	4.0 lb/short ton of product acid

A total of 13 study sites were selected by the research staff of the California Air Resources Board and are identified in Table 2. The eight utility power plants included in this study represent approximately 80 percent of the fossil-fueled electrical power plant generating capacity in the South Coast Air Basin.

TABLE 2. FACILITIES STUDIED

SO_2 emission source	Agency or company and location
Electrical utility generating stations	Southern California Edison Alamitos El Segundo Etiwanda Huntington Beach Ormond Beach Redondo Beach
	Los Angeles Department of Water and Power Haynes Valley
Carbon monoxide boiler	Chevron, El Segundo
Petroleum coke calcining kilns	Great Lakes Carbon, Wilmington
	Martin Marietta Carbon, Carson
Sulfuric acid units	Stauffer Chemical, Carson
	Collier Carbon, Wilmington

The technical feasibility assessment was based on determining the potential for 90 percent SO_2 removal by flue gas scrubbing. Existing demonstrated technology was considered a significant factor in assessing the SO_2 removal technology of scrubbing processes and their subsequent application to the various specific sites included in the study. Using this criterion, attention was focused on nonregenerative lime-limestone scrubbers that remove 90 percent of the SO_2. Such scrubbers are used extensively in Japan on oil- and some coal-fired boilers and in the United States on coal-fired units. The more complex and less developed regenerable processes were to be considered in the event that 90 percent removal efficiency was not achievable by means of first-generation, nonregenerable technology or if problems arising from the quantity or disposal of wastes produced from the nonregenerables made their application impractical.

The study involved a number of facets, including the following:

a. Assessment of scrubber technology
b. Characterization of the sites
c. Identification and assessment of scrubber system operation
d. Determination of site-specific feasibility and costs.

The approach taken to assess feasibility of installing SO_2 scrubbers is summarized in Table 3.

Assessment of the technology potential for the nonregenerable systems was based on evaluation of the results reported for the operational installations on numerous oil- and some coal-burning boilers in Japan and coal-burning units in the United States. Information developed through discussions with personnel knowledgeable of the details of the Japanese processes and those familiar with U. S. technology was used to augment the published data. Similar contacts were made with regard to the smaller scrubber units applicable to the industrial, nonutility installations.

For the data needed to evaluate each Los Angeles study site, information was derived from conferences with cognizant technical personnel from the various companies involved. The responses of various organizations

TABLE 3. SULFUR DIOXIDE SCRUBBER -- FEASIBILITY STUDY APPROACH

Major areas of investigation	Specific tasks
Assess scrubber technology	Determine sulfur dioxide removal efficiency Assess scrubber operability
Characterize power plants and industrial sites	Make on-site visits Analyze responses to questionnaires defining plant characteristics and layout Review plot plans and aerial photographs
Identify and assess scrubber system operation	Determine ability to reduce sulfur dioxide to required levels Identify operating characteristics Quantify operating requirements Identify waste disposal impacts
Determine site-specific feasibility and costs (capital, operation and maintenance and annualized)	Obtain sizing, operating, and cost data from scrubber suppliers--Chemico, FMC (industrial), Peabody (industrial), Pullman Kellogg, Research Cottrell (utility and industrial divisions), and UOP Consider effects of retrofit complexity and equipment redundancy on scrubber installations Include cost benefits of using 0.5 percent sulfur oil instead of current 0.25 percent oil Relate scrubber operating costs to selling price of product

to questionnaires developed by The Aerospace Corporation were also used. Based on scrubber supplier inputs and published data, scrubber system requirements and operating conditions were identified and quantified. These included scrubber reagent, fresh water, power, and wastes produced by each of the sites. Further, by utilization of site plot plans, aerial photographs, and equipment sizing information provided by various scrubber suppliers, layout sketches were made showing size, location, and orientation of the scrubber modules, lime storage facilities, and the waste handling and holding facilities. In addition, major impacts or modifications to existing facilities as determined by a review of the plot plans and site visits were identified.

Based on budget-type information provided by the scrubber manufacturers for grass-roots installation, capital cost estimates for retrofitting the sites were prepared as a function of several levels of complexity. The costs associated with a number of levels of equipment redundancy were determined. Annualized charges were defined which included capital charges, scrubber system operation, and waste disposal. Costs associated with plant or unit shutdown for installation of scrubber equipment were not included.

2. SUMMARY AND CONCLUSIONS

The study was oriented towards determining the feasibility of installing SO_2 scrubbers on selected utility boiler and industrial emission sources in the Los Angeles area. Four basic considerations in assessing feasibility in this study were addressed:

a. Technical feasibility of 90 percent SO_2 removal
b. Scrubber process definition
c. Feasibility of scrubber system installations at selected sites
d. Cost of site-specific capital equipment, total capital investment, and annualized costs.

Thirteen sites, which included six Southern California Edison (SCE) and two Los Angeles Department of Water and Power (DWP) generating stations (Table 4) and five industrial boiler and process sites were studied. The latter included a boiler burning carbon monoxide (CO) in the flue gas from a catalytic cracker regenerator, petroleum coke calcining kilns, and sulfuric acid units (Table 5). In general, the SO_2 removal requirement used in the study was a nominal 90 percent removal. The current emissions and the specific SO_2 removal requirements to meet study objectives for the various sources are defined in Table 6.

2.1 TECHNICAL FEASIBILITY OF SO_2 CONTROL REQUIREMENTS

As a result of this study, it was concluded that 90 percent removal of SO_2 flue gas, originating from oil-fired utility boilers and from industrial processes, can be accomplished on the basis of existing nonregenerable scrubbing technology. Consistent removal efficiences of 90 percent or greater have been demonstrated in Japan, primarily on oil-fired and some coal-fired boiler installations. Currently, scrubber units are being installed on coal-fired units in the United States to meet 90 percent SO_2 control requirements. Removal efficiencies in excess of 90 percent have been demonstrated with some scrubbers installed on industrial combustion and process sources of SO_2 in the United States.

TABLE 4. ELECTRICAL UTILITY FACILITY CHARACTERISTICS

Electric utility generating station	Generating capacity, MW	No. of units	Average capacity factor, 1976
Southern California Edison			
Alamitos	1,950	6	0.442
El Segundo	1,020	4	0.444
Etiwanda	904	4	0.498
Huntington Beach	870	4	0.434
Ormond Beach	1,600	2	0.454
Redondo Beach	1,602	8	0.15[a]/0.451
Los Angeles Department of Water and Power			
Haynes	1,633	6	0.667
Valley	526	4	0.158[b]
Total	10,105	38	0.424[c]

[a] 0.15 applies to Units 1 through 4; 0.451 applies to Units 5 through 8

[b] Units 1 and 2 were for 1975

[c] Weighted average (excluding a and b)

TABLE 5. PETROLEUM AND CHEMICAL PROCESSING FACILITY CHARACTERISTICS

Installation	Unit size, tons/day	No. of units
Carbon monoxide boiler -- Chevron	a	1
Petroleum coke calcining kilns		
Great Lakes Carbon	900 (ea)	3
Martin Marietta Carbon	960	1
Sulfuric acid units		
Stauffer Chemical	300 (ea)	2
	200	1
Collier Carbon	450	1
Total	--	9

[a] Not available -- boiler rated at 250,000 lb/hr steam

TABLE 6. SULFUR DIOXIDE EMISSION CONTROL CONDITIONS CONSIDERED IN THIS STUDY

Electrical utilities and industrial sources	Current		Objectives	
	Status	Approximate emissions, ppm	Removal by scrubber, percent	Emissions
Electrical utility boilers -- DWP and SCE units	Sulfur content in fuel oil not to exceed 0.25 percent	150	90 from combustion of oil with 0.5 percent sulfur	30 ppm (approx.)
Carbon monoxide boiler -- Chevron	SO_2 content of flue gas emissions is a function of crude being processed, in the range of 150 to 400 ppm	225 (avg)	88 for 400 ppm inlet	50 ppm maximum
Petroleum coke calcining kilns				
Great Lakes Carbon	Emissions are function of crude: currently 300 to 380 ppm (approx. 1.3% sulfur in coke)	300 (wet)	88 for normal production rates and 300 ppm	1.5 lb SO_2 per short ton of coke charged into kiln
Martin Marietta Carbon	2.3 to 2.5 percent sulfur crude	700 (wet)	93 for 2.5 percent sulfur crude	
Sulfuric acid units				
Stauffer Chemical	300 to 500 ppm	400	33 for Units 1 and 2 66 for Unit 3	4.0 lb SO_2 per short ton of product
Collier Carbon	350 ppm	400	15 (ave.)	

2.2 SCRUBBER PROCESS DEFINITION

Since a significant data base exists to support the SO_2 removal capability of the lime-limestone nonregenerable process for the large utility installations, this process was selected for further evaluation and quantification. Nonregenerable lime scrubbing, rather than limestone, was chosen for process definition and quantification (Figure 1) because lime has smaller space and handling requirements. Consideration of limestone would not result in any fundamental changes to the results of this study because basic scrubber tower sizes are nominally the same for both, being determined by the volumetric flow and spatial velocity of the flue gas through the tower. However, for a given amount of SO_2 removal, approximately 100 percent more limestone ($CaCO_3$) reagent, by weight, would be required in contrast to lime (CaO) because of chemical differences in the reagent and the slightly lower limestone utilization. The limestone process would also require pulverizing facilities, which are not needed with lime, and approximately 5 percent more scrubber waste would be produced if limestone were used.

Because of the limited area available at certain sites and the experience in applying the double alkali process to industrial use, the latter process (Figure 2) was considered, in addition to lime scrubbers for the smaller, nonutility installations in this study.

Electrical power, water, and flue gas reheating requirements were defined. A generalized schematic summarizing the various operating conditions is given in Figure 3, and total quantities are provided in Table 7 for all sites studied.

Filtered scrubber waste totalling approximately 328,000 tons or 163 acre-feet would be produced annually by the eight utility sites. The industrial sources studied would add approximately 14 percent. The disposable waste from the lime scrubbers was estimated to contain 72 percent solids subsequent to vacuum filtration, the latter being accomplished at the scrubber site. Use of trucks to transport the waste to two Class I, geographically appropriate disposal sites in Los Angeles County was determined to be feasible with

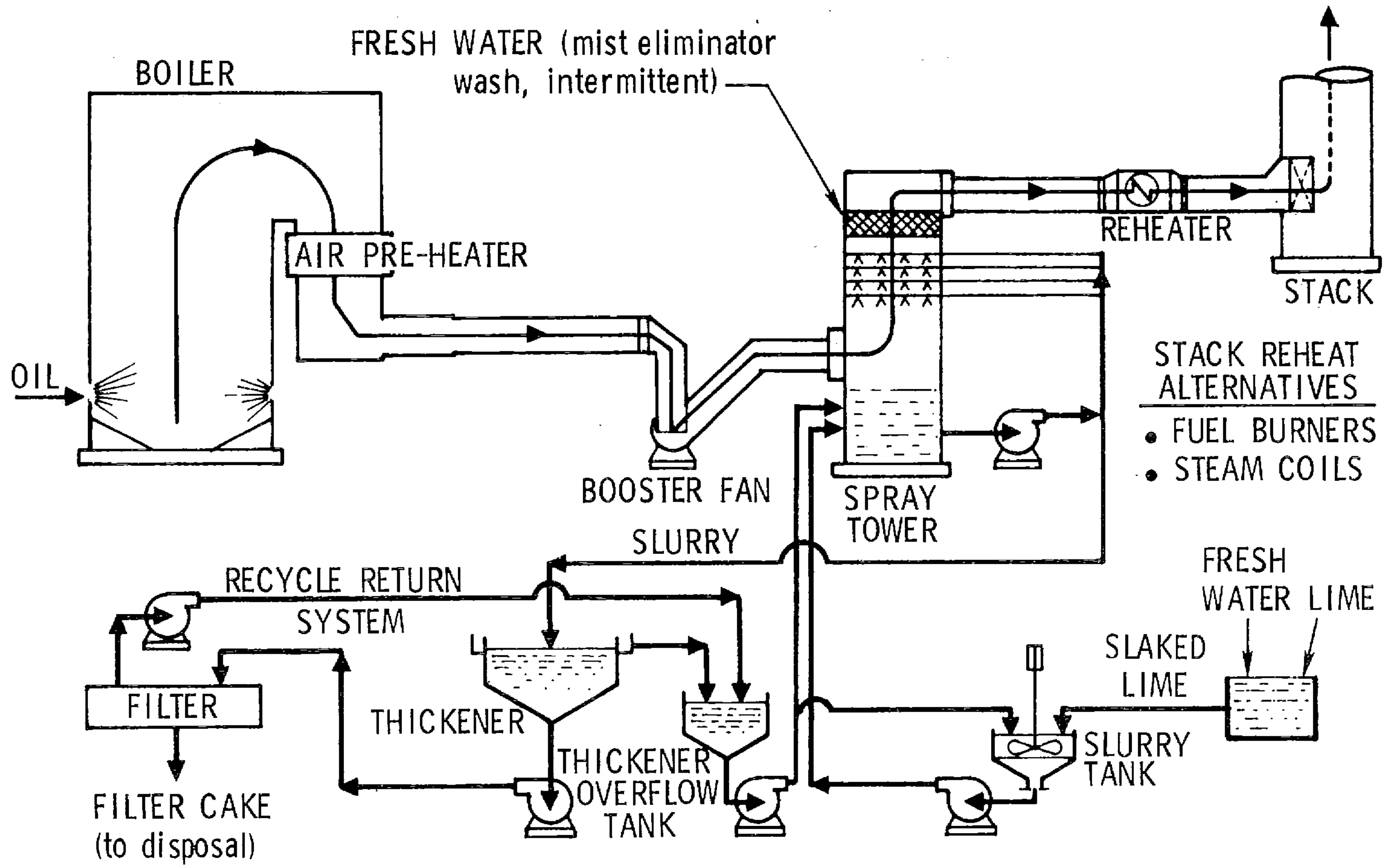

Figure 1. Lime scrubbing schematic

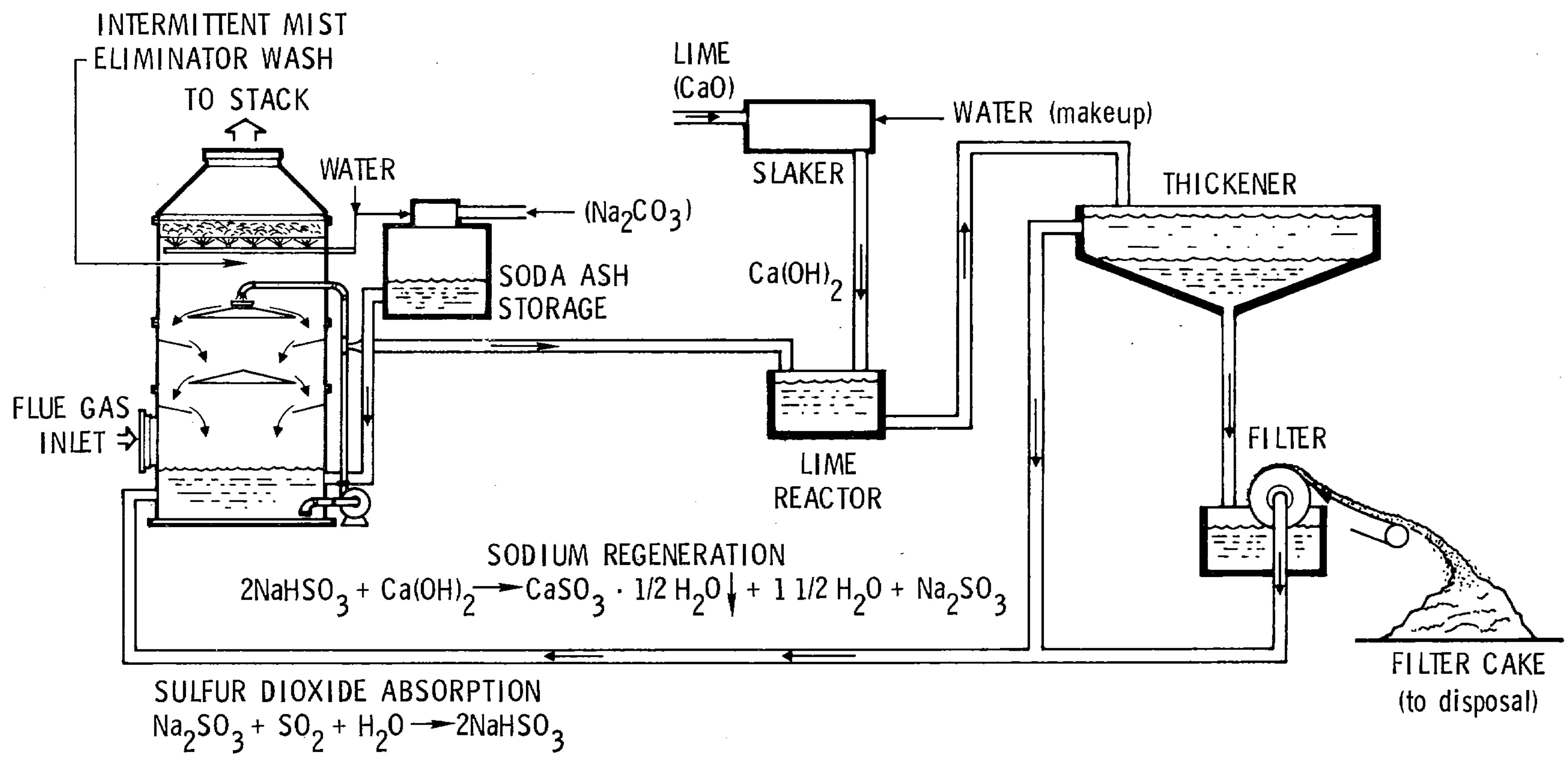

Figure 2. Double alkali process schematic

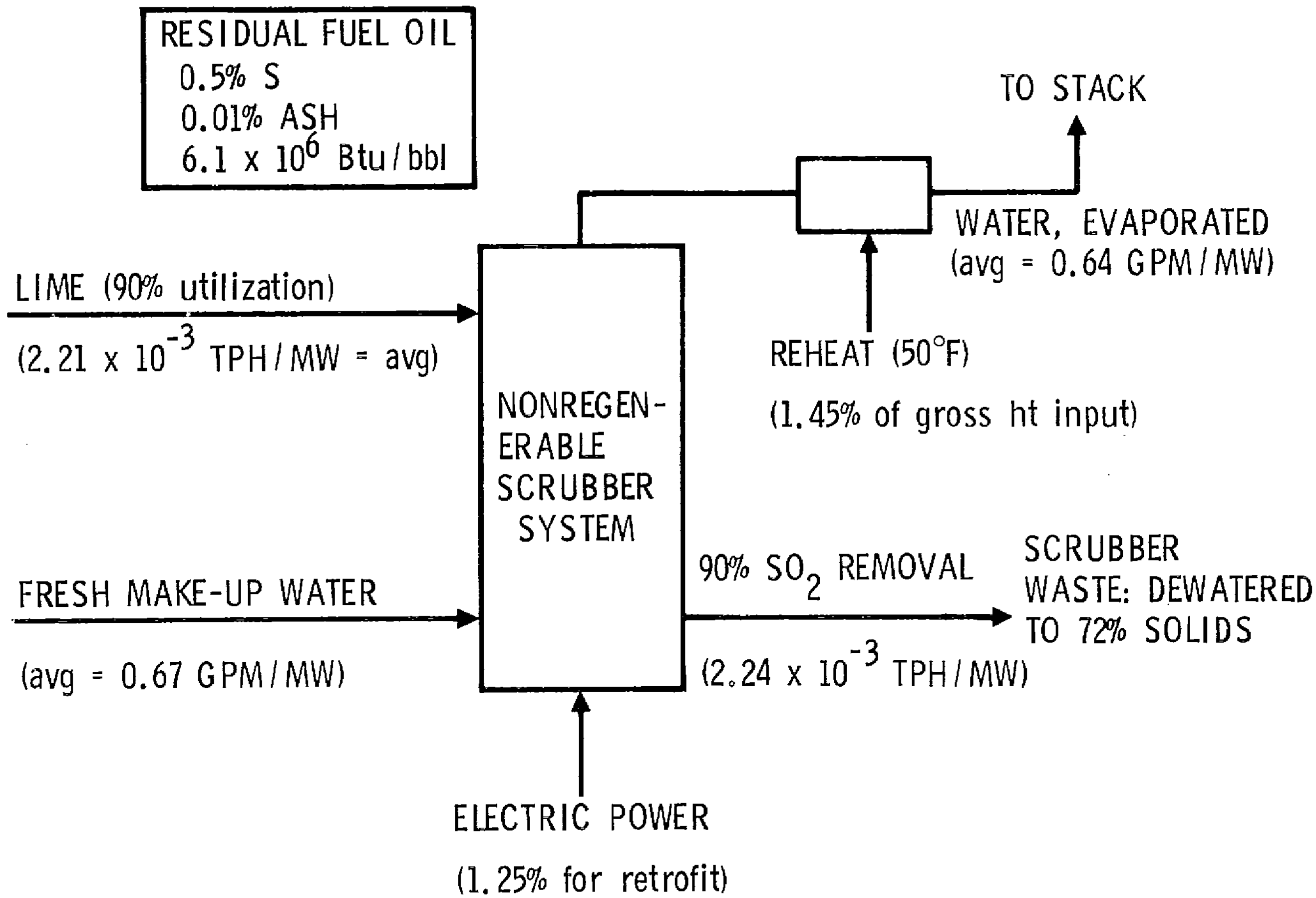

Figure 3. Generalized sulfur dioxide scrubber parameters -- electric utility boilers

TABLE 7. QUANTIFICATION OF SCRUBBER SYSTEM PARAMETERS

Parameter	Utility	Industrial process
Number of sites	8	4[a]
Total generating capacity, MW	10,105	Not applicable
Number of units retrofitted	38	8
Annual operation		
Capacity factor	0.424	--
Hours	--	8,200 (typical)
Sulfur dioxide removed annually, tons	91,100[b]	9,340
Scrubber waste produced annually		
Tons	327,800	44,500
Acre-feet	163	23.1
Annual lime consumption, tons	89,000	10,500
Current daily fresh water use		
Gallons	4,510,000	1,100,000
Increased consumption--all units, percent	37	22
Annual electric power required, KWh	469×10^{6} [c]	44×10^{6}
Annual reheat requirement (50°F)	1.45[d]	13.0×10^{10} Btu

[a]Fifth site not applicable -- see discussion in Section 4.3.2

[b]90 percent sulfur dioxide removal; fuel oil burned contains 0.5 percent sulfur

[c]Equivalent to 1.25 percent of power generated

[d]Percent of gross heat input

nominal impact on the remaining life of the disposal sites. An operating cost of about $7.14 per ton of disposable dewatered waste was estimated. The conversion of wastes to a useable product and the potential marketability of waste products were not within the scope of this study.

2.3 FEASIBILITY OF SCRUBBER INSTALLATIONS

Feasibility of SO_2 scrubber installation was based on factors defined for this study and are summarized in Table 3. For the eight utility sites studied, retrofitting of a total of 38 generating units, 41 boilers, with vertical, nonregenerable scrubbers was determined to be feasible on the basis of operating information furnished by the utilities, site visits, plot plans, aerial photographs, and scrubber size and operating information provided by scrubber suppliers. In general, the availability of land and space near the boiler was of primary importance in siting the scrubbers and in determining the resultant complexity of installation (Table 8). While other equipment such as horizontal nonregenerable scrubbers or processes such as those capable of producing sulfur or sulfuric acid might also be feasible at at certain utility sites, the potential optimization, if any, of processes or equipment was not an objective of this study.

For the catalytic cracker carbon monoxide boiler and the process industries installations, retrofitting with scrubbers was found to be feasible (Table 9). Both nonregenerative lime and double alkali processes were considered. Lime scrubbers that are commercially available for industrial applications from a major U.S. supplier that was contacted in this study are provided in discrete modular sizes. In one instance, multiple scrubber units were required and could not be accommodated because of space limitations. In that case, a double alkali system with a single scrubber tower was considered.

One industrial site, the Collier Carbon sulfuric acid plant, Wilmington, California, is operating an ammonia scrubber, which reduces SO_2 emissions to approximately 4.7 pounds of SO_2 per ton of product. In order to meet the 4.0-pound value, 15 percent SO_2 removal would be

TABLE 8. ENGINEERING ASSESSMENT OF SITE-SPECIFIC INSTALLATION FEASIBILITY -- UTILITIES

Generating station	Capacity, MW	No. of boilers	No. of scrubbers	Retrofit installation complexity[a]
Southern California Edison				
Alamitos	1950	6	10	Moderate
El Segundo	1020	4	8	Difficult
Etiwanda	904	4	6	Nominal
Huntington Beach	870	4	4	Nominal
Redondo Beach	1310	4	6	Difficult
	292	7	2	Difficult
Ormond Beach	1600	2	8	Moderate
Los Angeles Department of Water and Power				
Haynes	1633	6	10	Moderate
Valley	526	4	4	Nominal

[a] Based on availability of space and complexity of installation

TABLE 9. ENGINEERING ASSESSMENT OF SITE SPECIFIC INSTALLATION FEASIBILITY -- INDUSTRIAL SITES

Installation	Unit or plant rating	No. of units	No. of scrubbers[d]	Installation complexity[a]
Carbon monoxide boiler -- Chevron	250,000 lb/hr steam	1	2	Nominal
Petroleum coke calcining kilns				
Great Lakes Carbon	2700 tons/day raw coke	3	3	Difficult
Martin Marietta Carbon	960 tons/day raw coke	1	1	Nominal
Sulfuric acid units				
Stauffer Chemical	800 tons/day sulfuric acid	3	3[e]	Moderate
Collier Carbon	450 tons/day sulfuric acid	1	1[b]	Nominal[c]

[a]Primarily based on availability of space
[b]Existing
[c]If additional scrubber is required; see discussion in Section 4.3.2
[d]Double alkali process
[e]Nonregenerable lime process

required. It was determined that the existing scrubber could be operated to meet the study objective of 4.0 pounds. However, some questions were raised about the possibility of increasing plume opacity above current allowables. The scrubber supplier indicated that techniques could be employed to decrease plume opacity if it occurred. In addition, space is available in the event opacity were a problem and a nongenerable scrubber is required.

2.4 COST ESTIMATES

Capital, operating, and annualized cost estimates were determined. Capital investment estimates utilized generic scrubber equipment costs for new installations provided by scrubber suppliers. Total capital investment estimates were computed on the basis of a range of retrofit and redundancy factors. Owner total capital investment costs for the utility scrubber installations ranged from an average of \$118 to \$154 per kilowatt, with an overall average of \$135 per kilowatt (late 1977 dollars) (Table 10a). The lower figure includes a 10 percent factor for redundancy and retrofit complexity and represents the lower limit anticipated for a non-complex installation with limited redundancy. The higher value includes significantly greater factors, i.e., 40 percent each. The 10 to 40 percent installation complexity range is estimated as being the range that would encompass those items that cannot be specifically defined unless a detailed engineering study were conducted for each site. They may include relocating underground and surface facilities and installation of complex duct work from the scrubber to existing stack entry locations if a detailed design study were to indicate it was practical or to extend the ducting to new stacks. In estimating capital equipment costs for this study, costs of new stacks were included. These costs are itemized for each utility site in Section 4.5.1.1 and are summarized in Table 11.

The total capital investment for the industrial process scrubbers does not lend itself to a generalization such as dollars per kilowatt. Therefore, the average costs for each site are indicated in Table 11, and the range of retrofit costs in Table 10b.

Average annualized costs were calculated as 8.8 mills/kWh, or \$3612 per ton of SO_2 removed, for a 20-year expected life for the utility scrubber systems, including 0.062 mills/kWh for scrubber waste transport and disposal. Considering the cost benefit derived from the use of oil with 0.5 percent sulfur, which is approximately \$0.70 per barrel less than the fuel with 0.25 percent sulfur which is now in use, the operating cost would

TABLE 10a. TOTAL CAPITAL INVESTMENT FOR UTILITY INSTALLATIONS: RETROFIT AND REDUNDANCY FACTORS INCLUDED

Late 1977 dollars

Installation	Generating capacity,[a] MW	Average capacity factor, 1976	Grass roots installation, owner's capital investment, \$/kW[b] (average)	Total capital investment			
				Maximum[c] \$/kW	Minimum[c] \$/kW	Average[c] \$/kW	Average[d] \$(000,000)
Southern California Edison							
Alamitos	1,950	0.442	91.3	138.1	103.4	120.6	235.2
El Segundo	1,020	0.444	107.4	161.5	120.9	161.5[e]	164.7[e]
Etiwanda	904	0.498	109.5	164.7	123.3	143.9	130.1
Huntington Beach	870	0.434	108.6	163.3	122.3	142.7	124.2
Ormond Beach	1,600	0.454	92.7	139.4	104.4	121.8	194.9
Redondo Beach	1,310 292	0.451[f] 0.15	100.0	150.4	112.6	150.4[e]	197.0[e] 43.9
Los Angeles Department of Water and Power							
Haynes	1,633	0.667	89.4	134.4	100.7	117.5	191.9
Valley	526	0.158	117.4	176.6	132.3	154.3	81.2
Average	--	--	102.01	153.5	115.0	134.9[g]	--

[a]Total generating capacity 10,105 MW

[b]See Table 63

[c]Maximum capital investment includes +40 percent for retrofit and +40 percent for redundancy
Minimum capital costs include +10 percent for retrofit and +10 percent for redundancy
Average capital costs include +25 percent for retrofit and +25 percent for redundancy

[d]Total capital investment is \$1.363 billion

[e]Maximum retrofit and redundancy factors used because of installation complexity

[f]0.451 applies to Units 5 through 8; 0.15 applies to Units 1 through 4

[g]Weighted average

TABLE 10b. INDUSTRIAL PROCESS SO_2 SCRUBBER CAPITAL INVESTMENT

Late 1977 dollars

Installation and No. of units	Supplier capital cost estimate, \$(000, 000)	Grass roots installation, owner's total capital investment, \$(000, 000)	Total capital investment, \$(000, 000)		
			Maximum[a]	Minimum[a]	Average[a]
Carbon monoxide boiler--Chevron (1)	2.6[b, c]	9.4	14.1	10.6	12.4
Coke kilns--Great Lakes Carbon (3)	2.8[b, c] (each)	30.4	45.7	34.2	39.9
Coke kiln--Martin Marietta Carbon (1)	2.8[b, c]	10.1	15.2	11.4	13.3
Sulfuric acid units--Stauffer Chemical (3)	0.78[d] (each)	8.5	12.8	9.6	11.2
Total	--	--	--	--	82.6[e]

[a] Maximum based on +40 percent retrofit and +40 percent redundancy factors (see Table 65). Minimum based on +10 percent retrofit and +10 percent redundancy factors. Average based on +25 percent retrofit and +25 percent redundancy factors.

[b] Double alkali process

[c] Includes \$100,000 for reheat heat exchanger estimated from Ref. 10. Adjusted to late 1977 dollars.

[d] Lime scrubbing process

[e] Maximum retrofit and redundancy factors used for Great Lakes Carbon installation because of installation complexity

TABLE 11. SULFUR DIOXIDE SCRUBBER COST SUMMARY

Average costs in late 1977 dollars

Installation and No. of units	Total capital investment		Annualized cost, including disposal[a]			Approximate product selling price, $	Percent of selling price
	Millions of dollars[b,c]	$/kW	$/ton sulfur dioxide removed	mills/kWh or $/ton of product	Millions of dollars		
Electrical utility sites --	1,363	135	3,612[d]	8.8 mills[d]	339.3	--	--
SCE and DWP units (8)			3,200[e,f]	7.8 mills[e,f]	300.7[e]	45[g] 35[h]	17 22
Carbon monoxide boiler -- Chevron (1)	12.4	--	3,440	Not applicable	3.2	--	--
Coke kilns -- Great Lakes Carbon (3)	45.7	--	2,415	$19.72	11.7	110	18
Coke kiln -- Martin Marietta Carbon (1)	13.3	--	1,140	$13.93	3.5	110	13
Sulfuric acid units Stauffer Chemical (3)	11.2	--	5,544	$10.23	2.7	50	20

[a] Based on 20-year lifetime of facility

[b] Average value, see Section 4.5.1.1

[c] Maximum retrofit and redundancy factors applied (+40 percent, each) because of installation complexity (others +25 percent, each)

[d] Excluding SCE Redondo Beach Units 1 through 4 and DWP Valley Station. Both are age limited (assumed as 10 yr): annualized costs 32 mills/kWh

[e] Includes 1.0 mill/kWh credit from use of 0.5 percent sulfur oil at $0.70 per barrel less than 0.25 percent sulfur oil

[f] 7.8 mills/kWh equivalent to $5.59/bbl, or $0.91 per million Btu input

[g] Domestic service rate

[h] General service rate

be reduced to 7.8 mills/kWh or \$3200 per ton of SO_2 removed (Table 11). These costs, however, do not include costs incurred as a result of shutdown of the operating units during scrubber installation.

Comparable annual costs for 20-year life industrial process scrubbers range from \$1140 to \$5544 per ton of SO_2 removed. Other comparisons are shown in Table 11.

For industrial process scrubbers, the effect of paying for scrubber equipment at a faster rate than the 20-year lifetime was determined. If emission source capacity factors remained unchanged, amortizing the capital equipment costs in 5 years instead of 20 would increase the annualized costs by a factor of 1.59.

The effect of remaining life and capacity factor of an electrical generating facility is illustrated by assessing the effect of a 10-year life on the SCE Redondo Units 1 through 4 and the DWP Valley plant. These are old installations and operate at low capacity factors of approximately 15 percent as contrasted to approximately 42 percent for the other units in the study. The average operating cost increases from 8.8 mills/kWh to 31.6 mills/kWh, or \$13,500 per ton of SO_2 removed (see Section 4.5.2 and Appendix E).

3. RECOMMENDATIONS

Inasmuch as installation of sulfur dioxide (SO_2) scrubbers on specific units in the Los Angeles area has been shown to be feasible, certain considerations are of importance regarding the effect of SO_2 scrubbing on the industry as a whole, on other environmental control systems, and on the environment itself. Therefore, it is recommended that studies be conducted as follows:

a. Determine the feasibility of installing SO_2 scrubbers on other major stationary sources of emissions such as industrial boilers, primary metals and glass furnaces, sulfur recovery units, petroleum process heaters, and oil field recovery vapor phase reactors

b. Determine the effect of wet SO_2 scrubbers on the formation of SO_3 and on SO_3 acid mist emissions

c. With SO_2 and NO_x control devices operating simultaneously on utility and other boilers, determine their impact on the feasibility of installation, the interactions of the two systems, the reliability of operation of each control system and of the combined systems, and the total environmental control costs for systems to meet prescribed standards.

4. STUDY APPROACH

The study entailed various aspects in the evaluation of the feasibility of using scrubbers to remove SO_2 from stationary sources in the Los Angeles area. The factors considered were as follows (Table 12):

a. Definition of stationary source characteristics

b. Sulfur dioxide technology assessment

c. Identification and assessment of scrubber system operations

d. Determination of site-specific scrubber installation feasibility

e. Capital investment and annual operating costs.

Initially, the acquisition of a data base was required, defining the characteristics of each site to the extent necessary for determination of scrubber equipment requirements (Section 4.1). This was accomplished by conferences and on-site visits with personnel from the various industries, responses to questionnaires that defined operating information, and use of plot plans provided by the various organizations. Recent aerial photos were also utilized in the study. Concurrently with the site survey, an assessment was conducted of the feasibility of scrubbers to reduce the concentration by specified amounts, i.e., by 90 percent for utility installations and approximately 90 percent for industrial applications. The background for the selection of nonregenerable lime scrubbers for removal of SO_2 involved evaluation of the operating experience in Japan and the United States (Section 4.2).

Identification of lime scrubber systems operation and assessment of the impact of disposing the waste produced are discussed in Section 4.3. Scrubber sizing data, energy, heat, water, and reagent (lime) requirements for the various sites are quantified. Properties and quantities of the waste produced by the scrubber were estimated. The potential landfill disposal sites were identified, and the impact of superimposing the scrubber waste quantities on current landfill fill rates were calculated.

TABLE 12. SULFUR DIOXIDE SCRUBBER -- FEASIBILITY STUDY APPROACH

Major areas of investigation	Specific tasks
Assess scrubber technology	Determine sulfur dioxide removal efficiency Assess scrubber operability
Characterize power plants and industrial sites	Make on-site visits Analyze responses to questionnaires defining plant characteristics and layout Review plot plans and aerial photographs
Identify and assess scrubber system operation	Determine ability to reduce sulfur dioxide to required levels Identify operating characteristics Quantify operating requirements Identify waste disposal impacts
Determine site-specific feasibility and costs (capital, operation and maintenance, and annualized)	Obtain sizing, operating, and cost data from scrubber suppliers -- Chemico, FMC (industrial), Peabody (industrial), Pullman Kellogg, Research Cottrell (utility and industrial divisions), and UOP. Consider effects of retrofit complexity and equipment redundancy on scrubber installations. Include cost benefits of using 0.5 percent sulfur oil instead of current 0.25 percent oil. Relate scrubber operating costs to selling price of product.

The feasibility or potential of installing scrubbers at each site, possible equipment sites, and problems are presented in Section 4.4.

Lastly, capital investment and annualized costs based on scrubber supplier inputs, as well as costs for retrofitting an existing installation, and redundant equipment are discussed in Section 4.5. Scrubber waste disposal costs which are included in the annual operating costs are also presented in Section 4.5.

4.1 STATIONARY SOURCE OPERATING CHARACTERISTICS

A total of eight electrical utility sites and five industrial sources of SO_2 emission were designated by the Research Staff of the California Air Resources Board for study (Table 13).

