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Environmental Protection Technology Series

SURVEY OF FLUE GAS DESULFURIZATION SYSTEMS

MOHAVE STATION, SOUTHERN CALIFORNIA EDISON CO.

U.S. Environmental Protection Agency
Office of Research and Development
Washington, D. C. 20460

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MOHAVE STATION, SOUTHERN CALIFORNIA EDISON CO.

by

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EPA REVIEW NOTICE

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Mr. Wade H. Ponder, former EPA Project Officer, had primary responsibility within EPA for this project report. Information and data on plant operation was provided by Dr. Alexander Weir, Jr., Southern California Edison Company, during and subsequent to the survey visit. Mr. Charles D. Fleming was responsible for editorial review of this report.

The authors appreciate the efforts and cooperation of everyone who participated in the preparation of this report.

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SUMMARY

Two prototype sulfur dioxide absorber modules were installed in 1973 at the Mohave Generating Station of Southern California Edison Company. A vertical module rated at 170 MW was installed to treat a 450,000 scfm portion of the flue gas from Unit 1 and a horizontal module, also rated at 170 MW, was installed to treat a similar flue gas portion from Unit 2. Units 1 and 2 are identical boilers each having a maximum net continuous generating capacity of 790 MW. Each unit burns 390 ton/hr of pulverized coal at full load. The heat content of the coal is about 11,500 BTU/lb. The ash and sulfur content are approximately 10 and 0.4 percent, respectively.

The vertical absorber was in the process of starting up when it was damaged by a fire on January 24, 1974. The unit was subsequently rebuilt and was restarted for test operations which were conducted from November 2, 1974, to April 1975. The unit was modified for additional tests which were completed July 2, 1975.

The horizontal module was operated from November 1, 1973, to January 16, 1974, for shakedown purposes. During a test program from January 16, 1974 to February 9, 1975, the

unit operated for 5927 hours in various test modes. This module has been dismantled and removed from the station.

Particulate and SO_2 removal efficiencies varied with the tests that were run. The emission regulation for this plant is 0.15 lb/MM BTU for sulfur dioxide. Both absorbers are preceded by electrostatic precipitators operating at 98.2 percent efficiency, but designed at 97.2 percent efficiency.

The spent limestone slurry from the vertical absorber is thickened in a clarifier, vacuum filtered or centrifuged, and converted to aggregate at an on-site IU Conversion Systems, Inc. plant. The filtrate water is returned to the absorber.

The spent lime slurry from the horizontal module was thickened in a clarifier and pumped to a disposal pond. Calcilox, a sludge stabilizer manufactured by the Dravo Corporation, was mixed into the thickened slurry before it entered the disposal pond. Supernatant liquor was pumped back from the pond to the absorber. This system operated in a closed water loop. Estimates of capital and annual operating costs have not been published.

Pertinent facility and FGD operational data are summarized in the following table.

SUMMARY OF FGD DATA - MOHAVE

Identification	Vertical module UOP	Horizontal module SCE
Module rating, MW (net)	170	170
Fuel	Coal	Coal
Gross heating value, BTU/lb	11,500	11,500
Ash, percent	10	10
Sulfur, percent	0.4	0.4
Process	Wet limestone (lime alternate)	Wet lime (limestone alternate)
New or retrofit	Retrofit	Retrofit
Start-up date	January 1, 1974	November 1, 1973
Start of test program	November 2, 1974	January 16, 1974
Efficiency, %		
Particulates	Not available	Not available
SO_2	Not available	75 - 98
Water make-up, gpm/MW (net)	Not available	Not available
Sludge disposal	Converted to aggregate	Stabilized in sludge pond

1.0 INTRODUCTION

The Control Systems Laboratory of the U.S. Environmental Protection Agency has initiated a study to evaluate the performance characteristics and degree of reliability of flue gas desulfurization (FGD) systems on coal-fired utility boilers in the United States. This report on the Mohave Generating Station of the Southern California Edison Company is one of a series of reports on such systems.

This report is based on information obtained during and subsequent to a plant survey visit on July 24, 1974.

Section 2.0 presents pertinent data on facility design and operation including allowable SO_2 emission rates. Section 3.0 describes the flue gas desulfurization system and Section 4.0 analyzes FGD system operating history.

2.0 FACILITY DESCRIPTION

The Mohave Generating Station, operated by Southern California Edison Company (SCE), is located in Clark County, Nevada, about ten miles north of the southern tip of Nevada. The plant is situated in a sparsely populated desert area. The Lake Mead National Recreational Area lies 20 miles north of the plant, and the Fort Mohave Indian Reservation is 10 miles to the south. The plant is jointly owned by the City of Los Angeles Department of Water and Power, Nevada Power Company, the Salt River Project Agricultural Improvement and Power District and Southern California Edison Company.

The station consists of two coal-fired generating units, each rated at 790 MW (net). The boilers are Combustion Engineering, dry-bottom, pulverized-coal-fired units. Unit 1 was placed in service in 1970; Unit 2 in 1971.

Low-sulfur coal is transported to the station from the Black Mesa Mine via a 285-mile slurry pipeline. Average coal characteristics are 11,500 BTU/lb, 10 percent ash and 0.4 percent sulfur. The maximum fuel sulfur content anticipated for this station is about 0.60 percent, corresponding to a furnace outlet SO_2 concentration of about 1.0 SO_2/MM BTU. The maximum SO_2 emissions allowed under the

Clark County Regulation[a] is 0.15 lb SO_2/MM BTU input to the boiler.

Research-Cottrell electrostatic precipitators (ESP), operating with an efficiency of 98.2 percent, provides primary particulate emission control for each boiler.

The installation of five FGD modules on each boiler at this station would be necessary to comply with the existing Clark County regulations. Module selection will be based on the results obtained from the operation of the two experimental test modules described in this report.

Table 2.1 presents pertinent data on plant design, operation and atmospheric emissions.

---

[a] On May 20, 1975 a new Nevada law became effective which prohibits the enforcement of the Clark County Air Pollution Control regulations on the Mohave Generating Station until July 1, 1977 and requires the State of Nevada Environmental Commission to hold hearings prior to July 1, 1976 for the purpose of reviewing all contaminant emission standards applicable to fossil-fuel-fired steam generating facilities.

