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Demonstration of Wellman-Lord/Allied Chemical FGD Technology: Demonstration Test First Year Results

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Demonstration of Wellman-Lord/Allied Chemical FGD Technology: Demonstration Test First Year Results

by

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ABSTRACT

A full scale unit to demonstrate the Wellman-Lord/Allied Chemical process for desulfurizing flue gas was installed at Northern Indiana Public Service Company's 115 MW coal-fired Unit No. 11 located at the Dean H. Mitchell Station. A Test Program was conducted during a year of demonstration beginning September 16, 1977, to evaluate the capabilities of the Wellman-Lord/Allied Chemical process. During the demonstration year, operating experience was limited due to both boiler and FGD related operating problems. The FGD plant had a reliability factor of 50% (hours operated/hours called upon to operate). SO_2 removal efficiency averaged 89%. Economic performance was distorted by considerable off normal operation of the boiler which limited utilization of the FGD plant and by partial operation of the FGD plant during which a substantial part of the operating costs continued to accrue. There were two major effects on boiler operation from retrofit of the FGD plant. These are (1) a boiler derating of 9% from the consumption of steam by the FGD plant and (2) the design capacity of the FGD unit which limits the boiler to no more than 80% of full load except for short periods of time.

The Test Program was extended for at least six months following completion of a number of projects aimed at eliminating or minimizing the problems that have limited utilization of the FGD plant.

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A full-scale unit to demonstrate the Wellman-Lord/Allied Chemical process for desulfurizing flue gas was installed on a coal-fired boiler belonging to Northern Indiana Public Service Company (NIPSCO). An Acceptance Test for verifying that the performance guarantees could be met was successfully completed on September 15, 1977. A scheduled year of demonstration was begun on September 16, 1977. This report presents the results of a Test Program conducted during the demonstration year to evaluate the capabilities of the Wellman-Lord/Allied Chemical process. This regenerable process employs sodium sulfite for scrubbing the flue gas and thermal regeneration for recovery of the SO_2. The recovered SO_2 is reduced to produce a molten sulfur product.

The FGD plant operated a total of about 90 days during the year. Operation was sporadic due to both boiler and FGD problems. The principal boiler problems that prevented FGD operation were unstable flue gas flows and steam pressures resulting from poor coal quality, coal feeding problems, and from poor quality of the boiler feedwater. Major FGD plant interruptions occurred as a result of booster blower failures. Prominent among the failures were imbalance of the blower due to flyash buildup on the fan blades and subsequent corrosion and erosion of the blades. The problem was aggravated by frequent operation at flue gas temperatures below the dew point. Eventual reblading of the booster blower was required. The longest period of sustained operation of the FGD plant was 42 days and occurred after the coal feeding and the boiler feedwater problems had been largely solved and after reblading of the booster blower.

The FGD plant had a reliability factor of 50% (hours operated/hours called upon to operate) despite only 90 days of total operation. Reliability is the ability of the FGD plant to operate within specific limits of boiler operation. There was considerable operation of the boiler in an off normal condition as a result of the coal feeding and boiler feedwater problems.

Overall, the boiler was operated a total of 325 days of the year but for only 179 days at stable enough conditions for operation of the FGD plant.

The SO_2 removal performance guarantee of 90% was met or exceeded 45% of the time, based on one-hour averaging times. The average removal efficiency was 89% and was met or exceeded 66% of the time. The operating set point was for maintaining a 90% reduction in the SO_2 concentration on a wet volume basis. This equates to about 89% removal, after the dilution effects resulting from added water in the flue gas are taken into account.

Economic performance during the Demonstration year was distorted by considerable off normal operation of the boiler which limited utilization of the FGD plant and by partial operation of the FGD plant (not counted as operating time) during which utility and raw material costs continued to accrue. The annualized unit cost of operating the FGD plant amounted to 15.81 mills/kWh compared with a projected annual unit cost of 14.86 mills/kWh. The high costs despite the low utilization of the FGD plant reflects fixed charges and standby operating costs such as labor.

The effect on boiler operation from the FGD installation was threefold. First, substantial electric power is not available for distribution as a result of FGD plant energy usage, primarily as steam. During a 42 day sustained run of the FGD plant, the power not available amounted to nearly 11 megawatts. Second, the boiler was limited to a sustained load of 92 gross megawatts by FGD capacity limitations. Operation at higher loads is possible for only limited periods of time. During the same 42 day run, which was after correction of the coal feeding and the water quality problems, boiler gross output averaged 79 MW while the FGD plant was operating. Without the FGD plant, the boiler could have generated 89 MW of electric power with the same heat input. Third, there is also a lower limit of operation below which the SO_2 reduction unit will not operate. This establishes minimum limits for boiler load or for coal sulfur content.

About midway in the demonstration year, booster blower problems prompted the initiation of a series of improvements to minimize FGD down time. The major improvements included boiler air preheater modifications and duct insulation to raise the flue gas temperature above the dew point and included reblading of the booster blower fan. Since these projects could not be completed before the end of the demonstration year, evaluation of the demonstration unit will continue for at least another six to twelve months. The results of the evaluation as well as a more detailed assessment of the first year of operation will be presented in a subsequent report.

SECTION 1

INTRODUCTION

BACKGROUND

The Environmental Protection Agency (EPA) is actively engaged in a number of programs to demonstrate sulfur-oxide emission control processes applicable to stationary sources. These demonstration programs comprise operation of an emission control unit of such size and for such duration as to permit valid technical and economic scaling of operating factors to define the commercial practicality of the process for potential industrial users. Among the candidate processes being evaluated, which have the potential to become a major SO_x emission control method, is the Wellman-Lord/Allied Chemical (WL/Allied) process developed by Davy Powergas and Allied Chemical. The Wellman-Lord SO_2 Removal Process removes the SO_2 from the flue gas and recovers the sulfur values as SO_2 which in turn can be used to produce (by other processes) sulfur, sulfuric acid, or liquid SO_2. The Allied Chemical Sulfur Reduction Process reduces the SO_2 to produce molten sulfur. The two processes have been combined to demonstrate flue gas desulfurization (FGD) technology by which the scrubbing medium is regenerated and reused and by which the product obtained is sulfur. This configuration will be referred to as the WL/Allied process, although the processes are not contingent upon each other and each can be used in other regenerable FGD configurations. The demonstration unit has been constructed by Davy Powergas and is being operated by Allied Chemical under contract to the Northern Indiana Public Service Company (NIPSCO). The EPA shared in the cost of construction of the unit and is conducting a comprehensive test program. The WL/Allied process as developed by the two design organizations is based upon the recovery of sulfur dioxide (SO_2) in concentrated form and its subsequent reduction to elemental sulfur. The product is to be sold to partially offset the process costs. This is the first coal-fired Wellman-Lord application, as well as the first joint Wellman-Lord/Allied Chemical installation.

PROGRAM STATUS

The WL/Allied FGD facility has been installed at NIPSCO's Dean H. Mitchell Station in Gary, Indiana. The FGD plant is designed to treat all of the flue gas discharged from the Unit No. 11 coal-fired boiler of the Mitchell Station. Unit No. 11 is hereafter referred to as Mitchell No. 11. Initial startup of the FGD plant began on July 19, 1975. After several delays as a result of FGD plant and boiler operational problems and boiler shutdowns for repairs, the FGD plant was ready for acceptance testing on August 29, 1977. The Acceptance Test, successfully completed on September 15, 1977, demonstrated that the process performance guarantees could be met.[1]

Immediately following the Acceptance Test, operation of the FGD plant was continued for a scheduled one year of demonstration. The intent was to demonstrate the performance of this FGD unit for an extended period of operation. TRW, under contract to EPA, is providing the test services required for evaluating the performance of the FGD plant. This report summarizes the results of the test program carried out during the first year of demonstration. A more detailed evaluation will be presented in a subsequent report after all testing has been completed.

During the demonstration year, operating experience was limited due to both boiler and FGD related operating problems. A plant improvement program was initiated during the latter half of the demonstration year for the purpose of minimizing the major difficulties. The demonstration test program has been extended for at least an additional six to twelve months to more fully evaluate the FGD process.

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[1] Adams, R. C., S. J. Lutz, and S. W. Mulligan. Demonstration of Wellman-Lord/Allied Chemical FGD Technology: Acceptance Test Results. EPA-600/7-79-014a. TRW Inc., Durham, NC January 1979.

SECTION 2

DEMONSTRATION YEAR OVERVIEW

PROGRAM OBJECTIVES & SCOPE

The principal objectives of the test program, as originally conceived, were as follows:

1. Verification of the reduction in pollutants achieved by the WL/Allied process FGD unit.

2. Validation of the estimated technical and economic performance of the demonstration unit.

3. Assessment of the applicability of the WL/Allied process to the general population of utility boilers.

Each of these objectives was partially achieved during the first year of operation despite limited data availability as a result of several boiler and FGD plant outages and of several periods of partial operation of the FGD plant. Because of the sporadic operation of the FGD plant, the test program has been extended six to twelve months beyond the scheduled one year of demonstration. The additional operating time will provide a more complete evaluation of the process in response to the program objectives. The scope of the test program extension will be described later.