The utility sites included six Southern California Edison (SCE) and two Los Angeles Department of Water and Power (DWP) power plants, with a combined generating capacity of 10,105 megawatts (Table 14). These

TABLE 13. FACILITIES STUDIED

SO_2 emission source	Agency or company and location
Electrical utility generating stations	Southern California Edison Alamitos El Segundo Etiwanda Huntington Beach Ormond Beach Redondo Beach Los Angeles Department of Water and Power Haynes Valley
Carbon monoxide boiler	Chevron, El Segundo
Petroleum coke calcining kilns	Great Lakes Carbon, Wilmington Martin Marietta Carbon, Carson
Sulfuric acid units	Stauffer Chemical, Carson Collier Carbon, Wilmington

TABLE 14. ELECTRICAL UTILITY FACILITY CHARACTERISTICS

Electric utility generating station	Generating capacity, MW	No. of units	Average capacity factor, 1976
Southern California Edison			
Alamitos	1,950	6	0.442
El Segundo	1,020	4	0.444
Etiwanda	904	4	0.498
Huntington Beach	870	4	0.434
Ormond Beach	1,600	2	0.454
Redondo Beach	1,602	8	0.15[a]/0.451
Los Angeles Department of Water and Power			
Haynes	1,633	6	0.667
Valley	526	4	0.158[b]
Total	10,105	38	0.424[c]

[a] 0.15 applies to Units 1 through 4; 0.451 applies to Units 5 through 8

[b] Units 1 and 2 were for 1975

[c] Weighted average (excluding a and b)

plants provide approximately 80 percent of the generating capacity of the fossil-fueled plants in the South Coast Air Basin. Coastal and inland plants were included. The Edison coastal plants studied were Alamitos, El Segundo, and Redondo Beach in Los Angeles County. Others were Huntington Beach and Ormond Beach coastal plants in Orange and Ventura Counties, respectively, and Etiwanda, an inland site in San Bernardino County. Both DWP plants are located in Los Angeles County. DWP Haynes is a coastal site, and DWP Valley is located inland.

The five industrial sites studied (Table 15) are located in Los Angeles County. The Chevron, USA carbon monoxide (CO) boiler installation is located in a coastal plant in El Segundo. The others, located in the Carson-Wilmington area, are Great Lakes Carbon and Martin Marietta Carbon, which operate petroleum coke calcining kilns, and Stauffer Chemical and Collier Carbon, which produce sulfuric acid.

TABLE 15. PETROLEUM AND CHEMICAL PROCESSING FACILITY CHARACTERISTICS

Installation	Unit size	No. of units
CO boiler -- Chevron	250,000-lb/hr steam	1
Petroleum coke kilns		
Great Lakes	900 tons/day, each	3
Martin Marietta	900 tons/day	1
Sulfuric acid units		
Stauffer	900 tons/day, each	2
	200 tons/day	1
Collier	450 tons/day	1
Total		9

4.1.1 Sulfur Dioxide Emissions

Current annual SO_2 emissions from the 13 sites assessed in the study have been estimated as approximately 61,700 tons per year. Approximately 82 percent are emitted by the eight utility sites in the study, burning 0.25% sulfur, and the remainder by the industrial sources. If the SO_2 were controlled in accordance with the conditions shown in Table 16, the emissions resulting from burning higher sulfur (0.5 percent oil) would be reduced to 12,090 tons per year, for an overall reduction of about 80 percent relative to current quantities. A more detailed discussion is presented in the following paragraphs.

4.1.1.1 Utilities

The SO_2 emissions from the eight utility sources which currently burn 0.25 percent sulfur fuel oil are approximately 150 parts per million (ppm) (Table 17). Based on currently available capacity factors (1976) for the individual units (Appendix A) and exclusive use of oil, a total of 50,600 tons of SO_2 are being emitted annually, the annual fuel consumption being 59.57 million barrels of oil containing 0.25 percent sulfur.

4.1.1.2 Industrial Sources

Other sources studied included boilers burning CO in flue gases from fluid catalytic cracker units, petroleum coke calcining kilns, and sulfuric acid units. A total of five sites included the CO boiler at the Chevron El Segundo refinery, three kilns operated by Great Lakes Carbon in Wilmington, and one kiln operated by Martin Marietta Carbon, Carson, California. The sulfuric acid plants included three units at the Stauffer Chemical Company Domingues plant in Carson and the single unit at the Collier Carbon plant in Wilmington. These five sites currently emit an average total of approximately 11,110 tons per year of SO_2 (Table 18), which is based on average conditions, identified in Table A-9 through A-13 in Appendix A. Although when visited, Martin Marietta Carbon was calcining

TABLE 16. SULFUR DIOXIDE EMISSION CONTROL CONDITIONS CONSIDERED IN THIS STUDY

Electrical utilities and industrial sources	Current		Objectives	
	Status	Approximate emissions, ppm	Removal by scrubber, percent	Emissions
Electrical utility boilers -- DWP and SCE units	Sulfur content in fuel oil not to exceed 0.25 percent	150	90 from combustion of oil with 0.5 percent sulfur	30 ppm (approx.)
Carbon monoxide boiler -- Chevron	SO_2 content of flue gas emissions is a function of crude being processed, in the range of 150 to 400 ppm	225 (avg)	88 for 400 ppm inlet	50 ppm maximum
Petroleum coke calcining kilns				
Great Lakes Carbon	Emissions are function of crude: currently 300 to 380 ppm (approx. 1.3% sulfur in coke)	300 (wet)	88 for normal production rates and 300 ppm	1.5 lb SO_2 per short ton of coke charged into kiln
Martin Marietta Carbon	2.3 to 2.5 percent sulfur crude	700 (wet)	93 for 2.5 percent sulfur crude	
Sulfuric acid units				
Stauffer Chemical	300 to 500 ppm	400	33 for Units 1 and 2 66 for Unit 3	4.0 lb SO_2 per short ton of product
Collier Carbon	350 ppm	400	15 (ave.)	

TABLE 17. ELECTRICAL GENERATING PLANT OPERATING CHARACTERISTICS

Installation	Generating capacity, MW	No. of boilers	Operating range, percent of maximum capacity	Average capacity factor, 1976	Barrels of oil burned yearly, (000,000)	Current sulfur dioxide emissions,[a] tons/yr (000)	Sulfur dioxide removed,[b] tons/yr (000)	Resultant emissions, ppm
Southern California Edison								
Alamitos	1,950	6	20 to 100	0.442	10.69	9.37	16.87	27
El Segundo	1,020	4	10 to 100	0.444	5.68	5.12	9.21	28
Etiwanda	904	4	10 to 100	0.498	5.80	5.17	9.30	26
Huntington Beach	870	4	20 to 100	0.434	4.70	4.05	7.29	24
Ormond Beach	1,600	2	20 to 100	0.454	8.75	7.67	13.80	31
Redondo Beach	1,602	11	20 to 100	0.15,[c] 0.451	8.31	6.89	12.40	27
Los Angeles Department of Water and Power								
Haynes	1,633	6	20 to 100	0.667	14.40	11.33	20.39	27
Valley	526	4	20 to 100	0.158[d]	1.24	1.00	1.81	24
Total	10,105	41	--	0.424[e]	59.57	50.60	91.07[f]	--

[a] While burning 0.25 percent sulfur oil at average capacity factor for 1976

[b] 90 percent sulfur dioxide removed while burning 0.50 percent sulfur oil

[c] 0.15 applies to Units 1 through 4; 0.451 applies to Units 5 through 8

[d] Units 1 and 2 based on 1975 operation

[e] Weighted average (excluding c and d)

[f] A total of 101,190 tons/year of sulfur dioxide would be generated from burning 0.5 percent sulfur coal

TABLE 18. INDUSTRIAL SOURCE OPERATING CHARACTERISTICS

Installation	Operation per year at rated output, hr	Site rating		Current sulfur dioxide emissions						Sulfur dioxide emissions allowable
				Average			Maximum			
		tons/day	tons/year (000)	ppm	lb/ton	tons/yr	ppm	lb/ton	tons/yr	
Chevron (carbon monoxide boiler)	7,555	[a]	[a]	225	--	1,210	400	--	2,150	50 ppm maximum
Great Lakes Carbon (three coke kilns)	7,920	2,700[b]	594	300	12.6[b]	5,465	380	16.0[b]	6,920	1.5 lb/ton[b]
Martin Marietta Carbon (one coke kiln)	8,040	960[b]	250	450[c]	13.2[b,c]	2,120[c]	700[d]	20.5[d]	2,395[d]	1.5 lb/ton[b]
Stauffer Chemical (three sulfuric acid units)	7,884	800[f]	260	400 400	4.8[e,f] 10.2[f,g]	475[e] 335[g]	500 500	6.0[e,f] 12.8[f,g]	590[e] 420[g]	4.0 lb/ton[f]
Collier Carbon (one sulfuric acid unit)	7,500	450[f]	141	400	4.67	330	500	5.84	410	4.0 lb/ton[f]
Total	--	--	--	--	--	11,110[h]	--	--	--	--

[a] Not available--boiler rated at 250,000 lb/hr steam

[b] Raw coke charged into kiln (green coke)

[c] 450 ppm based on green coke containing 1.6 percent sulfur

[d] 700 ppm based on green coke containing 2.5 percent sulfur from Alaskan North Slope crude

[e] For units number 1 and 2

[f] Acid produced

[g] Unit number 3

[h] Includes number at footnote d (2,395); number at footnote c (2,120) excluded

coke with a sulfur content of 1.6 percent sulfur, it was in the process of transitioning to the processing of green coke from Alaskan North Slope crude, which contains approximately 2.5 percent sulfur. The totals in Table 18 include the coke of Alaskan origin.

4.1.2 Sulfur Dioxide Removal Requirements

Meeting the conditions of the SO_2 control conditions summarized in Table 16 requires removal rates ranging from 14.3 to 93.7 percent for the 13 different sources studied Tables 17 and 19. The following paragraphs discuss the removal requirements and resultant reduction in emissions. The technology potential and actual processes capable of achieving these removal levels will then be discussed, followed by an assessment of the feasibility of installing the equipment at the various sites.

4.1.2.1 Utilities

The study addressed the feasibility of removing 90 percent of the SO_2 from the emissions of utility boilers burning 0.5 percent oil. The uncontrolled emissions that would be generated from this condition would total 101,190 tons per year. Correspondingly, 10,120 tons per year of SO_2 would be emitted with 90 percent removal for an overall SO_2 emission reduction of 80 percent relative to current conditions where oil with 0.25 percent sulfur is burned.

4.1.2.2 Industrial Sources

In meeting the allowable emissions of 30 ppm (maximum) for the CO boiler, 1.5 pounds of SO_2 per ton of coke charged (green coke), and 4.0 pounds per ton of sulfuric acid, slightly different SO_2 removal rates are required. These are shown in Table 19. For average conditions, removal efficiencies of less than 90 percent are required, except when green coke from Alaskan crude is processed. For Martin Marietta, which expected to process that material, a removal efficiency of 92.7 percent is needed. For the maximum reported emission conditions, the coke calcining kilns require

TABLE 19. INDUSTRIAL SOURCE SULFUR DIOXIDE REMOVAL REQUIREMENTS

Installation	Operation per year at rated output, hr	Site rating, tons/yr (000)	Sulfur dioxide emissions allowable	Sulfur dioxide removal requirements, percent		Sulfur dioxide removed, tons/yr (average)
				Average	Maximum	
Chevron (carbon monoxide boiler)	7,555	[a]	50 ppm maximum	78	88	944
Great Lakes Carbon (three coke kilns)	7,920	594[b]	1.5 lb/ton[b]	88.1	93.7	4,815
Martin Marietta Carbon (one coke kiln)	8,040	250[b]	1.5 lb/ton[b]	88.6	92.7[c]	3,054[e]
Stauffer Chemical (three sulfuric acid units)	7,884	260[d]	4.0 lb/ton[d]	16.7	33.3	79
			4.0 lb/ton[d]	60.8	68.8	204
Collier Carbon (one sulfuric acid unit)	7,500	141[d]	4.0 lb/ton[d]	14.3	31.5	47
Total	--	--	--	--	--	9,143[e]

[a] Not available; boiler rated at 250,000 lb/hr steam

[b] Coke charged into kiln (green coke)

[c] For green coke from Alaskan North Slope crude containing 2.5 percent sulfur

[d] Acid produced

[e] Includes removals based on footnote c condition

about 94 percent removal. Under average conditions, where currently 11,110 tons SO_2 per year are being emitted, application of the reduced emission allowables would result in removal of 9143 tons of SO_2 (Table 19). All processes, except the coke calcining, require average removal levels below 90 percent. This quantity represents on overall reduction of 82 percent of the SO_2 emissions from these five sources.

4.2 SULFUR DIOXIDE SCRUBBER TECHNOLOGY

Scrubber technology for removal of SO_2 from utility boiler flue gases and other industrial stationary sources is available in Japan and the United States. In Japan, because of its stringent ambient air requirements, 90 percent SO_2 or greater removal is generally required. Virtually all of the units burn oil. In the United States, the technology on new sources has evolved in response to the 1971 New Source Performance Standards and with coal as the fuel. Removal requirements on existing installations are based on individual state regulations. The rationale for considering the feasibility of achieving 90 percent SO_2 removal on oil-fired boiler and industrial retrofit installations is discussed in the following sections.

4.2.1 Japanese Applications

Scrubbers to control SO_2 emissions have been applied on a wide range of industries in Japan since 1972. In 1977, the total number of power and industrial plants with flue gas desulfurization (FGD) scrubbers, in various phases of implementing their installation, exceeded 500 (Table 20) (Ref. 1). The total FGD capacity exceeded 28,000 megawatts. On an overall basis, the wet lime and limestone processes which are used on utility and industrial boilers, iron-ore sintering machines, sulfuric acid units, and other nonutility applications constitute nearly one half of the total.

Scrubber installations on electrical utility boilers burning primarily oil comprise approximately one half of the scrubber capacity (Table 21). Of these power plants, about 65 percent use the wet lime and

TABLE 20. OPERATIONAL SULFUR DIOXIDE SCRUBBER INSTALLATIONS IN JAPAN -- 1977

From Ref. 1

Scrubbing process	Number of plants	Scrubber size, MW			Percent of total
		Range	Typical	Total	
Wet lime, limestone	94	28 to 230	185	13,400	47.3
Indirect lime, limestone (double alkali)	47	30 to 300	105	4,475	15.8
Regenerable	30	20 to 330	165	3,785	13.4
Sodium solution	335	3 to 90	14	6,655	23.5
Total	506	--	--	28,315	100.0

TABLE 21. NONREGENERABLE FGD SYSTEM INSTALLATIONS IN JAPAN -- ELECTRIC UTILITY BOILERS

All oil-fired boilers unless otherwise indicated

Power company	Power station	Boilers		FGD, MW	Absorbent, precipitant	Year of completion
		No. of Units	MW			
Tohoku	Sinsendai	2	600	150	Na_2SO_3, $CaCO_3$	1974
	Hachinohe	4	250	125	Lime	1974
	Niigata	4	250	125	Na_2SO_3	1976
	Niigata H.	1	600	150	Limestone	1976
	Akita	3	350	350	Na_2SO_3, $CaCO_3$	1977
Tokyo	Kashima	3	600	350	Carbon, $CaCO_3$	1972
	Yokosuka	1	265	130	Limestone	1974
Chubu	Nishinagoya	1	220	220	Na_2SO_3	1973
	Owase	1	375	375	Lime	1976
	Owase	2	375	375	Lime	1976
Hokuriku	Toyama	1	500	250	H_2SO_4, $CaCO_3$	1974
	Fukui	1	350	350	H_2SO_4, $CaCO_3$	1975
	Nanao	1	500	500		1978
Kansai	Sakai	8	250	63	Carbon	1972
	Amagasaki	2	156	35	Lime	1973
	Amagasaki			121	Lime	1975
	Amagasaki	1	156	156	Lime	1976
	Osaka	3	156	156	Limestone	1975
	Osaka	2	156	156	Limestone	1975
	Osaka	4	156	156	Limestone	1976
	Kainan	4	600	150	Lime	1974
Chugoku	Mizushima	2	156	100	Limestone	1974
	Tamashima	3	500	500	Limestone	1975
	Tamashima	2	350	350	Limestone	1976
	Shimonoseki	2	400	400	Limestone	1976
Shikoku	Anan	3	450	450	Na_2SO_3, $CaCO_3$	1975
	Sakaide	3	450	450	Na_2SO_3, $CaCO_3$	1975
Kyushu	Karita	2	375	188	Lime	1974
	Karatsu	2	375	188	Limestone	1976
	Karatsu	3	500	250	Limestone	1976
	Ainoura	1	375	250	Limestone	1976
	Ainoura	2	500	250	Limestone	1976
	Buzen	1	500	250	Na_2SO_3, $CaCO_3$	1977
	Buzen	2	500	250	Na_2SO_3, $CaCO_3$	1978
EPDC	Takasago	1	250[a]	250	Limestone	1975
	Takasago	2	250[a]	250	Limestone	1976
	Isogo	1	265[a]	265	Limestone	1976
	Iosgo	2	265[a]	265	Limestone	1976
	Takenara	1	250[a]	250	Limestone	1977
Niigata	Niigata	1	350	175	Limestone	1975
Showa	Ichihara	1	150	150	Na_2SO_3, $CaCO_3$	1973
	Ichihara	5	250	250	Limestone	1976
Toyama	Toyama	1	250	250	H_2SO_4, $CaCO_3$	1975
Mizushima	Mizushima	5	156	156	Lime	1975
Sumitomo	Niihama	3	156	156	Limestone	1975
Sakata	Sakata	1	350	350	Limestone	1976
		2	350	350	Limestone	1977
Fukui	Fukui	1	250	250	Limestone	1977

[a]Coal-fired boilers

limestone direct scrubbing processes (Ref. 2). Overall efficiencies consistently in excess of 90 percent are typical for the utility installations (Figure 4). More detailed scrubber system and operating information on specific large installations is shown in Table 22. Scrubber system operability, defined as the amount of scrubber operation expressed as a percentage of scheduled operating hours of the gas source, in most of the cases reported (Table 22) exceeds 95 percent. As may be noted, this operability status is achieved in most instances without resorting to standby (redundant) scrubber modules.

Scaling of the mist eliminator is a major problem and cause of scrubber outage in U.S. installations. Scaling occurs as a result of lime or limestone in the mist reacting with SO_2 and oxygen in the flue gas to form gypsum on the wall of the eliminator, which is generally integral with the scrubber tower. Generally, scaling is less of a problem in Japan than the United States. This may be attributable to a number of reasons (Ref. 1):

a. A low concentration of lime of limestone in the mist resulting from a high utilization (over 90 percent) of lime or limestone; CaO/SO_2 mole ratio of 1.0 to 1.05 is used to remove 90 to 98 percent of SO_2.

b. A low concentration of SO_2 in the gas passing through the eliminator, which is a result of lower inlet concentrations and of the high SO_2 removal ratio. With coal as a fuel in the United States, inlet SO_2 concentrations are higher.

e. Process conditions resulting from lower SO_2 concentrations wherein mist and wash liquor contain a considerable amount of gypsum, which works as seed crystals to prevent scaling.

d. The eliminator is usually washed with a circulated liquor, but, when an appreciable amount of scale forms, it is washed with fresh water to dissolve the scale.

e. The use of a gas cooler (prescrubber) which cools and humidifies the flue gas.

Based on the low inlet SO_2 concentration of the emission sources found in this study, it is expected that items (a) through (c) will be applicable to the oil-fired units in this study. As in Japan, intermittent fresh water wash (item d) can also be utilized in the scrubbers considered in this study.

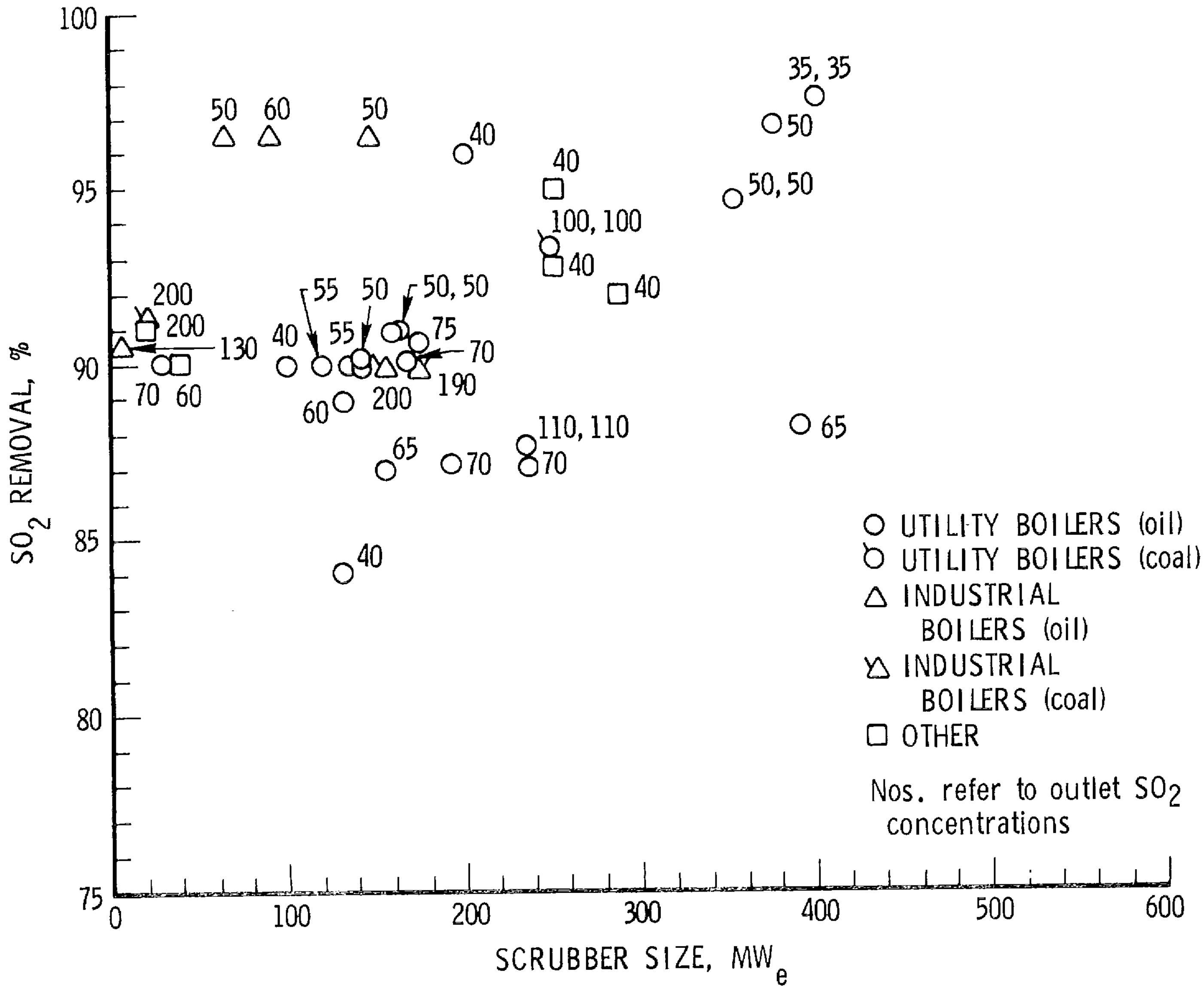

Figure 4. Overall sulfur dioxide scrubber efficiences in Japan (Ref. 2)

TABLE 22. SCRUBBER OPERATING AND OPERABILITY CHARACTERISTICS IN JAPAN -- LIME AND LIMESTONE PROCESSES

From Refs. 1 and 2

Process	Company	Plant	FGD size, MW	Fuel	Absorbent	Inlet sulfur dioxide, ppm	Sulfur dioxide removed, percent	Absorber			System operability, percent[a]	Year in service
								Type	Ph	No. of units		
Mitsubishi	Kyushu	Karita	188	Oil	Lime	600	95	Packed tower	6.4	1	100	1974
	Chubu	Owase	375	Oil	Lime	1,600	93	Packed tower	6.5 to 7.0	2[b]	98	1976
	Kyushu	Karatsu	250	Oil	Limestone	530	90	Packed tower	6.2	1	100	1976
	Kawaski Steel	Chiba	250	c	Lime	500 to 1,000	91 to 98	Packed tower	6.4 to 7.5	c	90 to 100	1975
Mitsui-Chemico	EPDC	Takasago	250	Coal	Limestone	1,500	93	Venturi	6.2	1	97	1975-76
Chemico-Mitsui	Mitsui Aluminum	Omuta	156	Coal	Lime	2,300	90	Venturi	7.5	1+1[d]	100	1972
Babcock-Hitachi	Chugoku	Tamashima	500	Oil	Limestone	1,460	96	Perforated plate	6.6	3+1[d]	98	1975
	EPDC	Takahara	250	Coal	Limestone	1,700	98	Perforated plate	6 to 6.5	1	>95	1977
IHI - Chemico	EPDC	Isogo	265	Coal	Limestone	400	93	Venturi	5 to 6	1	>99	1976
Sumitomo Fuji-Kasai	Sumitomo Metal	Kashima	630[e]	Coke	Limestone	400 to 600	93 to 95	Perforated plate	6.7	2[b]	100	1975
		Wakayama	125[e]	c	Limestone	650	97	c	6	c	98	1975
Chubu - MKK	Ishihara Chemical	Yokkaichi	83[f]	Oil	Limestone	1,500	90	Screen	6	c	c	1974
Ishikawajima - TCA	Chinchibu	Kumagaya	35[g]	c	Lime	700	93	TCA	c	c	c	1972
Kobe Steel	Kobe	Amagaski	115[e]	c	Lime	240 to 400	91 to 94	Spray tower	6 to 8	c	c	1976

[a]Operability defined as hours FGD system was operated divided by the boiler operating hours, expressed as a percentage

[b]2 denotes parallel units

[c]Not available

[d]One standby unit

[e]Sintering machine

[f]Industrial boiler

[g]Diesel engine

4.2.2 United States Applications

The total utility boiler scrubber capacity (expressed in megawatts) that has been installed in the United States, is under construction, or is in a contract-award status is greater than in Japan: 36,229 (Table 23) vs 28,315 megawatts (Table 21). However, in Japan most of the scrubbing capacity is operational on primarily oil-fired units. In the United States, 31 coal-fired units and 10,550 megawatts are operational. With a total of 89 scrubber units on coal-fired boilers that will be operational in the United States, wet lime and limestone scrubbers will comprise 74 units and 85 percent of the total megawatt capacity. Installation of scrubbers on new boilers predominate, with a total 24,176 megawatts, being approximately 90 percent of the lime and limestone units.

Demonstrated 90 percent SO_2 removal on utility boilers burning coal is limited because such high removal efficiencies have generally not been required in the past. However, recently 85 to 90 percent removal is required of five installations burning high sulfur coal (Table 24), and scrubber suppliers are contracting to deliver that performance.

The number of industrial boiler sites in the United States with operational scrubbers under construction or under control total 41, with a megawatt equivalent (MWe)* of approximately 2450 (Ref. 3). Approximately 70 percent of the scrubbing capacity is operational.

Recent lime-limestone scrubber system availability† (or operability) information for utility boilers burning coal is summarized in Table 24. For the 11 units reporting (Ref. 4), values range from 63 to 99 percent with 7 exceeding 90 percent.

Some causes of equipment outages and reduced availability include reheat burner vibration and poor mixing of gas; reheat exchanger

*The term MWe relates industrial scrubber capacity (based on flue gas flow rates) to an equivalent electrical utility installation. For the industrial SO_2 sources in the study the factor was 1950 actual cubic feet per minute per megawatt (ACFM/MW).

†See Table 25 for defintion.

TABLE 23. STATUS OF COAL-FIRED UTILITY-BOILER FGD SYSTEMS IN THE UNITED STATES -- BY TYPE, AS OF MARCH 1978

From Ref. 4

Status	No. of units	Capacity, MW	New or retrofit	No. of units	Capacity, MW	Processes -- No. of units and capacity, MW														Lime and limestone, percent of total MW
						Lime or limestone		Double alkali		Magnesium oxide		Wellman-Lord		Aqueous/sodium carbonate		Regenerable, not selected		Not selected		
Operational	31	10,550	N	15	7,788	14	7,663	0	--	0	--	0	--	1	125	0	--	0	--	98
			R	16	2,762	12	2,277	0	--	1	120	1	115	2	250	0	--	0	--	82
Under Construction	38	15,664	N	33	14,259	29	12,550	2	825	0	--	1	375	1	509	0	--	0	--	88
			R	5	1,405	2	608	1	277	0	--	2	520	0	--	0	--	0	--	43
Contract Awarded	20	10,415	N	18	9,740	17	9,340	0	--	0	--	0	--	1	400	0	--	0	--	96
			R	2	675	1	575	0	--	0	--	0	--	1	100	0	--	0	--	85
Planned	42	19,050	N	29	14,335	8	4,210	0	--	0	--	2	1,000	1	125	0	--	18	9,000	29[a]
			R	13	4,715	5	1,239	0	--	3	726	0	--	0	--	1	650	4	2,100	26[a]
Total	131	55,679	N	95	46,122	68	33,763	2	825	0	--	3	1,375	4	1,159	0	--	18	9,000	--
			R	36	9,557	20	4,669	1	277	4	846	3	635	3	350	1	650	4	2,100	--

[a]For 63 percent and 44 percent of the new and retrofit installations, respectively, the process has not been selected.

TABLE 24. SCRUBBER OPERATING AND OPERABILITY CHARACTERISTICS IN THE UNITED STATES -- LIME AND LIMESTONE PROCESSES

From Ref. 4, for December 1977 to January 1978

Utility	Generating unit	FGD size, MW	New or retrofit	Absorbent	Startup date	Percent sulfur in coal	Sulfur dioxide removed, percent	FGD supplier	Recent availability or operability, percent
Arizona Public Service	Cholla No. 1	115	R	Limestone	10/73	0.4 to 1.0	58.5[a]	RC	99[f]
Columbus and Southern Electric	Conesville No. 5	400	N	Lime	1/77	4.5 to 4.9	89.5	UOP	95
Duquesne Light	Elrama	510	R	Lime	10/75	1.0 to 2.8	83[b]	Chemico	c
	Phillips	410	R	Lime	7/73	1.0 to 2.8	83[b]	Chemico	c
Indianapolis Power and Light	Petersberg No. 3	530	N	Limestone	10/77	3.0 to 3.5	80[d]	UOP	c
Kansas City Power and Light	Hawthorn No. 3	140	R	Lime	11/72	0.5 to 3.5	70	CE	73
	Hawthorn No. 4	100	R	Lime	8/72	0.5 to 3.5	70	CE	70
	La Cygne No. 1	820	N	Limestone	2/73	5.0	76	B & W	97
Kansas Power and Light	Lawrence No. 4	125	R	Limestone	12/68	0.5	75[a]	CE	c
	Lawrence No. 5	400	N	Limestone	11/71	0.5	65[a]	CE	c
Kentucky Utilities	Green River Nos. 1,2,3	64	R	Lime	9/75	3.8	80	AAF	63
Louisville Gas and Electric	Cane Run No. 4	178	R	Lime	8/76	3.5 to 4.0	85	AAF	85
	Paddy's Run No. 6	65	R	Lime	4/73	3.5 to 4.0	80	CE	99[e]
Northern States Power Co.	Sherburne No. 1	710	N	Limestone	3/76	0.8	50[a]	CE	93
	Sherburne No. 2	710	N	Limestone	4/77	0.8	50[a]	CE	93
Pennsylvania Power	Bruce Mansfield No. 1	825	N	Lime	4/76	4.7	92[d]	Chemico	c,f
	Bruce Mansfield No. 2	825	N	Lime	7/77	4.7	92[d]	Chemico	c,f
So. Carolina Public Service	Winyah No. 2	280	N	Limestone	7/77	1.0	35[a]	B & W	g
Springfield Utilities	So. West No. 1	200	N	Limestone	4/77	3.5	92	UOP	c
TVA	Shawnee No. 10A	10	R	Lime/Limestone	4/72	2.9	h	UOP	h
	Shawnee No. 10B	10	R	Lime/Limestone	4/72	2.9	h	Chemico	h
	Widows Creek No. 8	550	R	Limestone	5/77	3.7	80	TVA	97
Texas Utilities	Martin Lake No. 1	793	N	Limestone	8/77	1.0	70.5	RC	c

[a] Low sulfur coal
[b] Design value for 2 percent sulfur coal
[c] Not available
[d] Design objective
[e] Boiler not operational; most recent data November-December 1976
[f] October-November 1977
[g] No forced outages; FGD units being acceptance tested
[h] Experimental unit; not applicable

TABLE 25. IDENTIFICATION OF INSTALLATIONS SHOWN IN FIGURE 5

Identification No. and utility	Generating unit	FGD size, MW	New or retrofit	Percent sulfur in coal	Absorbent
1. Commonwealth Edison	Will Co. No. 1	167	R	0.3	Limestone
2. Kansas City Power and Light	Hawthorn No. 4	100	R	0.5 to 3.5	Lime
3. Kansas City Power and Light	Hawthorn No. 3	140	R	0.5 to 3.5	Lime
4. Kansas City Power and Light	LaCygne No. 1	820	N	5.0	Limestone
5. Louisville Gas and Electric	Paddy's Run No. 6	65	R	3.5 to 4.0	Lime
6. Arizona Public Service	Cholla No. 1	115	R	0.4 to 1.0	Limestone
7. Kentucky Utilities	Green River Nos. 1,2,3	64	R	3.8	Lime
8. Northern States Power Co.	Sherburne No. 1	710[a]	N	0.8	Limestone
9. Penn Power	Bruce Mansfield No. 1	825	N	4.7	Lime
10. Louisville Gas and Electric	Cane Run No. 4	178	R	3.5 to 4.0	Lime

[a] FGD installation has 12 scrubber modules. Eleven are required for operation at full load.

Notes to Figure 5

Availability: Hours the FGD system is available for operation (whether operated or not) divided by the hours in the period, expressed as a percentage.

Operability: Hours the FGD system was operated divided by the boiler operating hours during the period, expressed as a percentage.

Reliability: Hours the FGD system was operated divided by the hours the FDG system was called on to operate, expressed as a percentage.

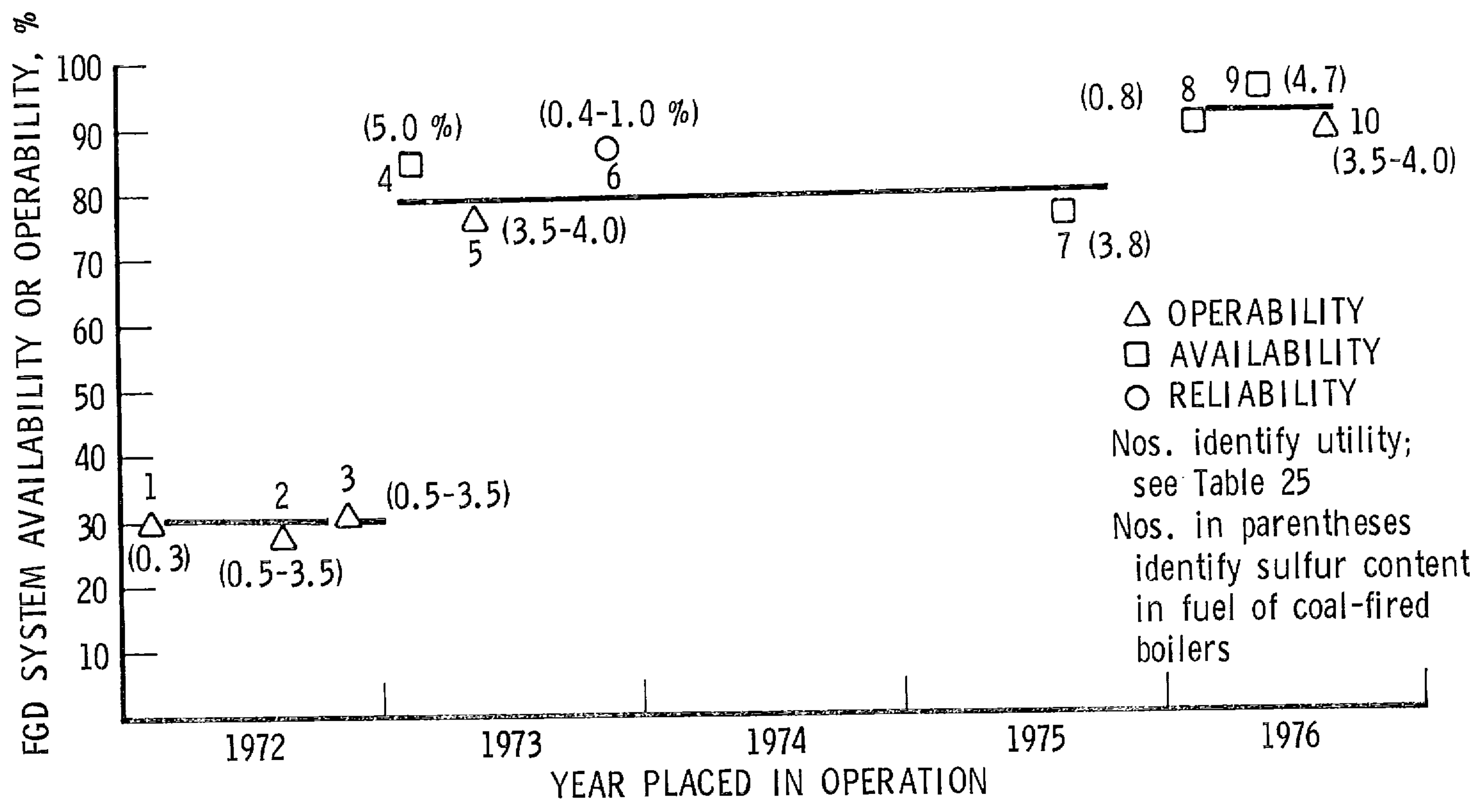

Figure 5. Average plant lime-limestone FGD system availability or operability in the United States (Ref. 5)

tube corrosion; stack liner corrosion; mist eliminator scaling; spray nozzle plugging; damper corrosion; scrubber module erosion (as a result of rubber liner debonding); fan, pump, and valve corrosion and erosion and instrumentation problems.

Many of the corrosion and erosion problems were caused by improper selection of materials. These are being solved by the use of more resistant materials at critical locations, and solutions are being factored into recent designs. Relative to coal, erosion problems in the oil-fired installations considered in this study should be virtually nonexistent because of the low ash content in the oil and the scrubber system slurries. The low SO_2 concentrations in the flue gas from the oil-fired units in this study which are generally lower than the levels in Japan, will contribute toward reduced mist eliminator scaling problems.

Some problems can be eliminated by judicious application of redundant equipment, such as pumps and valves. Other outages that contribute to poor availability can be traced to weather-related problems, such as line and valve freezing, and therefore are not applicable to Southern California.

Trends indicating discrete levels of improvements in availability (or operability) of lime and limestone scrubbers are shown in Figure 5. Recent installations have demonstrated indices in excess of 90 percent on units scrubbing flue gases with high concentrations of SO_2 and particulates.