Table 2.1 PERTINENT DATA ON PLANT DESIGN, OPERATION AND ATMOSPHERIC EMISSIONS

Boiler identification number	1	2
Rated generating capacity, MW (net)	790	790
Average capacity factor, 1973		
Served by stack no.	1	1
Boiler manufacturer	CE	CE
Year placed in service	1970	1971
Maximum coal consumption, ton/hr	390	390
Maximum heat input, MM BTU/hr	10,000	10,000
Stack height above grade, ft.	500	500
Flue gas rate - maximum, scfm @ 60°F	2,100,000	2,100,000
Flue gas temperature, °F	270	270
Emission controls:		
Particulate	electrostatic precipitator	
SO_2 (treats 450,000 scfm of each unit only)	Vertical absorber module	Horizontal absorber module
SO_2 emission rate:		
Allowable, lb/MM BTU	0.15	0.15
Actual, lb/MM BTU	Not available	

3.0 FLUE GAS DESULFURIZATION SYSTEMS

3.1 PROCESS DESCRIPTION

In 1971 and 1972 eight different pilot plant FGD systems were tested at the Mohave Station. At the conclusion of these tests SCE decided that two prototype FGD modules should be installed at Mohave, each sized to handle one-fifth of the gas flow from one of the generators. Accordingly, a Universal Oil Products Company (UOP) turbulent contact absorber (TCA) vertical module was installed on Unit 1 to operate using limestone, and a Southern California Edison four-stage, countercurrent, horizontal unit was installed on Unit 2 to use a lime slurry. Results of the operational test programs for these two units will be used to determine the type of full-scale system that would be suitable for the station. These results will also be used to specify equipment for installation at the Navajo Station to be constructed by the Salt River Project Agricultural Improvement and Power District and possibly for the Kaiparowitz Station of SCE.

Vertical Module

Flue gas from the ESP on Unit 1 passes through a 5,500 horsepower booster fan before it enters the vertical module shown in Figure 3.1. The UOP unit is designed to treat 450,000 scfm of exhaust gas. The liquid-to-gas contacting ratio (L/G) for the unit is 83 gallons of limestone slurry per 1000 scf of flue gas. The design gas velocity through the unit is 12.6 ft/sec. In its original configuration, this unit was a four-stage turbulent contact absorber (TCA). The unit has subsequently been modified for further testing. Electric power consumption for the TCA system amounts to about 3 percent of the total generating capacity of the station, whereas for the horizontal spray chamber installation on Unit 2 the electric power consumption is only about one-half as high (1.5%).

As shown in Figure 3.1, exhaust gas from the Unit 1 boiler passes through an electrostatic precipitator and a forced draft fan before it enters the TCA. The gas flows upward through the absorber, passes through a demister which is washed continuously, and is reheated from 120° to about 175°F by a direct heat exchanger located in the exit duct. The boiler supplies the steam for this heater.

The rate of limestone addition to the FGD system is equivalent to about 130 percent of the stoichiometric rate required for reaction with sulfur dioxide in the gas. Part of the slurry from the circulation tank is diverted to a clarifier for thickening. The thickened sludge can be dewatered either by a vacuum filter or by a centrifuge. The filtrate is returned to the hold tank, and the dewatered

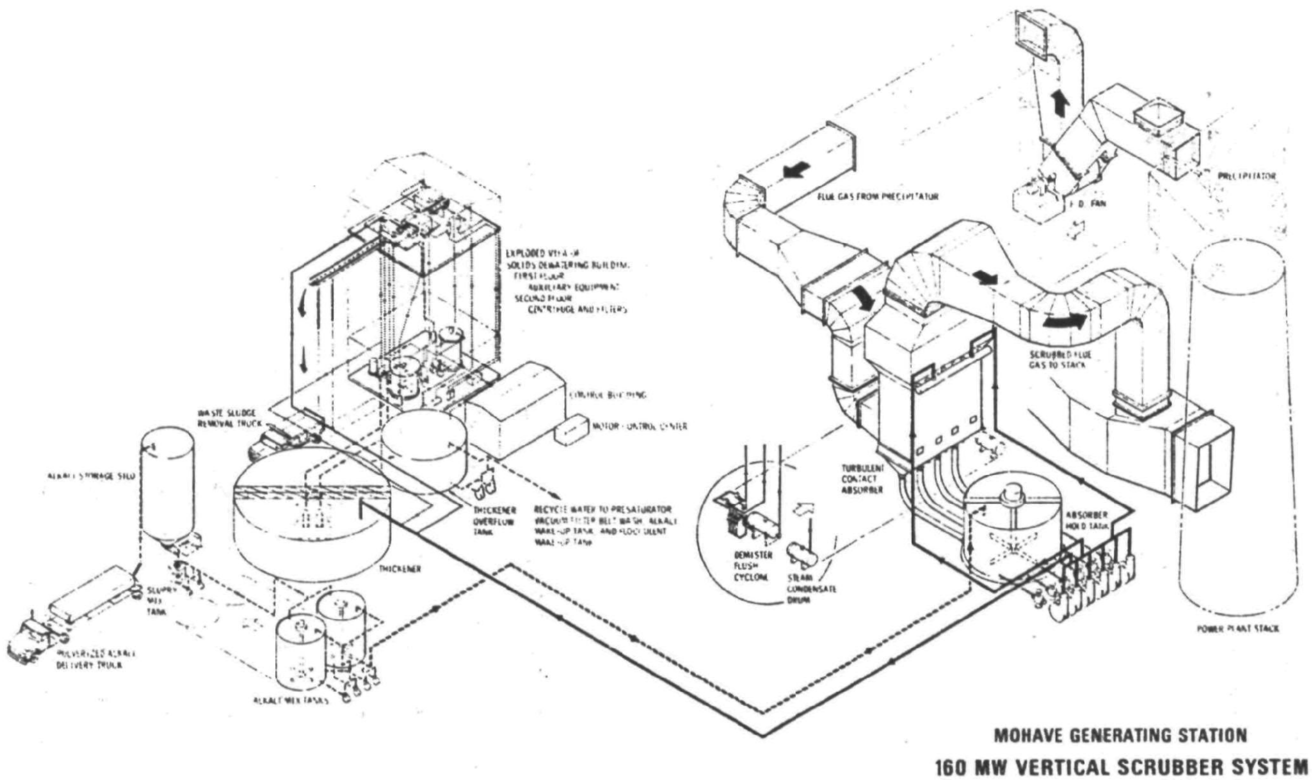

Figure 3.1 A simplified sketch of the vertical TCA type FGD system which is installed on Mohave 1.

sludge is hauled by truck to an on-site IU Conversion Systems plant where it is made into aggregate.

Limestone for the FGD system is purchased in ground form from La Habra Products in Lucerne Valley, California.

There are no limestone milling facilities on-site at the present time. Instead, finely-ground limestone is stored in a 300 ton silo. A slurry tank is provided for the scrubbing system.