This interim report presents and evaluates the more significant operating and performance data obtained during the first year of demonstration immediately following completion of the Acceptance Test. Of primary importance are SO_2 removal performance (Objective No. 1); reliability, energy and raw material consumptions, product rates, operating costs and boiler load following (Objective No. 2); and derating and other effects on the boiler

(Objective No. 3). Only a minimum number of special tests for evaluating the WL/Allied process at varying boiler operating conditions were completed. Therefore, only limited data are available for evaluating the applicability of the process to other utility boilers (Objective No. 3). Achievement of Objective No. 2 is limited with respect to load following capability and to economic performance. Operating costs are distorted somewhat by excessive boiler and FGD plant outages. The test program is being extended in expectation of fewer outages and improved reliability which, if achieved, will provide more representative cost data.

PROCESS DESCRIPTION

Flue gas from Unit No. 11 of the D. H. Mitchell Station (Mitchell No. 11) is delivered to the suction of the FGD plant's booster blower. Mitchell No. 11 is a 115 MW pulverized coal-fired, balanced draft boiler with cold end electrostatic precipitator (ESP) particle control. The boiler was designed to use a coal with a nominal sulfur content of a little above three percent. The FGD unit was designed to accept flue gas at SO_2 concentrations equivalent to that sulfur level in the coal.

The WL/Allied FGD process removes SO_2 from the flue gas stream by scrubbing with an aqueous sodium sulfite/bisulfite solution and subsequent thermal regeneration to recover the SO_2. The liberated SO_2 is then reduced to elemental sulfur which is sold. The FGD unit was designed to remove 90% of the SO_2 delivered with the flue gas at flue gas rates equivalent to a boiler load of 92 MW (80% of full boiler load). The absorber is designed to take up to about 388,000 acfm (110 MW equivalent) of flue gas but this rate can be sustained for only a limited time because of limited capacity of the solution regeneration part of the FGD plant.

The critical design criteria are approximately as follows:

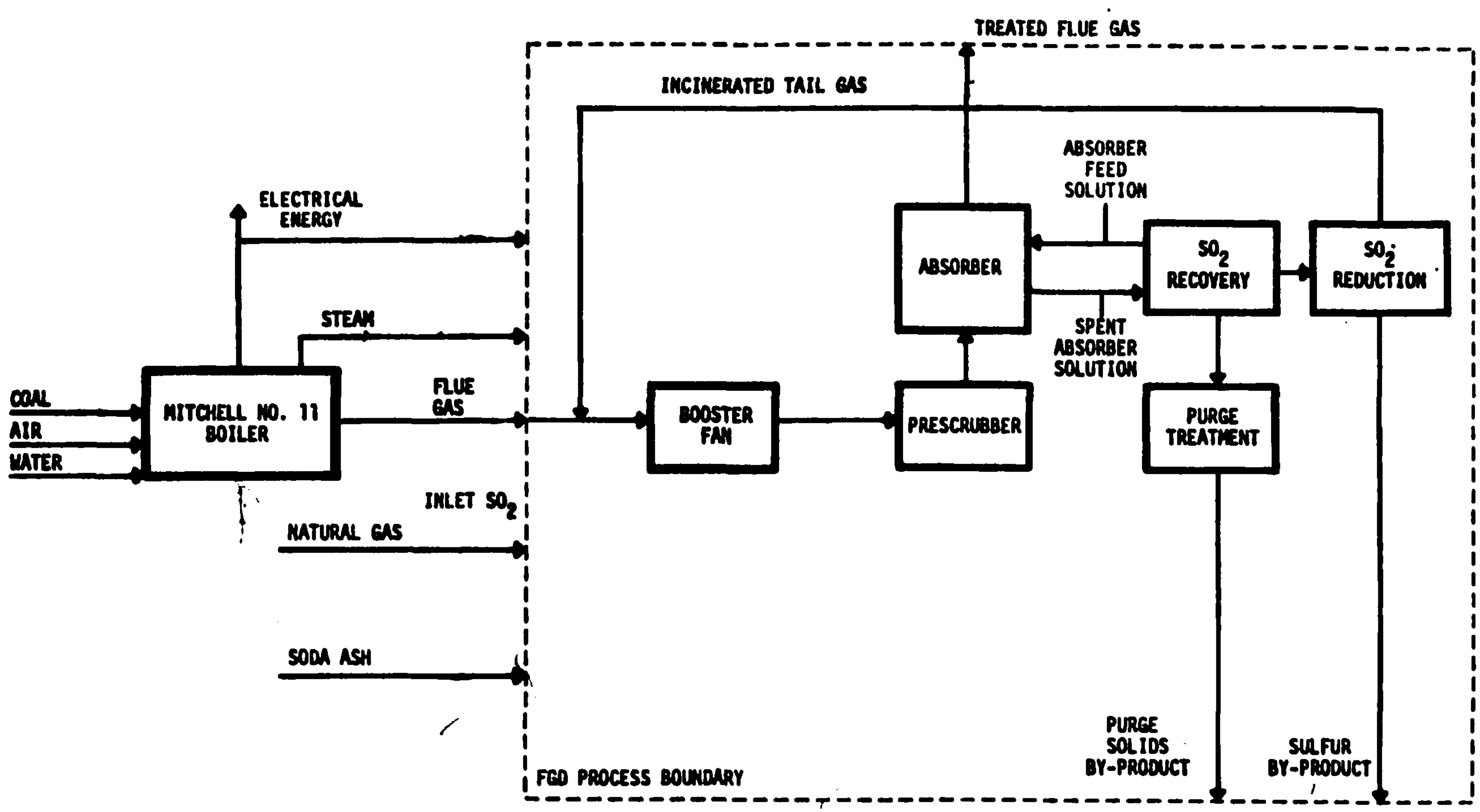
Flue gas temperature, °F	300
Flue gas pressure, psia	14.7
Maximum flue gas flow, acfm	388,000
Gross MW equivalent, MW	110
Steam equivalent, lb/hr	749,000
Design flue gas flow, acfm	320,000
Gross MW equivalent, MW	92
Steam equivalent, lb/hr	603,000
Inlet SO_2 at design flow, lb/hr	4,842
Equivalent SO_2 concentration, ppmv	2,185

Any combination of flue gas volume and inlet SO_2 concentration that results in an SO_2 feed rate greater than about 5,000 lbs/hr for periods up to 83 hours is excess capacity for the recovery area. This means that sustained operation at excess capacity would lower the performance level to below 90% SO_2 recovery. The absorber and the recovery area have the turn-down capability for steady state operation down to 46 MW boiler load. However, the lower limit for sustained operation of the reduction area is higher than 46 MW due to operating characteristics of the reduction system.

The block diagram (Figure 2.1) shows the process steps. The FGD plant accepts the total flue gas stream from the discharge of the boiler's induced draft (ID) fans using a booster blower to force the flue gas stream through the prescrubber and absorber.

The prescrubber is a single-stage orifice contactor for removing additional particulate matter. A pump recirculates the scrubber water from a sump back to the contactor. In order to control a solids buildup in the liquid stream, a purge stream is withdrawn; makeup water is added to the pre-scrubber to compensate for this loss and to humidify the flue gas. This purge stream is sent to the power station's fly ash settling ponds.

FIGURE 2.1 BLOCK FLOW DIAGRAM OF MAJOR PROCESS STEPS



The cooled, humidified flue gas leaves the prescrubber and enters the bottom of a three stage absorber where the gas is contacted with the sulfite/bisulfite solution flowing countercurrently to the gas stream. The solution absorbs the SO_2 and the treated flue gas is then discharged to the atmosphere through a stack.

The spent sulfite/bisulfite solution is removed from the bottom tray of the absorber and sent to a surge tank for storage prior to regeneration in the SO_2 recovery step. During recovery of the SO_2, the spent absorbent is regenerated in a steam-heated, single-effect evaporator and is then returned to the absorber feed tank. The surge tank and absorber feed tank provide surge capacity for operating for limited time periods at flue gas rates in excess of 92 MW equivalent. To prevent accumulation of sodium sulfate in the absorbing solution stream, a purge stream is sent to the purge treatment area. Here, the purge stream is crystallized and centrifuged and the solid product is removed and dried, yielding a salable sulfate by-product. The sodium values lost in the purge stream are made up by adding Na_2CO_3 to the regenerated sulfite/bisulfite solution.

SO_2 released in the evaporator is taken overhead and sent to the SO_2 reduction area. The reduction step is a proprietary process developed by Allied Chemical which utilizes natural gas (CH_4) for the reduction of SO_2 to H_2S and, ultimately, to elemental sulfur in molten form. A small stream of tail gas is returned after incineration to the inlet of the booster blower.