4.2.3 INDUSTRIAL APPLICATIONS

Numerous direct lime-limestone scrubbing and indirect (double alkali) processes are operational in Japan on industrial boilers, small utility boilers, and other SO_2-emitting stationary sources Tables 26 and 27, Ref. 2. A total of 49 lime-limestone units with megawatt equivalents (MWe) in the range of 20 to 288, totalling 7512 MWe are identified, with 35 units under 180 megawatts and 15 under 100 megawatts. Sulfur dioxide removal rates in excess of 90 percent are typical. Twenty-six units in the range of 33 to 269 MWe, demonstrating SO_2 removal efficiencies of typically 90%. were reported to be using scrubber technology developed in

TABLE 26. WET LIME-LIMESTONE PROCESS SCRUBBER INSTALLATIONS IN JAPAN
From Ref. 2

User	Plant site	Capacity, MW	Source of gas	SO_2, ppm		SO_2 removal, %	Absorbent	Year of completion
				Inlet	Outlet			
Babcock-Hitachi Process[a]								
Cl ugoku Electric	Mizushima	99	Utility boiler	-b-	--	--	$CaCO_3$	1974
Asahi Chemical	Mizushima	154	Industrial boiler	--	--	--	$CaCO_3$	1975
Kansai Electric	Osaka	160	Utility boiler	--	--	--	$CaCO_3$	1975
Kansai Electric	Osaka	160	Utility boiler	--	--	--	$CaCO_3$	1975
Showa Power	Ichihara	80	Utility boiler	--	--	--	$CaCO_3$	1976
Showa Power	Ichihara	154	Utility boiler	--	--	--	$CaCO_3$	1976
Maruzumi Paper	Kawanoe	263	Industrial boiler	--	--	--	$CaCO_3$	1976
Not identified	--	160	Industrial boiler	--	--	--	$CaCO_3$	1976
Electric Power Dev.	Takehara	273	Utility boiler[c]	--	--	--	$CaCO_3$	1977
Ishikawajima Harima (IHI) - TCA Process[a]								
Chichibu Cement	Kumagaya	33	Diesel engine	700	50	93	CaO	1972
Onahama Smeltery	Onahama	38	Converter	--	--	--	CaO	1972
Furukawa Mining	Ashio	19	H_2SO_4 plant	--	--	--	CaO	1972
Chichibu Cement	Kumagaya	34	Diesel engine	--	--	--	CaO	1973
Hibi Smeltery	Hibi	96	Smelter	--	--	--	CaO	1974
Tokuyama Soda	Tokuyama	176 x 2	Industrial boiler	--	--	--	--	1975
Sumitomo Power	Niihama	144	Utility boiler	--	--	--	$CaCO_3$	1975
Mitsui Alumina	Wakamatsu	96	Boiler, kiln	--	--	--	$CaCO_3$	1975
Chemico - Mitsui and Mitsui - Chemical Processes[a]								
Mitsui Aluminum	Omuta	164	Industrial boiler[c]	2, 000	200	90	$Ca(OH)_2$	1972
Mitsui Aluminum	Omuta	176	Industrial boiler	1, 500	150	90	$CaCO_3$	1975
Electric Power Dev.	Takasago	269	Utility boiler[c]	1, 500	150	90	$CaCO_3$	1975
Electric Power Dev.	Takasago	269	Utility boiler[c]	1, 500	150	90	$CaCO_3$	1976
Ishikawajima Harima (IHI) - Chemico Process[a]								
Electric Power Dev.	Isogo	288 x 2	Utility boiler[c]	500	70	86	$CaCO_3$	1976

[a]Scrubbers developed in the United States
[b]Dashes indicate data not reported
[c]Coal-fired boilers. Other boilers are oil-fired.

TABLE 26. WET LIME-LIMESTONE PROCESS SCRUBBER INSTALLATIONS IN JAPAN (Continued)
From Ref. 2

User	Plant site	Capacity, MW	Source of gas	SO_2, ppm		SO_2 removal, %	Absorbent	Year of completion
				Inlet	Outlet			
Mitsubishi Heavy Industries (MHI) Process								
Nippon Kokan	Koyasu	20	H_2SO_4 plant	2, 200	200	91	$Ca(OH)_2$	1964
Kansai Electric	Amagasaki	32	Utility boiler	700	70	90	$Ca(OH)_2$	1972
Onahama Refining	Onahama	29	Copper smelter	20, 000	100	>99	$Ca(OH)_2$	1972
Kawasaki Steel	Chiba	38	Sintering plant	600	60	90	$Ca(OH)_2$	1973
Kansai Electric	Kainan	128	Utility boiler	550	60	89	$Ca(OH)_2$	1974
Tokyo Electric	Yokosuka	128	Utility boiler	250	40	84	$CaCO_3$	1974
Tohoku Electric	Hachinohe	122	Utility boiler	850	85	90	$Ca(OH)_2$	1974
Kyushu Electric	Karita	176	Utility boiler	800	75	90	$Ca(OH)_2$	1974
Kawasaki Steel	Mizushima	240	Sintering plant	830	40	95	$Ca(OH)_2$	1974
Kansai Electric	Amagasaki	120	Utility boiler	500	50	90	$Ca(OH)_2$	1975
Niigata Power	Niigata	170	Utility boiler	700	70	90	$Ca(OH)_2$	1975
Kawasaki Steel	Mizushima	288	Sintering plant	500	40	92	$Ca(OH)_2$	1975
Kawasaki Steel	Chiba	102	Sintering plant	800	60	92	$Ca(OH)_2$	1975
Teijin	Ehime	86	Industrial boiler	1, 700	60	96	$Ca(OH)_2$	1975
Mizushima Power	Mizushima	282	Utility boiler	1, 050	40	96	$Ca(OH)_2$	1975
Tohoku Electric	Niigata	134	Utility boiler	550	55	90	$CaCO_3$	1976
Kawasaki Steel	Mizushima	240	Sintering plant	550	40	93	$Ca(OH)_2$	1976
Toyobo	Iwakuni	64	Industrial boiler	1, 400	50	90	$Ca(OH)_2$	1976
Kashima Power	Kashima	138	Utility boiler	1, 000	100	90	$CaCO_3$	1976
Kyushu Electric	Karatsu	234	Utility boiler	550	70	87	$CaCO_3$	1976
Kyushu Electric	Karatsu	182	Utility boiler	550	70	87	$CaCO_3$	1976
Kyushu Electric	Ainoura	234	Utility boiler	880	110	88	$CaCO_3$	1976
Kyushu Electric	Ainoura	234	Utility boiler	880	110	88	$CaCO_3$	1976
Not identified	--	152	Utility boiler	500	65	87	$Ca(OH)_2$	1976
Not identified	--	170	Utility boiler	--[a]	--	--	$CaCO_3$	1976

[a] Dashes indicate data not reported

TABLE 27. INDIRECT LIME-LIMESTONE PROCESS INSTALLATIONS IN JAPAN
From Ref. 2

Process developer	Absorbent, precipitant	User	Plant site	Capacity, MW	Source of gas	Inlet SO_2, ppm	Year of completion
Showa Denko	Na_2SO_3, $CaCO_3$	Showa Denko	Chiba	160	Industrial boiler	1,400/40[a]	1973
		Kanegafuchi Chem.	Takasago	96	Industrial boiler	1,500	1974
		Showa Pet. Chem.	Kawasaki	64	Industrial boiler	1,400	1974
Showa Denko-Ebara	Na_2SO_3, $CaCO_3$	Nippon Mining	Saganoseki	38[b]	H_2SO_4 plant	--[c]	1973
		Yokahama Rubber	Hiratsuka	34	Industrial boiler	--	1974
		Nisshin Oil	Isogo	32	Industrial boiler	--	1974
		Poly Plastics	Fuji	68	Industrial boiler	--	1974
		Ajinomoto	Yokkaichi	26	Industrial boiler	--	1974
		Kyowa Pet. Chem.	Yokkaichi	48	Industrial boiler	--	1974
		Japan Food	Yokkaichi	32	Industrial boiler	--	1975
		Yokohama Rubber	Mie	32	Industrial boiler	--	1975
		Asia Oil	Yokohama	78	Industrial boiler	--	1975
Kureha-Kawasaki	Na_2SO_3, $CaCO_3$	Tohoku Electric	Shinsendai	134	Utility boiler	420	1974
		Shikoku Electric	Sakaide	403	Utility boiler	1,070/5[a]	1975
		Shikoku Electric	Anan	403	Utility boiler	1,500	1975
		Kyushu Electric	Buzen	234	Utility boiler	1,500	1977
		Tohoku Electric	Akita	336	Utility boiler	1,500	1977
Tsukishima	Na_2SO_3, CaO	Kinuura Utility	Nagoya	59	Industrial boiler	--	1974
		Daishowa Paper	Fuji	84	Industrial boiler	--	1975

[a]Outlet SO_2 concentration, ppm
[b]Megawatt equivalent
[c]Dashes indicate data not reported

the United States. With the indirect process (double alkali: sodium sulfite absorbent and lime or limestone regenerant), 19 installations including 18 boilers and one sulfuric acid unit were reported. Sizes ranged from 26 to 403 megawatts, with 13 installations of 160 megawatts or less. Limited data on SO_2 removal were provided, but in both cases identified it was in excess of 97 percent.

Experience in the United States (Refs. 6 and 7) is summarized in Table 28, with five lime-limestone units and seven double alkali installations.

4.3 SCRUBBER SYSTEM CHARACTERISTICS

The characteristics and requirements for a nonregenerable lime system suitable for operation with utility boilers are described in Section 4.3.1. A description of systems applicable for industrial use is given in Section 4.3.2.

4.3.1 UTILITY SCRUBBERS

A typical schematic of a nonregenerable lime system is shown in Figure 6. Boiler flue gases exiting from the air preheater enter a booster fan which raises the pressure to overcome the pressure drop in the system; approximately 10-inches water column for the spray tower configuration shown. The flue gases from the utility systems studied enter the tower at approximately 255° F.

A number of techniques are available to promote gas and liquid contact to enhance SO_2 absorption by the liquid. Contacting methods include the use of atomization and sprays, perforated plates, packing, baffles, and combinations of these methods. For vertical towers, flow is usually countercurrent, the flue gases flowing upward. Horizontal absorber configurations are also in use where the flue gas flows horizontally through the scrubber and the slurry is sprayed downward normal to the gas flow.

A vertical-spray tower configuration is illustrative of the type of equipment in use (Figure 6). Once the SO_2 is absorbed, reactions occur with available calcium ions in a reaction tank, shown integral with

TABLE 28. NONREGENERABLE SCRUBBER SYSTEM INSTALLATIONS ON INDUSTRIAL SOURCES IN THE U.S.: LIME-LIMESTONE AND DOUBLE ALKALI SYSTEMS From Refs. 6 and 7

Installation	Location	Source of gas	Boiler size, MW	New or retrofit	Fuel or sulfur source	Sulfur, %	SO_2 Inlet, ppm	SO_2 removed, %	Startup
Lime-Limestone Process[a]									
Armco Steel	Middletown, Ohio	Industrial boiler	2 x 24	R	Coal	0.8	N/A	N/A	1975
Badger Paper	Pestigo, Wisconsin	Recovery boiler	100 TPD pulp	R	--	--	N/A	N/A	7/73
Duval Sierrita	Sahuarita, Arizona	Ore kiln	4 TPH MoO_3	N	MoS_2	35	N/A	N/A[c]	1970
Rickenbacker Air Force Base	Columbus, Ohio	Industrial boiler	20 MW	R	Coal	3.2	N/A[b]	90	3/76
USS Agrichemical[d]	Ft. Mead, Florida	H_2SO_4 unit	1500 TPD H_2SO_4	R	--	--	1000-3000	90[e]	7/75
Double Alkali Process									
Caterpillar Tractor	E. Peoria, Illinois	Industrial boiler	4 x 25	2N, 2R	Coal	3.2	2000	90	3/78
Caterpillar Tractor	Joliet, Illinois	Industrial boiler	2 x 9	R	Coal	3.2	N/A	>90[f]	9/74
Caterpillar Tractor	Morton, Illinois	Industrial boiler	2 x 6	R	Coal	3.2	N/A	N/A	1/78
Caterpillar Tractor	Mossville, Illinois	Industrial boiler	4 x 14	1N, 3R	Coal	3.2	N/A	>90[f]	10/75
Firestone	Pottstown, Pennsylvania	Industrial boiler	3	N/A	Coal	2.5	1000	90[g]	1/75
FMC Industrial Div	Modesto, California	Ore kiln	2 kilns	N/A	Ore and coke	6-12	4000-8000	>99[h]	12/71
General Motors	Parma, Ohio	Industrial boiler	4 x 8	R	Coal	2.5	1300	90	3/74

[a] All use lime except d
[b] N/A = Not available
[c] Reliability index 96%
[d] Limestone slurry absorbent
[e] >99% operability
[f] 80-85% availability
[g] >90% availability
[h] >95% operability

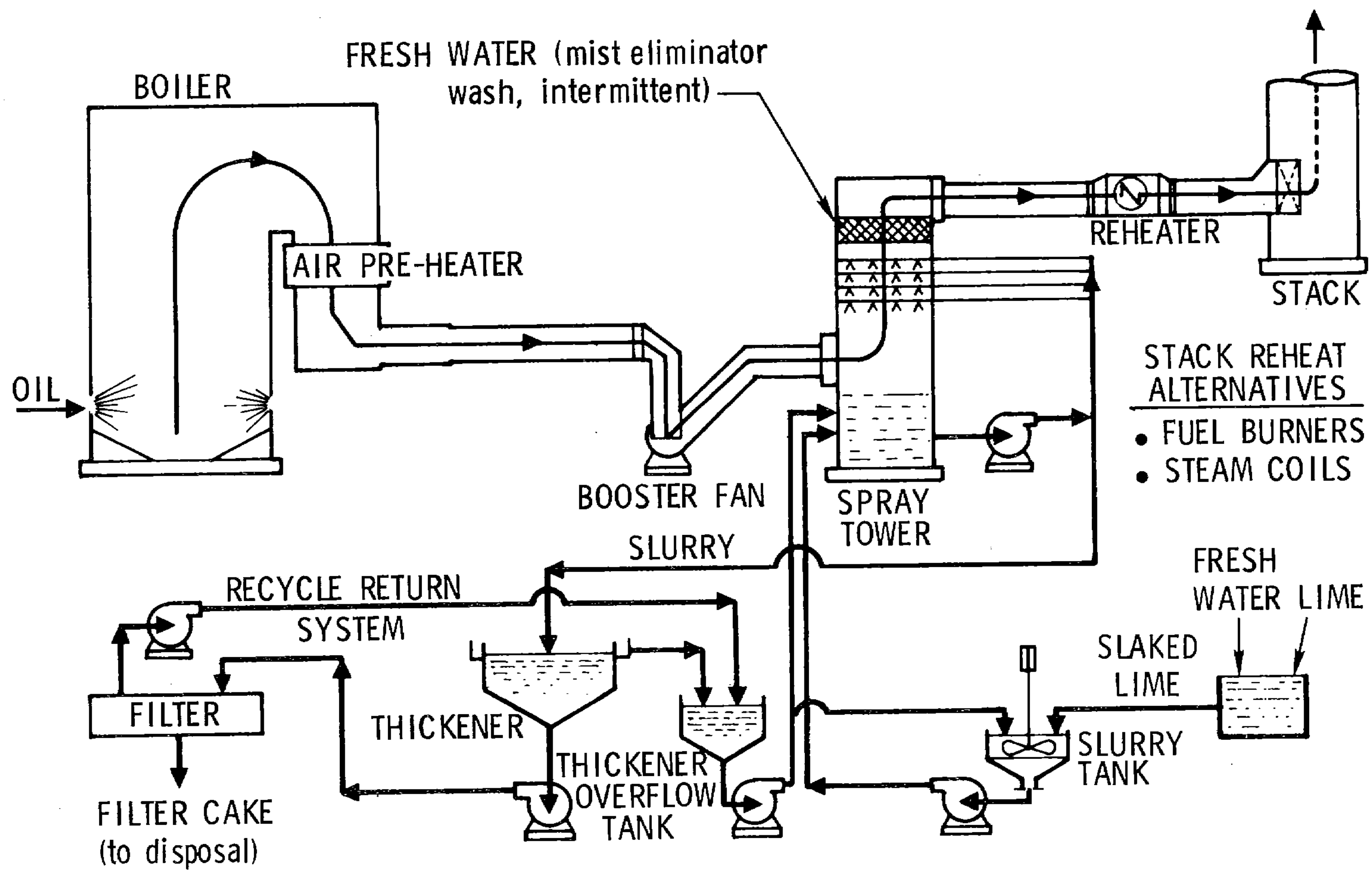

Figure 6. Lime scrubbing schematic

and at the bottom of the scrubber, to form calcium sulfite. Oxidation of the calcium sulfite to form calcium sulfate (gypsum) also occurs as a result of contact with air. The degree of oxidation tends to increase as the time of exposure to air increases, i. e., holdup times in the reaction tank and concentrations of oxygen relative to the sulfur compounds. For instance, for a given size unit (dictated by the amount of flue gas being processed), the lower the SO_2 concentration, the higher the degree of sulfite oxidation. This degree of oxidation is important because the physical and dewatering properties of the slurry and resultant solid are affected. The waste properties anticipated for the typical lime system being described are discussed later in this section.

The flue gas, after being cleaned, passes through mist eliminators prior to exiting the absorber. The mist eliminators reduce entrained water droplets, reduce corrosion potential of downstream hardware, and minimize reheat requirements. The cleaned flue gases are reheated at least 50°F above the adiabatic saturation temperature,approximately 130°F, to provide buoyancy and reduce water vapor condensation after exiting the chimney.

Reheaters may be direct-fired or may be heat exchangers utilizing steam. In both cases, thermal energy must be transferred to the flue gases. In the direct-fired configuration, oil is burned, and the combustion products are mixed with the flue gases to achieve the flue gas temperature increase. While this does not derate the generating capacity of the plant, burning of oil in this reheat system would require approximately 1.45 percent of the boiler gross heat input (Section 4. 3) for a 50°F rise and 0. 5 percent sulfur in the oil would contribute approximately an additional 4 ppm SO_2 to the emissions. On the other hand, a steam heat exchanger would tend to derate generating capacity as (based on an understanding of existing practices) it would divert steam from the turbines to the reheater.

Makeup lime slurry is pumped from the slurry tank to the reaction tank at the bottom of the absorber. Pebble lime is transferred from storage silos to service bins, which feed the lime slakers. Fresh water is introduced in the slaking process. Slaked lime (about 15 percent solids) is pumped into slurry tank, which holds approximately a one-day capacity. The reacted slurry (approximately 12 percent solids) is withdrawn continuously from the reaction tank and pumped to the dewatering equipment. The dewatering equipment may consist of a thickener to concentrate the solids to approximately 50 percent and then rotary drum vacuum filters that further increase the solids content from 70 to 75 percent. Conveying, holding, and loading facilities to permit trucking of the filter cake to disposal sites complete the system. As indicated later, considerations included a holding pond to contain 60 days' production of scrubber waste filter cake to allow for logistics purposes. Reclaimed water from the thickener and filters is returned to thickener overflow tank and reaction tank and is then blended with fresh water in the slaker circuits. Fresh water is introduced in the slaking circuit intermittently to wash the mist eliminators.

Boiler size and operating characteristics with which the scrubbers were matched are shown in Table 29. All boilers are intermediately loaded, cycling daily over a range of approximately 20 to 100 percent of capacity. The flue gas rate, which is the major factor is sizing the scrubber diameter, is in the range of 343,000 to 1,603,000 actual cubic feet per minute (ACFM) at the flue gas temperatures shown, typically 255°F. The concentration of SO_2 in the flue gas is approximately 300 ppm.

In addition to containing 0.5 percent sulfur, other significant characteristics of the oil used in the study were 0.01 percent ash and a heat content of 6.1 million Btu per barrel.

Fresh makeup water, power required to operate the pumps, fans and other scrubber system equipment, and flue gas reheat requirements were defined from information from various sources. The basis for defining the requirements is presented in Table 30 and summarized in Figure 7. Site-related quantities are shown in Table 31.

TABLE 29. UTILITY BOILER CHARACTERISTICS FROM SCE AND DWP DATA (see Appendix A)

Installation	No. of boilers	Boiler sizes, MW × No.	Year placed in service	No. of stacks	Operating characteristics[a]					
					Capacity factor, %	Range of boiler operation, % of maximum	Approx hr/yr each	Flue gas temp, °F	AFCM each, nominal × 10³	Unit heat rate, Btu/kWh
Southern California Edison										
Alamitos	6	175 × 2	1956 1957	2	36 to 41	10 to 100	7300	275	469	9,988
		320 × 2	1961 1962	2	45 to 51	10 to 100	6700	260	819	9,503
		480 × 2	1966 1966	2	45 to 46	20 to 100	6600	255	1157	8,935
El Segundo	4	175 × 2	1955 1956	2	37 to 47	10 to 100	6200	290	450	9,988
		335 × 2	1964 1965	2	41 to 52	10 to 100	6500	250	854	9,503
Etiwanda	4	132 × 2 320 × 2	1953 1963	2	46 to 51 45 to 47	10 to 100 10 to 100	7000 6800	265 260	384 861	10,337 9,619
Huntington Beach	4	215 × 3	1958 1958	2	35 to 51	10 to 100	7300	275	602	9,200
		225 × 1	1961 1961		46	20 to 100	6800	250	603	9,180
Redondo Beach	11	41 × 7 175 × 2	1949 1954 1957	4 2	15 44 to 45	N/A 10 to 100	N/A 5800	N/A 275	N/A 469	N/A 9,988
		480 × 2	1967 1967	2	41 to 50	20 to 100	6400	255	1157	9,045
Ormond Beach	2	800 × 2	1971 1973	2	43 to 47	20 to 100	6900	255	1728	9,272
Los Angeles Department of Water and Power										
Valley	4	94 × 1 101 × 1 171 × 1 160 × 1	1954 1954 1955 1956	1 1 1 1	11[b] 10[b] 19 23	N/A[c] N/A N/A N/A	2000[b] 1900[b] 4800 5300	340 340 250 250	343 343 520 520	10,900 10,900 10,000 10,000
Haynes	6	230 × 1 240 × 1 228 × 1 235 × 1 350 × 2	1962 1963 1964 1965 1966 1967	1 1 2 2 2	66 64 63 66 67 to 74	25 to 100 25 to 100 20 to 100 20 to 100 40 to 100	7050 6100 4220 7100 5000	255 255 250 250 245	564 564 587 587 784	9,100 9,100 9,100 9,100 8,650

[a]Applicable to 1976
[b]Applicable to 1975
N/A = not available

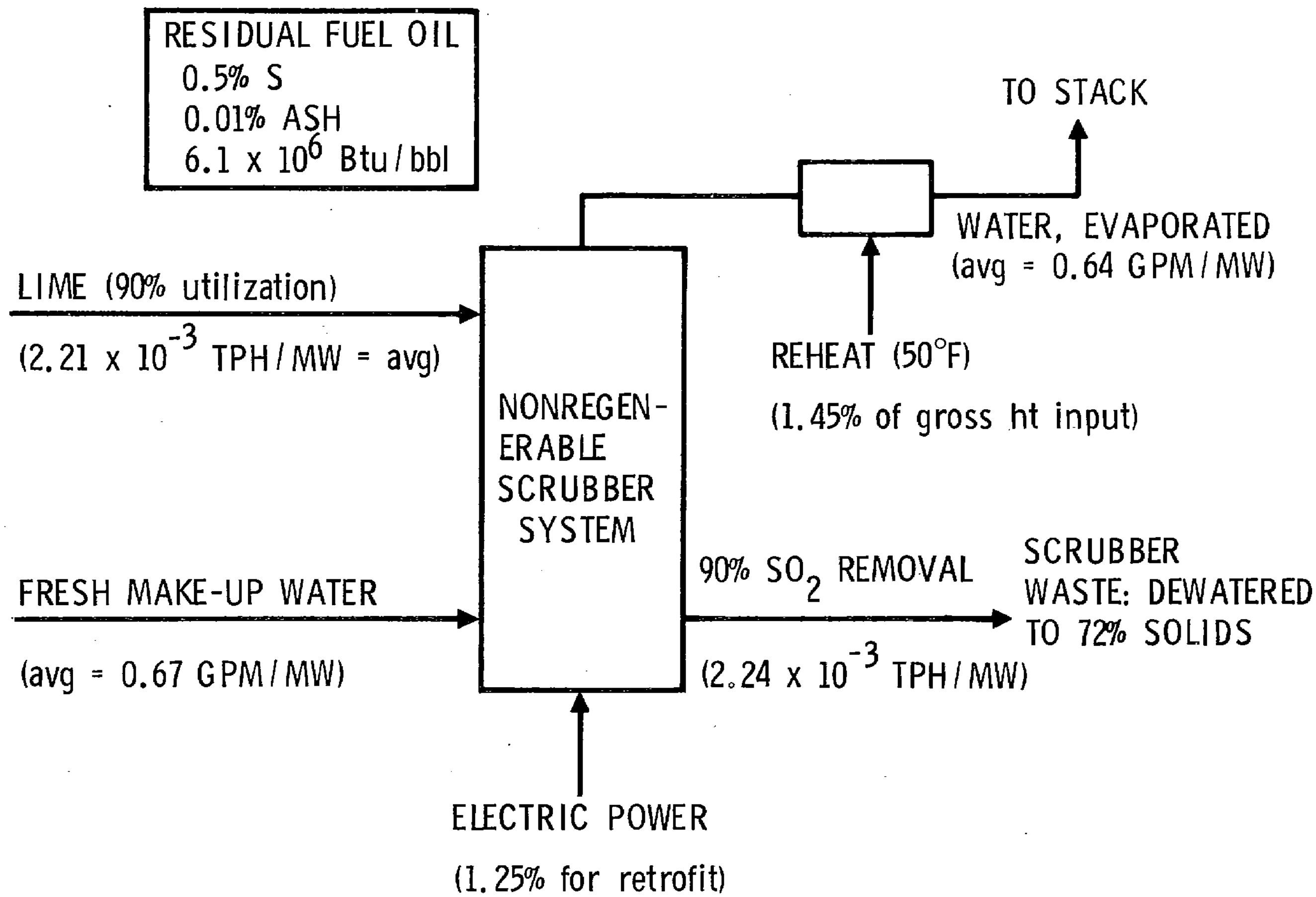

Figure 7. Generalized electric utility boiler sulfur dioxide scrubber parameters

TABLE 30. WATER AND ENERGY ESTIMATES FOR NONREGENERABLE LIME SCRUBBING

Source	Fresh water makeup, gpm/MW	Electric power, % of generated	Reheat 50°F, % of gross heat input[a]	Ref.
Japanese Processes[b]	0.65	1.00	1.45[c]	2
U.S. Processes[d]	0.64	1.26	1.40	3, 8, 9
Scrubber Suppliers:				Supplier inputs, this study
A	0.82	0.92	--	
B	0.63	0.63	1.45	
C	0.62	0.64	--	
D	0.64	1.25	1.20	
Average	0.67	0.95	1.38	
Estimate (this study)	0.67	1.25[e]	1.45	

[a] Minimum computed value: 1.0%

[b] Average

[c] Corrected from Japanese conditions to 50°F reheat

[d] Corrected to 0.5% sulfur content

[e] Added 0.30% increment to account for additional retrofit requirements

TABLE 31. SULFUR DIOXIDE SCRUBBER ENERGY AND FRESH WATER REQUIREMENTS -- ELECTRIC UTILITIES

Installation	Generating capacity, MW	Average capacity factor[a]	Electrical requirement, kW[b]	Reheat requirement, bbl/day oil[c]	Boiler oil consumption, bbl/day	Fresh water consumption,[c] gal/day		
						Current[a] (000)	Increase, scrubbing (000)	Increase, scrubbing, %
Southern California Edison								
Alamitos	1, 950	0.442	24, 375	440	30, 340	758	831	110
El Segundo	1, 020	0.444	12, 750	225	15, 560	615	437	71
Etiwanda	904	0.498	11, 300	230	15, 900	6, 764	434	6
Huntington Beach	870	0.434	10, 875	186	12, 860	615	364	59
Ormond Beach	1, 600	0.454	20, 000	348	23, 970	308	701	228
Redondo Beach	1, 602	0.451[d]	20, 025	315	21, 740	779	612	79
Los Angeles Department of Water and Power								
Haynes	1, 633	0.667	20, 142	572	39, 460	328	1, 051	320
Valley	526	0.158	6, 575	49	3, 390	1, 990	80	4
Total	10, 105	-	126, 042	2, 365	163, 220	12, 157	4, 510	-

[a] 1976
[b] Based on 1.25 % of generating capacity
[c] Based on 50°F reheat: 1.45 % of gross heat input or equivalent
[d] Units 1 through 4: 0.15

A closed-loop system requires an average of 0.67 gpm/MW fresh water makeup. This is based on estimates prepared by various scrubber suppliers and other sources (Table 30). Approximately 0.64 gpm/MW is evaporated in the scrubber and exits from the stack in the flue gases, and the remainder, about 0.03 gpm/MW, leaves as occluded water in the filter cake, which is estimated to contain 72 percent solids.

Scrubber system electric power requirements to operate pumps, fans, conveyors, and other mechanical equipment averaged 0.95 percent of the power generated (Table 30). In order to account for any additional power resulting from complex retrofit ducting and other retrofitting, an estimate of 1.25 percent of the power generated was used in computing requirements (Table 31). Similarly, flue gas reheating requires 1.45 percent of the gross heat input for a 50°F rise (Table 30). If because of climate-related or other factors, a temperature rise of 125°F were needed to bring the flue gas to its prescrubbing temperature of 255°F, reheat would represent 3.6 percent of gross heat input. The 50°F reheat equates to 2365 barrels of oil required daily. Currently, 163,200 barrels per day are consumed.

Lime utilization of 90 percent is a reasonable expectation for the nonregenerable systems. The quantities of lime that would be consumed by the various installations are summarized in Table 32. A total of 89,000 tons annually is required.

From Ref. 8 data, estimated scrubber waste characteristics were computed. Because of the low SO_2 content in the flue gas, high rates of conversion to gypsum are expected (Ref. 9): a 60 percent conversion of the calcium sulfite ($CaSO_3 \cdot 1/2\ H_2O$) to gypsum ($CaSO_4 \cdot 2\ H_2O$). The estimated composition of the waste solids is shown in Table 33. With the 90 percent lime utilization, the unreacted lime in the presence of air quickly ozidizes to calcium carbonate and would comprise about 7 percent of the waste solids. The remainder, less than one percent, is ash. Because of the high gypsum content in the slurry solids, the filter cake is expected to contain approximately 72 percent solids and have a bulk density of 83-lb/cu ft

TABLE 32. LIME REQUIREMENTS AND SCRUBBER WASTES PRODUCED -- ELECTRIC UTILITY BOILERS

Installation	Generating capacity, MW	Average capacity factor[a]	Annual lime requirement, TPY (000)[b]	Annual disposable waste produced	
				Tons (000)[d]	Ac-ft
Southern California Edison					
Alamitos	1,950	0.442	16.4	60.7	30.2
El Segundo	1,020	0.444	9.0	33.1	16.5
Etiwanda	904	0.498	9.0	33.5	16.6
Huntington Beach	870	0.434	7.1	26.2	13.0
Ormond Beach	1,600	0.454	13.8	49.7	24.7
Redondo Beach	1,602	0.451[c]	12.1	44.7	22.1
Los Angeles Department of Water and Power					
Haynes	1,633	0.667	19.8	73.4	36.5
Valley	526	0.158	1.8	6.5	3.2
Total	10,105	--	89.0	327.8	162.8

[a] For 1976

[b] 90% lime utilization

[c] Units 1 through 4: 0.15

[d] Filter cake containing 72.5% solids

TABLE 33. ESTIMATED FILTERED WASTE CHARACTERISTICS

Solids: 72.5%

Wet bulk specific gravity: 1.33

1.8 ac-ft/1000 tons SO_2 removed

Analysis, dry basis, %:

$CaSO_3 \cdot 1/2\ H_2O$	37
$CaSO_4 \cdot 2\ H_2O$	56
$CaCO_3$	7
Ash	<1
	100

(spg = 1.33). The volume occupied by the filter cake is approximately 1.8 acre-feet per 1000 tons of SO_2 removed. The quantities of waste produced annually from each of the sites is shown in Table 32. A total of 328,000 tons of filter cake are produced per year, occupying 163 acre-feet.

Sizes of the major scrubber equipment were provided by the scrubber suppliers; typical sizes and quantities for the various installations are shown in Table 34. Scrubber tower sizes are also shown. The responses by scrubber suppliers providing vertical tower configurations generally resulted in tower diameter dimensions within one foot of each other. These data are used in the siting feasibility study described in Section 4.4.1

Scrubber module sizes are generally in the range of 30 to 35 feet in diameter with a height of approximately 80 feet. Most sites required multiple modules.

TABLE 34. MAJOR SCRUBBER SYSTEM EQUIPMENT SIZES -- ELECTRIC UTILITY INSTALLATIONS

Installation	No. of boilers	Boiler sizes, MW × no.	No. of stacks	Scrubber tower[a] Total no.	Scrubber tower[a] Diam, ft	Scrubber tower[a] Height,[b] ft	Thickeners Total no.	Thickeners Diam, ft	Pump[c] pads, total no.	Waste-holding pond dimensions,[d] ft × ft × ft (depth)
Southern California Edison										
Alamitos	6	175 × 2	2	2	30	80	3	40	4	145 × 145 × 10
		320 × 2	2	4	30	80			8	
		480 × 2	2	4	35	82			8	
El Segundo	4	175 × 2	2	4	22	76	3	30	4	60 × 135 × 15
		335 × 2	2	4	28	80			8	
Etiwanda	4	132 × 2	2	2	26	78	2	35	4	110 × 110 × 10
		320 × 2	2	4	28	80			4	
Huntington Beach	4	215 × 3	2	3	34	82	2	35	6	100 × 100 × 10
		225 × 1		1	34	82			2	
Ormond Beach	2	800 × 2	2	8	32	80	3	36	16	135 × 135 × 10
Redondo Beach	11	41 × 7	4	2	30	80	3	40	4	70 × 145 × 15
		175 × 2	2	2	30	80			4	
		480 × 2	2	4	35	82			8	
Los Angeles Department of Water and Power										
Haynes	6	230 × 1	1	2	25	78	3	40	2	135 × 135 × 15
		240 × 1	1	2	25	78			2	
		228 × 1	2	1	34	82			2	
		235 × 1	2	1	34	82			2	
		350 × 2	2	4	30	80			8	
Valley	4	94 × 1	1	1	23	76	2	25	2	50 × 50 × 10
		101 × 1	1	1	23	76			2	
		171 × 1	1	1	30	80			2	
		160 × 1	1	1	30	80			2	

[a]Superficial gas velocity = 9 to 10 ft/sec; estimated tower Δp = 5-inch water column (IWC); total Δp (excluding inlet duct and including stack) = 10 IWC

[b]Includes an integral recirculation tank

[c]Each estimated at 10 × 20 ft

[d]For 60-day capacity

The pressure drop for the system downstream of the booster fan, (Figure 6) is anticipated in the range of a 6- to 10-inch water column (IWC), with an estimated one-inch pressure drop experienced at the stack inlet.

The superficial gas velocity through the tower is 9 to 10 ft/sec. The liquid to gas ratio (L/G) in the scrubber is approximately 80 (gpm/1000 ACFM). Slurry recirculation rate is in the range of 20, 000 to 30, 000 gpm depending on scrubber size. Retention time of the slurry in the reaction tank, which is integral with the tower, is approximately 5 minutes. The solids content of the slurry to the thickener is approximately 12 percent, with the flow from each scrubber module being in the range of 30 to 45 gpm, again depending on scrubber size. The solids content of the slaked lime slurry is expected to be about 15 percent. Fresh water is introduced via the lime slaking circuit and also intermittently during the mist eliminator wash cycle.

The solids content of the thickener underflow to the vacuum filters is anticipated to be in the range of 40 to 50 percent, with the solids content of the filter cake from the filter estimated as 72 percent. The filter cake is conveyed to a holding pond capable of containing 60 days production to smooth out the disposal transportation logistics and to allow for any temporary disruptions in the availability of transportation.

4.3.2 Industrial Process Scrubbers

On the basis of the review of the availability of scrubbers in the sizes required for the industrial processes, lime-limestone and double alkali processes were considered. Experience with scrubbers (absorbers) using these absorbents is discussed in Section 4.2.3; the lime process is described in Section 4.3.1. Aside from size considerations, the lime process is basically applicable to the industrial sources of SO_2.

A schematic of the other process, the double alkali process, is shown in Figure 8. Sulfur dioxide is absorbed in a solution containing sodium sulfite (Na_2SO_3), sodium bisulfite ($NaHSO_3$), and sodium sulfate (Na_2SO_4). As SO_2 is absorbed, the sodium sulfite is converted to sodium bisulfite, and a small percentage is oxidized to sodium sulfate. If high dissolved sulfite concentrations are maintained in the scrubbing liquid, the resultant dissolved calcium concentration is considerably below saturation level, thereby eliminating the formation of calcium sulfate scale.

A bleed stream is taken from the recirculating system in the SO_2 absorption loop at the same rate that SO_2 is being removed from the flue gas. The bleed stream is fed to the regeneration loop, where the sodium bisulfite is reacted with the slaked lime ($Ca[OH]_2$) in a low residence time agitated tank. The reaction of lime and sodium bisulfite regenerates sodium sulfite and forms calcium sulfite ($CaSO_3 \cdot 1/2\ H_2O$). The slurry is pumped from the lime reactor to the thickener where the solids containing calcium sulfite are concentrated. The overflow, which contains the regenerated sodium sulfite, is returned for reuse to the recirculation tank, shown integral with, and at the bottom of, the SO_2 absorber. The underflow from the thickener is pumped to vacuum filters, where a filter cake of approximately 60 to 70 percent solids is formed and washed to minimize the entrained sodium values. Sodium makeup in the form of soda ash (Na_2CO_3) is approximately 2 to 5 percent of the SO_2 collected for most applications.