Separate control rooms are provided for the horizontal and vertical absorbers.

Horizontal Module

Flue gas from Unit 2 passes through the ESP and through a 1750 horsepower booster fan before it enters the horizontal module shown in Figure 3.2. The booster fan requirements for this module are less than for the vertical module due to a decreased pressure drop through the absorber. The module, designed by SCE, was scaled up from a 1 MW pilot unit previously tested by SCE. Lime slurry is sprayed from nozzles in the top of the scrubber perpendicular to the gas flow. There is no packing in this spray chamber module. The module consists of four countercurrent stages with fresh slurry contacting the gas having the lowest SO_2 concentration. The unit operates with an L/G of 20-40 gallons of slurry per 1000 scf of flue gas. The liquid recirculation rate can be adjusted over a wide range. The horizontal module was designed to treat 450,000 scfm of flue gas. The

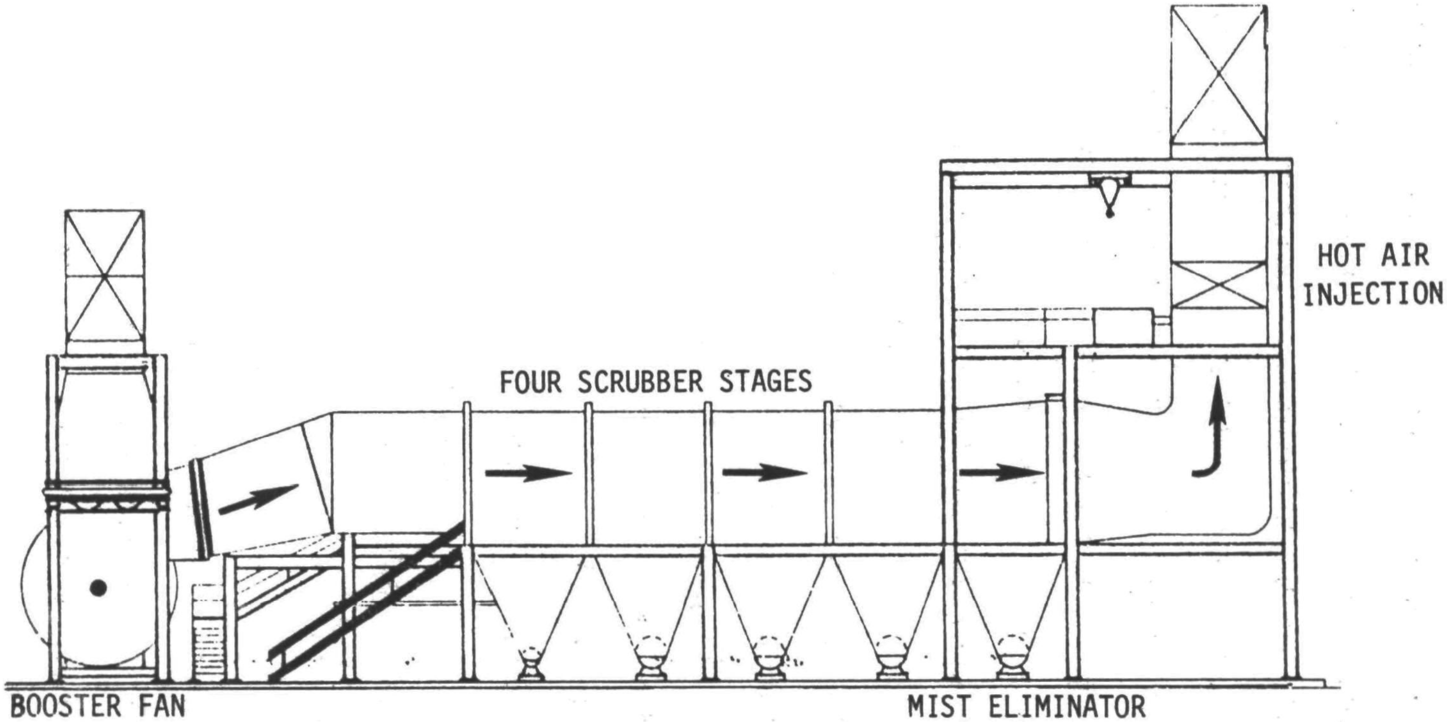

Figure 3.2 A simplified side view of the horizontal FGD module installed on Mohave 2.

design gas velocity through the unit is 21.6 ft/sec. Cleaned flue gas passes through a demister which is washed intermittently on both sides. The gas is then reheated from 120° to about 175°F by indirect heat exchange with hot air. Ambient air is preheated to about 400°F and is mixed with the cleaned gases as they exit from the module. This causes a 15 to 20 percent dilution of the flue gases. The boiler supplies the steam for this heater.

The rate of lime addition to the FGD system is about equivalent to the stoichiometric rate required for reaction with sulfur dioxide in the gas. Part of the slurry from the circulation tanks is pumped to a thickener and the underflow is then pumped to a lined pond, fixed with Calcilox supplied by Dravo, and allowed to settle. Supernatant water from the pond is recirculated to the horizontal module. The unit operates on a closed water loop; the only water leaving the system consists of water in the exit flue gas, water of hydration in the gypsum product, and a small amount of water (3% of total water leaving) evaporated in the sludge pond.

The present goal is to produce a sludge that will achieve a hardness sufficient to support a load of 2-4 tons per square foot within three months. Table 3.1 summarizes operating design parameters and specifications for the two FGD modules.

Table 3.1 SUMMARY OF PERTINENT DATA

FOR THE SO_2 ABSORBER MODULES

	Vertical module	Horizontal module
L/G ratio, gal./1000 scfm	83	20 to 40 for each of four stages
Superficial gas velocity, ft/sec	12.6	21.6
Equipment sizes, ft.	18 x 40 x 90 high	15 x 30 x 60 long
Equipment internals	4 stages of ping pong balls	sprays
Material of construction		
Shell	rubber lined	various linings
Internals	polypropylene/ inconel	none

3.2 INSTALLATION SCHEDULE

Work on the horizontal and vertical modules of the FGD system at the Mohave Power Plant was initiated in December 1972, and ground was broken in February 1973. Start-up of the horizontal unit was achieved on schedule November 1, 1973, but a major malfunction of the generating unit occurred on November 9, so that the start of the test program was delayed until January 16, 1974. Start-up of the vertical unit was January, 1974. However during the last phase of construction and start-up, on January 24, 1974, a fire inside the module caused appreciable damage to the internal rubber lining and other internals, and delayed start of the test program on that unit until October 31, 1974.