PERFORMANCE EVALUATION METHODOLOGY

Evaluation was in response to the test objectives and proceeded in six steps:

1. Collect applicable data and operating information.

2. Define hours of operation within each operating mode.

3. Process the raw data for each consecutive 30-day period and for specific periods according to the mode of operation.

4. Assess performance with regard to pollutant removal, dependability, energy consumption, and costs.

5. Assess the response of selected dependent variables to changes or fluctuations in the major independent variables.

6. Assess the effect of upsets and transients on SO_2 removal capability.

A variety of measurement techniques, described in Section 4.0, were used to develop the data base.

The core test system consisted of sensors for various boiler and flue gas operating variables (with emphasis on the FGD inlet and outlet flue gas parameters) and accumulation of the sensor analog signals by a data acquisition system (DAS). The frequency of analog signal scan by the DAS was six minutes, from which one-hour averages were computed. The DAS had the capability of storing the data on magnetic tape; however, hardware difficulties with the tape transport unit were experienced throughout the demonstration year, so that very little automated data reduction was possible. Backup storage was available on teletype printouts or on charts taken from strip chart recorders. These data sources had to be utilized at considerable penalty in the excessive time required to access the data and reduce it manually.

The basic time interval was one hour and SO_2 removal performance was assessed on the basis of a one-hour averaging time. Not all of the operating variables were measurable at one-hour intervals. Primary examples are coal composition, coal rates, product rates and raw material rates. Therefore, to make the necessary comparisons, one-hour data was accumulated, evaluated and reported for each 30-day period. For reporting purposes, periods were assigned to conform as closely as possible to calendar months. Starting on September 16, 1977; periods were as shown (Table 2.1). It was also desirable to accumulate data according to operating mode status (FGD plant down, FGD plant full operation, FGD plant partial operation).

TABLE 2.1 DEMONSTRATION YEAR OPERATING PERIODS

Period No.	Start - End
1	0000, 9/16/77 to 0800, 10/4/77
2	0800, 10/4/77 to 0800, 11/3/77
3	0800, 11/3/77 to 0800, 12/3/77
4	0800, 12/3/77 to 0800, 1/2/78
5	0800, 1/2/78 to 0800, 2/1/78
6	0800, 2/1/78 to 0800, 3/3/78
7	0800, 3/3/78 to 0800, 4/2/78
8	0800, 4/2/78 to 0800, 5/2/78
9	0800, 5/2/78 to 0800, 6/1/78
10	0800, 6/1/78 to 0800, 7/1/78
11	0800, 7/1/78 to 0800, 7/31/78
12	0800, 7/31/78 to 0800, 8/30/78
13	0800, 8/30/78 to 2400, 9/16/78

Before evaluation, the raw data were assembled according to specific time periods and the routine calculations were made. This processing was to have been done by computer. However, failure of the tape transport device resulted in only a minimum of data available to the computer from magnetic tape storage. Therefore, we were forced to resort to manual processing and reduction of data from backup teletype hard copy and from strip charts. This has, for the present, limited evaluations primarily to SO_2 removal capability, dependability, raw material and energy consumption, and cost of the FGD plant and to overall performance of the boiler. More specific results will be evaluated in a subsequent report. Additional correlations, where meaningful, will also be reported. Several of the correlations expected to be made are not applicable, given the sporadic operation of the FGD plant. For example, unit costs per ton of SO_2 removed is distorted when the SO_2 that is removed and recovered must be vented because the reduction unit is not operating. Occurrences of this type were frequent.

SCOPE OF FOLLOW-ON PROGRAM

This Interim Report evaluates the performance of the FGD unit for the scheduled one year of demonstration beginning September 16, 1977. The test program has been extended for an additional six to twelve months beginning September 30, 1978.

The test program as originally planned was to include one year of test and evaluation during the year immediately following the Acceptance Test. It became apparent after about six months of sporadic operation that the FGD plant was not able to operate in a manner acceptable for commercial application due to factors not entirely attributable to FGD deficiencies. During a mid-year review, it was concluded by the project participants that the major problems were either boiler related or were problems encountered at the boiler/FGD interface, in particular booster blower and damper problems. It was decided at that time that the major problems were probably correctable and to do this a plant improvement program was initiated. The improvement was to be substantially completed before the end of the scheduled boiler outage in September 1978. The boiler outage coincided with the end of the demonstration year. The test program is continuing for another six to twelve months beginning with boiler startup following the scheduled shutdown in September.

The follow-on test program is essentially an extension of the first year of test and evaluation. However, emphasis will be placed on reliability of FGD plant operation first at a constant load condition and then while following normal swings in boiler load. As a part of the follow-on program, boiler baseline data were collected with the FGD plant down and completely isolated. The results are expected to show any differences in boiler operating characteristics compared to the results of the first Baseline Test performed prior to installation of the FGD plant.[2]

In addition, special tests are proposed to evaluate the FGD system at its capacity limits and to establish the load following capability of the FGD unit. Other non-routine testing will be done to determine the sulfate formation rate during SO_2 absorption.

[2] Adams, R. C., T. E. Eggleston, J. L. Haslbeck, R. C. Jordan and Ellen Pulaski. Demonstration of Wellman-Lord/Allied Chemical FGD Technology: Boiler Operating Characteristics. EPA-600/7-77-014. TRW, Inc., Vienna, Va. February 1977.

SECTION 3
TEST RESULTS

SUMMARY

Test data were collected during the demonstration year, which extended from 0000, September 16, 1977, to 0000, September 16, 1978. Monthly summaries of various operating parameters for both the boiler and the FGD plant have been compiled (Table 3.1). Part of the data base is appended (Appendix A).

During the demonstration year, the boiler operated a total of 7,800 hours out of a possible 8,760 hours for a boiler utilization factor of 89%. The mean power output of the boiler during the period of operation was 76 MWG;* included in this figure are 372 hours of power output at less than 46 MWG. The boiler capacity factor (kWh generated/generating capacity) was 0.585. An average of 33,900 kg (74,700 lbs) of coal per hour was burned with a mean heating value of 24,400 kJ/kg (10,500 BTU/lb). The gross heat rate of the boiler averaged 11,000 kJ/kWh (10,400 BTU/kWh).

The FGD plant operated a total of 2,155 hours. Flue gas and steam at conditions at which stable operation of the FGD plant was possible were delivered a total of 3,949 hours. Partial operation, with reduction area down and minimal recovery of SO_2 or with the bypass damper open, occurred a total of 1,681 hours, for a total operating time for the absorber/evaporator of 3,836 hours. Removal efficiency averaged 89% during those hours at an average inlet SO_2 concentration of 2,081 ppm. Average steam usage of the FGD plant was 26,000 kg (58,000 lb) per hour (this is equivalent to a loss of available generating capacity of 8.7 megawatts gross). The annualized unit cost of operating the FGD plant amounted to 15.81 mills/kWh.

*In this report, the symbol MWG refers to the gross megawatts generated by the boiler.