The scrubbing solution is normally controlled at a pH of 6 to 7, with 6.5 as a design point. Above a pH of 7, carbon dioxide absorption

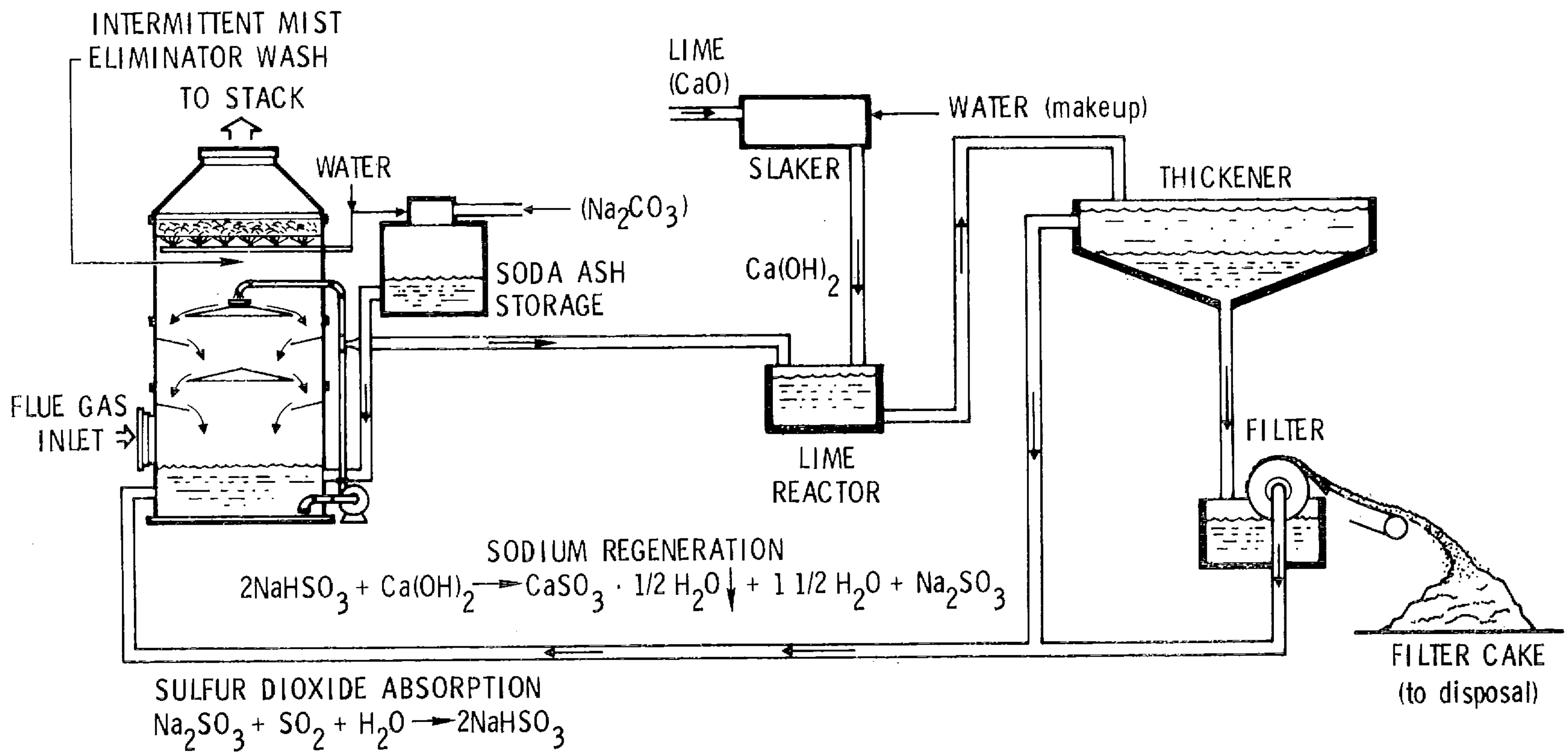

Figure 8. Double alkali SO_2 scrubbing process

becomes significant and can lead to formation of calcium carbonate scaling. Below a pH of 6, the increase in SO_2 vapor pressure reduces the system's ability to absorb SO_2. At a pH setpoint of 6.5, the sulfite-bisulfite solution is highly buffered and can readily adapt to changes in SO_2 inlet concentrations while maintaining constant collection efficiency.

Formation of sodium sulfate, which cannot be readily regenerated to recover sodium values, is inhibited through the use of a high ionic strength scrubbing solution that contains a high sulfate concentration. This limits the oxidation of sulfite to sulfate and minimizes the consumption of sodium chemicals.

The regeneration of sodium values takes place in the lime reactor where the reaction of sodium bisulfite with lime is controlled at a pH of 8.5. This is generally an optimum condition for sodium bisulfite, and operating at this pH assures responsiveness of the control system. This greatly reduces the possibility of introducing excess lime, thus providing near-stoichiometric lime utilization. In addition to poor chemical utilization, excessive lime would result in poor filter cake quality. Oxidation of the calcium sulfite to form calcium sulfate (gypsum) also occurs as a result of the sulfite slurry being in contact with air during the slurry processing. The degree of oxidation is important because the physical and dewatering properties of the slurry and resultant solid are affected. The reacted slurry is withdrawn continuously from the lime reactor and pumped to the dewatering equipment. The dewatering equipment consists of a thickener to concentrate the solids to approximately 40 percent and then to rotary drum filters that further increase the solids content from 60 to 70 percent. Conveying, holding, and loading facilities to permit trucking of the filter cake to disposal sites complete the system. A holding pond was included capable of containing approximately a 60-day production of scrubber waste filter cake to allow for logistics purposes. Water from the thickener is returned to a regenerator surge tank and then to the absorber. Fresh water is introduced continuously via the slaking circuit, in the filter cake wash, and intermittently in the mist eliminator wash stream.

Makeup lime is transferred from a lime storage bin to the slaker, and the lime slurry is then pumped to the reactor where the Na_2SO_3 is regenerated as described previously.

As in the case of the lime system described in Section 4.3.1, the flue gas, after being scrubbed, passes through mist eliminators prior to exiting the absorber. The mist eliminators reduce entrained water droplets, reduce corrosion potential of downstream hardware, and minimize reheat requirements. The cleaned flue gases may require reheating to a temperature above the adiabatic saturation temperature of the gases to provide buoyancy and reduce water vapor condensation after exiting the chimney. For purposes of this study, a 50° F increase in flue gas temperature was considered. A discussion of reheaters is provided in Section 4.3.1.

The size of the emission source and operating characteristics with which the scrubbers were matched are shown in Table 35. All units are operated continuously at or near full capacity. The flue gas rates, which were the major factor in sizing the scrubber diameter, are in the range of 14,000 to 350,000 actual cubic feet per minute (ACFM), with SO_2 concentrations ranging from 300 to 700 ppm, at flue gas temperatures in the range of 80 to 550° F.

Fresh makeup water and electrical requirements to operate the pumps, fans, and other scrubber equipment were defined on the basis of information received from the scrubber suppliers. These are presented in Table 36 for each of the four sites studied.

The makeup water requirement ranges from 0.06 gpm/MWe for the Stauffer units to 1.6 gpm/MWe for the Chevron scrubber as a result of the temperature and saturation levels of the flue gas entering the scrubber and the water leaving the system occluded in the filter cake and in the sulfate purge (Tables 35 and 37). For disposal purposes and based on scrubber supplier inputs, the occluded water was estimated as 50 percent in the double alkali process; the filter cake and purge water, Table 37, are quantified accordingly.

TABLE 35. INDUSTRIAL PLANT SO_2 EMISSION RELATED CHARACTERISTICS

Site	Emission source	Equipment rating, each unit	No. of units	No. of stacks	Operating characteristics		
					Hours operated per year	Flue gas temp. °F	ACFM, each unit (000)
Chevron, USA	Carbon monoxide boiler	250,000-lb steam per hour	1	1	8400	500-550	270
Great Lakes Carbon	Petroleum coke calcining kilns	900 tons per day[a]	3	3	7900	500	196[c]
Martin Marietta Carbon	Petroleum coke calcining kiln	960 tons per day[a]	1	1	8040	185	190 to 230
Stauffer Chemical	Sulfuric acid units	300 tons per day[b]	2	2	8400	80	14[c]
		200 tons per day[b]	1	1	8400	140	20[c]

[a]Input (green) coke

[b]Sulfuric acid produced

[c]SCFM

TABLE 36. SULFUR DIOXIDE SCRUBBER ENERGY AND FRESH WATER REQUIREMENTS -- INDUSTRIAL SYSTEMS

Site	Source	No. of units	Unit size, ea, MWe[a]	No. of hours operated annually[b]	Total annual requirements			Fresh water, gal/day
					Electrical requirement, kWh[c] (000, 000)	Heat required to reheat flue gas 50°F, Btu	Reheat, equivalent bbl oil	
Chevron, USA	Carbon monoxide boiler	1	80	8, 395	5.0	5.0×10^{10}	8, 200	1.8×10^5
Great Lakes Carbon	Petroleum coke calcining kiln	3	100	7, 920	19.5	6.2×10^{10}	10, 200	3.9×10^5
Martin Marietta Carbon	Petroleum coke calcining kilns	1	95	8, 040	6.5	2.1×10^{10}	3, 400	1.3×10^5
Stauffer Chemical	Sulfuric acid units	3	25	8, 424	1.3	3.2×10^{10}	5, 200	6.8×10^3

[a]Based on 1950 SCFM/MWe
[b]Equivalent hours at full capacity
[c]Based on scrubber supplier estimates

TABLE 37. LIME REQUIREMENTS AND SCRUBBER WASTES PRODUCED -- INDUSTRIAL SO_2 SOURCES

Site	Source	No. of units	No. of hours operated annually[a]	Annual requirement		Annual disposable waste produced		
				Lime	Soda ash	Filter cake, tons/yr[b]	Liquid purge, tons/yr	Acre-ft
Chevron, USA, El Segundo, CA	Carbon monoxide boilers	1	8, 395	1, 360	640	5, 666	2, 835	2.9
Great Lakes Carbon, Wilmington, CA	Petroleum coke calcining kilns	3	7, 920	5, 340	2, 250	22, 770	4, 750	11.8
Martin Marietta Carbon, Carson, CA	Petroleum coke calcining kiln	1	8, 040	3, 353	1, 625	14, 300	2, 090	7.4
Stauffer Chemical, Co., Carson, CA	Sulfuric acid units	3	8, 424	500[c]	None	1, 760[c]	None	1.0
Total				10, 553	4, 515	44, 496	9, 675	23.1

[a]Equivalent hours at full capacity

[b]Estimate by supplier for double alkali process at approximately 50% solids

[c]Nonregenerable lime process at approximately 72% solids

However, experience by the supplier has shown that filter cake with 60 to 70 percent solids can be attained. Using the supplier estimates (50 percent solids) for the double alkali installations, a total of 44,496 tons of scrubber waste would be produced. In addition, approximately 9,675 tons of water per year must be purged and either disposed of or treated. The disposal cost estimates (Section 4.5.3) considered the water as being disposed in a class I landfill with the waste. A total of approximately 23 acre-feet would be required for disposal.

The reheat requirement was computed, Ref. 10, and shown in Table 36, in terms of annual Btu heat input and its equivalent of 27,000 barrels of oil yearly.

Lime utilization in excess of 90 percent is a reasonable expectation for the double alkali and lime systems. The quantities of lime and soda ash that would be consumed by the various installations are summarized in Table 37. A total of 10,550 tons of lime and 4,500 tons of soda ash are required annually.

Sizes of the major scrubber equipment were provided by two scrubber suppliers, a lime-based system provided in discrete modular sizes and a double alkali system with a single scrubber sized to handle each specific flue gas flow. In one instance, namely, Great Lakes Carbon, where multiple lime scrubber units would have been required to handle the gas flow, they could not be accommodated because of severe space limitations. In that case, a double alkali system designed with a single scrubber tower was considered. Typical sizes for both types of installations are shown in Table 38. These provide the basic sizing information for the siting discussion in Section 4.4.

For three sites, lime scrubber module sizes were 15 to 16 feet in diameter, with a height of approximately 60 feet and required multiple modules. Comparable single scrubber modules were 21 to 23 feet in diameter and 67 to 72 feet high.

Because of the low SO_2 removal requirement for the Stauffer sulfuric acid units and the relatively low volumetric flow rate of stack gas, a single, small diameter lime scrubber, 6 feet in diameter and 20 feet high,

TABLE 38. MAJOR SCRUBBER SYSTEM EQUIPMENT SIZES--INDUSTRIAL INSTALLATIONS

Site	Emission Source	No. of units	Unit rating	No. of stacks	Scrubber tower dimensions						Thickeners[b]		Equipment area,[a,c] ft^2	Waste holding pond dimensions,[d] ft × ft × ft (depth)
					Lime process			Double alkali process						
					No.[a]	Diam, ft	Height, ft	No.[a]	Diam, ft	Height, ft	No.	Diam, ft		
Chevron, USA	Carbon monoxide boiler	1	250,000 lb steam/hr	1	2	16	63	1	21	67	1	14	4000	30 × 40 × 10
Great Lakes Carbon	Petroleum coke calcining kiln	3	900 tons per day	3	3[h]	15	60	1	23	72	3	16	4000	65 × 65 × 15
Martin Marietta Carbon	Petroleum coke calcining kiln	1	960 tons per day	1	3	15	60	1	23	72	1	16	3500	65 × 65 × 10
Stauffer Chemical	Sulfuric acid unit	3	300/200[e]	3	1	6	20	f	--	--	3	N/A[g]	600	30 × 30 × 10

[a]Number of items per unit
[b]Included in equipment area
[c]Excluding filter building: estimated as 25 × 25 ft
[d]For a 60-day output
[e]Units 1 and 3: 300 tons perday ea; Unit 2: 200 tons per day
[f]Not applicable
[g]Not available
[h]Can not be accomodated at this site

was possible. Instead of scrubbing 100 percent of the volumetric flow to remove 33 percent for Units 1 and 3, a side stream representing approximately 40 percent of the stack gas with 90 percent SO_2 removal was used for sizing purposes. The scrubbed gas would then be remixed to accomplish an overall 33 percent removal (Table 16). For Unit 2, approximately 70 percent of the flow requires 90 percent removal, for an overall 66 percent SO_2 reduction. A double alkali system was not considered for this application because its size was smaller than the supplier's (contacted in this study) product line.

One industrial site, the Collier Carbon sulfuric acid plant, Wilmington, California, is operating an ammonia scrubber which reduces SO_2 emissions to approximately 4.7 pounds of SO_2 per ton of product. In order to meet the 4.0-pound value, 15 percent SO_2 removal would be required. It was determined that the existing scrubber could be operated to meet the study objective of 4.0 pounds. Therefore, further study on scrubber siting at Collier Carbon was not pursued. However, some questions were raised about the possibility of increasing plume opacity above current allowables. The scrubber supplier felt there were techniques that could be employed to decrease plume opacity if it occurred. In addition, space is available in the event opacity were a problem and an additional scrubber using lime was required.

4.4 SITE SPECIFIC CONSIDERATIONS

The basic operating characteristics of each of the utility boilers are shown in Table 29 and scrubber characteristics in Table 34. The study encompassed 41 boilers, with typical sizes being 130, 175, 225, 320, and 480 megawatts. Some smaller units, 41 megawatts and 94 and 101 megawatts are installed at the Redondo and Valley plants, respectively. The Ormond Beach plant has two 800-megawatt boilers. A total of 58 scrubber towers were required for the 8 sites with diameters generally in the range of 30 to 35 feet, with some units as small as 22 to 23 feet.

According to scrubber supplier inputs, scrubber tower modules in the 30- to 35-ft-diam range were sized to handle gas volumes from 160- to 240-megawatt units. The considerations involved in siting the scrubbers and other major equipment are discussed for each generating plant in Section 4.4.1.

The characteristics of the industrial sites are summarized in Table 35 and scrubber equipment in Table 38. The megawatt equivalent (MWe) of the individual processes requiring scrubbers could be typified as being in the range of 75 to 100 megawatts except for the sulfuric acid units, which were each approximately 25 MWe.

Single scrubber towers of 21 to 23 feet in diameter, corresponding to 80 to 100 MWe for the double alkali process were used in estimating the cost of the installations except for the Stauffer plant, which used lime scrubbing for reasons previously described (Section 4.3.2). For determination of the feasibility of multiple-module siting, the nonregenerative lime-based configuration corresponding to that process was used for the Chevron and Martin Marietta sites. Single scrubbers could obviously be accommodated at those two sites, also. For the Great Lakes Carbon and Stauffer Chemical sites, single tower installations were appropriate. At Great Lakes, multiple scrubber modules did not appear to be feasible because of lack of space. At the Stauffer site, multiple units were not needed because of the relatively low volumetric flow rate of the stack gases; single lime-based scrubbers were capable of handling the system requirements.

A discussion of the installation at each of the industrial sites is provided in Section 4.4.2.

4.4.1 Electrical Utility Installations

A discussion of the nonregenerable lime processes applicable to the eight utilities studied was provided in Section 4.2, and the scrubber equipment sizes in Section 4.3.1. Engineering sketches of the scrubber equipment potential locations and siting considerations for each of the individual power plants are presented in this section. The sketches are keyed to plot plans (Figures B-1 through B-8, Appendix B).

In all cases, the scrubbers were located such that the existing stack potentially could be utilized. This was done in an attempt to minimize boiler downtime for constructing a new stack. Stack lining may be required because of the potentially corrosive conditions of the wet flue gas.

Because of the interposition of the scrubber between the air preheater and the stack, ducting from the boiler to the scrubber and from the scrubber to the stack is complex. The potential exists, however, for boiler operation to continue during scrubber construction, with ducting constructed off-site. Installation of the new ductwork requires shutdown of each boiler individually. Within the constraints indicated and the scope of the study, the scrubber was sited in locations that appeared likely to result in as little impact on boiler accessibility and operation as possible. In some cases (discussed individually for specific sites) existing equipment such as water tanks, secondary fuel areas, maintenance buildings, and roadways may require relocation. Also, the nature of the study did not permit an assessment of the impact of the scrubber installation on underground facilities. In some cases, this may be significant.

An overall assessment of the complexity and degree of difficulty in the installation of scrubber systems is summarized in Table 39. Of the eight utility sites studied, El Segundo and Redondo Beach stations appear to present the most severe scrubber system installation problems because of space limitations.

TABLE 39. ENGINEERING ASSESSMENT OF SITE-SPECIFIC INSTALLATION FEASIBILITY -- UTILITIES

Generating station	Capacity, MW	No. of boilers	No. of scrubbers	Retrofit installation complexity[a]
Southern California Edison				
Alamitos	1950	6	10	Moderate
El Segundo	1020	4	8	Difficult
Etiwanda	904	4	6	Nominal
Huntington Beach	870	4	4	Nominal
Redondo Beach	1310	4	6	Difficult
	292	7	2	Difficult
Ormond Beach	1600	2	8	Moderate
Los Angeles Department of Water and Power				
Haynes	1633	6	10	Moderate
Valley	526	4	4	Nominal

[a] Based on availability of space and complexity of installation

4.4.1.1 Alamitos

The Alamitos plant is an SCE coastal plant located adjacent to the San Gabriel River in Long Beach, in the southeast corner of Los Angeles County. The site is approximately 200 acres in area. The plant is comprised of 6 boilers and has a generating capacity of 1950 megawatts; photographs of Units 1 through 6 are shown in Figures 9 through 11. Potential locations of 30-ft-diam single module scrubbers servicing the 175-megawatt units, 1 and 2, are shown in Figure 12. Scrubbers for Units 3 and 4 are depicted in Figure 13 and for Units 5 and 6 in Figure 14. A possible location for the three 40-ft-diam thickeners, the filter building, and waste-holding pond in the northwest corner of the property is shown in Figure 15.

The impact of locating the scrubbers in the various locations shown is summarized in Table 40. Significant items include removal of fabric filter installation on Unit 3 stack, relocation of the secondary fuel area between Units 5 and 6, and rerouting of the roadway by Units 5 and 6.

The effect of locating other scrubber system equipment as shown in Figure 15 is summarized in Table 41. Location of the lime slaking and dewatering equipment in this area requires slurries to be pumped about 3500 feet to and from Units 5 and 6.

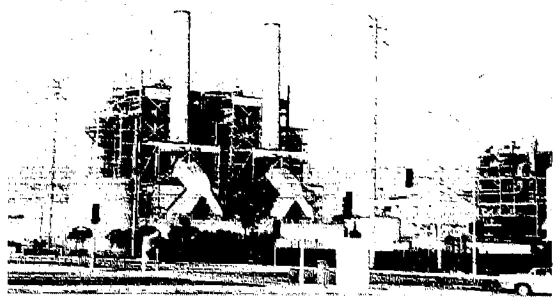

Figure 9. Alamitos, Units 1 and 2

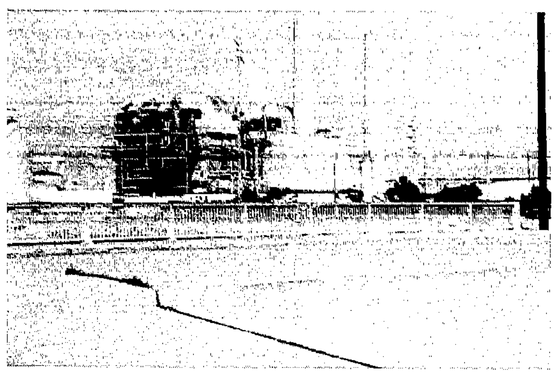

Figure 10. Alamitos, Units 3 and 4

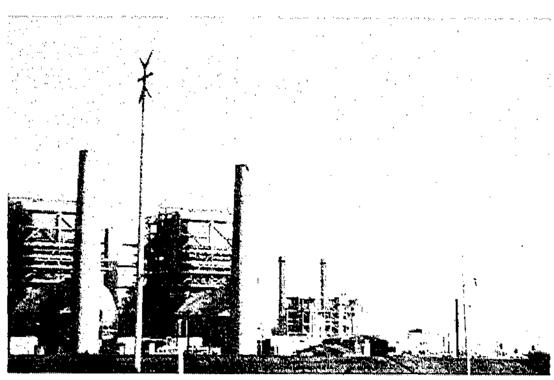

Figure 11. Alamitos, Units 4 and 6

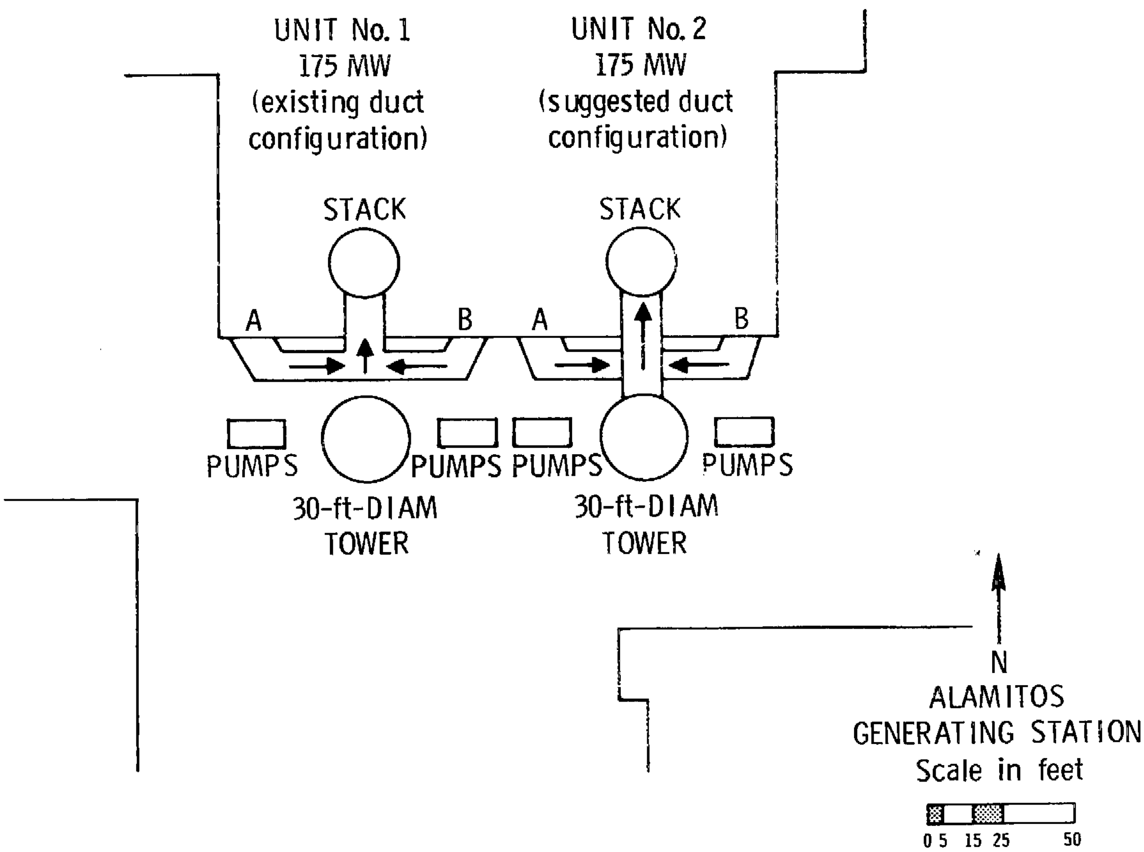

Figure 12. Scrubber siting: Alamitos, Units 1 and 2

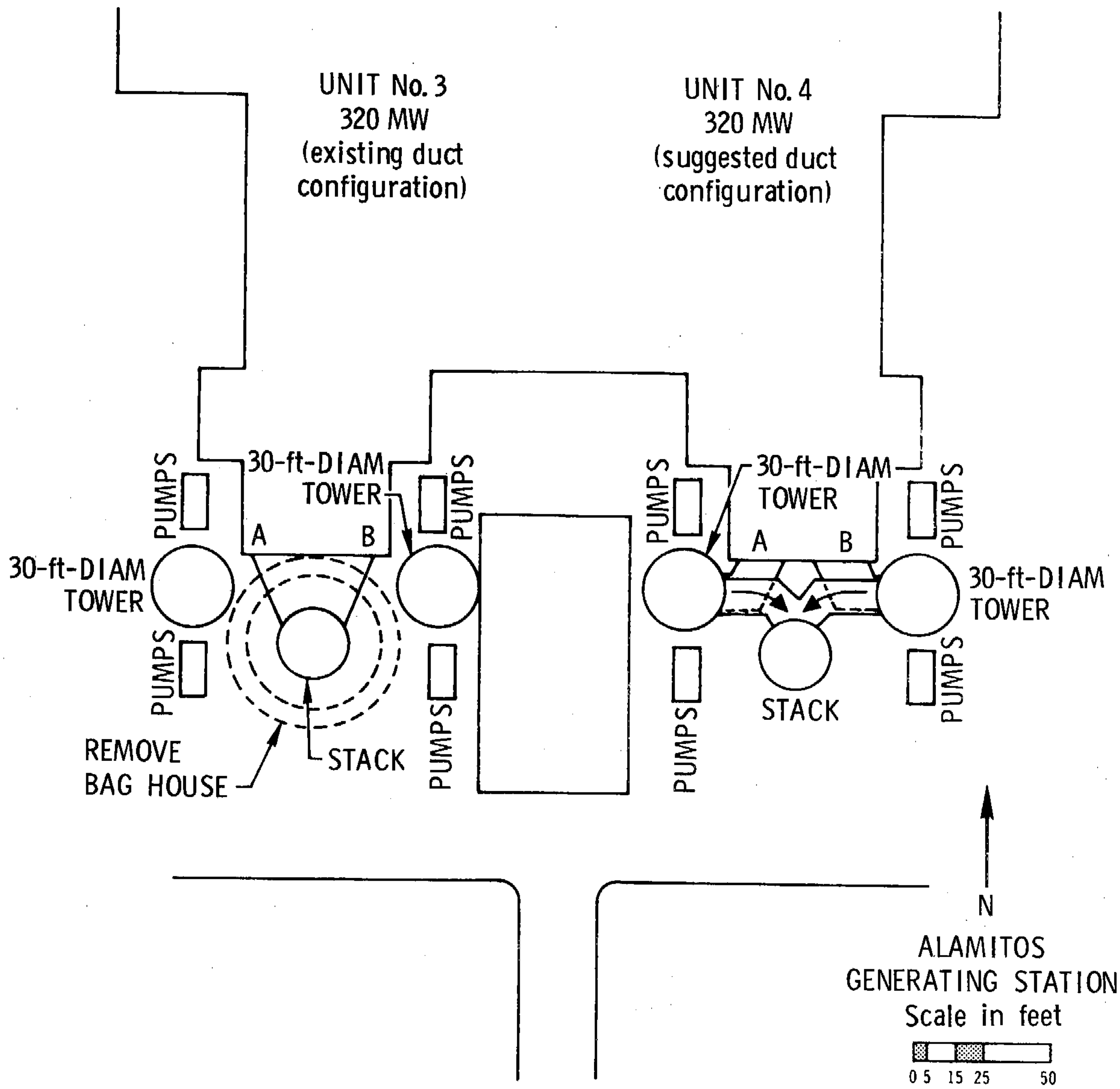

Figure 13. Scrubber siting: Alamitos, Units 3 and 4

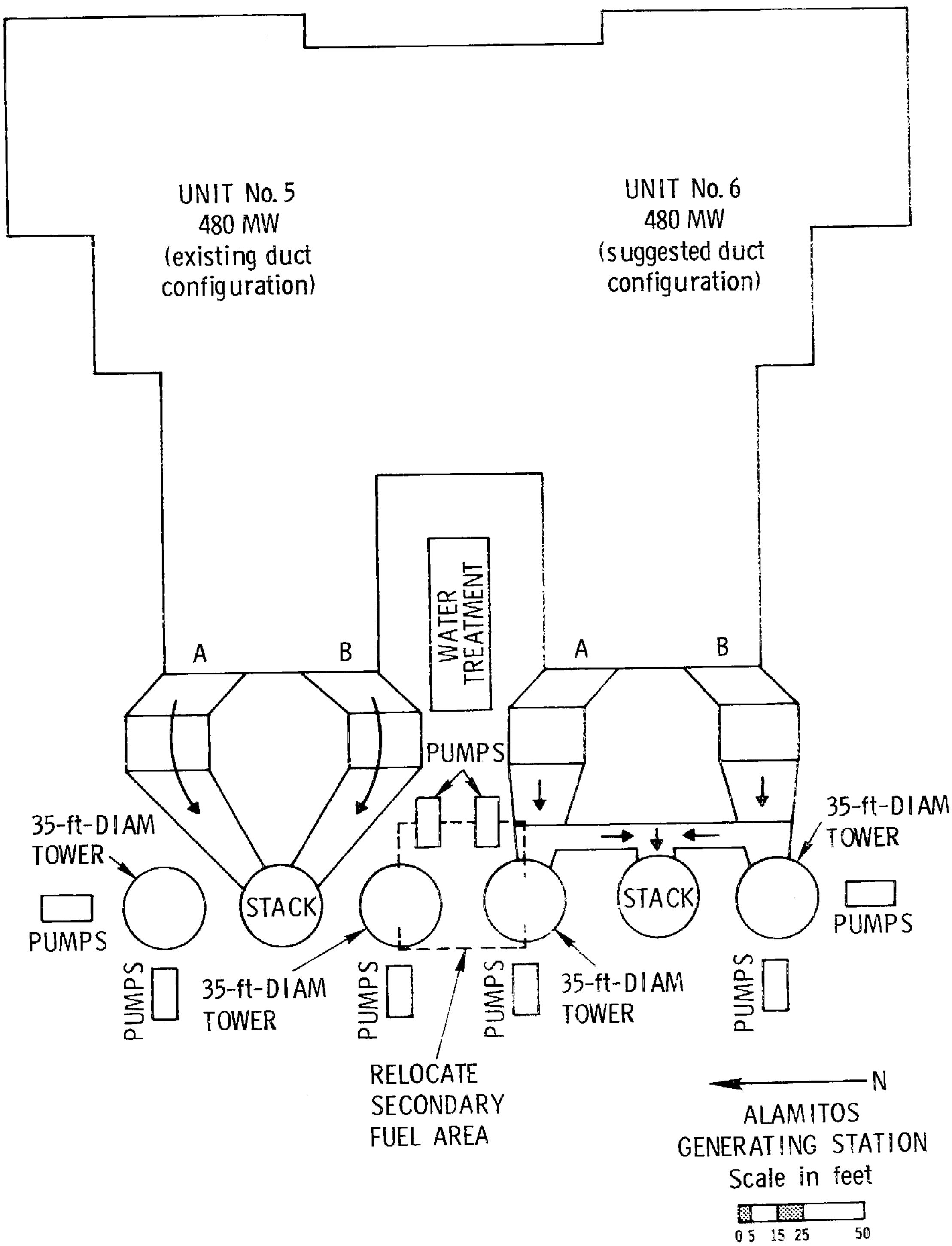

Figure 14. Scrubber siting: Alamitos, Units 5 and 6

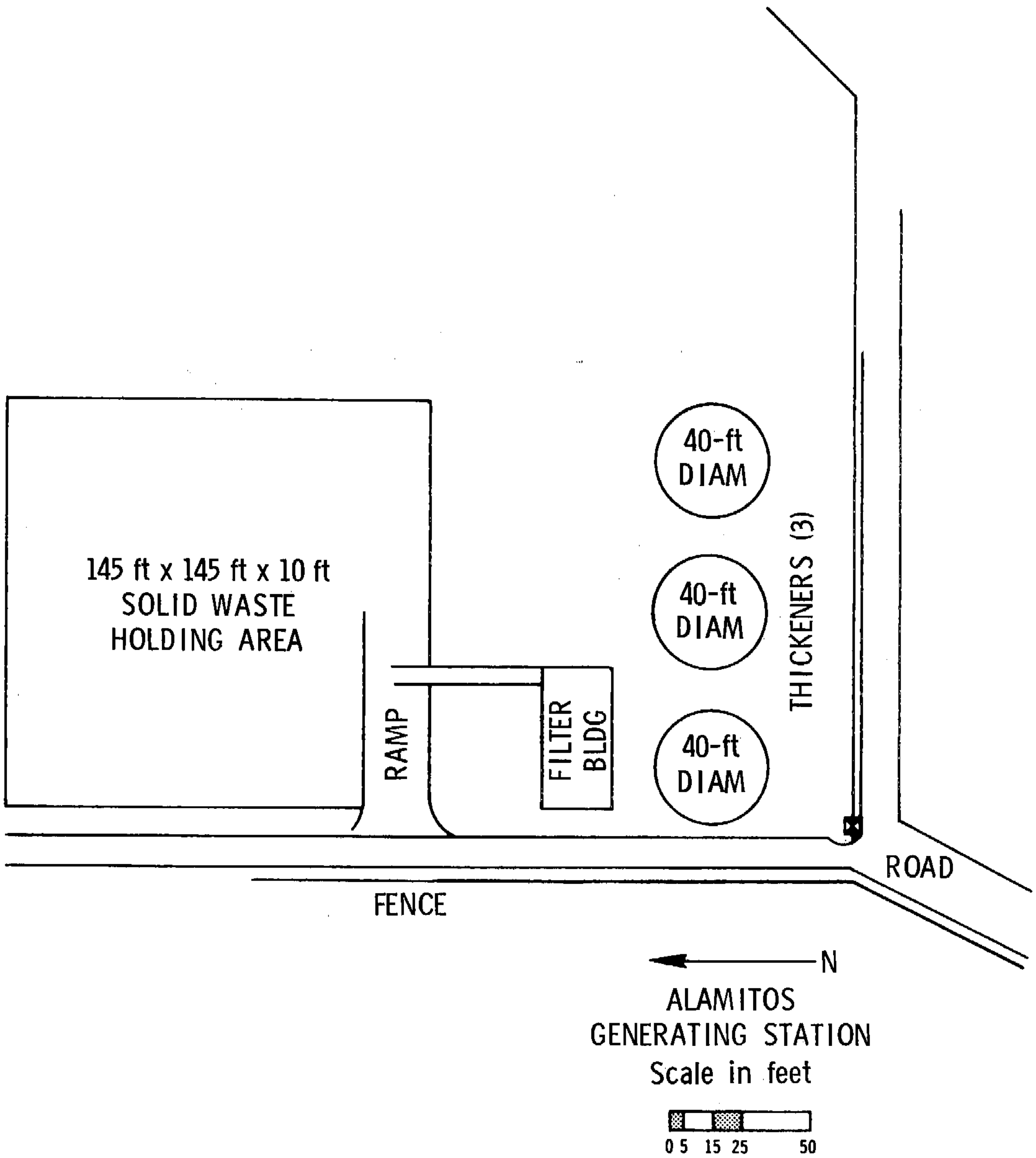

Figure 15. Other scrubber system equipment siting: Alamitos

TABLE 40. SCRUBBER SITING: ALAMITOS[a]

Generating Capacity, MW	Unit	No. of absorbers	Absorber diameter, ft	Absorber location	Impact[b]
175	1A 1B	1	30	South of stack	Installation of two 22-ft-diam absorbers instead of one 30-ft-diam may facilitiate ducting fabrication and installation
175	2A 2B	1	30	South of stack	Installation of two 22-ft diam absorbers instead of one 30-ft-diam may facilitate ducting fabrication and installation
320	3A	1	30	Open area northwest of stack	Remove baghouse now installed around No. 3 stack
	3B	1	30	Open area northeast of stack	3B absorber may encroach on water treatment facilities between Units 3 and 4; may require reconfiguring of facilities.
320	4A	1	30	Open area northwest of stack	4A absorber may encroach on water treatment facilities between Units 3 and 4; may require reconfiguration of facilities
	4B	1	30	Open area northeast of stack	None apparent
480	5A	1	35	Area north of stack	Requires rerouting of roadway
	5B	1	35	Area south of stack	Requires relocation of secondary fuel area
480	6A	1	35	Area north of stack	Requires relocation of secondary fuel area
	6B	1	35	Area south of stack	Requires rerouting of roadway

[a]Reference SCE Drawing 574936-7, Site Arrangement Plan, Rev. 7, dated 10-11-77 (Figure B-1, Appendix B)

[b]General Notes:

1. New ductwork to enable use of existing stack entry locations while keeping boilers in operation during major portion of scrubber installation will be complex.
2. Impact on existing underground facilities, lines, etc. (if any) is unknown.
3. New stacks or stack lining may be required because of potentially corrosive conditions in the stack.
4. Installation of scrubber towers may tend to reduce accessibility to existing equipment.