3.3 COST DATA

Data on the capital and annual operating costs of the FGD installations at the Mohave Plant have not been released.

4.0 FGD SYSTEMS OPERATING HISTORY

4.1 PERFORMANCE TEST PROGRAM

The initial start-up for the vertical module occurred on schedule on January 1, 1974. However, on January 24, 1974, the module sustained substantial damage from a fire of undetermined origin. The following repairs were made.

1. All internal structural members were replaced.
2. Deformed shell stiffeners were reinforced.
3. Distorted wall plates were replaced.
4. Internal piping was repaired or replaced.
5. Damaged internals, including demister and grid sections, were repaired or replaced.
6. Structural distortions were corrected.
7. Access door flanges were straightened or replaced.
8. Structural reinforcement was added.
9. Reheater supports were added.
10. Shell was sandblasted and relined with neoprene, replacing chlorobutyl rubber that had been used originally.
11. Distorted gratings and walkways were repaired or replaced.
12. Reheater shell was replaced.

Repair costs were estimated to be $1.6 million. Start of the test program was delayed until October 31, 1974.

Preliminary tests preceded start-up, and a formal test program was initiated on November 2, 1974. The program was concluded on April 30, 1975 with 2342 hours of operation, after which the system was shut down for modifications to a grid packed tower for additional tests. The overall operating time ratio for the system defined as the time the module operated as a percentage of the boiler operating time, was measured to be 60 percent during the first four months. Operating time data for the first four months of the test program appear in Table 4.1. The reliability of the system was lower in the first two months of the program than in the second two months, mainly because of migration of plastic spheres between adjacent grid compartments in the module, so that the unit had to be shut down for redistribution of the spheres and modification of the barrier grids. Other problems included pump failures, plugged spray nozzles, deposits on the demister and at the absorber inlet.

SCE operated the horizontal module in a short series of start-up tests that ended on January 16, 1974, when a formal test program was initiated to assess the performance and reliability characteristics of the system. The test program was concluded on February 9, 1975 after 5927 hours of operation. Subsequently the module has been dismantled and is being installed for tests at the Four Corners Plant operated by Arizona Public Service Company in Farmington, New Mexico.

Table 4.1 COMPARISON OF OPERATING TIME PARAMETERS

VERTICAL MODULE - MOHAVE - SCE

Month	Operating time ratio[a]	Reliability[b]	Availability[c]	Unavailability[d]
11/74	46	50	39	34.5
12/74	39	51	51	30.8
1/75	78	85	80	9.9
2/75	84	84	88	11.8
Overall	60	67	64	21.8

[a] FGD system actual operating time as a percentage of Unit 1 operating time.

[b] Actual FGD system operating time as a percentage of the time that the system was called upon to operate.

[c] Time FGD system was available to operate (whether or not operated) as a percentage of calendar time.

[d] Time FGD system was unavailable to operate when called upon to operate as a percentage of calendar time.

During the one-year program ten separate test blocks were conducted to obtain performance and operating data. Both lime and limestone reagents were tested. SO_2 spiking tests were also used to simulate the conditions with higher percent sulfur in the coal. Details of the SO_2 and particulate removal performance for this system were presented at the Atlanta symposium held by EPA in November, 1974.[1] SO_2 removal efficiency as a function of the L/G ratio, shown in Figure 4.1, ranged between 76 and 98 percent.

The overall operating time ratio for the system, defined as the time the FGD system operated as a percentage of the boiler operating time, was measured to be 73.5 percent during the one-year operation test. Month-by-month operating time data, as published by SCE, appear in Table 4.2.

Mechanical problems occurred during the test period. These problems included pump failures, a thickener underflow drain obstructed by a hard hat, fan alignment problems, scrubber spray nozzle failures, scrubber shell leaks and demister blade warping. In addition, a boiler makers strike occurred during the test period.

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[1] Weir, Alexander, Jr., et al, "The Horizontal Cross Flow Scrubber", Proceedings: Symposium on Flue Gas Desulfurization - Atlanta, November 1974, EPA Publication No. EPA 650/2-74-126a, pp 357-387.