TABLE 3.1 - A SUMMARY OF THE BOILER AND FGD PLANT OPERATING PARAMETERS

PERIOD	1	2	3	4	5	6	7	8	9	10	11	12	13	
START/END	9/16-10/4	10/4-11/3	11/3-12/3	12/3-1/2	1/2-2/1	2/1-3/3	3/3-4/2	4/2-5/2	5/2-6/1	6/1-7/1	7/1-7/31	7/31-8/30	8/30-9/16	Totals
Hrs, Total	440	721	720	720	720	720	720	719	720	720	720	720	400	8760
Hrs Boiler Operated	415	685	660	631	628	522	629	576	658	720	633	720	323	7800
Hrs Boiler Operated <46 MW	198	39	1	22	2	0	13	33	64	0	0	0	0	372
Hrs of FGD Absorber/ Evaporator Operation	83	274	473	183	0	301	448	0	619	102	320	720	313	3836
Hrs of FGD Full Operation	83	131	447	0	0	0	215[(1)]	0	268	4	0	715	311	2174
Avg Load, MW (Gross)	54	66	75	70	81	92	73	77	78	77	68	78	80	
Avg Load, MW (Net)	45	NA	NA	NA	NA	NA	NA	70	NA	70	59	71	72	
Avg Load, MWG, FGD Down	38	78	66	66	81	97	74	77	87	77	66	-	-	
FGD Avg Steam Usage, Lb/hr	58996	52439	56426	54518	-	51528	57112	-	64325	60300	55470	62233	59331	
Avg Coal Rate, Lb/hr	53157	87032	78060	71309	85060	91218	69358	68135	77483	70943	65905	75812	71629	
Coal HHV, Btu/hr	9890	10326	10409	10062	10307	10334	10398	10803	10687	10735	10796	10766	11104	
Boiler Heat Input, 10^6 Btu/hr	526	899	813	718	877	943	721	736	828	762	712	816	795	
Gross Heat Rate, Btu/kWh	9684	13616	10034	10250	10849	10302	9920	10053	10684	9981	10573	10411	9955	
MW Equiv. of FGD Steam Usage	8.7	7.2	8.1	8.0	-	6.6	8.3	-	9.1	8.6	8.2	8.8	7.4	
Avg Inlet SO_2, PPM	2178	2374	2297	1790	-	1365	2498	-	1905	2206	1946	2071	2197	
Max Inlet SO_2, PPM	2513	2995	3101	2727	-	2525	3349	-	2591	2800	2300	3000	2450	
Min Inlet SO_2, PPM	988	1757	685	552	-	740	492	-	NA	1600	700	1550	2000	
Avg Outlet SO_2, PPM	218	221	241	163	-	164	223	-	188	>470	211	215	220	
Max Outlet SO_2, PPM	314	682	566	322	-	352	680	-	685	>500	>500	365	265	
Min Outlet SO_2, PPM	72	134	106	48	-	46	64	-	NA	250	70	145	165	
Avg SO_2 Rate, In, Lb/hr	3218	6196	5324	3871	-	2974	6380	-	4371	3959	3756	4527	4875	
Avg SO_2 Rate, Out, Lb/hr	348	620	559	406	-	402	615	-	466	>910	438	507	537	
Avg % SO_2 Removal	89	90	90	90	-	87	90	-	89	<77	88	89	89	
Electricity, MW	0.741	0.677	0.659	0.684	-	0.750	0.785	-	0.718	0.754	0.723	0.771	0.780	
Natural Gas, 10^6 Btu/hr	9.5	7.4	11.2	0.8	-	1.0	5.9	-	5.5	1.2	6.0	11.2	10.1	
Steam, 10^6 Btu/hr	77.9	69.3	74.5	72.0	-	68.0	75.4	-	84.9	79.6	73.2	82.1	78.3	
Soda Ash Consumed, Tons	19	86	171	97	0	34.7	212	22.8	243	53	106.5	262.5	123.5	1431
Sulfur Produced, Long Tons	39	91	285	0	0	0	135	0	191	0	8.5	504.5	202	1456
By-Product Salt Produced, Tons	4	9	50	11.5	0	0	0	0	44	40	25.7	58	40.3	282.5

NA - Not Available

(1) With bypass damper open.

TABLE 3.2 - A SUMMARY OF THE BOILER AND FGD PLANT OPERATING PARAMETERS - METRIC UNITS

PERIOD	1	2	3	4	5	6	7	8	9	10	11	12	13	
START/END	9/16-10/4	10/4-11/3	11/3-12/3	12/3-1/2	1/2-2/1	2/1-3/3	3/3-4/2	4/2-5/2	5/2-6/1	6/1-7/1	7/1-7/31	7/31-8/30	8/30-9/16	TOTAL
Hrs, Total	440	721	720	720	720	720	720	719	720	720	720	720	400	8760
Hrs Boiler Operated	415	685	660	631	628	522	629	576	658	720	633	720	323	7800
Hrs Boiler Operated <46 MW	198	39	1	22	2	0	13	33	64	0	0	0	0	372
Hrs of FGD Absorber/ *Evaporator Operation*	83	274	473	183	0	301	448	0	619	102	320	720	313	
Hrs of FGD Full Operation	83	131	447	0	0	0	215[(1)]	0	268	4	0	715	311	2174
Avg Load, MW (Gross)	54	66	75	70	81	92	73	77	89	77	68	78	80	
Avg Load, MW (Net)	45	NA	NA	NA	NA	NA	NA	70	NA	70	59	71	72	
Avg Load, MW(G), FGD Down	38	78	66	66	81	97	74	77	87	77	66	-	-	
FGD Avg Steam Usage, kg/Hr	26760	23809	25594	24729	-	23373	25906	-	29177	27352	25162	28228	26912	
Avg Coal, Rate, kg/hr	24112	39477	35407	32345	38583	41376	31460	30906	35146	32179	29894	34388	32490	
Coal HHV, kJ/lb	10443	10903	10991	10624	10883	10911	10979	11407	11284	11335	11399	11367	11724	
Boiler Heat Input, 10^6 kJ/hr	555	949	858	758	926	996	761	777	874	805	752	862	839	
Gross Heat Rate, kJ/hr	10225	14377	11439	10823	11455	10878	10474	10615	11281	10539	11164	10993	10511	
MW Equiv. of FGD Steam Usage	8.7	7.2	8.1	8.0	-	6.6	8.3	-	9.1	8.6	8.2	8.8	7.4	
Avg Inlet SO_2, PPM	2178	2374	2297	1790	-	1365	2498	-	1905	2206	1946	2071	2197	
Max Inlet SO_2, PPM	2513	2995	3101	2727	-	2525	3349	-	2591	2800	2300	3000	2450	
Min Inlet SO_2, PPM	988	1757	685	552	-	740	492	-	NA	1600	700	1550	2000	
Avg Outlet SO_2, PPM	218	221	241	163	-	164	223	-	188	>470	211	215	220	
Max Outlet SO_2, PPM	314	682	566	322	-	352	680	-	685	>500	>500	365	265	
Min Outlet SO_2, PPM	72	134	106	48	-	46	64	-	NA	250	70	145	165	
Avg SO_2 Rate, In, kg/hr	1460	2810	2415	1756	-	1349	2894	-	1983	1796	1704	2053	2211	
Avg SO_2 Rate, Out, kg/hr	158	281	254	184	-	182	279	-	211	413	199	230	244	
Avg % SO_2 Removal	89	90	90	90	-	87	90	-	89	<77	88	89	89	
Electricity, MW	0.741	0.677	0.659	0.684	-	0.750	0.785	-	0.718	0.754	0.723	0.771	0.780	
Natural Gas, 10^6 kJ/hr	10.0	7.8	11.8	0.8	-	1.1	6.2	-	5.8	1.3	6.3	11.8	10.7	
Steam, 10^6 kJ/hr	82.3	73.2	78.7	76	-	71.8	79.6	-	89.6	84.1	77.3	86.7	82.7	
Soda Ash Consumed, Metric Tons	17.2	78.0	155.1	88.0	0	31.5	192.3	20.7	220.4	48.1	96.6	238.1	112.0	1298.0
Sulfur Produced, Metric Tons	39.6	92.5	289.6	0	0	0	137.2	0	194.1	0	8.6	512.6	205.2	1479.4
By-Product Salt Produced, Metric Tons	3.6	8.2	45.4	10.4	0	0	0	0	39.9	36.3	23.3	52.6	36.6	256.3

NA - Not Available

(1) With bypass damper open.