TABLE 41. OTHER MAJOR SCRUBBER EQUIPMENT SITING: ALAMITOS

Equipment	Size	Potential location	Impact
Thickeners	40-ft diam, 3 units	North of switch-yard and east of road paralleling west boundary of property	Slurry lines to Units 5 and 6 are approximately 3500 ft
Filter building	25 × 50 ft	North of switch-yard and east of road paralleling west boundary of property	None apparent
Solid waste holding pond and truck loading area	145 × 145 × 10 ft (approx. 60-day capacity)	North of switch-yard and east of road paralleling west boundary of property	None apparent
Lime storage and slaking area		Due north of Units 3 and 4 and south of fence	

4.4.1.2 El Segundo

The El Segundo plant has a total of four boilers, with a generating capacity of 1020 megawatts. The SCE site, approximately 40 acres in area, is located on the coast in the city of El Segundo. Units 1 and 2 and Units 3 and 4 are shown photographically in Figures 16 and 17, respectively. Possible locations of two 22-ft-diam modules for Units 1 and 2 are shown in Figure 18; Figure 19 depicts locations for Units 3 and 4. Potential locations of three 30-ft-diam thickeners, the lime slaking area, filter building, and a 135 × 60 × 15 ft solid waste holding pond are also shown in Figure 18.

Locating the thickeners and waste processing and holding areas as shown requires removal of an existing wall and utilization of the area to the property line, indicated by the chain link fence (Figure 16). Existing parking areas will also be utilized, and a propane storage area must be relocated (Table 42). An unused precipitator on Unit 2 must also be removed before a scrubber can be installed. Accessibility to existing facilities will be reduced. In general, the installation of scrubbers at this site presents considerable difficulty because of space limitations, especially around Units 1 and 2 (Table 43).

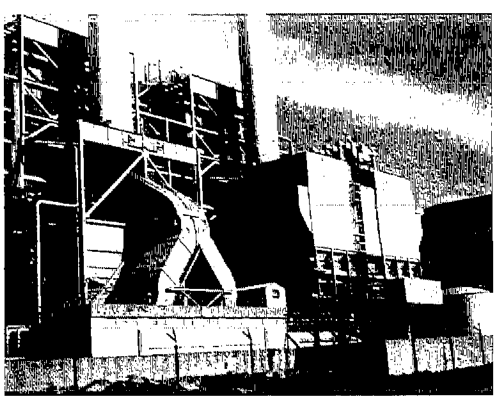

Figure 16. El Segundo, Units 1 and 2

Figure 17. El Segundo, Units 3 and 4

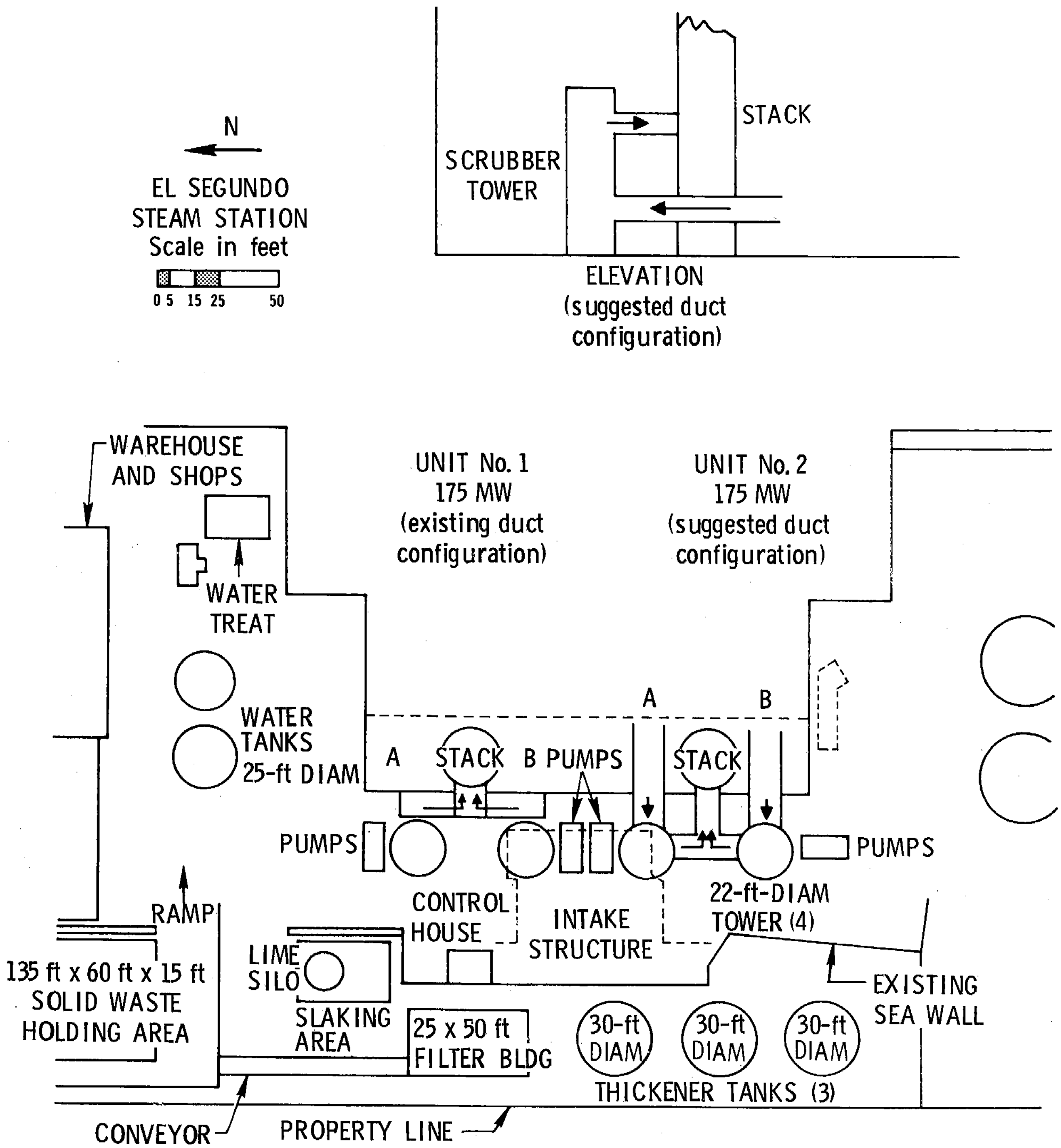

Figure 18. Scrubber siting: El Segundo, Units 1 and 2

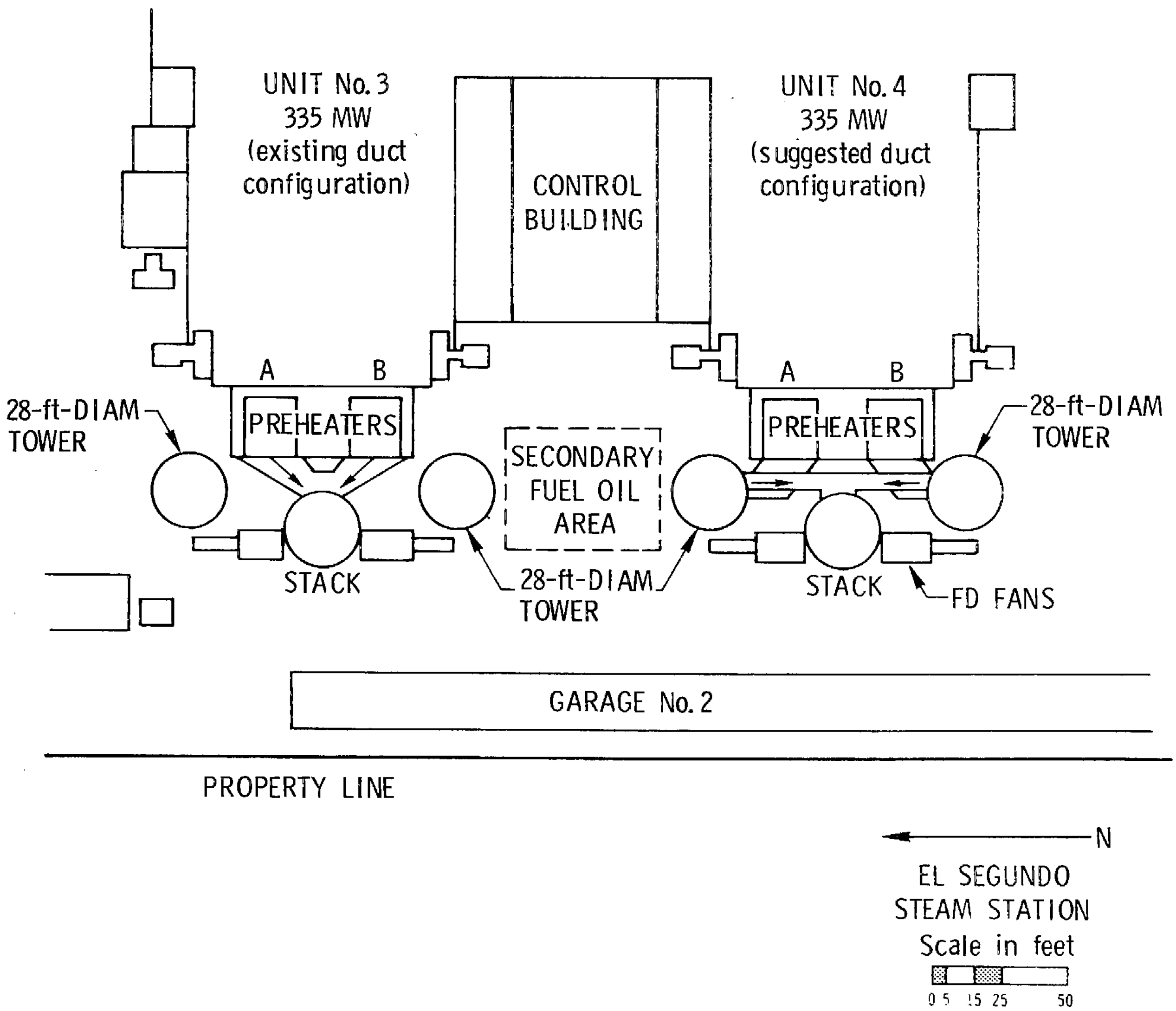

Figure 19. Scrubber siting: El Segundo, Units 3 and 4

TABLE 42. OTHER MAJOR SCRUBBER EQUIPMENT SITING: EL SEGUNDO

Equipment	Size	Potential location	Impact
Thickeners	30 ft diam, 3 units	In undeveloped area west of Unit No. 2 between wall and fence	None apparent
		or	
		In parking area south of Unit 4	Eliminates parking area
Filter building	25 × 50 ft	In undeveloped area west of Unit No. 1 between wall and fence	None apparent
		or	
		In parking area south of Unit 4	Eliminates parking area
Solid waste holding pond and truck loading area	60 × 135 × 15 ft (approx. 60-day capacity)	In undeveloped area west of warehouse and shops	
		or	
		In parking area south of Unit 4	Eliminates parking area
Lime storage and slaking area		In parking area south of Unit 4	Reduces number of parking spaces
		or	
		In undeveloped area between wall and fence	

TABLE 43. SCRUBBER SITING: EL SEGUNDO[a]

Size, MW	Unit No.	No. of absorbers	Absorber diameter, ft	Absorber location	Impact[b]
175	1A	1	22	West of Unit 1A	Reduces accessibility between scrubbers and existing west wall; can be alleviated by removing wall.
	1B	1	22	West of Unit 1B	Reduces accessibility between scrubbers and existing west wall; can be alleviated by removing wall.
175	2A	1	22	West of Unit 2A	Remove unused precipitator from Unit 2 Accessibility comment, same as 1A for 2A and 2B.
	2B	1	22	West of Unit 2B	
335	3A	1	28	North (outboard) of 3A, between preheater and stack area	None apparent
	3B	1	28	South (outboard) of 3B, between preheater and stack area	Accessibility around secondary fuel area may be curtailed
335	4A	1	28	North (outboard) of 4A, between preheater and stack area	Comments same for 3B
	4B	1	28	South (outboard) of 4B, between preheater and stack area	None apparent

[a]Reference: SCE Drawing 72555-5, Plot Plan, Rev. 5, dated 10-11-77 (Figure B-2, Appendix B)

[b]General Notes:
1. New ductwork to enable use of existing stack entry locations while keeping boiler in operation during major portion of scrubber installation will be complex.
2. Impact on existing underground facilities, lines, etc. (if any) is unknown.
3. New stacks or stack lining may be required due to potentially corrosive conditions in stack.
4. Installation of scrubber towers may tend to reduce accessibility to existing equipment.

4.4.1.3 Etiwanda

The SCE Etiwanda plant is located inland on a 205-acre site in San Bernardino County. It has a generating capacity of 904 megawatts and four boilers. Single scrubber modules, required for Units 1 and 2, are 26 feet in diameter (Figure 20). Units 3 and 4 scrubber modules are 28 feet in diameter, and each boiler requires two scrubbers (Figure 21). An existing shop building tends to restrict space in the vicinity of Unit 2; a drainage ditch is close to Unit 4 (Figure 21). Scrubber siting considerations are summarized in Table 44. Space for locating other major scrubber equipment thickeners, filter building, waste holding and lime slaking areas, does not appear to be a problem (Figure 22 and Table 45). Overall, scrubber installation at this site was not considered to be space-limited.

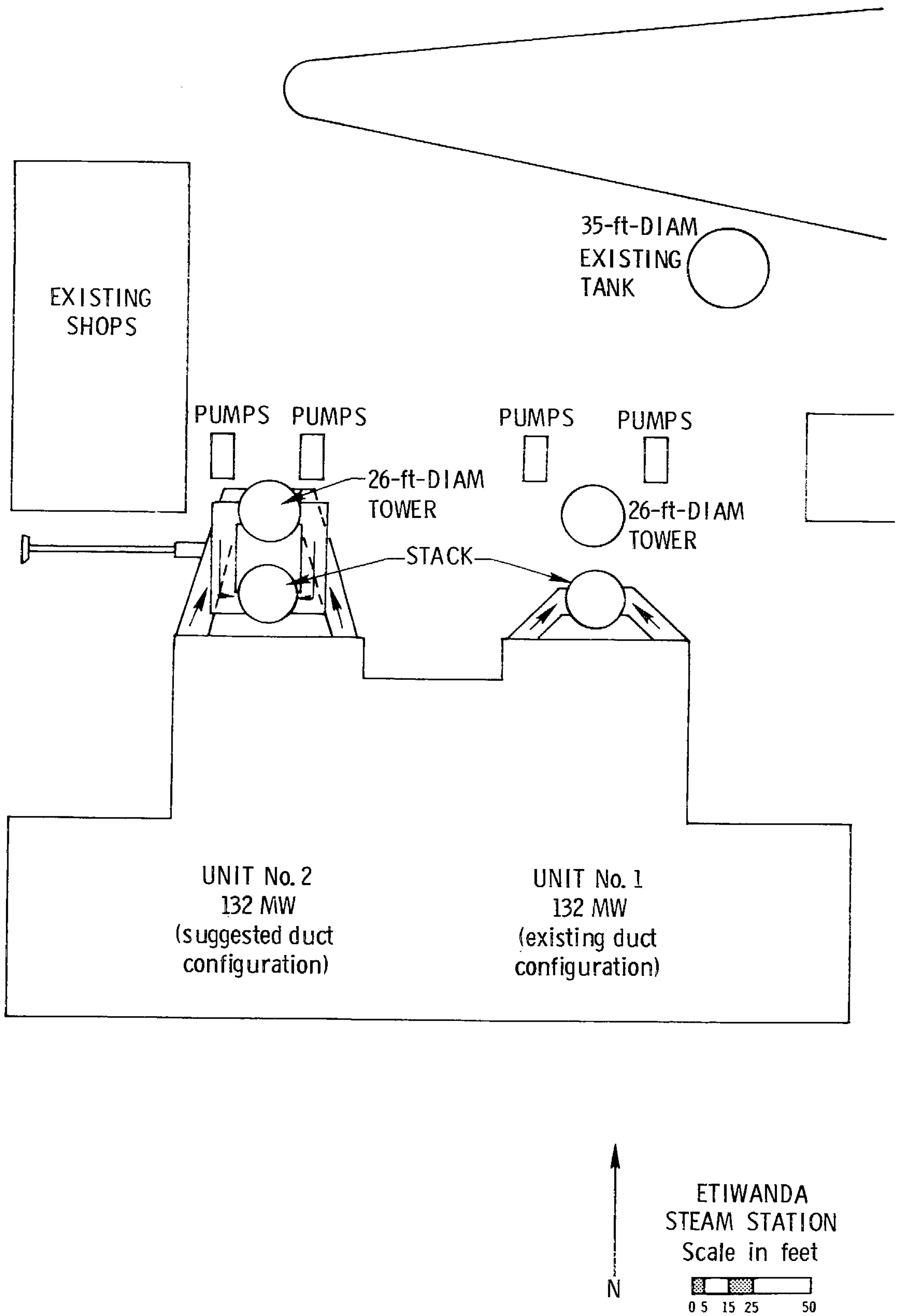

Figure 20. Scrubber siting: Etiwanda, Units 1 and 2

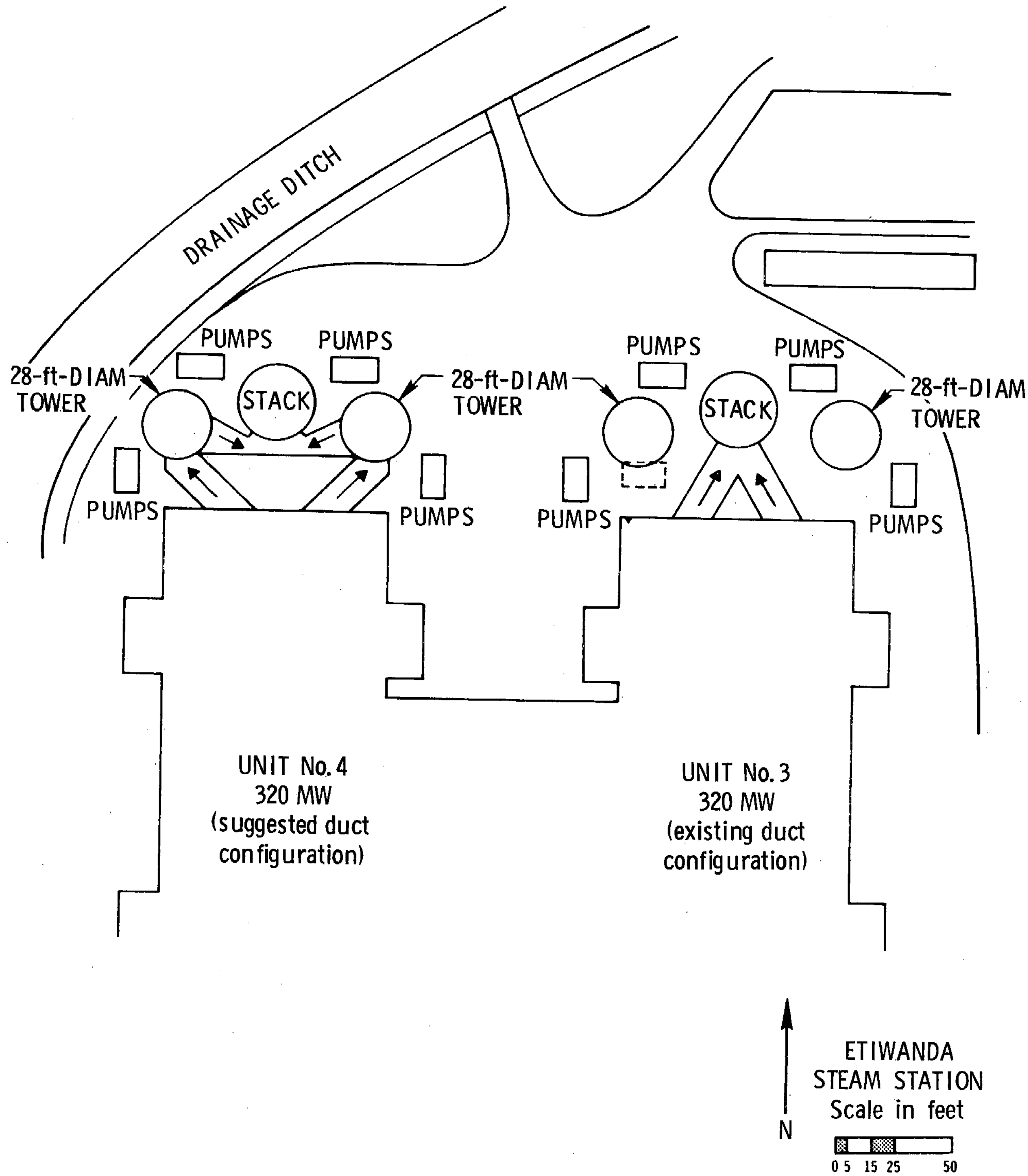

Figure 21. Scrubber siting: Etiwanda, Units 3 and 4

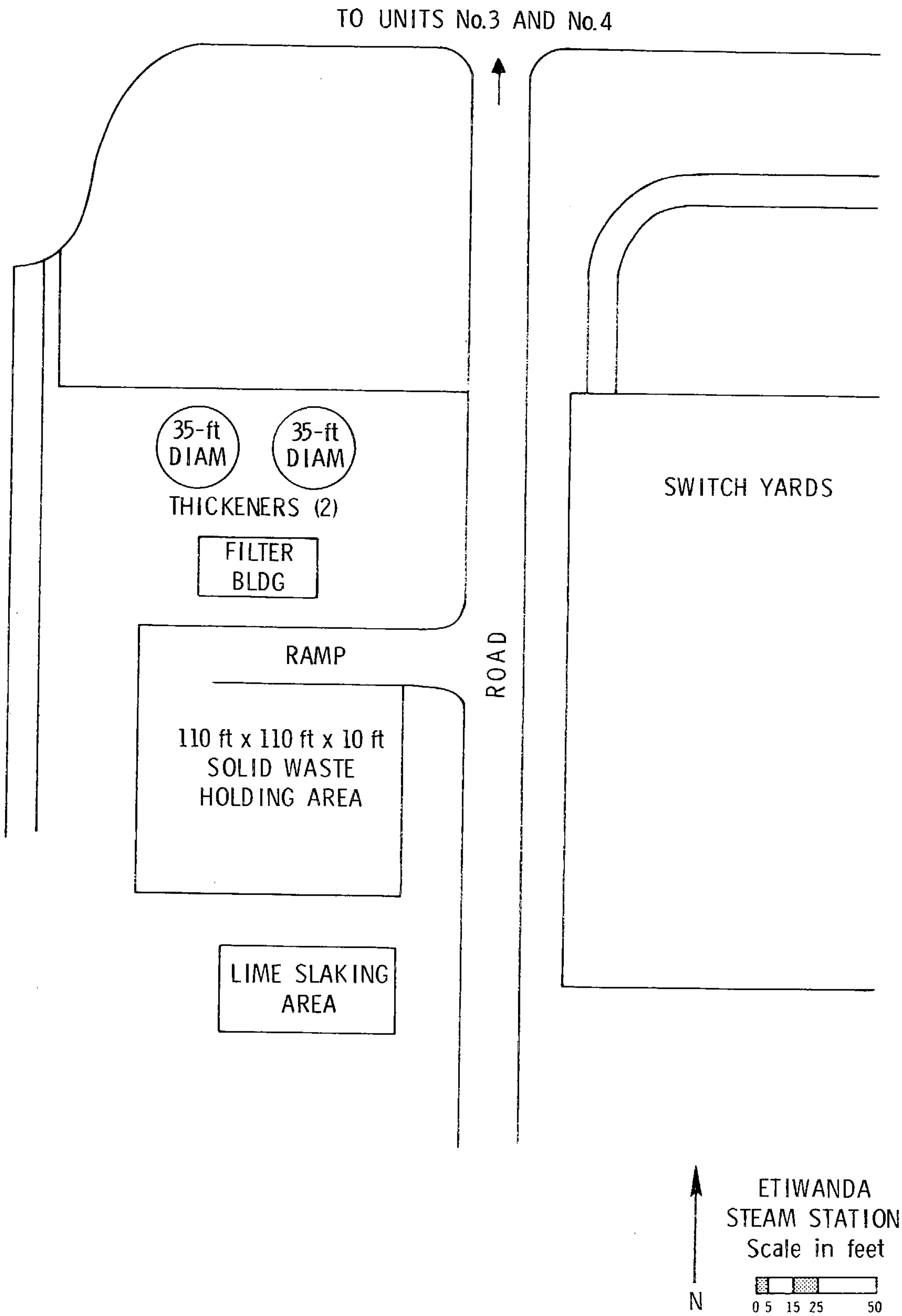

Figure 22. Other scrubber system equipment siting: Etiwanda

TABLE 44. SCRUBBER SITING: ETIWANDA[a]

Size, MW	Unit	No. of absorbers	Absorber diameter, ft	Absorber location	Impact[b]
132	1	1	26	Absorber centerline, approx. 35 ft north of unit's stack	None apparent
132	2	1	26	Same as for Unit 1	Limited access around southeast corner of existing shop building
320	3	2	28	One each, east and west of existing stack; Scrubber centerline, approx. 10 ft south of stack centerline	None apparent
320	4	2	28	Same for Unit 3	Accessibility around west scrubber and drainage ditch west of it is limited

[a] Reference: SCE drawing 562502-6, Site Arrangement Plan, Rev. 6, dated 7-14-77 (Figure B-3, Appendix B).

[b] General Notes:

1. New ductwork to enable use of existing stack breeching locations while keeping boilers in operation during major portion of scrubber installation will be complex.
2. Impact on existing underground facilities, lines, etc. (if any) is unknown.
3. New stacks or stack lining may be required due to potentially corrosive conditions in the stack.
4. Installation of scrubber towers may tend to reduce accessibility to existing equipment.

TABLE 45. OTHER MAJOR SCRUBBER EQUIPMENT SITING: ETIWANDA[a]

Equipment	Size	Potential location	Impact
Thickener	35-ft diam, 2 units	Open area south of Unit No. 4 and west of switch-yard	None apparent
Filter building	25 × 50 ft	South of thickeners	None apparent
Solid waste holding pond and truck loading area	110 × 110 × 10 ft deep (60-day capacity)	South of filter building	None apparent
Lime storage and slaking area		South of solid waste holding area	None apparent

[a]Reference: SCE drawing 562502-6, Site Arrangement Plan, Rev. 6, dated 7-14-77 (Figure B-3, Appendix B).

4.4.1.4 Huntington Beach

The SCE Huntington Beach generating station is a coastal plant located on a 53-acre site in Huntington Beach, Orange County. Four boilers are capable of providing steam for generating 870 megawatts. Scrubber siting layouts for single 34-ft diameter scrubbers for Units 1 and 2 and Units 3 and 4 are shown in Figures 23 and 24, respectively. Other major scrubber system equipment can be located west of Unit 4 as shown in Figure 25. In general, there do not appear to be any severe space constraints (Tables 46 and 47).

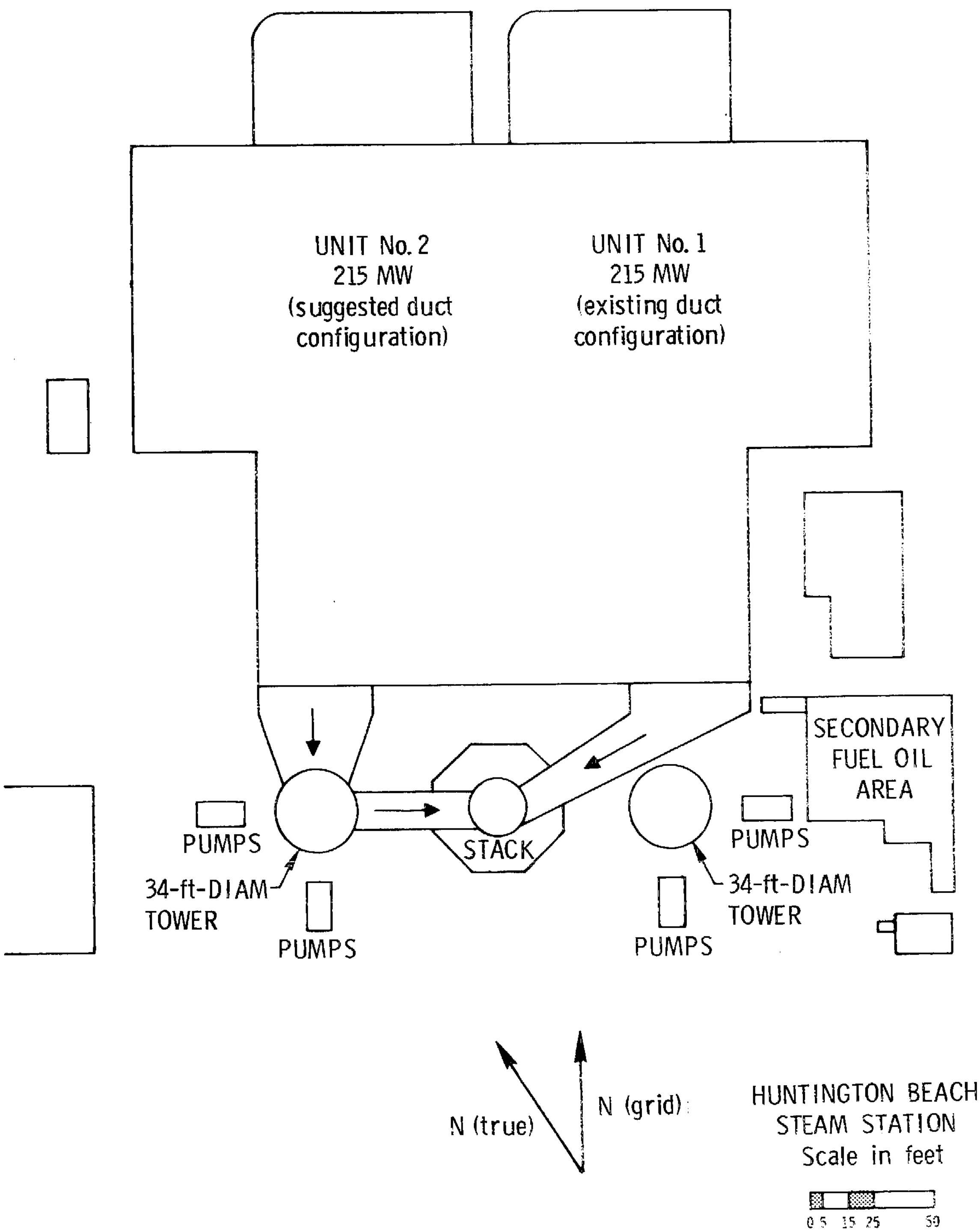

Figure 23. Scrubber siting: Huntington Beach, Units 1 and 2

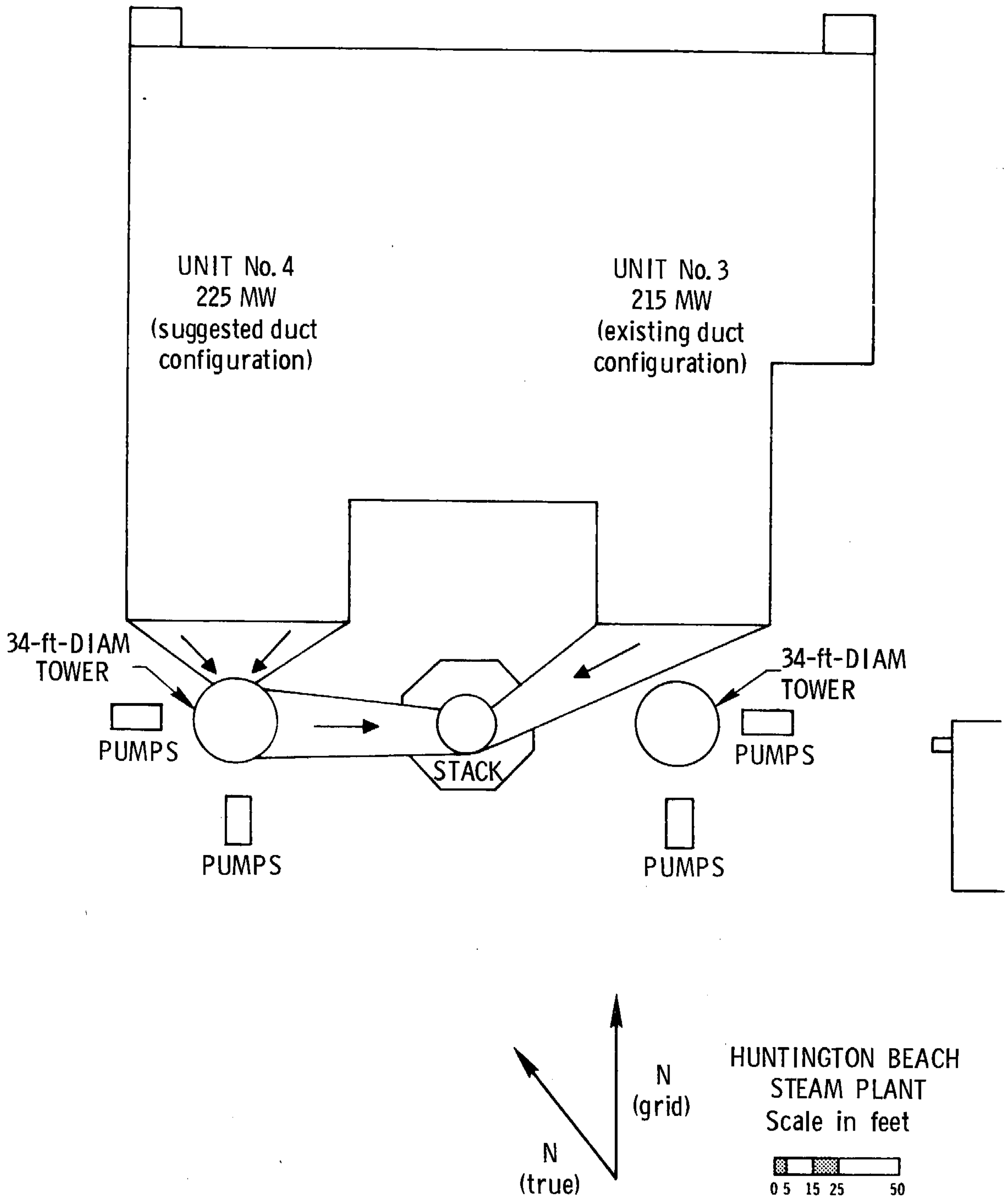

Figure 24. Scrubber siting: Huntington Beach, Units 3 and 4

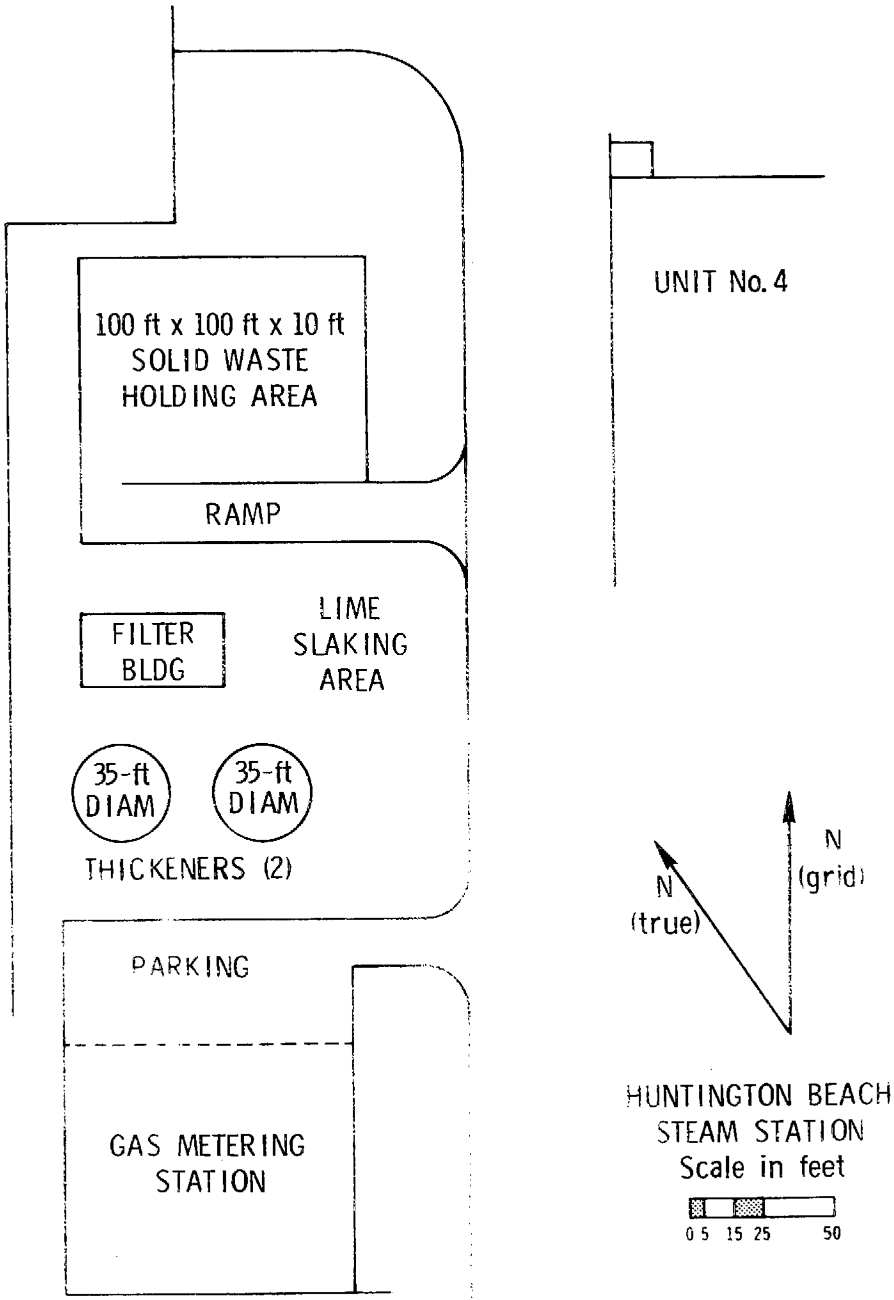

Figure 25. Other scrubber system equipment siting: Huntington Beach

TABLE 46. SCRUBBER SITING: HUNTINGTON BEACH[a]

Size, MW	Unit	No. of absorbers	Absorber diameter, ft	Absorber location	Impact[b]
215	1	1	34	Approx. 75 ft east of existing stack	None apparent
215	2	1	34	Approx. 75 ft west of existing stack	None apparent
215	3	1	34	Approx. 80 ft east of existing stack	None apparent
225	4	1	34	Approx. 80 ft west of existing stack	None apparent

[a]Reference: SCE drawing 545436-12, Plot Plan Civil, Rev. 12, dated 10-11-77 (Figure B-4, Appendix B)

[b]General Notes:

1. New ductwork to enable use of existing stack breeching locations while keeping boilers in operating during major portion of scrubber installation will be complex.
2. Impact on existing underground facilities, lines, etc. (if any) is unknown.
3. New stacks or stack lining may be required due to potentially corrosive conditions in the stack.
4. Installation of scrubber towers may tend to reduce accessibility to existing equipment.