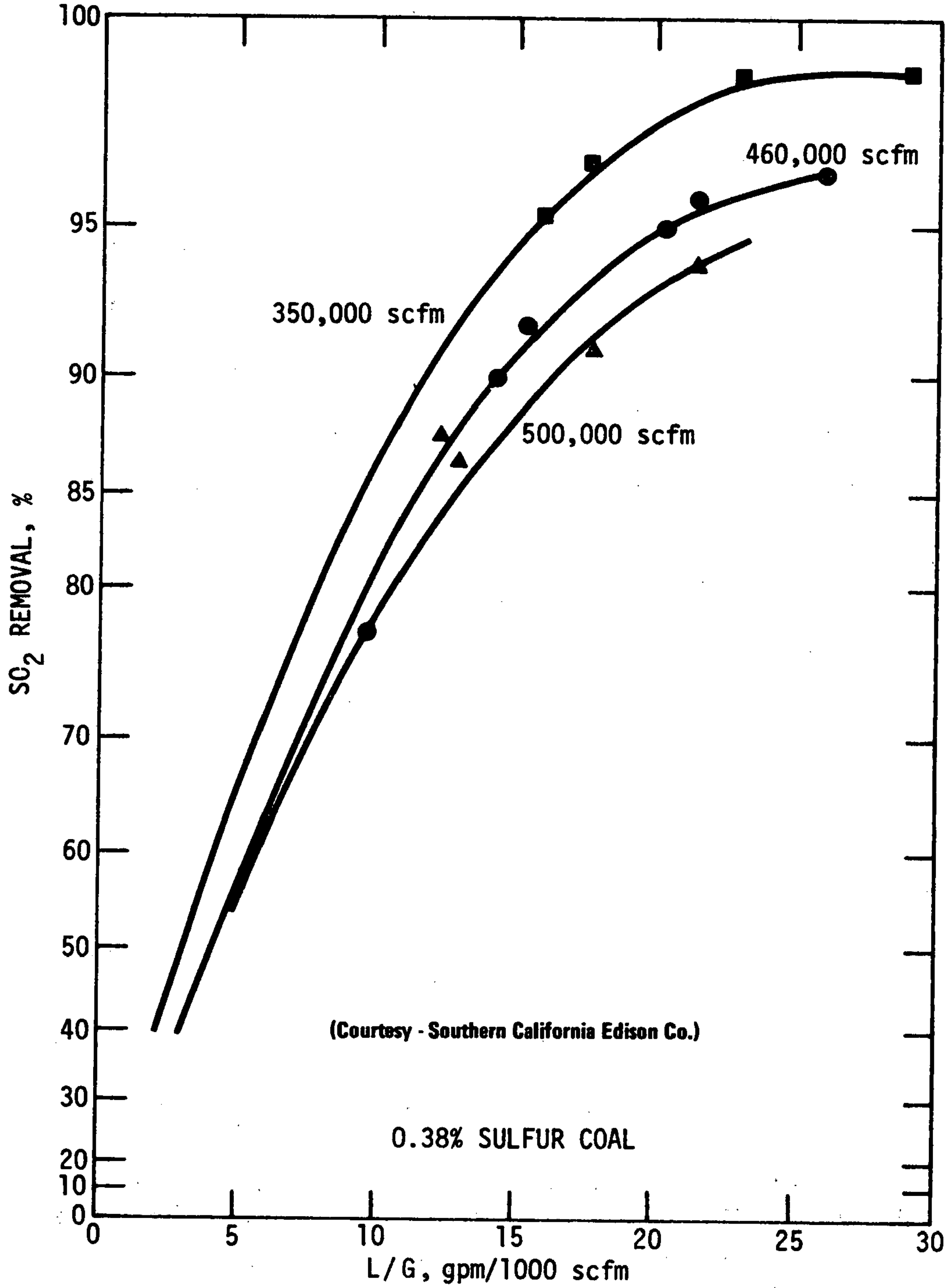


Figure 4.1 SO_2 Removal vs L/G Ratio
170 MW Horizontal Module.

Table 4.2 COMPARISON OF OPERATING TIME PARAMETERS

HORIZONTAL MODULE - MOHAVE - SCE

Month	Operating time ratio[a]	Reliability[b]	Availability[c]	Unavailability[d]
1/74	0.89	89	89	11
2/74	0.82	82	60	13
3/74	0.73	85	80	12
4/74	0.91	99	99	1
5/74	0.81	92	93	7
6/74	0.79	79	77	20
7/74	0.79	79	63	17
8/74	1.00	100	100	0
9/74	0.58	100	100	0
10/74	0.74	74	68	19
11/74	0.35	40	46	52
12/74	0.52	98	99	1
1/75	0.81	87	90	10
2/75	0.56	56	56	44
Total	0.74	87	81	13

[a] FGD system actual operating time as a percentage of Unit 2 operating time.

[b] Actual FGD system operating time as a percentage of the time that the scrubbing system was called upon to operate.

[c] Time FGD system was available to operate (whether or not operated) as a percentage of calendar time.

[d] Time FGD system was unavailable to operate when called upon to operate as a percentage of calendar time.

APPENDIX A

PLANT SURVEY FORM

PLANT SURVEY FORM

NON-REGENERABLE FGD PROCESSES

A. COMPANY AND PLANT INFORMATION

1. COMPANY NAME Southern California Edison
2. MAIN OFFICE Rosemead, California
3. PLANT MANAGER G.L. Fraser
4. PLANT NAME Mohave Generating Station
5. PLANT LOCATION Laughlin, Nevada
6. PERSON TO CONTACT FOR FURTHER INFORMATION Dr. A. Weir, Jr.
7. POSITION Principal Scientist for Air Quality
8. TELEPHONE NUMBER (213) 572-2785 1899 Johnson
9. DATE INFORMATION GATHERED
10. PARTICIPANTS IN MEETING

PARTICIPANTS IN MEETING	AFFILIATION
Mr. John Johnson	Southern California Edison
Mr. Dick Young	Southern California Edison
Mr. Wade Ponder	Environmental Protection Agency
Mr. John Busik	Environmental Protection Agency
Mr. Tim Devitt	PEDCo-Environmental
Mr. Fouad Zada	PEDCo-Environmental
Mr. Tom Ponder	PEDCo-Environmental

NOTE: Data in body of report have been updated subsequent to the collection of data for Appendix A.

5/17/74

B. PLANT DATA. (APPLIES TO ALL BOILERS AT THE PLANT).

	BOILER NO.				
	1	2			
CAPACITY, MW	790	790			
SERVICE (BASE, PEAK)	Base	Base			
FGD SYSTEM USED	None	None			

C. BOILER DATA. COMPLETE SECTIONS (C) THROUGH (R) FOR EACH BOILER HAVING AN FGD SYSTEM.

1. BOILER IDENTIFICATION NO. 19066:22266
2. MAXIMUM CONTINUOUS HEAT INPUT 20,000 MM BTU/HR
3. MAXIMUM CONTINUOUS GENERATING CAPACITY 790 MW
4. MAXIMUM CONTINUOUS FLUE GAS RATE, 4,200,000 SCFM @ 60 °F
5. BOILER MANUFACTURER Combustion Engineering
6. YEAR BOILER PLACED IN SERVICE 1970 & 1971
7. BOILER SERVICE (BASE LOAD, PEAK, ETC.) Base Load
8. STACK HEIGHT 500'
9. BOILER OPERATION HOURS/YEAR (197) Available
10. BOILER CAPACITY FACTOR * N/A
11. RATIO OF FLY ASH/BOTTOM ASH N/A

* DEFINED AS: $\frac{\text{KWH GENERATED IN YEAR}}{\text{MAX. CONT. GENERATED CAPACITY IN KW x 8760 HR/YR}}$

D. FUEL DATA

1. COAL ANALYSIS (as received)

	MAX.	MIN.	AVG.
GHV (BTU/LB.)	12,000	11,000	11,500
S %			0.38
ASH %			10.03

2. FUEL OIL ANALYSIS (exclude start-up fuel)

GRADE			
S %			
ASH %			

E. ATMOSPHERIC EMISSIONS

1. APPLICABLE EMISSION REGULATIONS

	PARTICULATES	SO_2
a) CURRENT REQUIREMENTS		
AQCR PRIORITY CLASSIFICATION		
CLARK COUNTY APCD REGULATION & SECTION NO.	26-2A, B, C	26-2D
MAX. ALLOWABLE EMISSIONS LBS/MM BTU (County)	0.064	0.15
b) FUTURE REQUIREMENTS, COMPLIANCE DATE	June 30, 1977	June 30, 1977
REGULATION & SECTION NO.	June 30, 1977	June 30, 1977
MAXIMUM ALLOWABLE EMISSIONS LBS/MM BTU	June 30, 1977	June 30, 1977

2. PLANT PROGRAM FOR PARTICULATES COMPLIANCE

Test Modules Program then install Production Scrubbers.