SO_2 REMOVAL

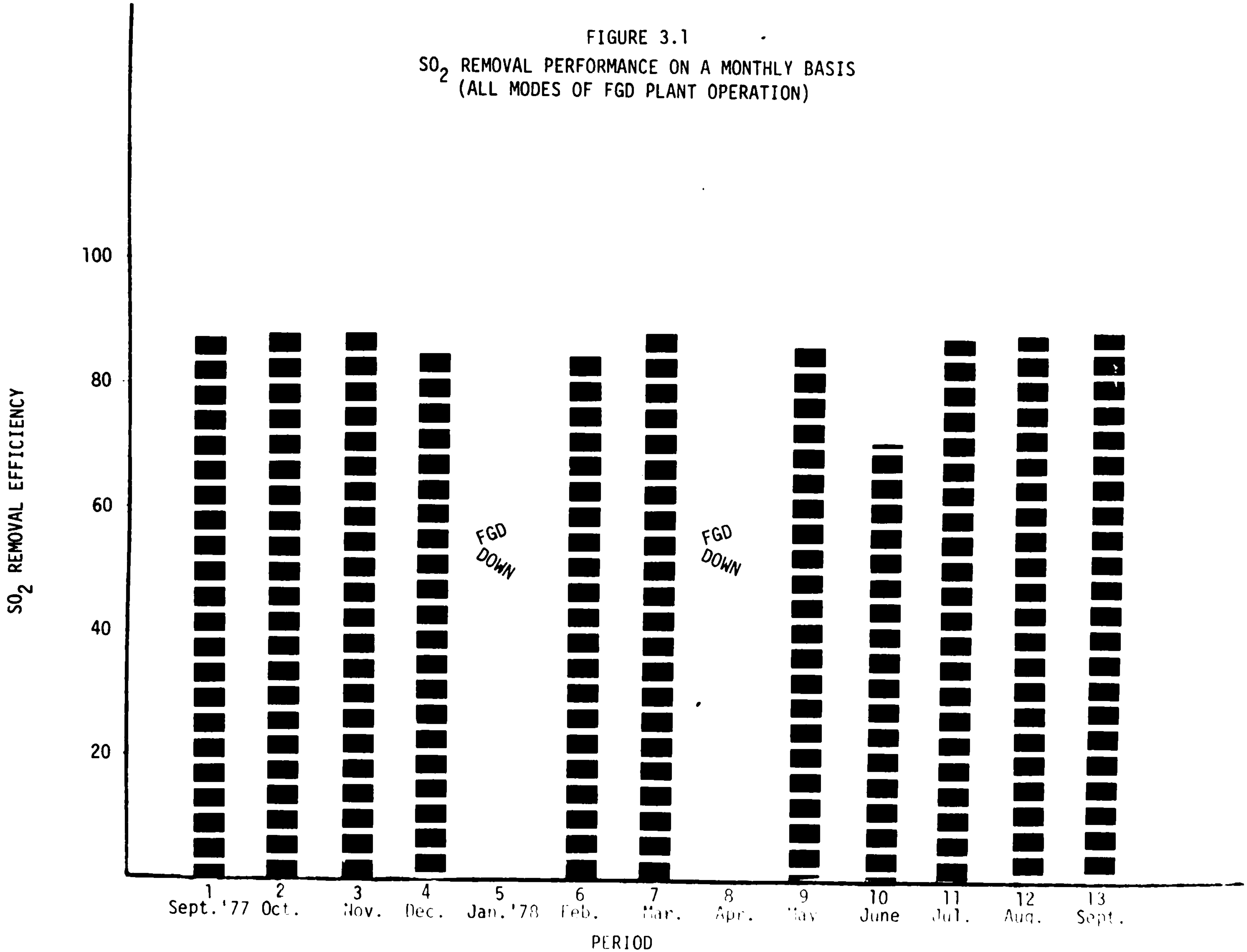
The performance guarantee of 90% SO_2 removal for the WL/Allied process does not specify an averaging time. However, it was demonstrated during acceptance testing that the FGD plant could operate continuously at design capacity and meet the guaranteed SO_2 removal performance requirement based on a two-hour averaging time. In this report, one hour averages are used to evaluate SO_2 removal performance. This is a more stringent averaging time requirement placed on the process than was required for acceptance testing (two-hour averages) or for the proposed Federal New Source Performance Standards[(3)] (24-hour averages). In a subsequent report, SO_2 removal performance will be assessed at averaging times other than one hour. For the time being test results are being compared to a higher standard of performance (one-hour averaging time) than that required for acceptance testing or for Federal emission standards under consideration.

During the demonstration year (9/16/77 to 9/16/78), the SO_2 removal performance guarantee of 90% was met or exceeded only 45% of the time (based on 2,572 hours of valid data out of a total absorber/evaporator operating time of 3,836 hours, one-hour averages). For longer averaging times, 89% or greater SO_2 removal was easily attained for most of the 30-day reporting periods (Figure 3.1). The absorption and SO_2 recovery steps of the process are such that it would not have been difficult to achieve 90% or higher removal, even for one-hour averaging periods. However, each additional increment of SO_2 removal incurs a penalty in higher evaporator duty and in higher soda ash make-up. Costs are thus minimized by operating very close to the performance guarantee level of sulfur removal. In practice, the FGD plant was operated to limit the concentration of SO_2 emitted to 10% or less of the inlet concentration. To determine percent removal, the outlet concentration must be corrected for dilution of the flue gas due to its becoming saturated before leaving the absorber. Flue gas dilution is typically 9%-10%, which is equivalent to about one percent of SO_2 removal. On the assumption that the operating goal was to achieve 89% removal or better, this goal was

(3) 40 CFR Part 60, Vol. 43 No. 182, 42154-42184 (Federal Register).

FIGURE 3.1

SO_2 REMOVAL PERFORMANCE ON A MONTHLY BASIS
(ALL MODES OF FGD PLANT OPERATION)



achieved for 66% of the hours of valid data (Figure 3.2). Furthermore, the data indicate that percent removal was 79% or better for 96% of the time. Overall, for the one year period, SO_2 removal efficiency averaged 89% (average of hourly averages).

In the preceding discussion, we have reported on the ability of the absorber to remove SO_2 without regard to whether or not the FGD plant was operating as a fully integrated, regenerable unit. For part of the time, only partial operation of the plant was attained. Two modes of partial operation are identified:

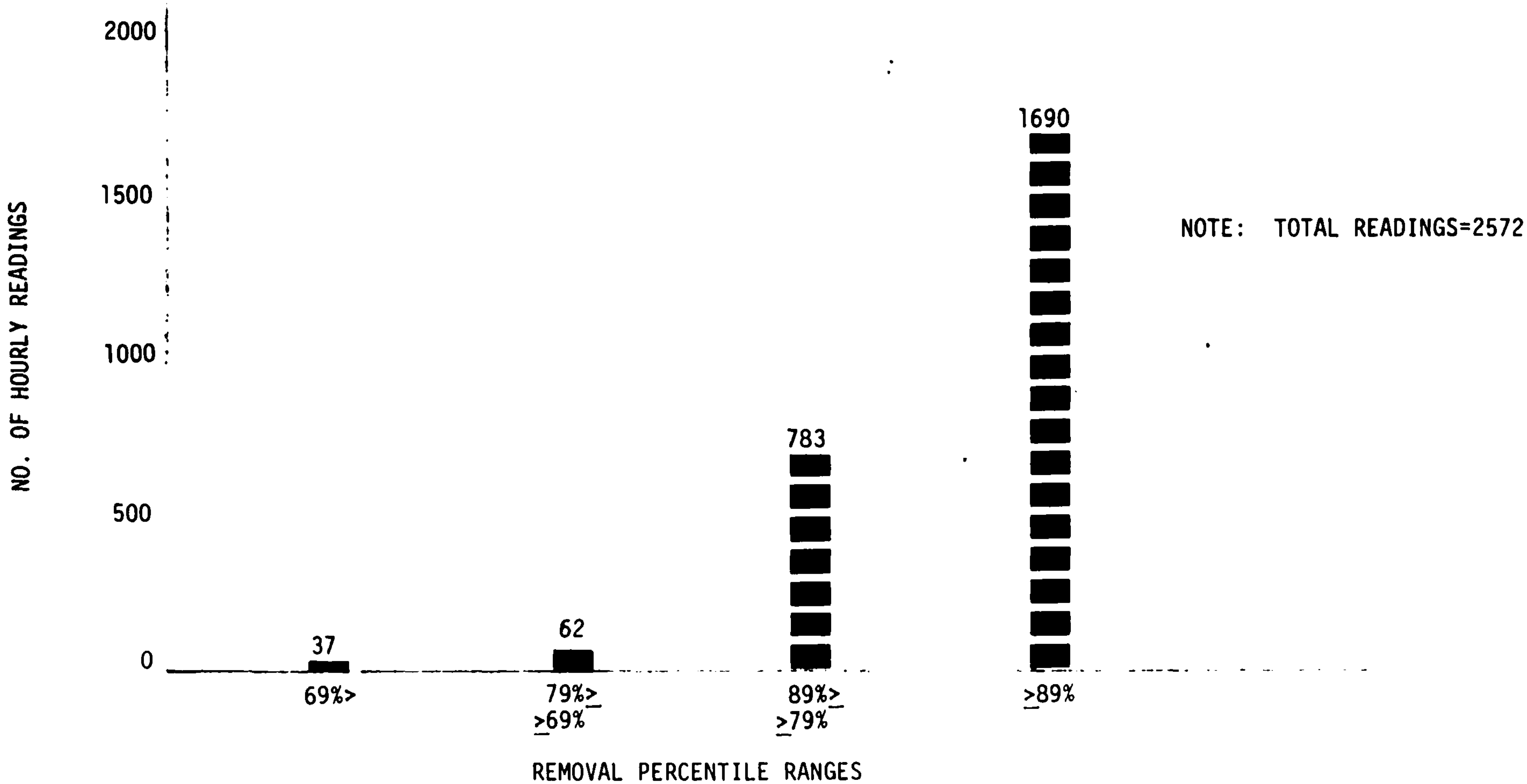
1. The SO_2 reduction unit was down for about 1,680 hours out of a total of 3,836 hours of absorber/evaporator operation. This necessitated venting the SO_2 recovered at the evaporator to the atmosphere. Thus, only the small portion of SO_2 removed in the sulfate purge stream was prevented from being emitted.

2. For short periods, the FGD plant was operated with the bypass damper open. In this mode, it is not known with certainty how much of the untreated flue gas has bypassed the absorber. Also, two directional flow past the bypass damper is possible. That is, air or flue gas from the bypass stack which is shared with Unit No. 6 may be drawn into the absorber through the open bypass.

There were also times that the FGD plant was operated outside of the design range of the input streams (flue gas rates equivalent to boiler loads in the range 46 MW to 92 MW and steam at design temperature and pressure conditions). SO_2 removal efficiency averaged 89% during the hours of full operation for which valid data are available.