TABLE 47. OTHER MAJOR SCRUBBER EQUIPMENT SITING: HUNTINGTON BEACH[a]

Equipment	Size	Potential location	Impact
Thickener	35-ft diam, 2 units	Open area west of Unit 4 road and north of parking area	None apparent
Filter building	25 × 50 ft	North of thickeners	None apparent
Solid waste holding pond and truck loading area	100 × 100 × 10 ft deep (60-day capacity)	North of filter building	None apparent
Lime storage and slaking area		East of filter building	None apparent

[a]Reference: SCE drawing 545436-12, Plot Plan Civil, Rev. 12, dated 10-11-77 (Figure B-4, Appendix B)

4.4.1.5 Ormond Beach

The SCE Ormond Beach generating station is located in Oxnard, Ventura County, on a 280-acre site. It is capable of generating 1600 megawatts and is comprised of two 800-MW boilers. The generating station is large in area, and locating other scrubber system major equipment does not appear to be a problem (Figures 26 and 27 and Table 48). Because of the large capacity of the boilers, multiple scrubber modules, four each, 32 ft in diameter, are required. Although there appears to be adequate space for the modules, the multiplicity of scrubbers in a relatively small area may pose some problems in ducting and in the accessability to various parts of the boilers (Figure 28 and Table 49).

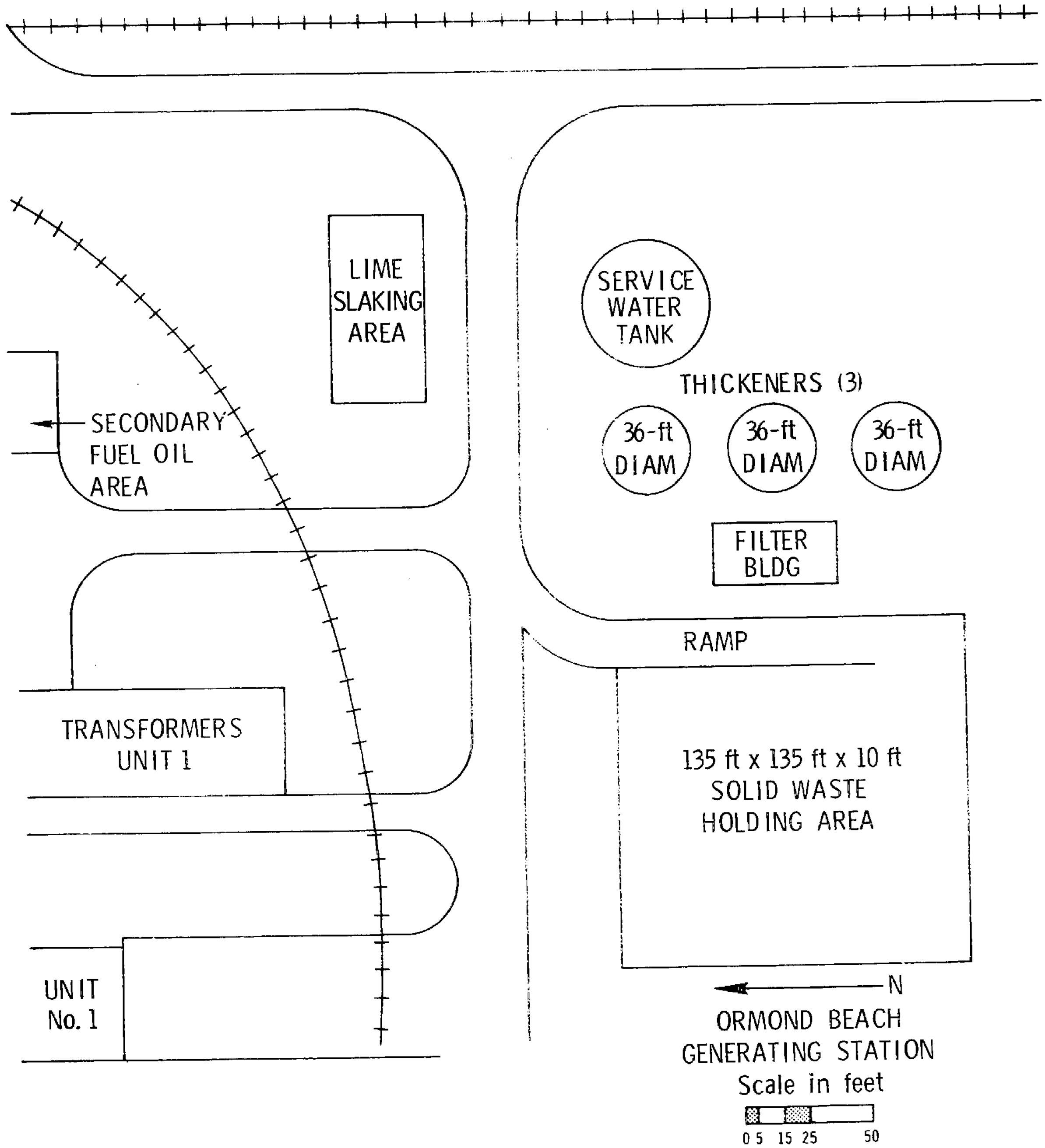

Figure 26. Other scrubber system equipment siting: Ormond Beach

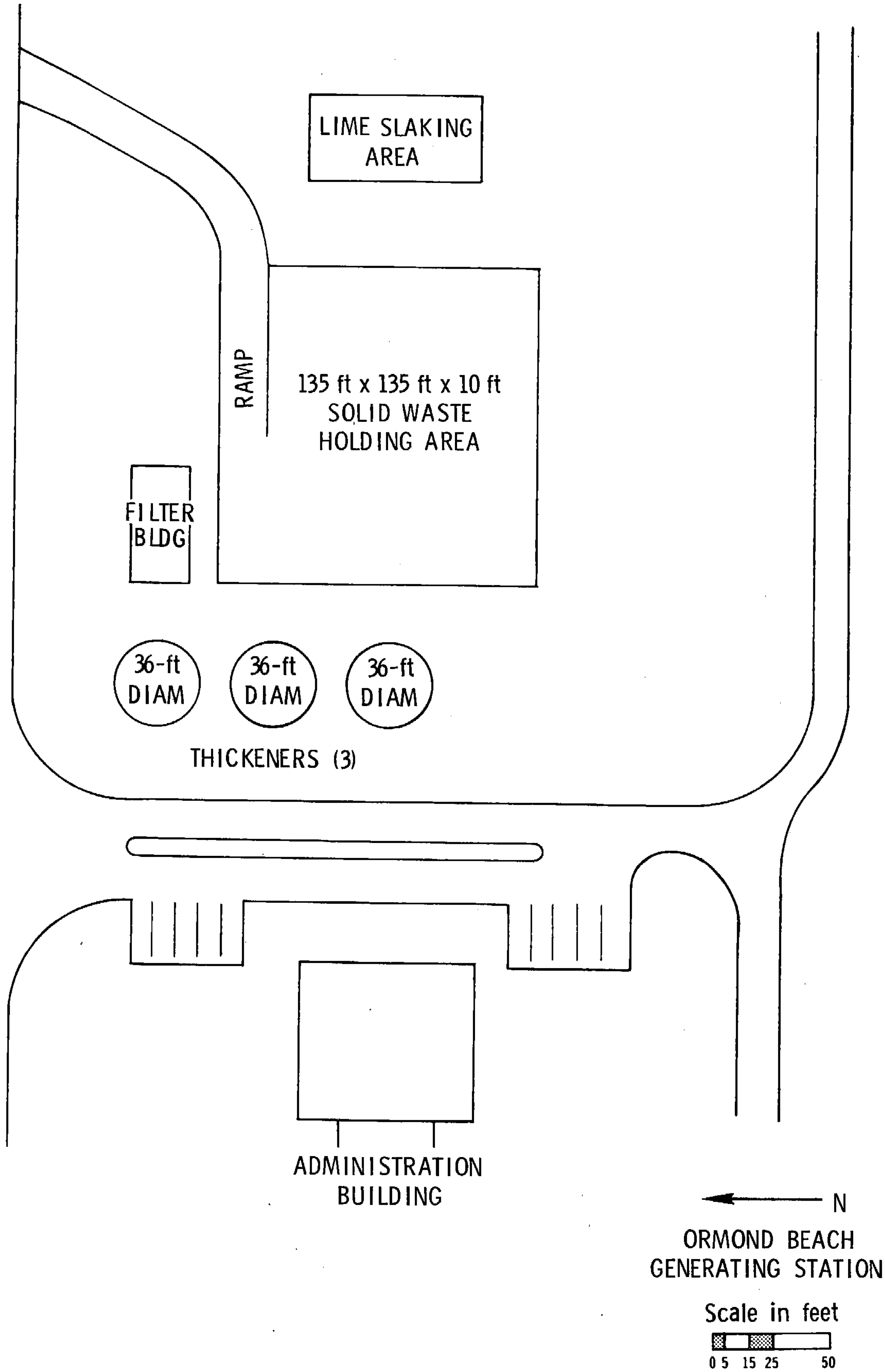

Figure 27. Other scrubber system equipment siting, alternative location: Ormond Beach

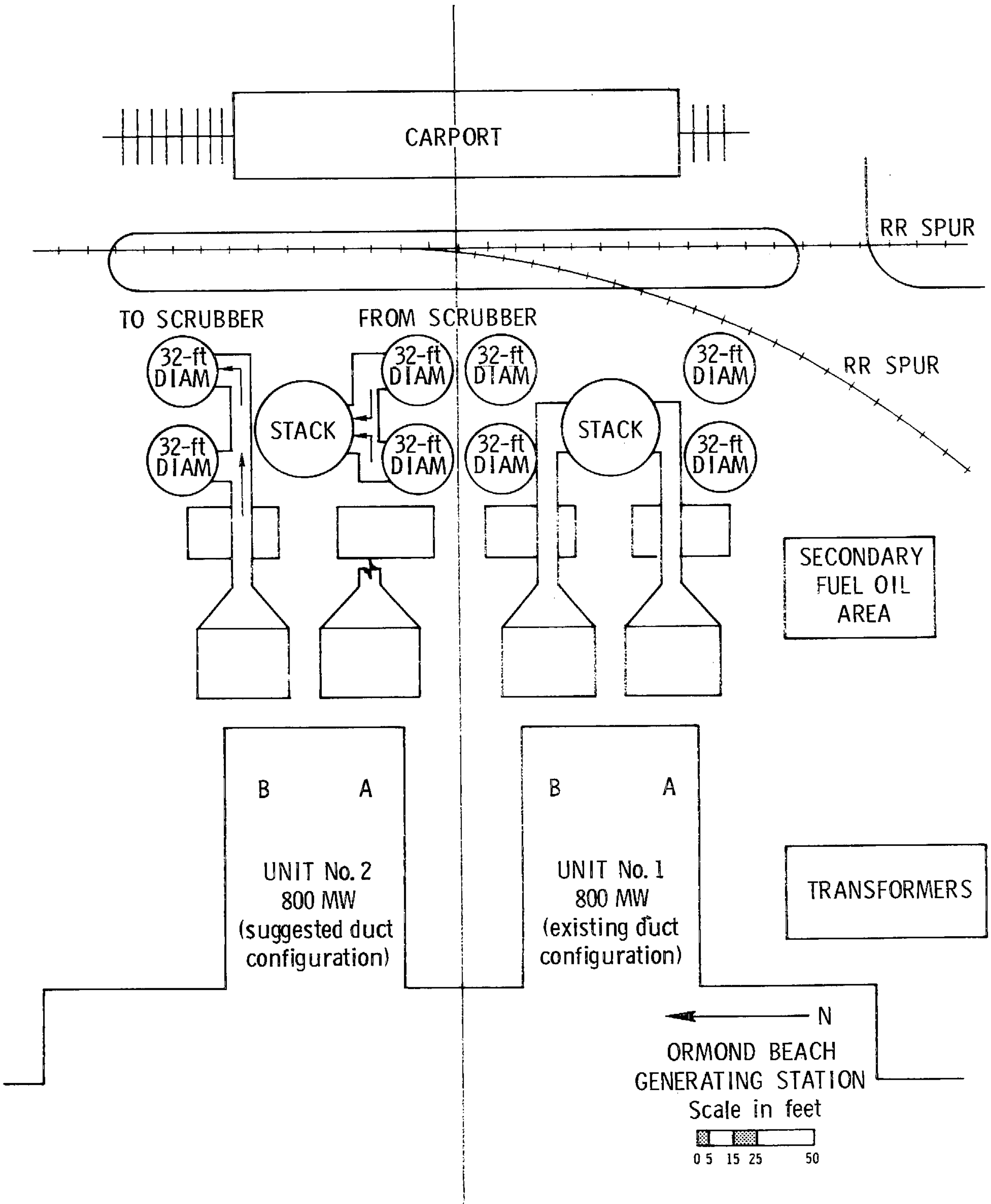

Figure 28. Scrubber siting: Ormond Beach

TABLE 48. OTHER MAJOR SCRUBBER EQUIPMENT SITING: ORMOND BEACH[a]

Equipment	Size	Potential location	Impact
Thickeners	36-ft diam, 3 units	(a) Open area south of existing road (south of Unit 1 and west of fuel tank No. 6) in vicinity of existing service water tank	None apparent
		or	
		(b) Open area east of administration building roadway	None apparent
Filter building	25 × 50 ft	(a) West of thickeners in (a) above	None apparent
		or	
		(b) East of thickener in (b) above	None apparent
Solid waste holding pond and truck loading area	135 × 135 × 10 ft (approx. 60-day capacity)	(a) West of filter building in (a) above	None apparent
		or	
		East of thickeners in (b) above	None apparent
Lime storage and slaking area		(a) North of service tank and roadway and south of rail spur (between tracks and road)	None apparent
		or	
		(b) East of solid waste holding area	None apparent

[a]Reference: SCE drawing 75432-12, Plot Plan, Rev. 12, dated 10-11-77 (Figure B-5, Appendix B)

TABLE 49. SCRUBBER SITING: ORMOND BEACH[a]

Size, MW	Unit	No. of absorbers	Absorber diameter, ft	Absorber location	Impact[b]
800	1A	2	32	Approx. 50 ft south of stack (E-W) centerline, and equally spaced, approx. 25 ft east and west of N-S stack centerline	None apparent
	1B	2	32	Approx. 50 ft north of stack (E-W) centerline, and equally spaced, approx. 25 ft east and west of N-S stack centerline	None apparent
800	2A	2	32	Same location relative to Unit 2 stack as in Unit 1A	None apparent
	2B	2	32	Same location relative to Unit 2 stack as in Unit 1B	None apparent

[a]Reference: SCE drawing 75432-12, Plot Plan, Rev. 12, dated 10-11-77 (Figure B-5, Appendix B).

[b]General Notes:

1. New ductwork to enable use of existing stack breeching locations while keeping boilers in operation during major portion of scrubber installation will be complex.
2. Impact on existing underground facilities, lines, etc. (if any) is unknown.
3. New stacks or stack lining may be required due to potentially corrosive conditions in the stack.
4. Installation of scrubber towers may tend to reduce accessibility to existing equipment.

4.4.1.6 Redondo Beach

The Redondo Beach generating station is on 41 acres, located in the city of Redondo Beach. It has a total of 11 boilers, with a total generating capacity of 1602 megawatts. It is comprised of seven boilers and four generating units capable of generating 292 megawatts (Figure 29). The units are approximately 30 years old, having been placed in service in 1948-1949. The capacity factor of these units is approximately 15 percent; the capacity factor of the rest of the units is about 45 percent. Units 5 and 6 (Figure 30) are 175 megawatts each, and Units 7 and 8 (Figure 31) are 480 megawatts each. They have been in service approximately 20 and 10 years, respectively.

Two 30-ft-diam scrubbers can handle the flue gas from boilers for Units 1 through 4 (Figure 32). Single scrubber modules 30 feet in diameter are appropriate for Units 5 and 6 (Figure 33); Units 7 and 8 require two 35 ft-diam scrubbers each (Figure 34). Although a relatively large open area exists south of Unit 8, it is required for the removal of turbines from the station as it is the only access with a rail spur.

Other equipment, such as three 40-ft-diam thickeners, a filter building, and waste holding area, may be located in an open area east of Unit 5 (Figure 33). A possible location for the lime slaking area is in the triangular area formed by the berm of fuel oil tank No. 4, the east property line, and the rail spur (Figure B-6, Appendix B).

Space in the vicinity of all boilers, especially for Units 5 through 8, is limited. With the installation of scrubbers, accessibility in the vicinity of those boilers may be severely restricted (Tables 50 and 51).

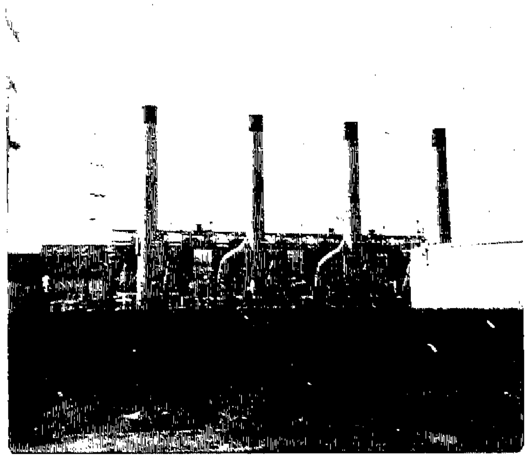

Figure 29. Redondo Beach: Units 1 through 4

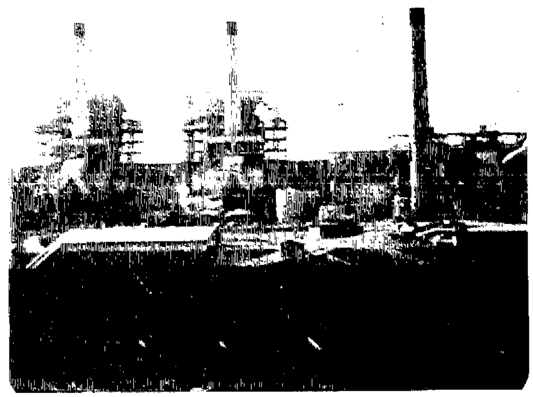

Figure 30. Redondo Beach: Units 5 and 6

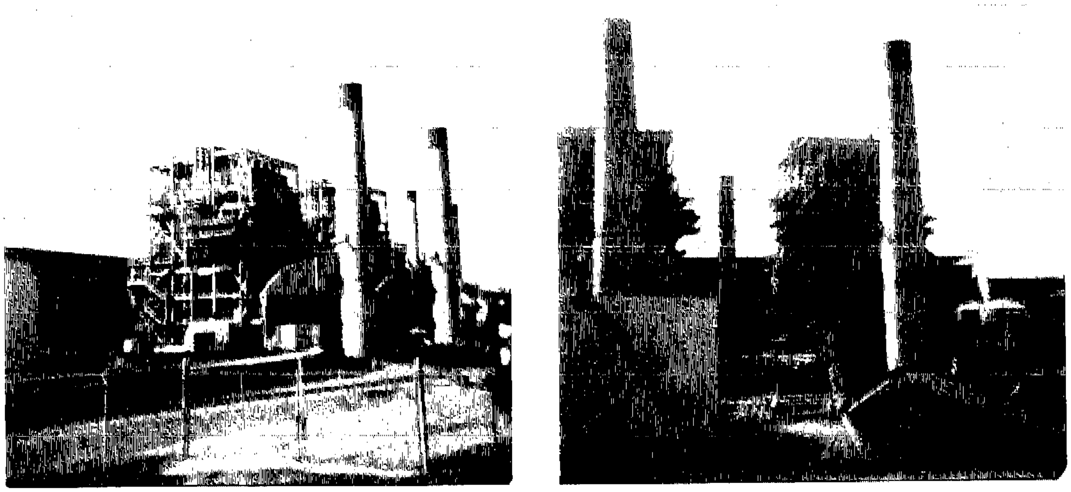

Figure 31. Redondo Beach: Units 7 and 8 (two views)

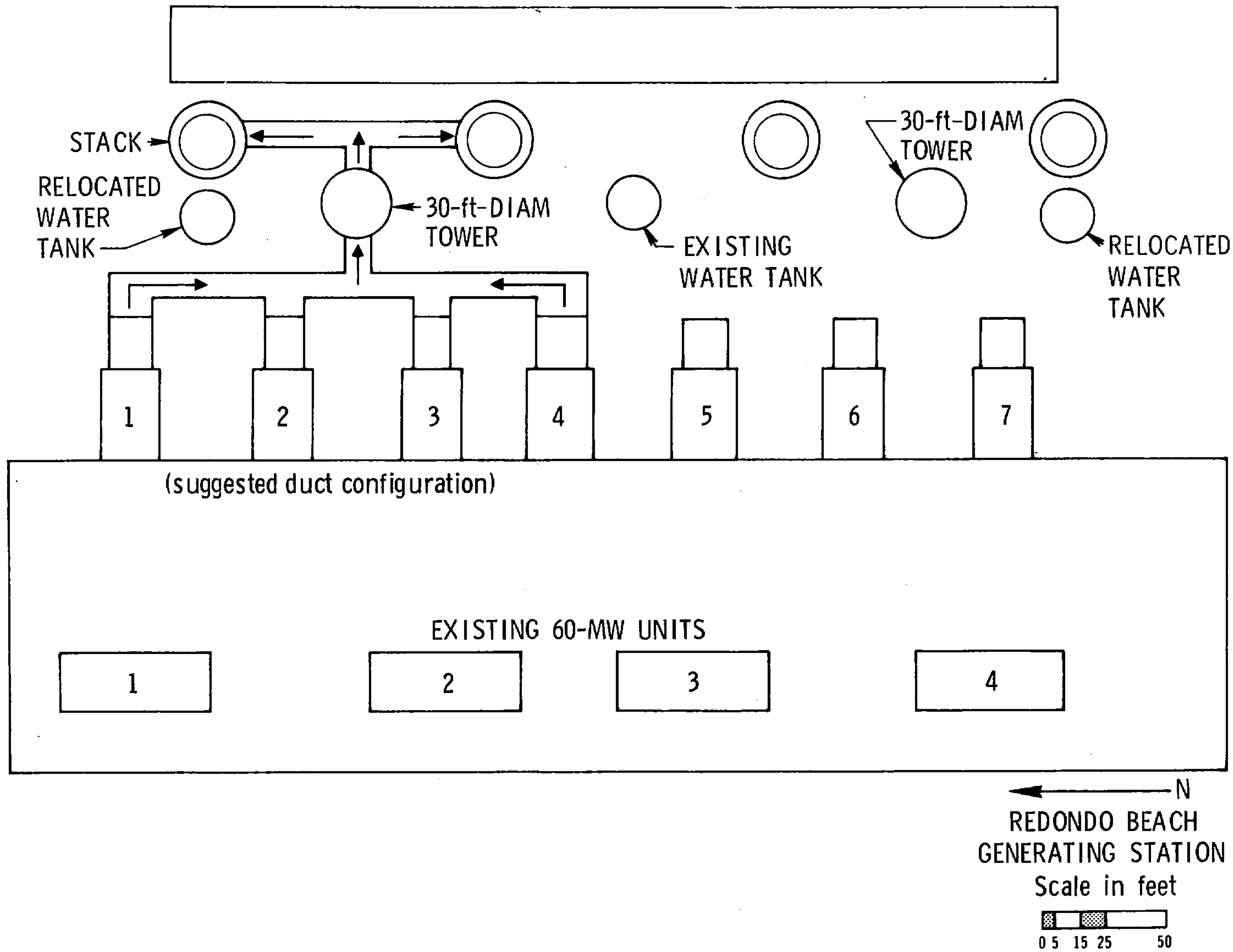

Figure 32. Scrubber siting: Redondo Beach, Units 1 through 4

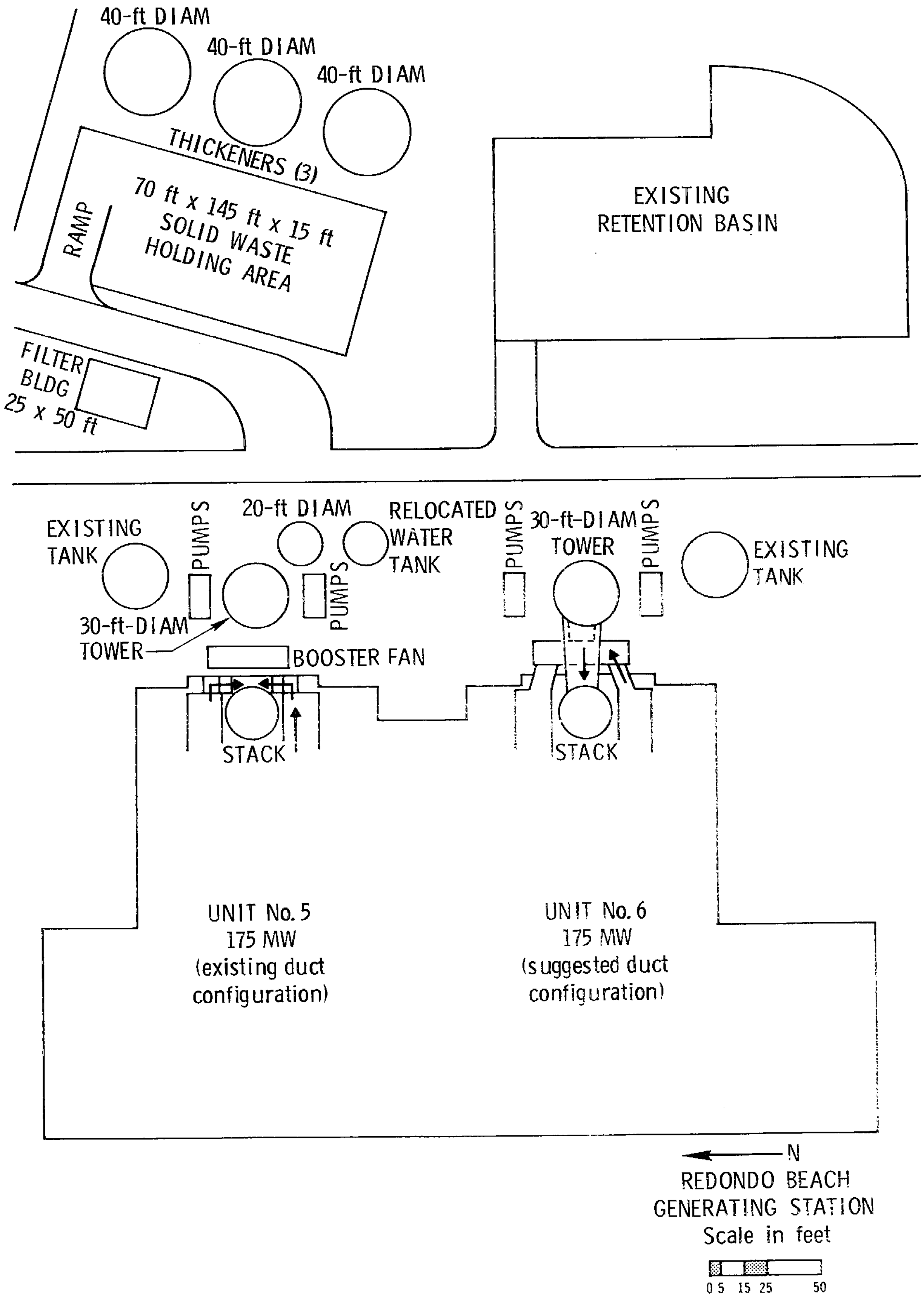

Figure 33. Scrubber siting: Redondo Beach

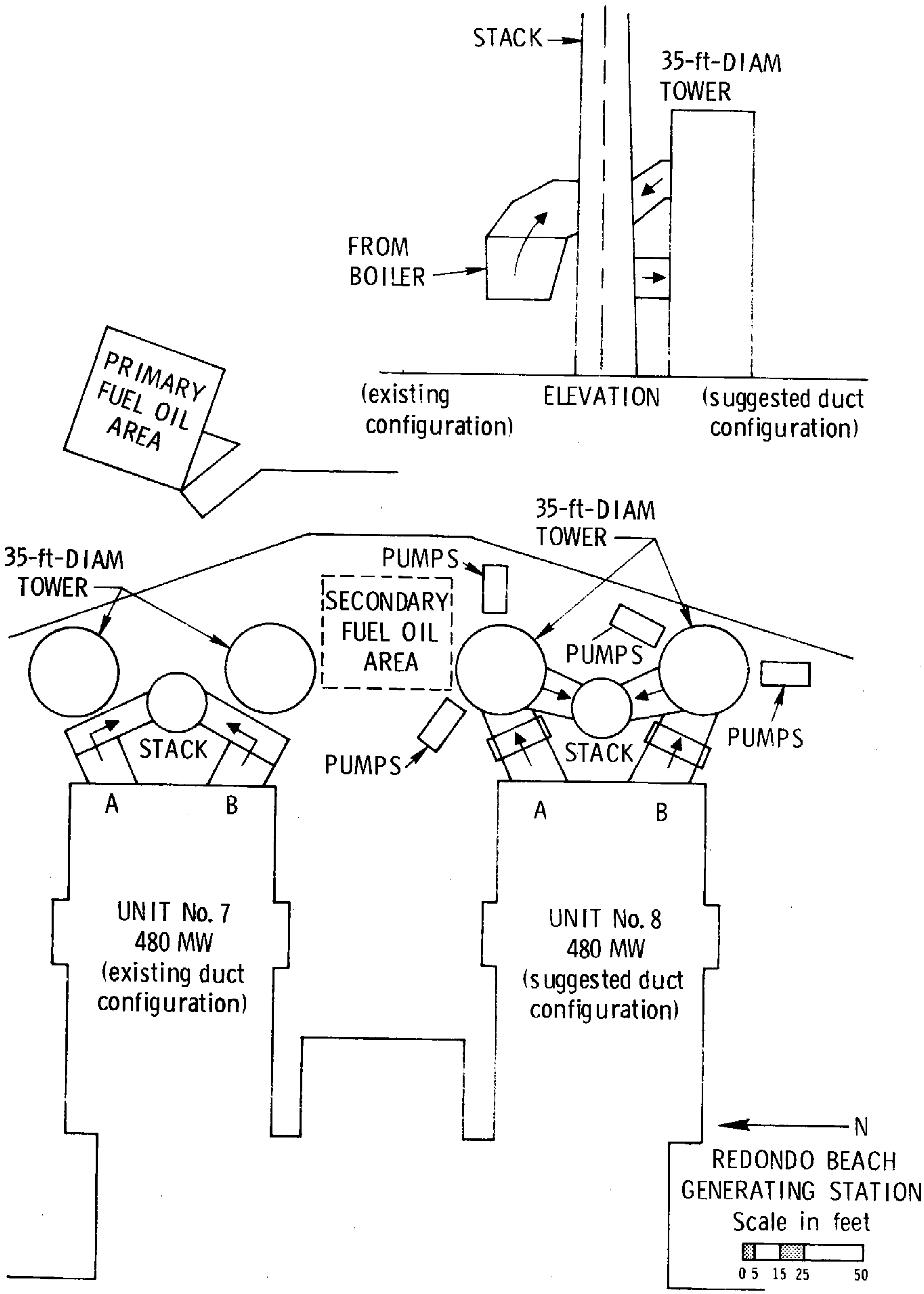

Figure 34. Scrubber siting: Redondo Beach, Units 7 and 8

TABLE 50. SCRUBBER SITING: REDONDO BEACH[a]

Size, MW	Unit	No. of absorbers	Absorber diameter, ft	Absorber location	Impact[b]
	1 2	1	30	Between boilers 2 and 3 and between stacks and boilers	Manifold 4 boilers into absorber and out into 2 stacks Relocate existing water tanks
	3 4	1	30	Between boilers 6 and 7 and between stacks and boilers	Manifold 3 boilers into absorber and out into 2 stacks Relocate existing water tank
175	5	1	30	In line with stack E-W centerline. Absorber N-S centerline, approx. 55 ft from stack centerline	Relocate existing tank
175	6	1	30	In line with stack E-W centerline. Absorber N-S centerline, approx. 55 ft from stack centerline	
480	7A	1	35	Centerline approx. 45 ft east of A-side of boiler	
	7B	1	35	Centerline approx. 45 ft east of B-side of boiler	Encroaches on accessibility past secondary fuel oil area into area between Units 7 and 8
480	8A	1	35	Centerline approx. 45 ft east of A-side of boiler	Same as 7B
	8B	1	35	Centerline approx. 45 ft east of B-side of boiler	

[a]Reference: SCE Drawing 579939-8, Plot Plan, Rev. 8, dated 10-11-77 (Figure B-6, Appendix B).

[b]General Notes:

1. New ductwork to enable use of existing stack entry locations will be complex.
2. Impact on existing underground facilities, lines, etc. (if any) is unknown.
3. New stacks or stack linings may be required due to potentially corrosive conditions in stack.
4. Installation of scrubbers may tend to reduce accessibility to existing equipment.

TABLE 51. OTHER MAJOR SCRUBBER EQUIPMENT SITING: REDONDO BEACH[a]

Equipment	Size	Potential location	Impact
Thickeners	40-ft diam, 3 units	Open area east of Unit 5 and north of retention basin paralleling H. V. lines	Relocate existing aboveground gas supply main
Filter building	25 × 50 ft	In corner of open area east of Unit 5, in vicinity of intersection of N-S & E-W roadways.	
Solid waste holding pond and loading area	70 × 145 × 15 ft (approx. 60-day capacity)	Diagonally across (NE to SW) open area between fuel oil tank No. 2 and Unit 5	Reroute underground water line
Lime storage and slaking area		Triangular area formed by berm of fuel oil tank No. 4, east property line and rail spur	

[a]Reference: SCE drawing 579939-8, Plot Plan, Rev. 8, dated 10-11-77 (Figure B-6, Appendix B).

4.4.1.7 Haynes

The DWP Haynes generating station is located in Long Beach, Los Angeles County, across the San Gabriel river and generally east of the SCE Alamitos plant. It is located on 155 acres. Its six units have a total generating capacity of 1600 megawatts. Units 1 and 2 will each require two 25-ft-diam scrubber modules (Figure 35). Units 3 and 4, which have double-stack installations, can each utilize one 34-ft-diam scrubber module (Figure 36).

Two 30-ft-diam scrubber modules were considered for Units 5 and 6 (Figure 37). Some roadway rerouting in the vicinity of Units 1 and 2 and a relocation of the water treatment facility between Units 5 and 6 will be required to accommodate the scrubbers (Table 52). Location of the dewatering equipment and waste holding pond is shown in Figure 38. It is in a low overhead clearance area (Table 53 and Figure B-7, Appendix B) and will require caution during construction.