See EPA Order - See July 9, 1974 Clark County Order

3. PLANT PROGRAM FOR SO_2 COMPLIANCE

F. PARTICULATE REMOVAL

1. TYPE

	MECH.	E.S.P.	FGD
MANUFACTURER		Research Cottrell	
EFFICIENCY: DESIGN/ACTUAL		97.2/98.2	
MAX. EMISSION RATE* LB/HR			
GR/SCF			
LB/MMBTU			

DESIGN BASIS, SULFUR CONTENT 0.5

G. DESULFURIZATION SYSTEM DATA

1. PROCESS NAME To Be Determined
2. LICENSOR/DESIGNER NAME: ______
   ADDRESS: ______
   PERSON TO CONTACT: ______
   TELEPHONE NO.: ______
3. ARCHITECTURAL/ENGINEERS, NAME: ______
   ADDRESS: ______
   PERSON TO CONTACT: ______
   TELEPHONE NO.: ______
4. PROJECT CONSTRUCTION SCHEDULE: DATE
   a) DATE OF PREPARATION OF BIDS SPECS. ______
   b) DATE OF REQUEST FOR BIDS ______
   c) DATE OF CONTRACT AWARD ______
   d) DATE ON SITE CONSTRUCTION BEGAN ______
   e) DATE ON SITE CONSTRUCTION COMPLETED ______
   f) DATE OF INITIAL STARTUP ______
   g) DATE OF COMPLETION OF SHAKEDOWN ______

*At Max. Continuous Capacity

5. LIST MAJOR DELAYS IN CONSTRUCTION SCHEDULE AND CAUSES:

____

____

____

____

____

____

6. NUMBER OF SO_2 SCRUBBER TRAINS USED ______________

7. DESIGN THROUGHPUT PER TRAIN, ACFM @ °F ______________

8. DRAWINGS: 1) PROCESS FLOW DIAGRAM AND MATERIAL BALANCE

2) EQUIPMENT LAYOUT

H. SO_2 SCRUBBING AGENT - **To be Determined**

1. TYPE ______________

2. SOURCES OF SUPPLY ______________

3. CHEMICAL COMPOSITION (for each source)

SILICATES ______________

SILICA ______________

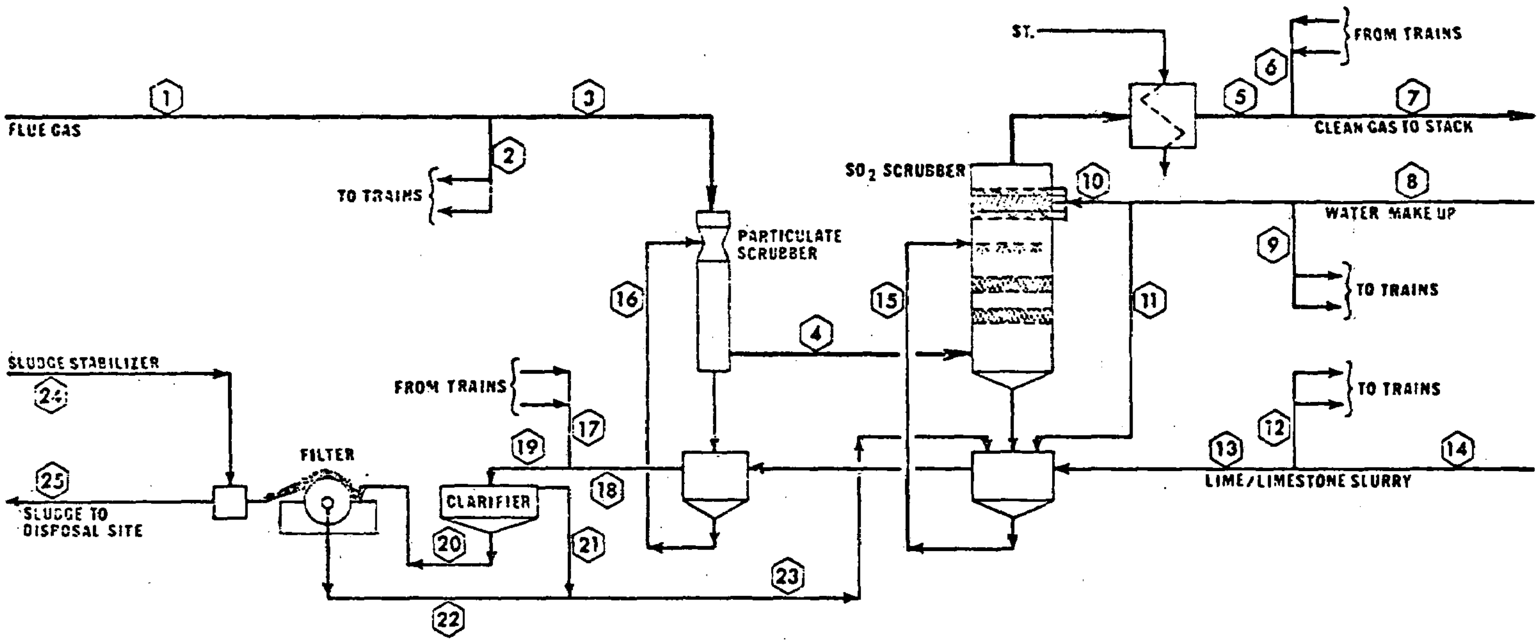
CALCIUM CARBONATE ______________

MAGNESIUM CARBONATE ______________

4. EXCESS SCRUBBING AGENT USED ABOVE STOICHIOMETRIC REQUIREMENTS ______________

5. MAKE-UP WATER POINT OF ADDITION ______________

6. MAKE-UP ALKALI POINT OF ADDITION ______________



STREAM NO.	1	2	3	4	5	6	7	8	9	10	11	12	13
RATE, lb/hr													
ACFM													
GPM													
PARTICULATES, lb/hr													
SO_2, lb/hr													
TEMPERATURE, °F													
TOTAL SOLIDS, %													
SPECIFIC GRAVITY,													

STREAM NO.	14	15	16	17	18	19	20	21	22	23	24	25	26
RATE, lb/hr													
ACFM													
GPM													
PARTICULATES, lb/hr													
SO_2, lb/hr													
TEMPERATURE, °F													
TOTAL SOLIDS, %													
SPECIFIC GRAVITY													

I. Representative flow rates based on operating data at maximum continuous load

5/17/7

J. SCRUBBER TRAIN SPECIFICATIONS - To be determined

1. SCRUBBER NO. 1 [a]

TYPE (TOWER/VENTURI) ______________

LIQUID/GAS RATIO, G/MCF @ ^{o}F ______________

GAS VELOCITY THROUGH SCRUBBER, FT/SEC ______________

MATERIAL OF CONSTRUCTION ______________

TYPE OF LINING ______________

INTERNALS:

TYPE (FLOATING BED, MARBLE BED, ETC.) ______________

NUMBER OF STAGES ______________

TYPE AND SIZE OF PACKING MATERIAL ______________

PACKING THICKNESS PER STAGE [b]

MATERIAL OF CONSTRUCTION, PACKING: ______________

SUPPORTS: ______________

2. SCRUBBER NO. 2 [a] - Same as Scrubber No. 1

TYPE (TOWER/VENTURI) ______________

LIQUID/GAS RATIO, G/MCF @ ^{o}F ______________

GAS VELOCITY THROUGH SCRUBBER, FT/SEC ______________

MATERIAL OF CONSTRUCTION ______________

TYPE OF LINING ______________

INTERNALS:

TYPE (FLOATING BED, MARBLE BED, ETC.) ______________

NUMBER OF STAGES ______________

TYPE AND SIZE OF PACKING MATERIAL ______________

a) Scrubber No. 1 is the scrubber that the flue gases first enter. Scrubber 2 (if applicable) follows Scrubber No. 1.

b) For floating bed, packing thickness at rest.

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PACKING THICKNESS PER STAGE[b] ____________

MATERIAL OF CONSTRUCTION, PACKING: ____________

SUPPORTS: ____________

3. CLEAR WATER TRAY (AT TOP OF SCRUBBER)

TYPE ____________

L/G RATIO ____________

SOURCE OF WATER ____________

4. DEMISTER

TYPE (CHEVRON, ETC.) ____________

NUMBER OF PASSES (STAGES) ____________

SPACE BETWEEN VANES ____________

ANGLE OF VANES ____________

TOTAL DEPTH OF DEMISTER ____________

DIAMETER OF DEMISTER ____________

DISTANCE BETWEEN TOP OF PACKING AND BOTTOM OF DEMISTER ____________

POSITION (HORIZONTAL, VERTICAL) ____________

MATERIAL OF CONSTRUCTION ____________

METHOD OF CLEANING ____________

SOURCE OF WATER AND PRESSURE ____________

FLOW RATE DURING CLEANINGS, GPM ____________

FREQUENCY AND DURATION OF CLEANING ____________

REMARKS ____________

____

____

5. REHEATER

TYPE (DIRECT, INDIRECT) ____________

b) For floating bed, packing thickness at rest.

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DUTY, MMBTU/HR ____________________

HEAT TRANSFER SURFACE AREA SQ.FT ____________________

TEMPERATURE OF GAS: IN __________ OUT __________

HEATING MEDIUM SOURCE ____________________

TEMPERATURE & PRESSURE ____________________

FLOW RATE ______________ LB/HR

REHEATER TUBES, TYPE AND MATERIAL OF CONSTRUCTION ____________________

REHEATER LOCATION WITH RESPECT TO DEMISTER ______________

____

METHOD OF CLEANING ____

FREQUENCY AND DURATION OF CLEANING ____________________

FLOW RATE OF CLEANING MEDIUM ______________ LB/HR

REMARKS ____

____

____

6. SCRUBBER TRAIN PRESSURE DROP DATA — INCHES OF WATER

PARTICULATE SCRUBBER	____________
SO_2 SCRUBBER	____________
CLEAR WATER TRAY	____________
DEMISTER	____________
REHEATER	____________
DUCTWORK	____________
TOTAL FGD SYSTEM	____________

7. FRESH WATER MAKE UP FLOW RATES AND POINTS OF ADDITION

TO: DEMISTER ______

QUENCH CHAMBER ______

ALKALI SLURRYING ______

PUMP SEALS ______

OTHER ______

TOTAL ______

FRESH WATER ADDED PER MOLE OF SULFUR REMOVED ______

8. BYPASS SYSTEM

CAN FLUE GAS BE BYPASSED AROUND FGD SYSTEMS ______

GAS LEAKAGE THROUGH BYPASS VALVE, ACFM ______

K. SLURRY DATA - To Be Determined

	pH	% Solids	Capacity (gal)	Hold up time
LIME/LIMESTONE SLURRY MAKEUP TANK				
PARTICULATE SCRUBBER EFFLUENT HOLD TANK (a)				
SO_2 SCRUBBER EFFLUENT HOLD TANK (a)				

L. LIMESTONE MILLING AND CALCINING FACILITIES: INDICATE BOILERS SERVED BY THIS SYSTEM.

TYPE OF MILL (WET CYCLONE, ETC.) ______

NUMBER OF MILLS ______

CAPACITY PER MILL ______ T/HR

RAW MATERIAL MESH SIZE ______

PRODUCT MESH SIZE ______

SLURRY CONCENTRATION IN MILL ______________________

CALCINING AND/OR SLAKING FACILITIES ______________________

SOURCE OF WATER FOR SLURRY MAKE UP OR SLAKING TANK ______________________

M. DISPOSAL OF SPENT LIQUOR - To Be Determined

1. SCHEMATICS OF SLUDGE & FLY ASH DISPOSAL METHOD

(IDENTIFY QUANTITIES OR SCHEMATIC) ______________________

2. CLARIFIERS (THICKENERS)

NUMBER ______________________

DIMENSIONS ______________________

CONCENTRATION OF SOLIDS IN UNDERFLOW ______________________

3. ROTARY VACUUM FILTER

NUMBER OF FILTERS ______________________

CLOTH AREA/FILTER ______________________

CAPACITY ____________________TON/HR (WET CAKE)

CONCENTRATION OF SOLIDS IN CAKE ______________________

PRECOAT (TYPE, QUANTITY, THICKNESS) ______________________

REMARKS ____

____

____

4. SLUDGE FIXATION

POINT OF ADDITIVES INJECTION ______________________

FIXATION MATERIAL COMPOSITION ______________________

FIXATION PROCESS (NAME) ______________________

FIXATION MATERIAL REQUIREMENT/TONS OF DRY SOLIDS OF SLUDGE

____

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ESTIMATED POND LIFE, YRS. ____________