FIGURE 3.2

SO_2 REMOVAL FREQUENCY DISTRIBUTION
NO. OF HOURLY READINGS VS. PERCENTILE RANGES
PERIOD 0800, 9/16/77 THRU 0800, 9/17/78



FGD PLANT DEPENDABILITY

Dependability of the FGD plant was assessed at two levels:

1. Its ability to operate when called upon without regard to pollutant removal performance (Viability Indices).

2. Its ability to meet performance standards for SO_2 removal when called upon.

The Viability Indices are those used to report FGD viability in the EPA Utility FGD Survey.[4] SO_2 removal performance is described in the preceding subsection.

Certain design decisions were made which have limited the ability of the FGD plant to follow the full range of normal boiler operation (operability). Doubtless, design changes could be made or redundancy provided on another installation that would maximize the FGD unit's ability to follow boiler operation. In this report, dependability is assessed relative to the specific design features of this FGD unit. Accordingly, the reliability of the FGD plant is defined as its ability to follow boiler operation only when specific design criteria are met. Thus, the FGD plant reliability is determined only for those hours that it is "called upon" to operate due to essential feed streams being available simultaneously (Figure 3.3):

1. flue gas at rates not less than 46 MWG equivalent
2. boiler steam at pressures ≥ 37.3 kg/cm^2 gauge (530 psig)
3. electricity
4. natural gas
5. soda ash
6. boiler stable within limits of greater than 46 MWG and coal sulfur content greater than 2.8% and less than 3.5%.

Also, the FGD plant cannot operate for sustained periods at flue gas rates above the equivalent of 92 MWG.

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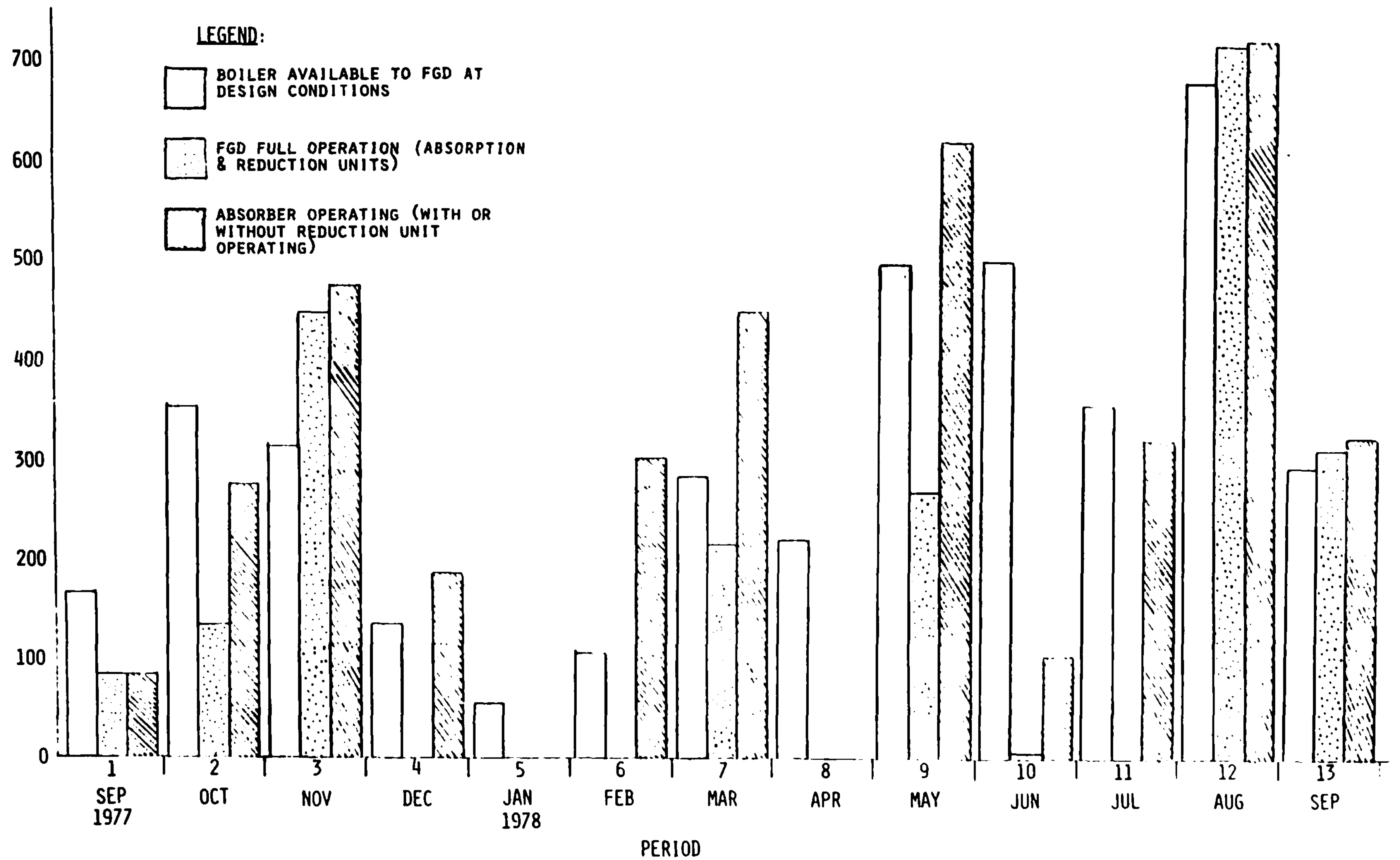
[4] Laske, B., et al. EPA Utility FGD Survey. EPA-600/7-78-051d, U. S. Environmental Protection Agency, Research Triangle Park, NC 1978.

FIGURE 3.3 NIPSCO BOILER AVAILABILITY & FGD OPERATING TIME



Viability Indices

These indices are defined in the FGD Survey reports (Table 3.3). However, the various parameters have been more precisely defined to conform with the specific operating configuration of this FGD process. Primarily, the specific definitions needing clarification are "FGD plant called upon" (defined above) and "FGD plant available":

> FGD plant available - defined as time all equipment required for accepting total flue gas, removing SO_2, recovering captured SO_2 as SO_2 or purge solids, and reducing SO_2 to elemental sulfur is in shape to operate and solution is in shape to operate with no more than 48 startup hours required from time steam of greater than 37.3 kg/cm^2 gauge (530 psig) is available.

Available and called upon hours are presented below (Table 3.4).

TABLE 3.4 HOURS FGD PLANT AVAILABLE AND CALLED UPON

Period	Hours FGD Plant Available(1)	Hours FGD Plant Called Upon
1. 9/16-10/3	440	165
2. October	131	357
3. November	531	319
4. December	496	131
5. January	720	53
6. February	720	107
7. March	720	283
8. April	0	216
9. May	368	495
10. June	97	499
11. July	43	353
12. August	720	679
13. 9/5-9/15	321	292
Total	5307	3949

(1) Hours FGD plant available obtained from Allied reports.

TABLE 3.3 DEFINITION OF VIABILITY INDICES[5]

Boiler Capacity Factor	(kWh generation in year)/(maximum continuous generating capacity in KW x 8760 hr/yr).
Boiler Utilization Parameter	Hours boiler operated/hours in period, expressed as a percentage.
Efficiency - Fly Ash	Operational - The actual percentage of fly ash removed by the FGD system and the particle control devices from the untreated flue gas. All others - The design efficiency (percentage) of fly ash removed by the FGD system and the particle control devices.
- SO_2	Operational - The actual percentage of SO_2 removed from the flue gas. All others - The design efficiency.
FGD Availability Factor	Hours the FGD system was available for operation (whether operated or not)/ hours in period, expressed as a percentage.
FGD Reliability Factor	Hours the FGD system operated/hours FGD system was called upon to operate, expressed as a percentage.
FGD Operability Factor	Hours the FGD system was operated/boiler operating hours in period, expressed as a percentage.
FGD Utilization Factor	Hours FGD system operated/hours in period, expressed as a percentage.
FGD Status - Category 1	Operational - Unit has been or is in service removing SO_2.
- Category 2	Under Construction - Ground has been broken for installation of FGD system has not become operational.
- Category 3	Planned, Contract Awarded - Contract has been signed for purchase of FGD system but ground has not been broken for installation.

(5) Laske, B., et al. EPA Utility FGD Survey. EPA-600/7-78-051d, U. S. Environmental Protection Agency, Research Triangle Park, NC 1978.

Overall dependability for the demonstration year (8,760 hours) was as follows:

<u>Boiler Utilization</u>. The boiler was operated for a total of 7,800 hours for a utilization factor of 89%.

<u>Boiler Capacity</u>. The boiler generated a total of 589.7 x 10^6 kWh of electricity for a capacity factor of 0.582 kWh actual/kWh maximum capacity (based on a nameplate maximum load of 115.6 MWG).