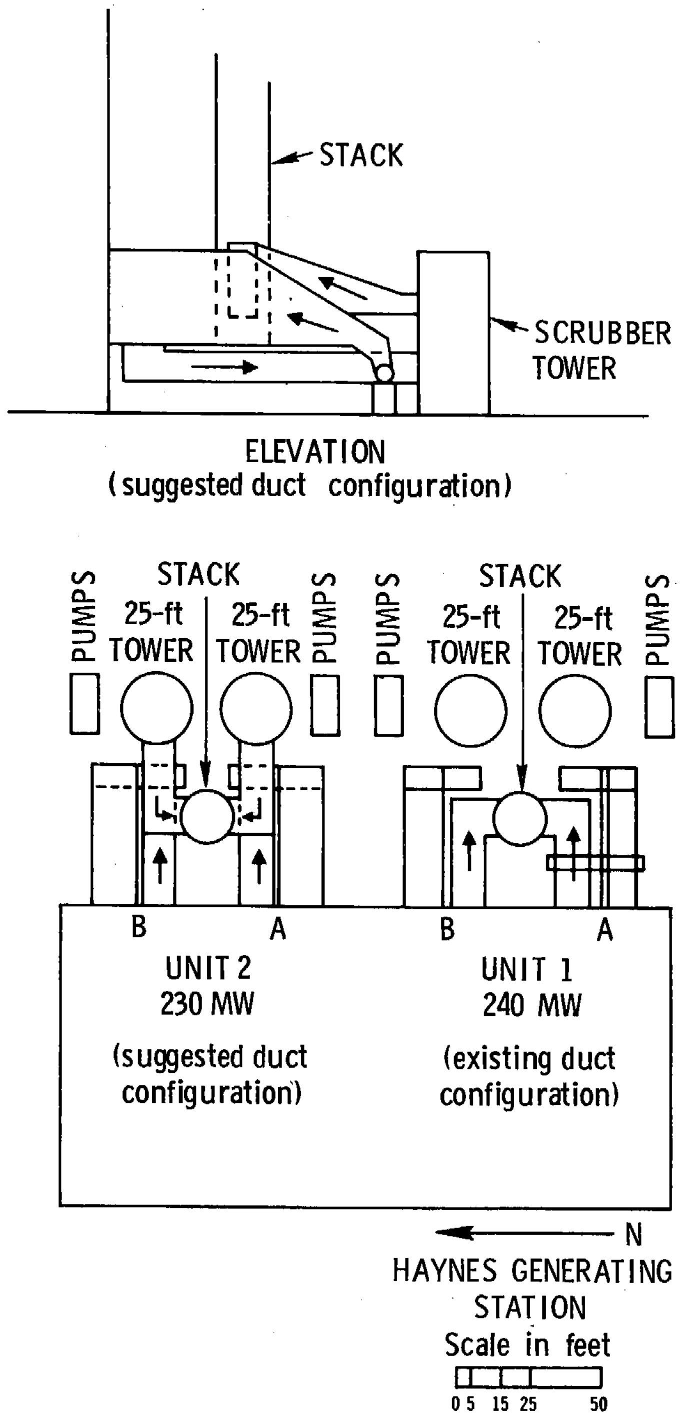

Figure 35. Scrubber siting: Haynes, Units 1 and 2

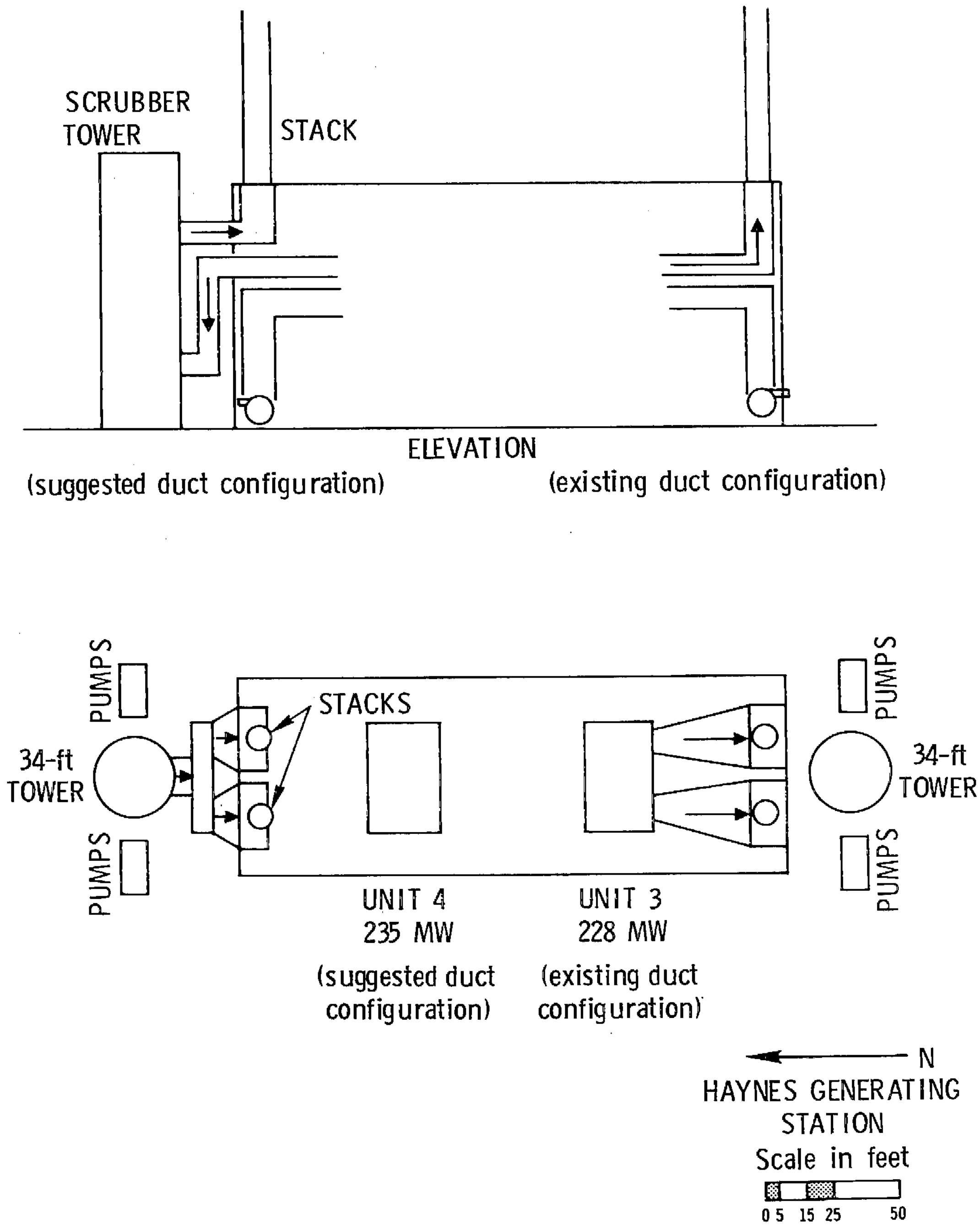

Figure 36. Scrubber siting: Haynes, Units 3 and 4

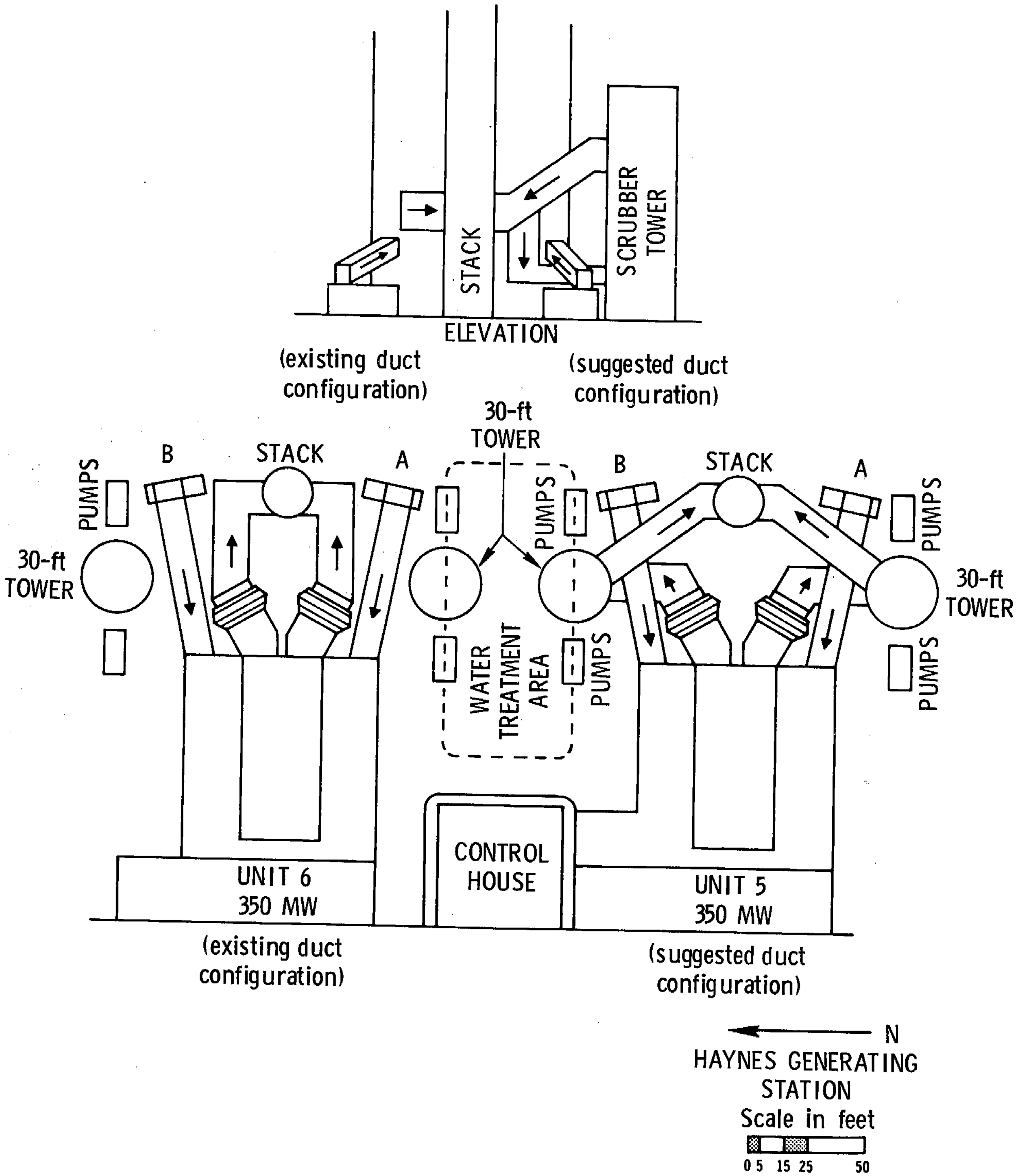

Figure 37. Scrubber siting: Haynes, Units 5 and 6

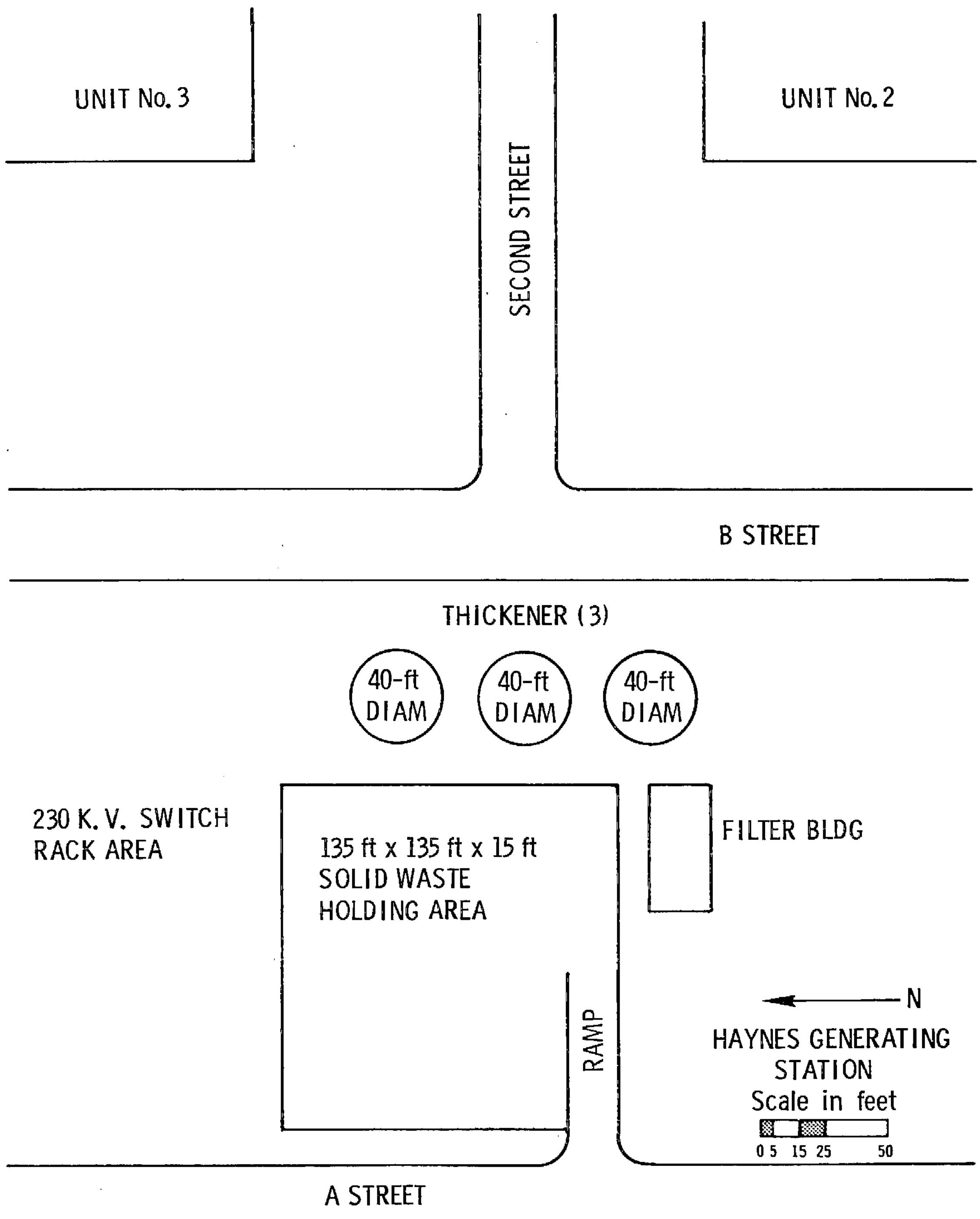

Figure 38. Other scrubber system equipment siting: Haynes

TABLE 52. SCRUBBER SITING: HAYNES[a]

Size, MW	Unit	No. of absorbers	Absorber diameter, ft	Absorber location	Impact[b]
230	1A	1	25	East of existing duct, in roadway	Loss of west lane of roadway
	1B	1	25	East of existing duct, in roadway	Loss of west lane of roadway
240	2A	1	25	East of existing duct, in roadway	Loss of west lane of roadway
	2B	1	25	East of existing duct, in roadway	Loss of west lane of roadway
235	3A 3B	1	34	In parking area south of Unit 3	See General Note 3
228	4A 4B	1	34	In parking area north of Unit 4	See General Note 3
350	5A	1	30	In open area south of existing ducts and north of existing tank	Existing covered parking area may require partial removal to improve access in area
	5B	1	30	North of existing ducting	Encroaches on water treatment area, which may require reconfig-uration; see General Note 3.
350	6A	1	30	South of existing ducting	Encroaches on water treatment area, which may require reconfig-uration; see General Note 3.
	6B	1	30	Open area north of existing ducting	See General Note 3.

[a]Reference: DWP drawing SE-PN100, Fire Hydrant and Domestic Water Supply Systems, Rev. 14,dated 12-7-76 (Figure B-7, Appendix B)

[b]General Notes:

1. New ductwork to enable use of existing stack entry locations will be complex.
2. Impact on existing underground lines, etc. (if any) is unknown.
3. Underground circulating water ducts located under scrubbers for Units 3, 4, 5B, and 6B.
4. New stacks or stack lining may be required due to potentially corrosive conditions in the stack.
5. Installation of scrubbers may tend to reduce accessibility to existing equipment.

TABLE 53. OTHER MAJOR SCRUBBER EQUIPMENT SITING: HAYNES[a]

Equipment	Size	Potential location	Impact
Clarifiers	40-ft diam, 3 units (20% excess capacity)	In switch yard area between Units 4 and 5 or Area east of Tank F	Low overhead clearance (partially underground would increase clearance)
Filter building	25×50 ft	In switch yard area between Units 4 and 5 or Area east of Tank F	Low overhead clearance during construction
Solid waste holding pond and truck loading area	$135 \times 135 \times 15$ ft (approx. 60-day capacity)	In switch yard area between Units 2 and 3 or Area east of Tank F	Low overhead clearance may require below-grade loading
Lime storage and slaking area		Triangular area north of Tank E or Area east of Tank F	Keep down lime dust

[a]Reference: DWP drawing SE PN100, Fire Hydrant and Domestic Water Supply Systems, Rev. 14, dated 12-7-76 (Figure B-7, Appendix B)

4.4.1.8 Valley Generating Station

The DWP Valley generating station is located in the City of Los Angeles on a 155-acre site. It has been operating at a relatively low capacity factor of 0.158. All of the units were placed in service in the mid-1950's: Units 1 and 2 in 1954, Unit 3 in 1955, and Unit 4 in 1956. The station's generating capacity is 526 megawatts.

One scrubber module, 23 feet in diameter, is required for each of the 101-MW Units 1 and 2 (Figure 39). Single scrubber modules 30 feet in diameter are required for each of Units 3 and 4, 171 and 160 MW, respectively (Figure 40). Space for the dewatering, waste holding pond, and lime slaking is is available west of Avenue C, between Second and Third Streets (Figure 41). Other than the general impacts discussed in Section 4.4.1, no significant siting considerations were observed (Tables 54 and 55).

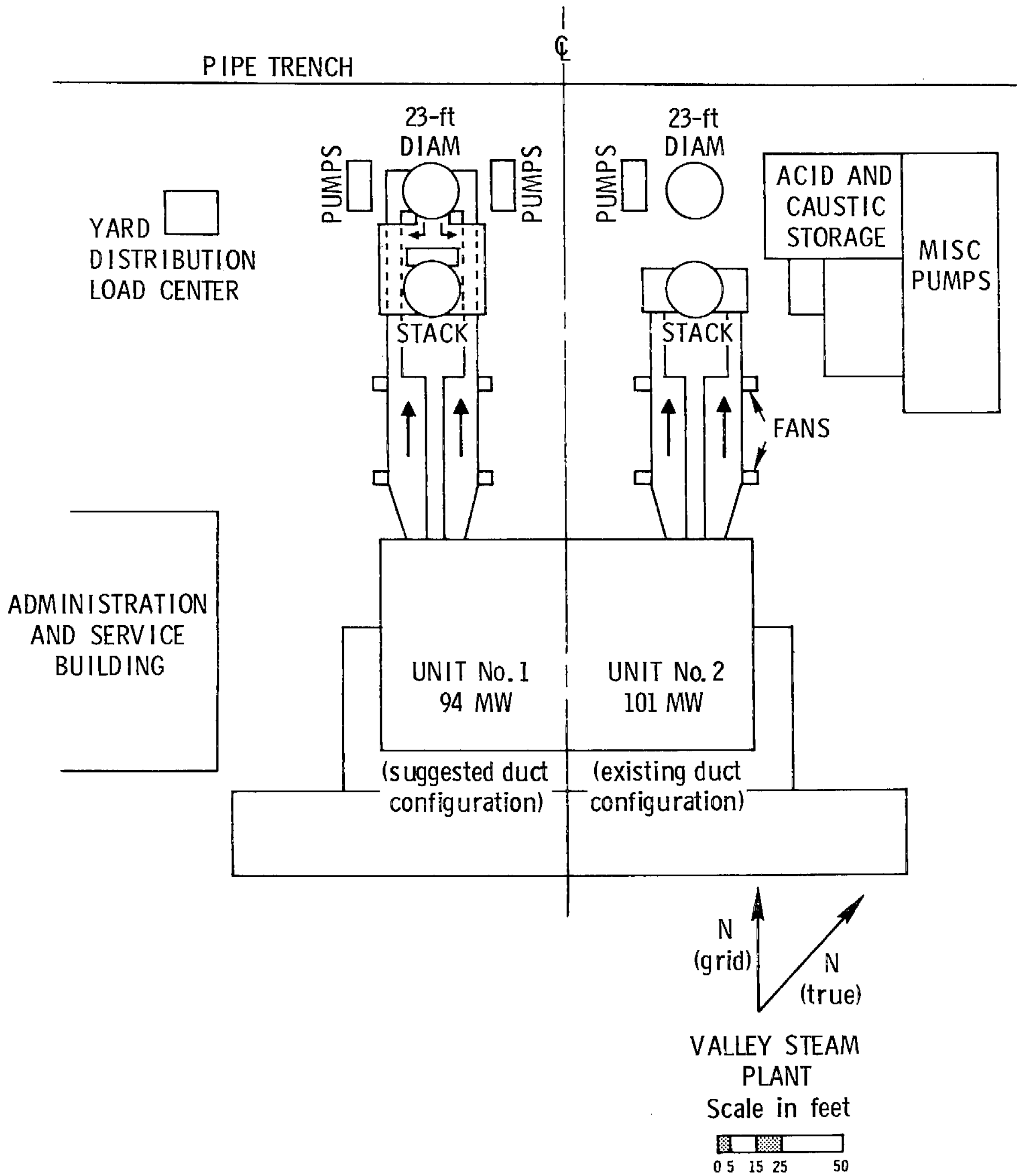

Figure 39. Scrubber siting: Valley, Units 1 and 2

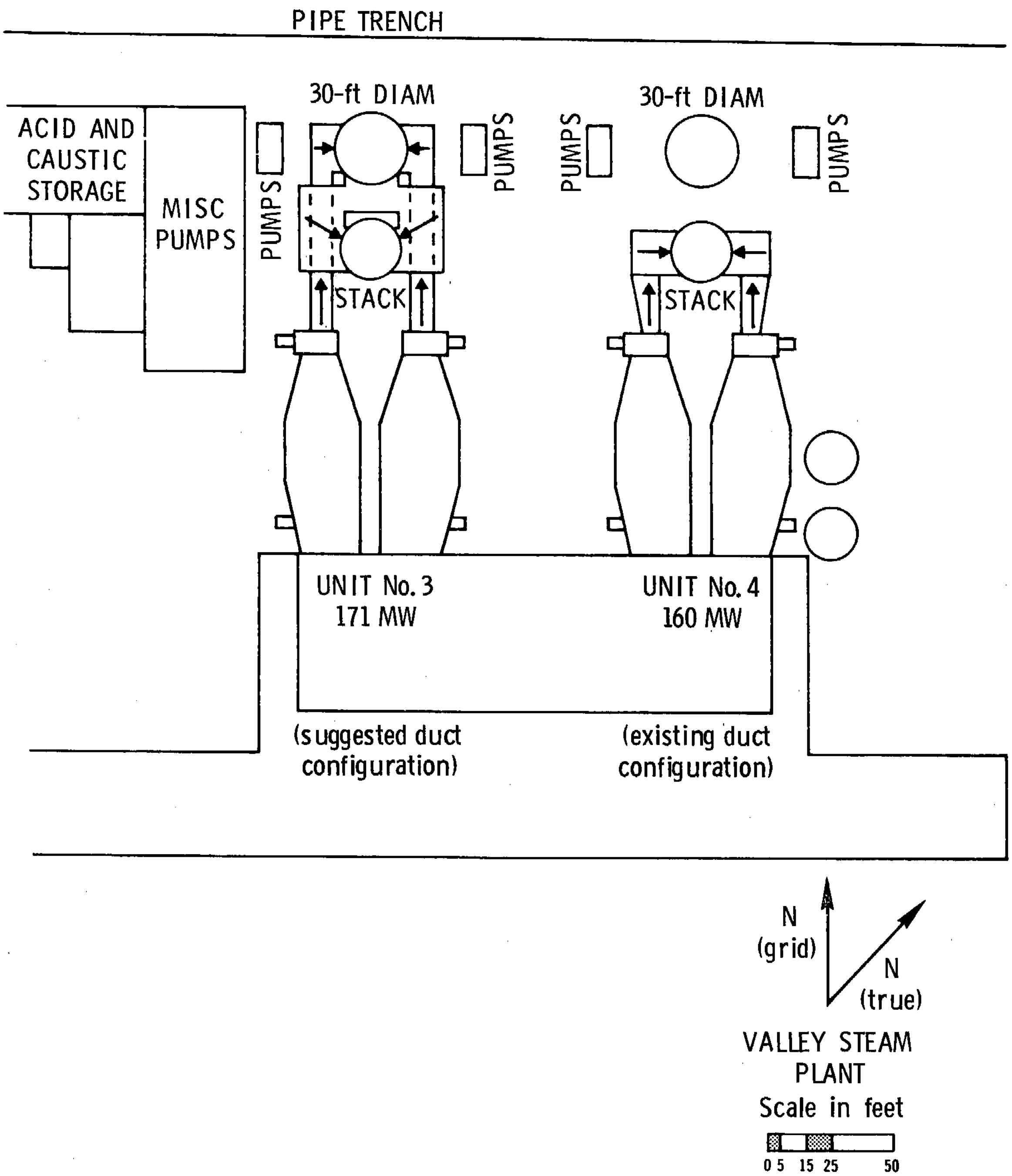

Figure 40. Scrubber siting: Valley, Units 3 and 4

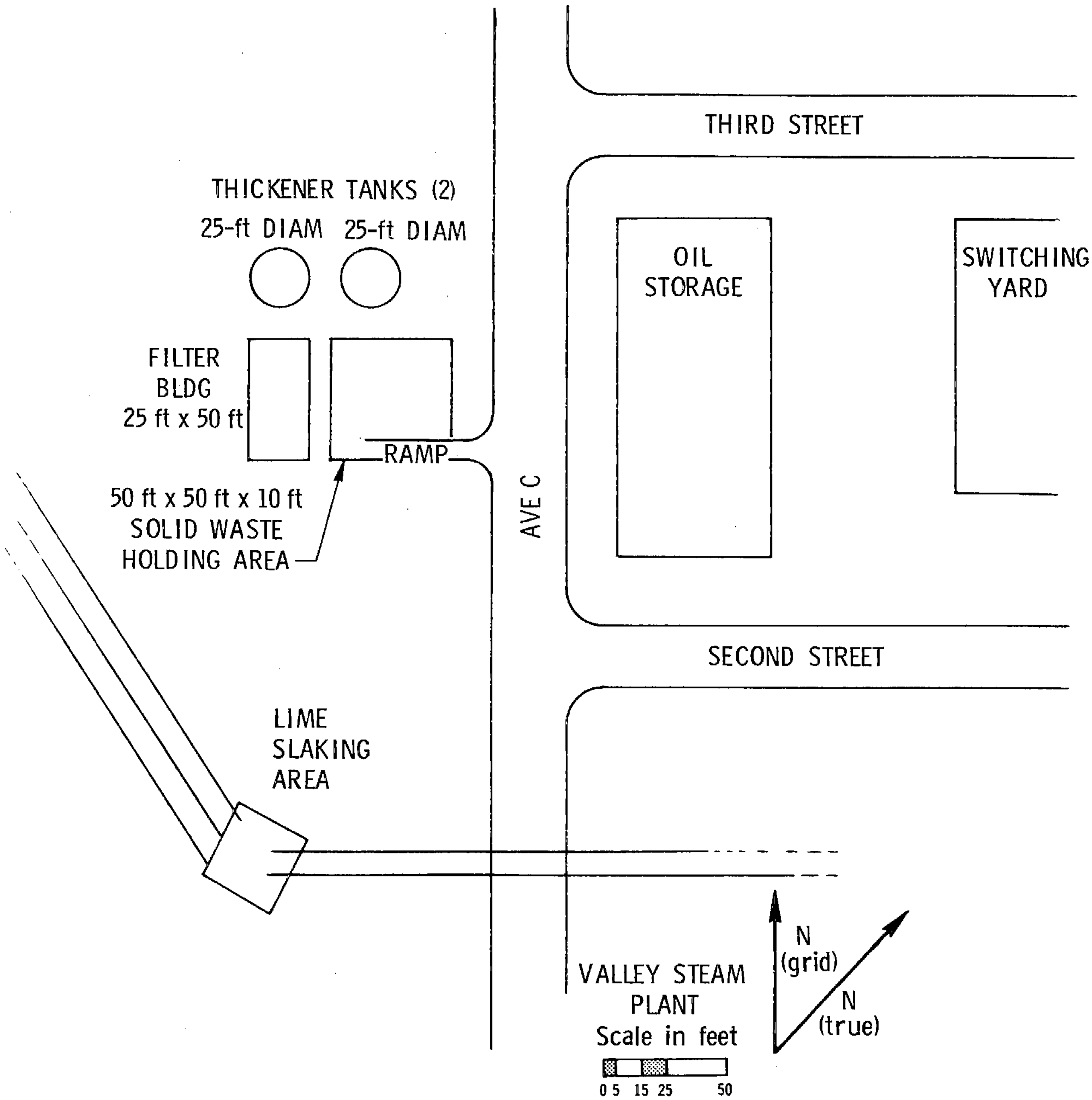

Figure 41. Other scrubber system equipment siting: Valley

TABLE 54. SCRUBBER SITING: VALLEY[a]

Size, MW	Unit	No. of absorbers	Absorber diameter, ft	Absorber location	Impact[b]
94	1	1	23	Approx. 40 ft north of stack	None apparent
101	2	1	23	Approx. 40 ft north of stack	None apparent
171	3	1	30	Approx. 40 ft north of stack	None apparent
160	4	1	30	Approx. 40 ft north of stack	None apparent

[a]Reference: DWP drawing M-60009, Site Development Valley Steam Plant, Rev. 12, dated 3-4-55 (with redlined additions received 1-3-78) (Figure B-8, Appendix B)

[b]General Notes:

1. New ductwork to enable use of existing stack breeching locations while keeping boilers in operation during major portion of scrubber installation will be complex.
2. Impact on existing underground facilities, lines, etc. (if any) is unknown.
3. New stacks or stack lining may be required due to potentially corrosive conditions in the stack.
4. Installation of scrubber towers may tend to reduce accessibility to existing equipment.

TABLE 55. OTHER MAJOR SCRUBBER EQUIPMENT SITING: VALLEY[a]

Equipment	Size	Potential location	Impact
Thickeners	25 ft diam, 2 units	Open area between Second and Third Streets and west of Avenue C	None apparent
Filter building	25 × 50 ft	South of thickeners	None apparent
Solid waste holding pond and truck loading area	50 × 50 × 10 ft pond (approx. 60-day capacity)	Westerly of and adjacent to Avenue C	None apparent
Lime storage and slaking area		South of solid waste holding area and adjacent to Avenue C	None apparent

[a]Reference: DWP drawing M-60009, Site Development Valley Steam Plant, Rev. 12, dated 3-4-55 (with redlined additions received 1-3-78) (Figure B-8, Appendix B).

4.4.2 Industrial Processes Applications

The nonregenerable processes applicable to the industrial processes studied were provided in Section 4.3.2. Enginering sketches of the possible scrubber equipment locations and the siting considerations for each of the four sites studied, Chevron, Great Lakes Carbon, Martin Marietta Carbon, and Stauffer Chemical, are presented in this section. The siting sketches presented with the discussion are keyed to plot plans, presented in Figures B-9 through B-11 in Appendix B.

As in the case of the utilities, the scrubbers were located so that existing stacks could be utilized and process equipment downtime could be minimized. Scrubber installation was estimated as requiring about eight months.

Because of the smaller volumetric flows and corresponding equipment, the retrofit ducting from the process equipment to the scrubber and from the scrubber to the stack does not appear to pose as complex a problem as it does with the utility installations. As with the utilities, the impact of scrubber installation on underground facilities was not defined, and detailed assessments could not be performed because of the nature of the feasibility study.

For the four sites studied, only Great Lakes Carbon appeared to pose severe siting constraints because of severe limitations on the amount of space available for the scrubbers and the ancillary equipment (Table 56).

TABLE 56. ENGINEERING ASSESSMENT OF SITE SPECIFIC INSTALLATION FEASIBILITY -- INDUSTRIAL SITES

Installation	Unit or plant rating	No. of units	No. of scrubbers[d]	Installation complexity[a]
Carbon monoxide boiler -- Chevron	250,000 lb/hr steam	1	2	Nominal
Petroleum coke calcining kilns				
Great Lakes Carbon	2700 tons/day raw coke	3	3	Difficult
Martin Marietta Carbon	960 tons/day raw coke	1	1	Nominal
Sulfuric acid units				
Stauffer Chemical	800 tons/day sulfuric acid	3	3[e]	Moderate
Collier Carbon	450 tons/day sulfuric acid	1	1[b]	Nominal[c]

[a]Primarily based on availability of space
[b]Existing
[c]If additional scrubber is required; see discussion in Section 4.3.2
[d]Double alkali process
[e]Nonregenerable lime process

4.4.2.1 Chevron

The Chevron fluid catalytic cracker carbon monoxide boiler (Figure 42) is in the central portion of the El Segundo facility. Adequate space is available for siting either a double alkali or lime-based system.

The boiler, which is approximately equivalent to 80 megawatts, requires a single scrubber module, 21 feet in diameter. This is based on the double alkali process requirements (Section 4.3.2). For multiple-unit lime scrubber installation, two 16-ft-diam units are required. The latter is shown in Figure 42. The filter building is estimated to be 25×25 feet; the waste holding pond, $30 \times 40 \times 10$ feet; and the scrubber equipment area, 4000 square feet. These are shown between Substation 11 and Catalyst Street, west of Coke Street. See, also, the plot plan in Figure B-9 in Appendix B. Tables 57 and 58 present the various siting impacts of the installations.

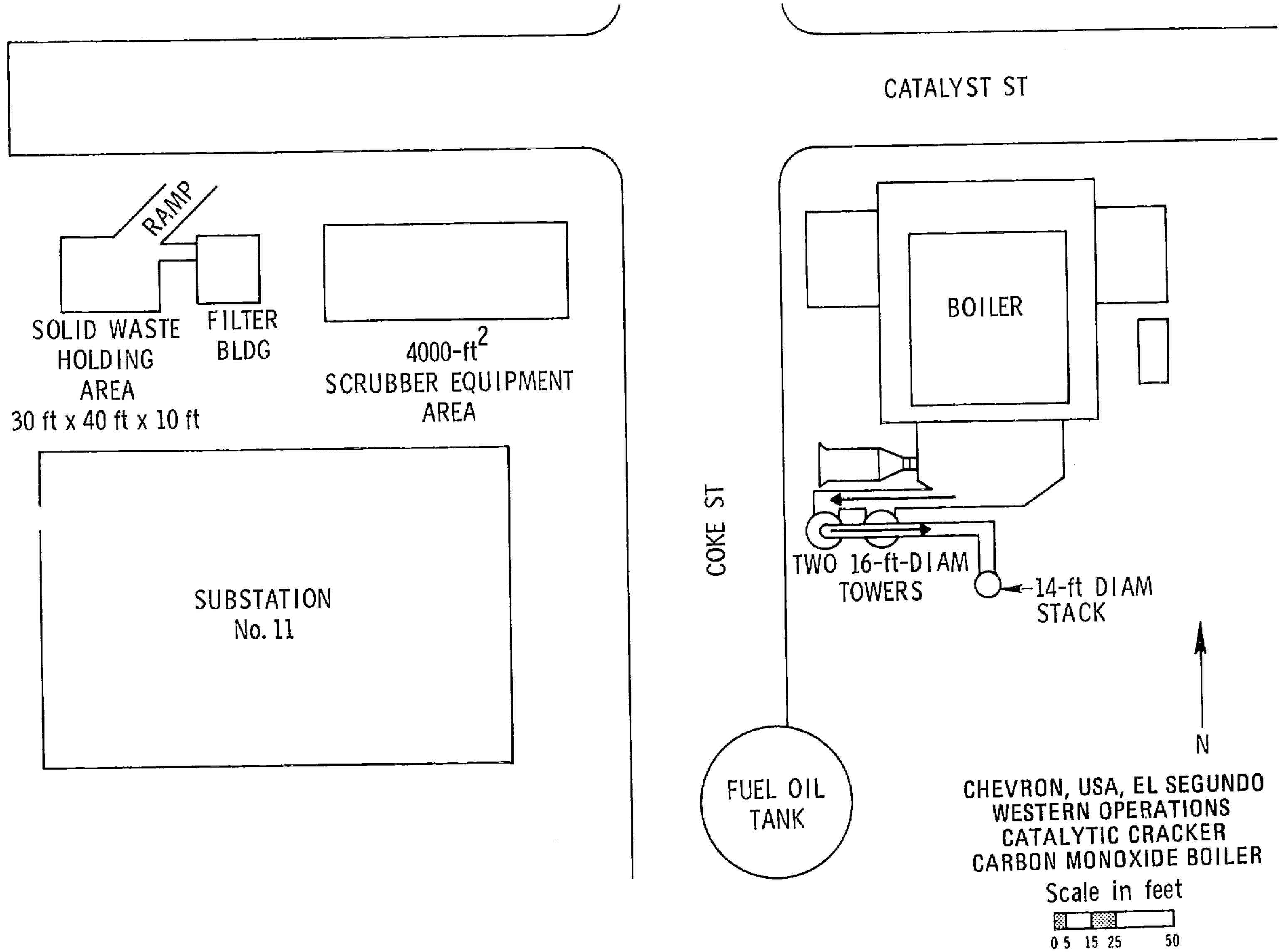

Figure 42. Scrubber equipment siting: Chevron, El Segundo

TABLE 57. SCRUBBER SITING: CHEVRON, U.S.A.[a]

Process	No. of absorbers	Absorber diam × height, ft	Absorber location	Impact[b]
Lime	2	16 × 63	In area west of existing stack and east of existing road	May restrict access to existing equipment. A new stack or stack lining may be required due to potentially corrosive conditions of the flue gas.
Double alkali	1	21 × 67	In area west of existing stack and east of existing road	Same as above. Also a 1.5-gpm calcium sulfite solution purge (9.0 tons/day) must be disposed, in in addition to the solid waste.

[a] Reference: Chevron, U.S.A. Dwg. SA-57080-17, Catalytic Cracking Unit Plot Plan, 10-10-72 (Figure B-9, Appendix B).

[b] Impact on underground facilities, lines, and equipment is unknown. If new stack is required, stack and absorbers may be located west of road and north of existing electrical substation.

TABLE 58. OTHER MAJOR SCRUBBER EQUIPMENT SITING: CHEVRON, U.S.A.[a]

Equipment	Size[b]	Potential location	Impact[c]
Scrubber equipment (thickener, slurry tank, slaker, and lime storage bin)	Total area, 400 ft^2, 80×50 ft	South and west of existing roads, in vicinity of intersection (north of electrical substation)	None apparent
Solid waste holding pond	$30 \times 40 \times 10$ ft (approx 60-day supply)	Approximately 100 ft west of scrubber equipment area	None apparent
Filter building	25×25 ft	Between holding pond and scrubber equipment area	None apparent

[a] Reference: Chevron, U.S.A. Dwg SA-57080-17, Catalytic Cracking Unit Plot Plan, 10-10-72 (Figure B-9, Appendix B).

[b] Areas required for lime or double alkali scrubbing processes are approximately the same.

[c] Impact on underground facilities, lines, and equipment is unknown.

4.4.2.2 Great Lakes Carbon

The Great Lakes Carbon plant is comprised of four petroleum coke calcining kilns. Three kilns, Nos. 2, 3, and 4, are operational. There are no current plans to operate kiln 1 because of its lack of a particulate control system, which in the case of kilns 2, 3, and 4 are fabric filter units. Therefore, only kilns 2, 3, and 4 were considered in this study.

The site is approximately 11 acres, and the availability of space to locate scrubbers and ancillary equipment is limited. The installation of single 23-ft-diam scrubber modules appears to be feasible although difficulty will be encountered because of space limitations. Figures 43 and 44 indicate the potential location for the scrubbers and ancillary equipment. This is further depicted photographically in Figures 45 through 53, which illustrate the limited space in the vicinity of the stacks for kilns 2, 3, and 4, wherein the scrubbers would be located.

Other major equipment including three 16-ft-diam thickeners, a filter building, and a 65 × 65 × 15 ft waste holding area may be located in a parking area southeast of the Administration building (Figure 44). The lime storage and slaking area is shown in Figure 43 in an open area at the north side of the facility.