CONCENTRATION OF SOLIDS IN FIXED SLUDGE ____________

METHOD OF DISPOSAL OF FIXED SLUDGE ____________

INITIAL SOLIDIFICATION TIME OF FIXED SLUDGE ____________

5. SLUDGE QUANTITY DATA - **To Be Determined**

POND/LANDFILL SIZE REQUIREMENTS, ACRE-FT/YR ____________

IS POND/LANDFILL ON OR OFFSITE ____________

TYPE OF LINER ____________

IF OFFSITE, DISTANCE AND COST OF TRANSPORT ____________

POND/LANDFILL DIMENSIONS AREA IN ACRES ____________
DEPTH IN FEET ____________

DISPOSAL PLANS; SHORT AND LONG TERM ____________

____

____

____

____

N. <u>COST DATA</u> - **To Be Determined**

1. TOTAL INSTALLED CAPITAL COST ____________

2. ANNUALIZED OPERATING COST ____________

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3. COST BREAKDOWN

COST ELEMENTS		INCLUDED IN ABOVE COST ESTIMATE		ESTIMATED AMOUNT OR % OF TOTAL INSTALLED CAPITAL COST
		YES	NO	
A.	<u>CAPITAL COSTS</u>			
	SO_2 SCRUBBER TRAINS	☐	☐	______
	LIMESTONE MILLING FACILITIES	☐	☐	______
	SLUDGE TREATMENT & DISPOSAL POND	☐	☐	______
	SITE IMPROVEMENTS	☐	☐	______
	LAND, ROADS, TRACKS, SUBSTATION	☐	☐	______
	ENGINEERING COSTS	☐	☐	______
	CONTRACTORS FEE	☐	☐	______
	INTEREST ON CAPITAL DURING CONSTRUCTION	☐	☐	______
B.	<u>ANNUALIZED OPERATING COST</u>			
	<u>FIXED COSTS</u>			
	INTEREST ON CAPITAL	☐	☐	______
	DEPRECIATION	☐	☐	______
	INSURANCE & TAXES	☐	☐	______
	LABOR COST INCLUDING OVERHEAD	☐	☐	______
	<u>VARIABLE COSTS</u>			
	RAW MATERIAL	☐	☐	______
	UTILITIES	☐	☐	______
	MAINTENANCE	☐	☐	______

4. COST FACTORS

a. ELECTRICITY ____________________

b. WATER ____________________

c. STEAM (OR FUEL FOR REHEATING) ____________________

d. FIXATION COST ______________ $/TON OF DRY SLUDGE

e. RAW MATERIAL PURCHASING COST ________ $/TON OF DRY SLUDGE

f. LABOR: SUPERVISOR ________ HOURS/WEEK ______ WAGE

OPERATOR ________ ______

OPERATOR HELPER ________ ______

MAINTENANCE ________ ______

O. MAJOR PROBLEM AREAS: (CORROSION, PLUGGING, ETC.)

To Be Determined

1. SO_2 SCRUBBER, CIRCULATION TANK AND PUMPS.

a. PROBLEM/SOLUTION ____________________

2. DEMISTER

PROBLEM/SOLUTION ____________________

3. REHEATER

PROBLEM/SOLUTION ____________________

4. VENTURI SCRUBBER, CIRCULATION TANKS AND PUMPS

PROBLEM/SOLUTION

5. I.D. BOOSTER FAN AND DUCT WORK

PROBLEM/SOLUTION

6. LIMESTONE MILLING SYSTEM OR LIME SLAKING

PROBLEM/SOLUTION

7. SLUDGE TREATMENT AND DISPOSAL

PROBLEM/SOLUTION

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8. MISCELLANEOUS AREA INCLUDING BYPASS SYSTEM

PROBLEM/SOLUTION ______________________________

P. DESCRIBE FACTORS WHICH MAY NOT MAKE THIS A REPRESENTATIVE INSTALLATION ______________________________

Q. DESCRIBE METHODS OF SCRUBBER CONTROL UNDER FLUCTUATING LOAD. IDENTIFY PROBLEMS WITH THIS METHOD AND SOLUTIONS. IDENTIFY METHOD OF pH CONTROL AND LOCATION OF pH PROBES.

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R. COMPUTATION OF FGD SYSTEM AVAILABILITY FACTOR

BOILER RATING OR MAXIMUM CONTINUOUS CAPACITY, MW ______

PERIOD MONTH/YEAR	FLUE GAS DESULFURIZATION MODULES							
	MODULE A		MODULE B		MODULE C		MODULE D	
	DOWN DUE TO		DOWN DUE TO		DOWN DUE TO		DOWN DUE TO	
	BOILER (HRS)	MODULE (HRS)	BOILER (HRS)	MODULE (HRS)	BOILER (HRS)	MODULE (HRS)	BOILER (HRS)	MODULE (HRS)

Availability factor computation:

1. Divide boiler capacity by the number of modules and obtain MW/module = χ
2. Multiply boiler capacity by number of hours during period = a
3. Add all down times due to module trouble for all modules during period = b
4. Add all down times due to boiler trouble or reduction in electricity demand for all modules during period = c
5. Availability factor = $\frac{[a - \chi\ (b + c)]100}{a - \chi\ c}$ = %

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TECHNICAL REPORT DATA

(Please read Instructions on the reverse before completing)

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4. TITLE AND SUBTITLE Survey of Flue Gas Desulfurization Systems Mohave Station, Southern California Edison Co.		5. REPORT DATE October 1975
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7. AUTHOR(S) Gerald A. Isaacs and Fouad K. Zada		8. PERFORMING ORGANIZATION REPORT NO.
9. PERFORMING ORGANIZATION NAME AND ADDRESS PEDCo-Environmental Specialists, Inc. Suite 13, Atkinson Square Cincinnati, Ohio 45246		10. PROGRAM ELEMENT NO. 1AB013; ROAP 21ACX-130
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15. SUPPLEMENTARY NOTES		

16. ABSTRACT The report gives results of a survey of the flue gas desulfurization (FGD) systems at Southern California Edison's Mohave Generating Station. Two prototype 170 MW SO2 absorber systems were installed: a vertical module treated a portion of the flue gas from boiler unit 1; and a horizontal module treated a similar flue gas portion from unit 2. Each unit has a maximum net generating capacity of 790 MW, burning coal with a heat content of about 11,500 Btu/lb. Ash and sulfur contents of the coal are about 10 and 0.4 percent, respectively. The vertical absorber was damaged by fire during startup on January 24, 1974. After repairs, test operations were conducted from November 2, 1974, to April 1975. The unit was then modified for additional tests which were completed on July 2, 1975. The horizontal module, after operating for 5927 hours in various test modes from January 16, 1974, to February 9, 1975, was dismantled and removed from the Station. Particulate and SO2 removal efficiencies varied with the tests that were run. Emission regulation for this plant is 0.15 lb/MM Btu for SO2. Both absorbers are preceded by electrostatic precipitators. Spent slurry from each absorber was dewatered and stabilized, and the water was returned to the FGD system. Estimates of capital and operating costs have not been published.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
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