<u>FGD Reliability</u>. Flue gas and steam within design limits were delivered by the boiler for a total of 3,949 hours. Full operation of the FGD plant was achieved for a total of 2,153 hours. Of these hours, the FGD plant operated outside of the design limits for steam pressure for 346 hours. Thus, the plant is capable of operating at times at reduced steam pressures. The reliability factor, determined on actual capability, is as follows:

$$\text{Reliability} = \frac{2153}{3949 + 346} \times 100 = 50\%$$

<u>FGD Operability</u>. The operability factor was 28% (hours FGD plant operated/hours boiler operated).

<u>FGD Utilization</u>. The utilization factor was 25% (hours FGD plant operated/hours in year).

Reliability is the ability of the FGD plant to operate within specific limits of boiler operation. Operability is the ability to follow boiler operation, but only if the swings in boiler operation are normal. The FGD plant should not be expected to operate during every conceivable off normal excursion of the boiler. The FGD plant achieved operability only 56% of the time that it achieved reliability. The wide disparity in these two indices was due to considerable operation of the boiler in an unstable and off normal condition.

In other words, the operability factor would have been higher with more stable boiler operation. An account of boiler and FGD plant operating problems are given in the next subsection.

Operating Problems

A whole series of problems were encountered right from the start of the demonstration year which prevented consistent operation of the FGD plant until the last two months of the year (Table 3.5). The problems were primarily boiler related or problems at the boiler/FGD plant interface. The major problems and corrective measures are summarized as follows:

- Coal Feeding and Coal Quality. Inability to maintain consistent feed rates to the coal mills and coal mill failures resulted in unstable flue gas rates and steam pressures. The FGD plant was unable to operate when these excursions from normal boiler operation were excessive. It appears that the major problem was the quality of the coal (a relatively new source of coal for Mitchell No. 11) which contained unmillable material and contributed to coal mill failures. With the use of Captain coal beginning on a permanent basis in Period 8 (April 1978), the coal feeding problems were minimized substantially. Other corrective actions were enlargement of the coal mill feed chutes and overhaul of the four coal mills and associated primary air fans.

- Boiler Feed Water Problems. Silica levels must be limited to prevent turbine blade fouling and erosion. Silica concentrations are maintained by limiting silica in the makeup water to parts per billion levels. If silica excursions occur, boiler blowdown is increased or the boiler is operated at a lower steam pressure. Fluctuations in boiler main steam pressure affected the pressure of the steam

TABLE 3.5 BOILER & FGD PLANT OPERATING HISTORY

		Hours		
Event	Period	Boiler Operated	Boiler Operated Within Design Limits	FGD Plant Full Operation
1. The Demonstration year commenced at 0000 on 9/16/77. The FGD plant operated until 1100 on 9/19/77.	9/16/77 to 9/19/77	83	75	83
2. The FGD plant was taken down due to unstable flue gas and steam flows due to coal feeding problems caused by wet coal. Due to the feeding problems, the wet coal had to be worked off at minimum loads. This was accomplished by 10/3. The FGD plant remained down until 10/7 to conduct flow tests at baseline conditions to verify the flow rates of the Acceptance Test.	9/19 to 10/7	413	114 [1]	0
3. The FGD plant operated with interruptions due to booster fan speed control repairs and had some partial operation (reduction unit not operating or bypass damper open) as a result of fluctuations in steam delivered by boiler.	10/7 to 10/19	272	188	131
4. The FGD plant went down for repair of the evaporator circulating pump. The plant was available on 10/21 but remained down for an expected boiler outage to make tube repairs. However, the boiler outage could not be scheduled due to power demand.	10/19 to 10/28	223	44 [2]	0

TABLE 3.5 (Continued)

Event	Period	Hours: Boiler Operated	Hours: Boiler Operated Within Design Limits	Hours: FGD Plant Full Operation
5. An FGD plant startup was attempted but was delayed due to an inoperative isolation damper and to problems with controls on the booster fan. After startup, FGD plant operation was interrupted by the boiler shutdown and by booster fan vibration caused by flyash buildup on the blades.	10/28 to 11/5	151	142	0
6. The FGD plant operated despite boiler load and main steam fluctuations. The major problem was high silica in the boiler feed water which was thought to be due to condenser leaks. Boiler main steam pressures had to be reduced to accommodate the high silica. This affected pressure control of steam to FGD plant. Some FGD plant partial operation occurred.	11/5 to 11/23	450	278	428
7. Boiler down to repair condensers.	11/23 to 11/26	0	-	-
8. Boiler startup on November 26. FGD plant not available due to evaporator repairs and booster blower being out of balance.	11/26 to 12/10	329	100	0
9. Boiler down 81 hours for condenser and precipitator repairs and to remove clinkers. Boiler was returned to service but high silica problem had not been corrected. Also, there were recurring coal feed problems. FGD plant was not operated due to boiler operating at low loads,	12/10 to 2/23	234	30	0

TABLE 3.5 (Continued)

Event	Period	Hours: Boiler Operated	Hours: Boiler Operated Within Design Limits	Hours: FGD Plant Full Operation
reduced steam pressure and operating with low sulfur coal. The absorber accepted flue gas for 114 hours. Reduction unit was not operated due to insufficient amount of SO_2 available (due to minimum boiler loads and low sulfur coal).				
10. FGD on standby at request of NIPSCO until coal mill and high silica problems are resolved. During this period, boiler was down for condenser repairs, precipitator repairs, boiler tube leaks, and turbine repairs. Low sulfur coal was burned for much of this period.	12/23/77 to 2/19/78	1102	81	0
11. FGD plant on at partial operation (reduction unit down and bypass damper open), SO_2 level in flue gas was low and pressure of steam delivered to FGD plant was unstable. FGD plant down 16 hours to balance booster blower.	2/19 to 3/6	368	125	0
12. FGD plant at full operation with bypass damper open. It was determined that the high silica levels in the boiler feed water were not due to condenser leaks as suspected but were a combination of high makeup water rates and higher than acceptable silica levels in the makeup water. Corrective steps were underway.	3/6 to 3/15	215	212	215 (3)

TABLE 3.5 (Continued)

Event	Period	Hours: Boiler Operated	Hours: Boiler Operated Within Design Limits	Hours: FGD Plant Full Operation
13. Boiler down for repairs and maintenance on coal mills, turbine, precipitator.	3/15 to 3/18	0	-	-
14. Full operation of FGD plant not possible due to erratic coal feed and resulting fluctuations in pressure of steam delivered to FGD plant, recurring imbalance of booster blower, and isolation damper malfunction. Boiler also switched to low sulfur coal due to difficulty with feeding high sulfur coal.	3/18 to 3/28	252	26	0
15. FGD plant down to reblade the booster blower and for isolation damper malfunction. Boiler down on 5/3 for isolation damper repairs and back up on 5/6. FGD plant up on 5/6 at partial operation (reduction area down and bypass damper open). Full operation not achieved due to bypass damper problems and erratic steam pressure. Inlet SO_2 was under the design limit part of time.	3/28 to 5/11	816	314	0
16. FGD plant full operation.	5/11 to 5/14	65	56	65
17. FGD plant at partial operation (reduction unit down) due to shift to low sulfur coal.	5/14 to 5/19	119	38	0
18. FGD plant full operation.	5/19 to 5/27	203	203	203

TABLE 3.5 (Continued)

Event	Period	Hours		
		Boiler Operated	Boiler Operated Within Design Limits	FGD Plant Full Operation
19. FGD plant at partial operation due to reduction unit and booster blower repairs and erratic steam pressure. Booster blower repairs requiring a boiler shutdown were delayed due to power demand.	5/27 to 7/6	948	737	0
20. Boiler down to repair ID fans, isolation damper and booster blower.	7/6 to 7/10	0	-	-
21. FGD plant at partial operation due to booster blower and steam pressure relief valve problems.	7/10 to 7/31	516	218	0
22. FGD plant at full operation except for short outages of reduction unit (4 hours total).	7/31 to 9/12	1046	968	1028
23. Boiler scheduled down for routine maintenance and to continue with FGD plant improvement projects.	9/12 to 9/15	0	-	-

Notes: (1) Hours to conduct flow tests not included.
(2) Hours FGD in standby for boiler shutdown not included.
(3) With bypass damper open.

delivered to the FGD plant, causing unstable operation. The high silica levels were found to be due to a high level of silica in the makeup water from a portable water treatment facility being used to supplement the power station's permanent makeup water supply. The condition was exacerbated because a considerable amount of the condensate returned from the FGD plant was being discarded due to apparent poor quality, which added more silica to the system by way of increased makeup water requirements. However, much of the condensate from the FGD plant was being dumped automatically as a result of false signals from the conductivity and pH monitors. Defects in this control system were corrected. Also, more stringent control of silica in the makeup water is in effect. As a result, control of silica in the boiler feedwater was improved and, as a result, boiler steam pressure became more stable. It took several months to determine the cause of the problem and correct it. This was because considerable time was lost while it was thought that the high silica levels were caused by cooling water leaking into the boiler feed water system at the condensers. Corrective actions were therefore at first directed toward stopping condenser leaks.