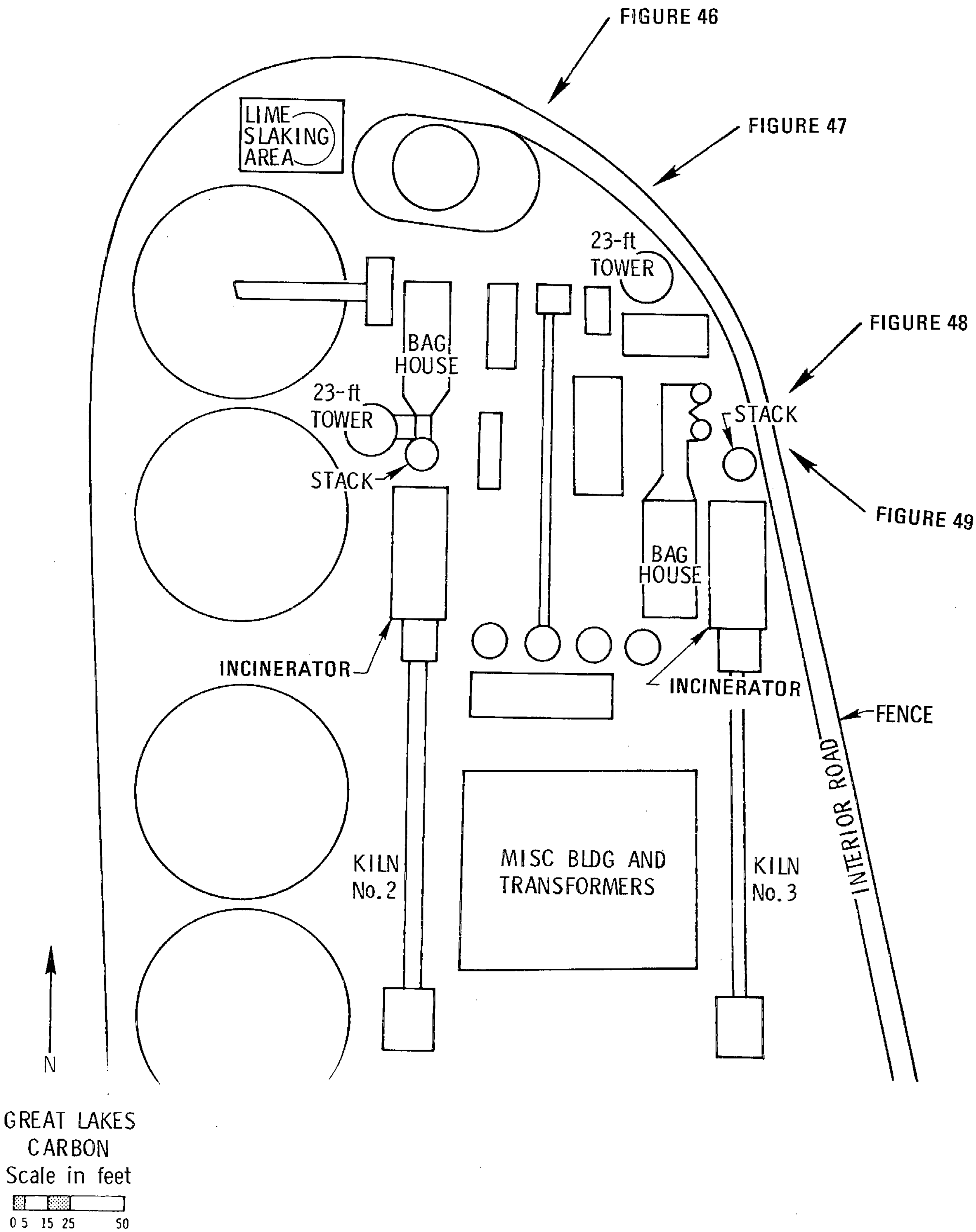

Figure 43. Scrubber equipment siting: Great Lakes Carbon; Kilns 2 and 3

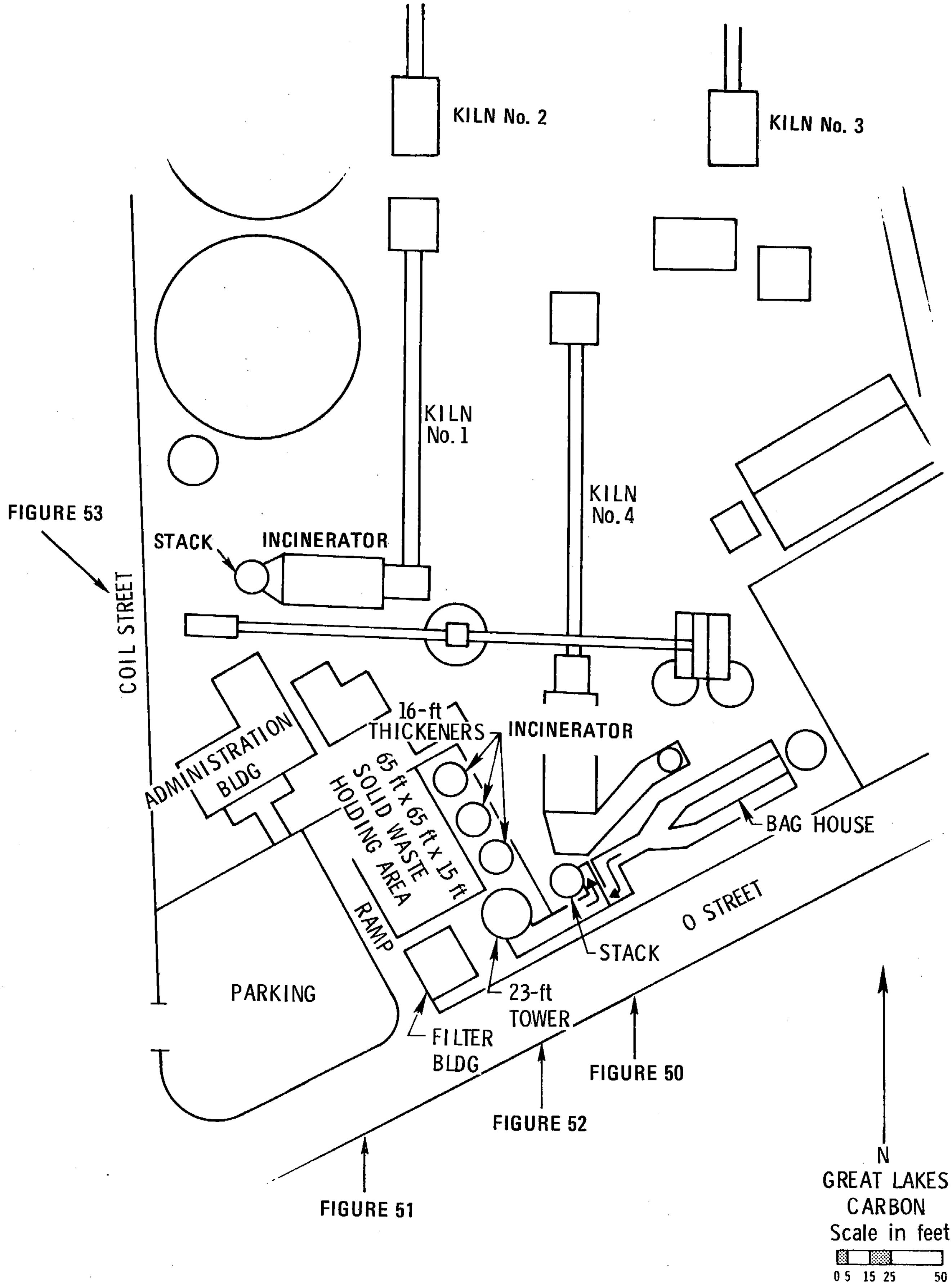

Figure 44. Scrubber siting: Great Lakes Carbon: Kiln 4

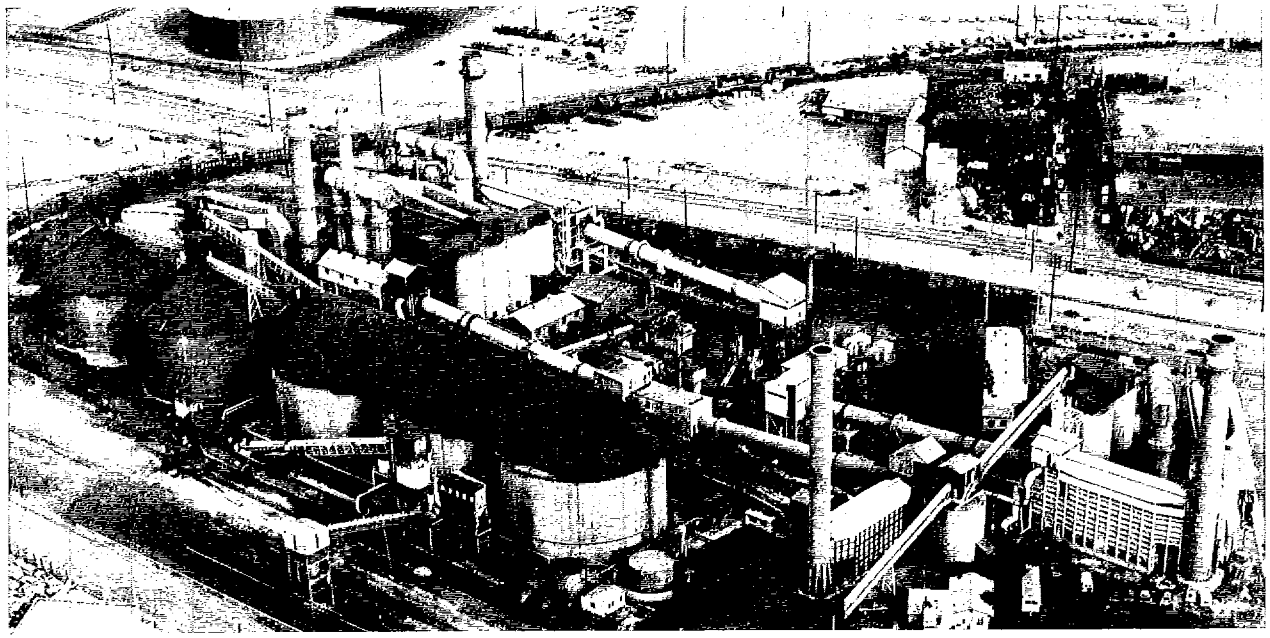

Figure 45. Great Lakes Carbon: overview

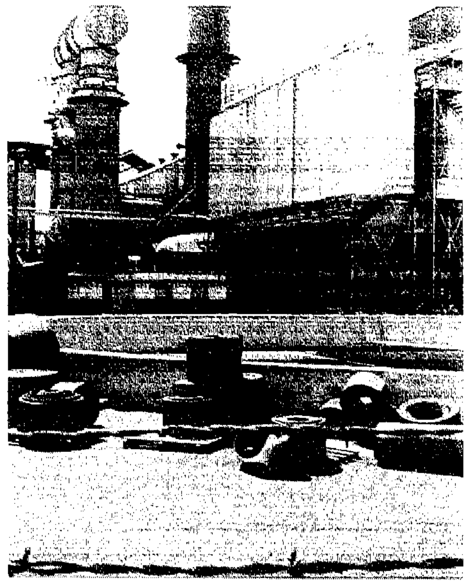

Figure 46. Kiln 2: baghouse and stack area

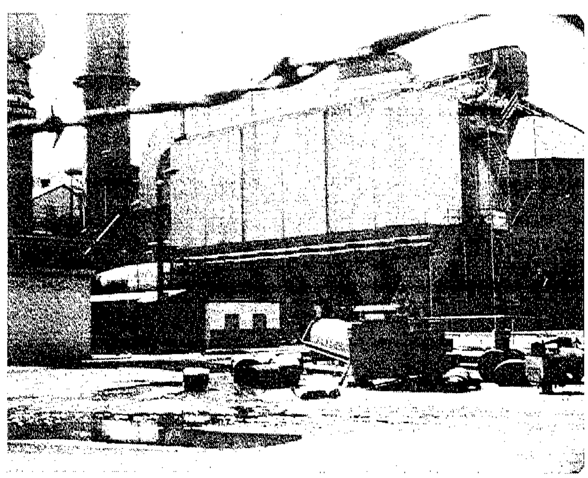

Figure 47. Kiln 2: baghouse and stack area

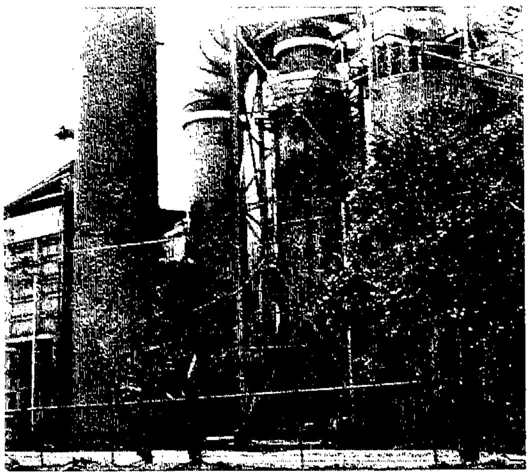

Figure 48. Kiln 3: incinerator, stack

Figure 49. Kiln 3 ducting

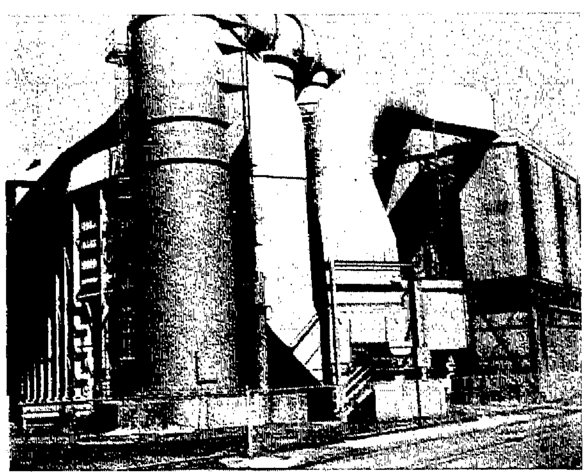

Figure 50. Kiln 4: incinerator, stack, and baghouse (l-r)

Figure 51. Administration building, parking lot, and stack (Kiln 1), with stack no. 2 in background

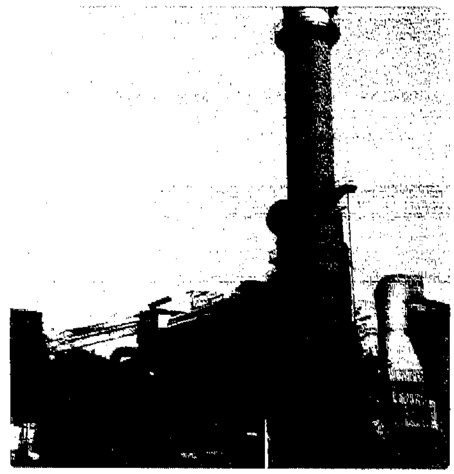

Figure 52. View looking north (east of Figure 51), vicinity of Kiln 4 stack

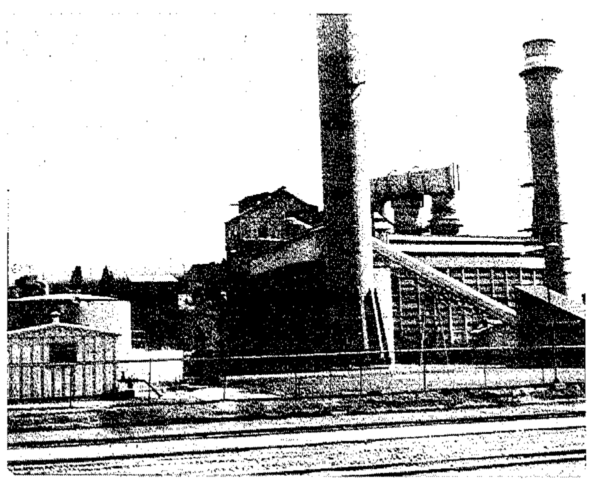

Figure 53. Kiln 1 and stack; Kiln 4 stack in right background

4.4.2.3 Martin Marietta Carbon

The Martin Marietta petroleum coke calcining plant is located on an 8-1/2 acre site in Carson, California (see Figure B-10, Appendix B, for plot plan). It is a single kiln installation as discussed in Section 4.3.2. Currently, the exhaust gases leave the carbon-particles afterburner (Figure 54) and pass through a wet ionizing scrubber as a final particulate removal step, prior to exiting via the stack. Both double alkali and lime scrubbing processes were considered. In both cases, the scrubber equipment area is depicted as being accommodated east of the SO_2 scrubber modules. A possible location for the waste processing area is shown east of the receiving area. Several other locations appear feasible in the event the placement of the waste processing equipment restricts accessibility to the receiving area (see plot plan, Figure B-10, Appendix B). Three 15-ft-diam lime scrubbers are shown. A single 23-ft scrubber module, typical of a double alkali installation, could also be accommodated. A summary of scrubber system siting impacts is provided in Tables 59 and 60.

Since the intent of this study was to assess feasibility of SO_2 scrubbing and not optimize scrubbing processes for each site, the double alkali scrubber was selected as a feasible approach (Section 4.3.2). However, it is understood that Martin Marietta Carbon is considering an alternative approach by modifying their existing wet ionizing particulate scrubber to reduce SO_2 emissions.

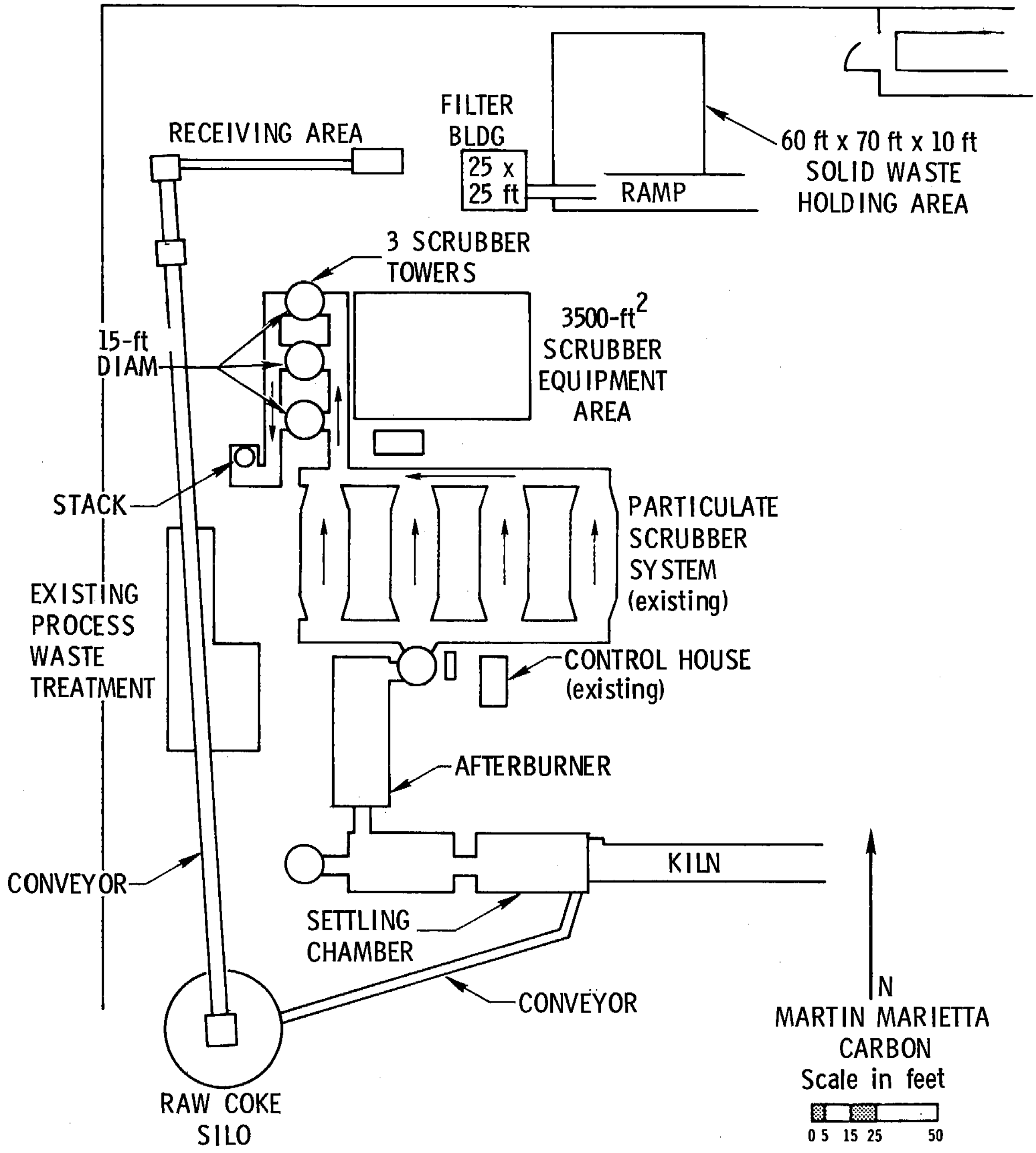

Figure 54. Scrubber equipment siting: Martin Marietta Carbon

TABLE 59. SCRUBBER SITING: MARTIN MARIETTA CARBON[a]

Process	No. of Absorbers	Absorber diam $\times$ height, ft	Absorber location	Impact[b]
Lime	3	15×60	North of existing stack and east of raw coke conveyor	Duct required from existing manifolding to scrubber and then from scrubber to stack. System has about 12% excess capacity. Also capability available to loss one scrubber and operate at about 75% of kiln capacity.
Double alkali	1	23×72	North of existing stack and east of raw coke conveyor	0.8 gpm sodium sulfate solution purge (4.8 tons/day), must be disposed in addition to solid waste.

[a]Reference: Martin Marietta Carbon, Carson, Ca. DWG 22-56121-A1, Plot Plan, 7/15/77 (Figure B-10, Appendix B)

[b]Impact on underground facilities, lines, and equipment is unknown.

TABLE 60. OTHER MAJOR SCRUBBER EQUIPMENT SITING: MARTIN MARIETTA CARBON[a]

Equipment	Size[b]	Potential location[b]	Impact[c]
Scrubber equipment (thickener, slurry tank, slaker, and lime storage bin)	Total area 3500 ft^2 70×50 ft	Open area north of exit manifold of wet ionizing scrubbers	None apparent
Solid waste holding pond	$65 \times 65 \times 10$ ft (approx. 60-day supply)	Adjacent (south) to north property line and east of raw coke receiving area	None apparent
Filter building	25×25 ft	West of solid waste holding area and north of scrubber equipment area	None apparent

[a] Reference: Martin Marietta Carbon, Carson, Ca. 90732, Dwg. 22-56121-A1, Plot Plan, 7/15/77 (Figure B-10, Appendix B)

[b] Areas required for lime or double alkali scrubbing process are approximately the same.

[c] Impact on underground facilities, lines and equipment is unknown.

4.4.2.4 Stauffer Chemical

Three sulfuric acid units are located within the Stauffer Chemical, Dominguez plant, a 33-acre site in Carson, California. The low volumetric flow of the exhaust gases results in a requirement for a single 6-ft-diam lime-based SO_2 scrubber tower for each unit. The scrubber locations are depicted in Figure 55 for Units 1 and 3 and in Figure 56 for Unit Unit 2. The scrubber ancillary equipment includes the lime silo and thickener and requires approximately 600 square feet for each scrubber installation. The location for each unit is also shown. Units 1 and 2 stacks as viewed from Wilmington Avenue are shown in Figures 57 and 58, respectively (see also plot plan, Figure B-11, Appendix B). Several possible locations for a filter bulding and 60-day waste holding pond are shown in Figure 59.

A summary of scrubber and equipment siting considerations are summarized in Tables 61 and 62.

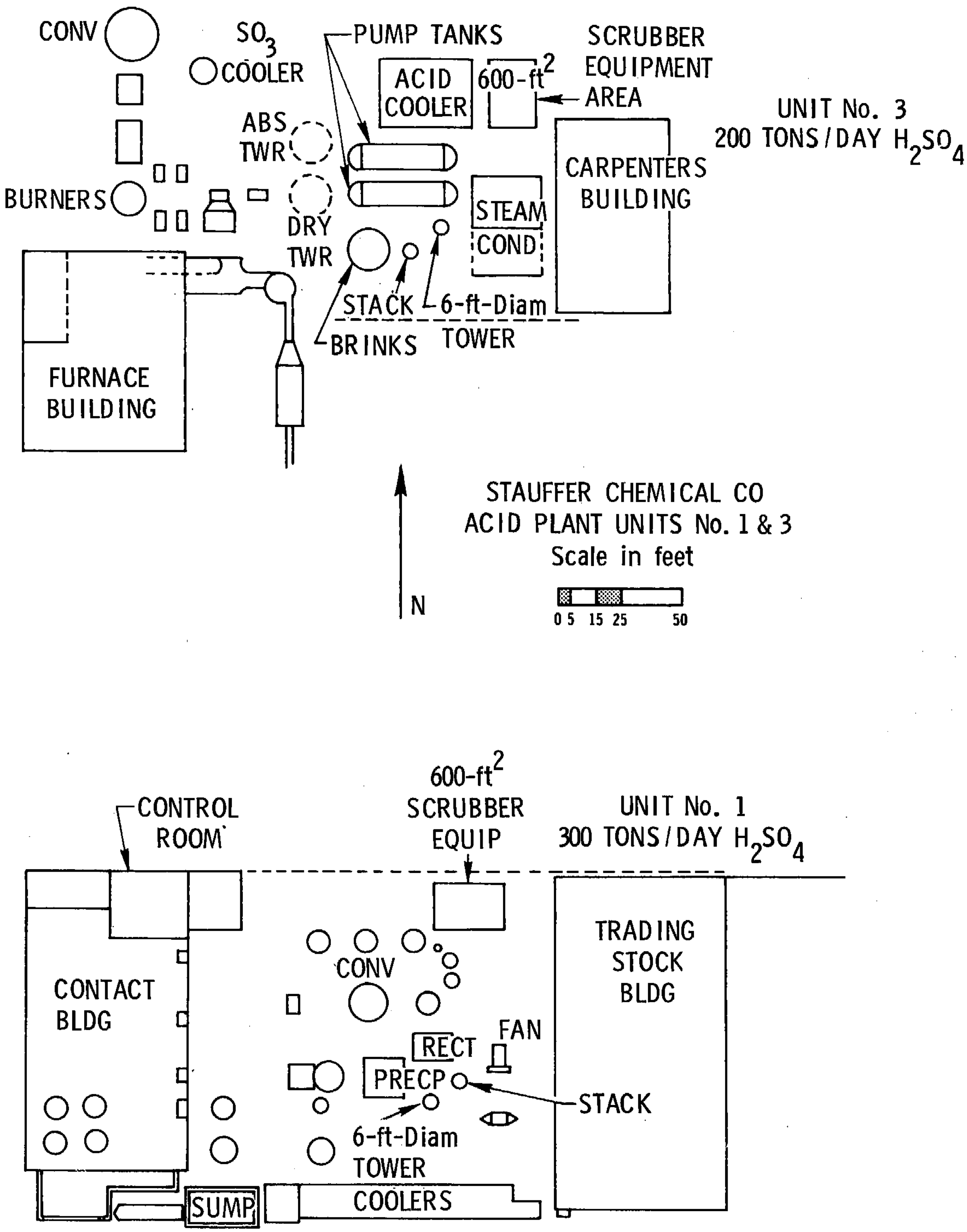

Figure 55. Scrubber equipment siting: Stauffer Chemical, sulfuric acid Units 1 and 3

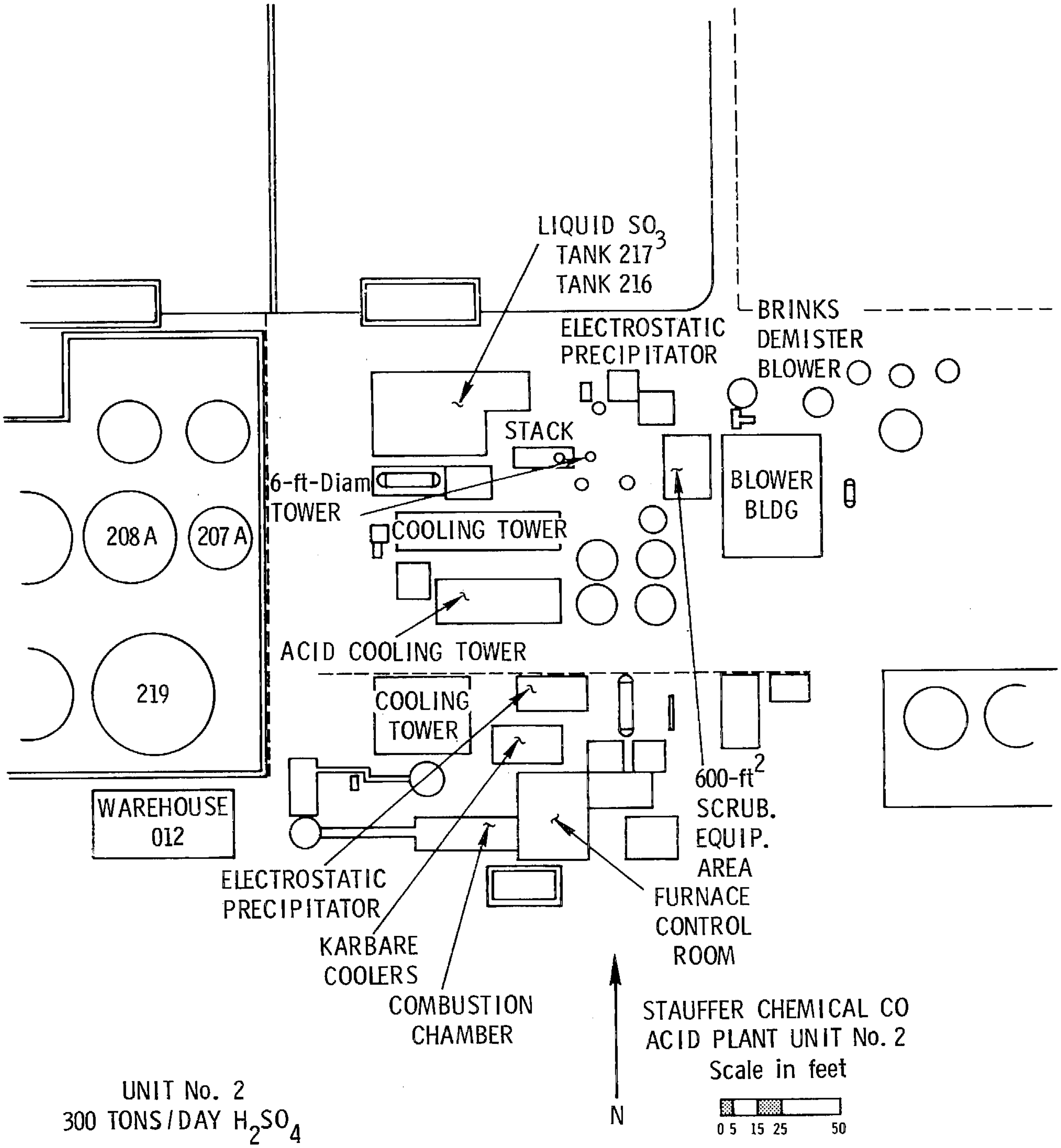

Figure 56. Scrubber equipment siting: Stauffer Chemical, sulfuric acid Unit 2

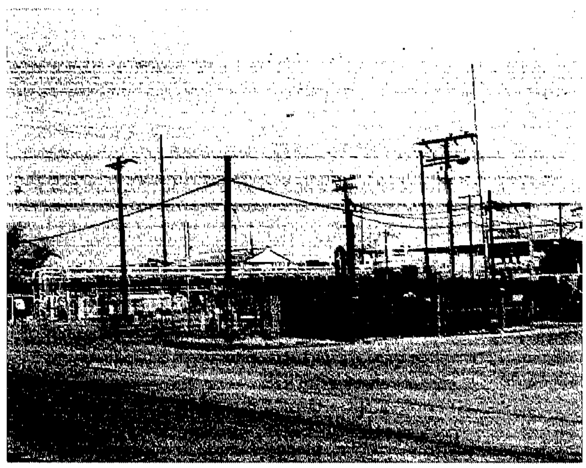

Figure 57. Stauffer Chemical: stack of sulfuric acid Unit 1 in center

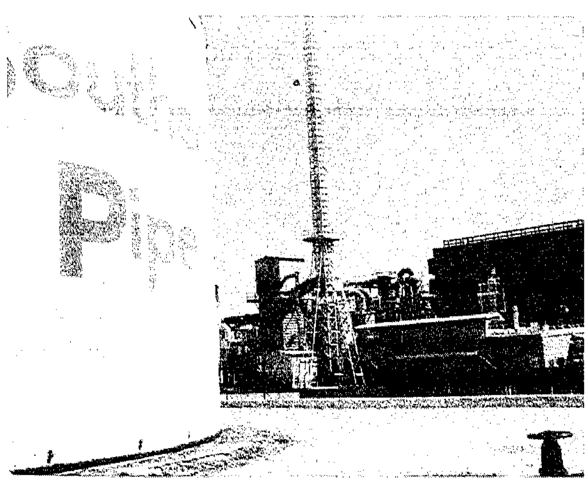

Figure 58. Stauffer Chemical: stack of sulfuric acid Unit 2

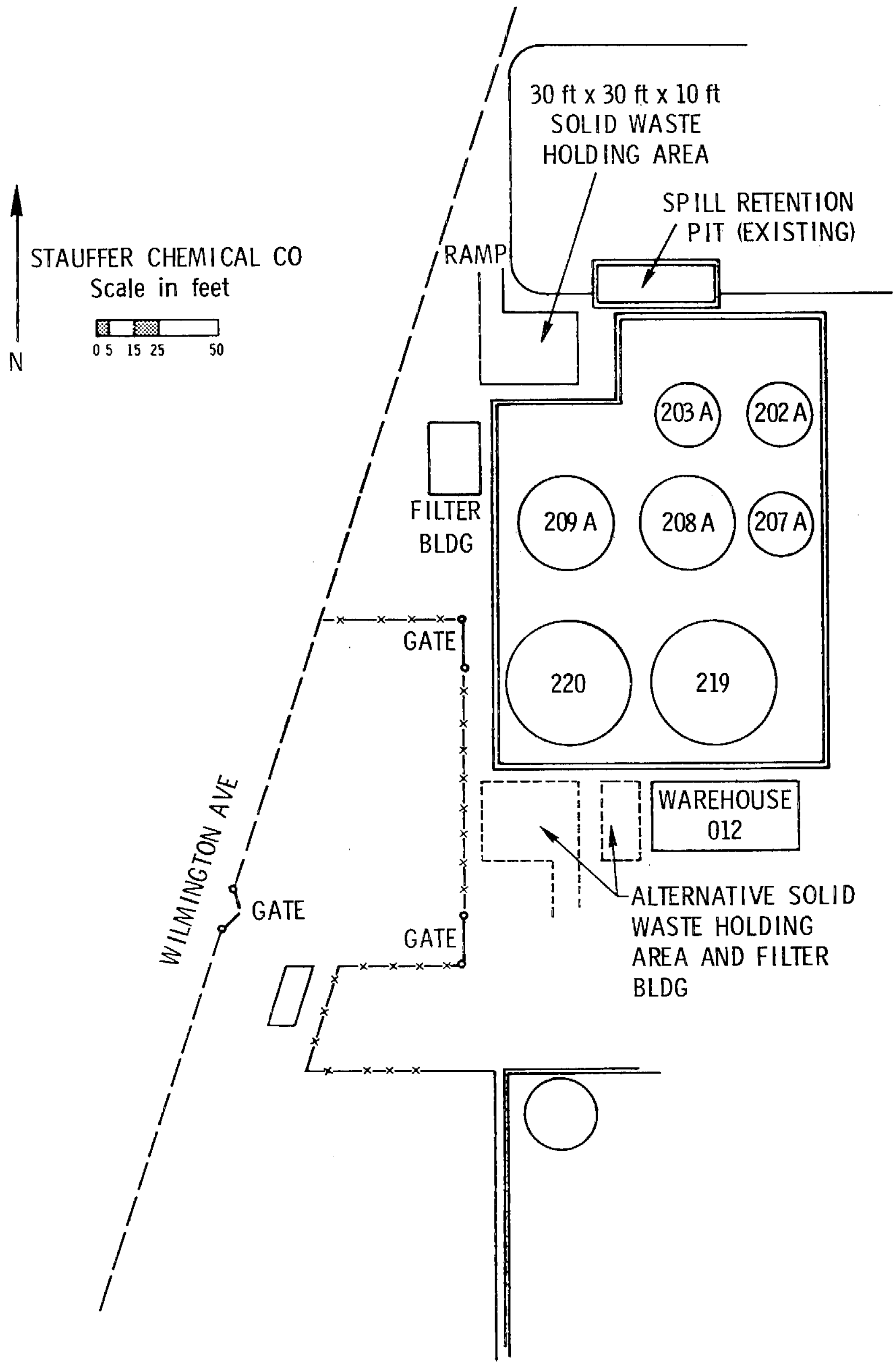

Figure 59. SO_2 scrubber waste filtering and holding areas: Stauffer Chemical

TABLE 61. SCRUBBER SITING: STAUFFER CHEMICAL CO., DOMINGUEZ PLANT[a]

Process	Unit	No. of Absorbers	Absorber diam × height, ft	Absorber location	Impact[b]
Lime	1	1	6 × 20	In vicinity of stack (east of precipitator and west of stack)	None apparent
Lime	2	1	6 × 20	In vicinity of stack (south of precipitator and east of stack)	None apparent
Lime	3	1	6 × 20	In open area (south of pump tank north-east of Brinks unit and stack	None apparent

[a]Reference: Stauffer Chemical Co. Drawing No. 1048-1-1, Plot Plan of Dominguez Plant, Rev. 8, 6-16-77 (Figure B-11, Appendix B).

General Notes:

1. Impact on underground facilities, lines, and equipment is unknown.
2. New ductwork to enable use of existing stack entry locations while heating acid unit in operation during major portion of scrubber installation may be complex.

TABLE 62. OTHER MAJOR SCRUBBER EQUIPMENT SITING: STAUFFER CHEMICAL, DOMINGUEZ PLANT[a]

Unit	Equipment	Size	Potential location[a]	Impact
1	Scrubber equipment (thickener, slurry tank, slaker, and lime silo)	600 ft^2 (approx. 20 × 30 ft)	Vicinity of northwest corner of trading stock bldg (33C), adjacent to roadway	Pump slurry, approx. 600 ft to filter
2	Scrubber equipment (thickener, slurry tank, slaker, and lime silo)	600 ft^2 (approx. 20 × 30 ft)	West of blower bldg and south of electro-static precipitator	Pump slurry, approx. 400 ft to filter
3	Scrubber equipment (thickener, slurry tank, slaker, and lime silo)	600 ft^2 (approx. 20 × 30 ft)	East of acid cooler and north of steam condenser, or west of acid cooler and north of absorption tower	None apparent
1, 2, 3	Filter building	20 × 30 ft	West of warehouse bldg 012 and south of tank No. 220, or north of parking area and east of tank 209A	None apparent
1, 2, 3	Solid waste holding pond and truck loading area	30 × 30 × 10 ft deep (approx 60-day capacity)	West of filter building and south of tank No. 220, or north of parking area and east of tank 209A	None apparent

[a]Reference: Stauffer Chemical Drawing No. 1048-1-1, Plot Plan of Dominguez Plant, Rev. 8, 6-16-77 (Figure B-11, Appendix B)