- Booster Blower. The primary problems were rapid deterioration of the fan blades from contact with the wet flue gas and flyash, imbalance of the fan due to flyash buildup and problems with blower and turbine controls and the lubrication system. This part of the FGD system was designed for a flue gas temperature above the dew point. However, flue gas temperatures below the dew point were common. The liquid phase is a weak acid, primarily sulfuric, which is corrosive. After several unsuccessful attempts to balance the blower, it was decided to reblade the fan in May 1978 (Period 9). These repairs were done in 31 days. To maintain the flue gas temperatures above the dew point, the air heaters were modified during the scheduled shutdown in September-October 1978 to raise the flue gas temperature. However, this resulted in additional heat lost in the exiting flue gas for a loss in boiler efficiency. Also, flue gas ducts inlet and outlet the booster blower were insulated and a system for cleaning the fan blades while in run is being installed.

- Isolation Damper. A guillotine damper, installed in the flue gas duct upstream of the booster blower, isolates the FGD plant from the boiler. Fly ash hardens in the damper tracks and prevents opening or closing when needed. This has either delayed startups or maintenance of the booster blower has had to be delayed until a boiler shutdown could be scheduled. The primary corrective action has been to provide another means of isolating the FGD plant from the boiler.

- Steam Pressure Reducing Valve. The valve has required a substantial amount of maintenance.

- Evaporator Circulating Pump. The pump for circulating the spent absorber solution through the evaporator heater is driven by a steam turbine, using 40 kg/cm^2 (550 psig) steam supplied from the boiler. Loss of this steam supply when the boiler was shut down required that the evaporator be drained immediately to prevent solidification of the solution components in the evaporator and the heater. The solution would then be diluted for storage. This resulted in evaporator startup delays. The corrective action has been to provide an electric drive for the circulating pump.

- Absorber Leaks. Leaks at the bottom collector tray of the absorber resulted in absorber solution losses which probably required additional soda ash makeup at an added cost. This is the solution from which sodium sulfate is removed from the process stream in the purge treatment area and dried to make a salable by-product. Purge treatment rates were less than normal as a result of the leaks. This prevented a full evaluation of purge treatment capacity. The corrective action was to make absorber repairs to eliminate the leaks during the scheduled boiler shutdown of September 1978.

Boiler Operation Outside of FGD Design Limits

During the demonstration year, the boiler did not operate within FGD plant design limits all of the time (Table 3.4) and by definition the FGD plant was "called upon" to operate only when the boiler was operating within the design limits. The essential streams that NIPSCO provided for operation of the FGD plant were:

- Flue gas (from Mitchell No. 11)
- Steam (from Mitchell No. 11)
- Electricity (from Mitchell No. 11)
- Cooling water (Mitchell Station source)
- Natural gas (Mitchell Station source)
- City water (Mitchell Station source)

Thus, the FGD plant was dependent on Mitchell No. 11 for flue gas, steam and electricity. Adequate supplies of electric power were not a problem but delivery of flue gas and steam in amounts and of a quality suitable for meeting the SO_2 removal performance requirements of the FGD plant contributed substantially to the problems encountered during this demonstration year.

Steam Supply

The FGD plant is designed to take up to 32,000 kg/hr (70,000 lb/hr) of 39 kg/cm^2 (550 psig) steam at 400°C (750°F). Boiler main steam at 130 kg/cm^2 (1800 psig) and 540°C (1000°F) is desuperheated and the pressure is reduced to deliver this steam. There were no limits specified in the design for the steam pressure and temperature. As reported above, unstable or low steam pressure limited operation of the FGD plant. The causes were unstable or low boiler main steam pressure resulting from coal feeding and boiler feedwater problems as well as inadequate control at the steam reducing station. Initially, operating experience indicated that a steam pressure of about 37 kg/cm^2 (530 psig) was the lower limit of stable operation. In practice, the FGD plant was sometimes able to operate at moderately less steam pressures.

Flue Gas Supply

The FGD plant is designed to operate continuously at a rate of 9,100 am^3/m (320,000 acfm) of flue gas at 150°C (300°F). The absorber is designed to take up to about 11,000 am^3/m (388,000 acfm) of flue gas. For a lower limit, Davy Powergas expects that the absorber can sustain operation down to 46 MW equivalent gross load. The FGD plant design is also limited to treating flue gas from high sulfur coal in a range of about 2.8 to 3.5% sulfur. Specific test data have not yet been collected to indicate what the lower limits are for sustained flue gas and inlet SO_2 rates. However, there were times that the FGD plant was not operated because, as a result of low inlet SO_2 rates, there was not enough recovered SO_2 available to sustain operation of the reduction unit.

Plant Improvement Projects

A program was initiated in June 1978 to undertake several projects for the purpose of eliminating or minimizing the various operating problems discussed above. The projects and approximate completion time are presented (Table 3.6).

TABLE 3.6 PLANT IMPROVEMENT PROJECTS

Item	Expect to Complete	Action
Coal supply	Completed June 78	An uninterrupted supply of Captain coal available for Mitchell No. 11 use.
Air heater	During September shutdown	Part of baskets which provide heat storage removed to raise inlet duct temperature.
Duct insulation	After September shutdown	Insulate duct before and after booster blower.
Blanks	During September shutdown	Provision to install blanks rapidly at inlet of booster fan as an alternative to the isolation damper.
Booster blower steam blowing	After September shutdown	Install a sparger pipe in the booster blower to periodically steam clean blades while in run.
Evaporator pump	During September shutdown	Electrify pump.
Absorber	During September shutdown	Recoat and repair leaks.
Booster blower turbine	After September shutdown	Provide enclosure to protect against SO_2 and weak acid attack.
Sulfur condenser	During September shutdown	Plug leaking tubes.

PROCESS ECONOMICS

Tables 3.7 and 3.8 show the capital costs of installation and the projected operating costs of the FGD unit.

Actual annualized operating costs, adjusted to the projected unit costs and prices, were very nearly the same as the projected costs (Table 3.9) despite the substantially lower utilities and raw materials costs that resulted from the low utilization (25%) of the FGD plant. Detailed cost breakdown for identifying the significant variances are not available but it is known that maintenance costs for the booster blower and other repairs were high. The actual costs are not typical of satisfactory operation that would be indicated by high utilization and operability factors. It is apparent that annualized costs were not affected substantially by low operability because fixed costs and labor charges continued to accrue.

RAW MATERIAL & ENERGY CONSUMPTION

The raw materials are sodium carbonate (soda ash) and natural gas. Soda ash consumption averaged 8,200 kg/day (9.0 tons/day) for the days of absorber/evaporator operation. The FGD unit is designed to consume 6,000 kg day (6.6 tons/day) at design rates of 9,100 am^3/m (320,000 acfm) of flue gas containing 2,185 ppm of SO_2. A leak past the bottom collector tray of the absorber resulted in a loss of absorber solution in unknown amounts which probably contributed to the excess consumption of soda ash.

Natural gas consumption averaged 483 m^3/Tonne (17,072 cf per ton) of sulfur produced for the periods of absorber/evaporator operation. The FGD unit is expected to produce one ton of sulfur with about 394 m^3 (13,900 cubic feet) of natural gas. Some gas was burned at the tail gas incinerator when the SO_2 reduction unit was not operating. Thus, part of the excess was consumed during the 1,683 hours that the reduction unit was not operating.

The total energy supplied by the boiler as steam and electricity averaged 10×10^{10} J/hr (95×10^6 Btu/hr), referred to boiler heat input (Table 3.10). This is 12% of the average heat input to the boiler. The energy equivalent of the natural gas averaged 74×10^8 J/hr (7×10^6 Btu/hr) during the time that the absorber/evaporator was operating.

TABLE 3.7 CAPITAL COST

Direct Capital Costs	Cost, $
Absorber & related equipment[1]	7,082,140
Fans[2]	399,130
Reheat[3]	262,550
By-product recovery: purge treatment	1,495,270
By-product recovery: SO_2 reduction	1,143,750
Utilities & services[4]	1,181,040
Stack requirements[5]	146,020
System modifications[6]	241,930
Unidentified	60,000
Direct cost subtotal	11,891,830
Indirect Costs	
Engineering	199,100
In-house construction expense	322,230
Allowance for funds used during construction	775,680
Allowance for start-up	3,700,510
Spares, offsite, taxes, freight, etc.	284,000
Other[7]	958,680
Indirect cost subtotal	6,240,210
Total capital cost	18,132,040
Cost per kilowatt of generating capacity, $/kW	156.85

[1] FGD plant receives flue gas from an existing ESP at a normal dust loading of 0.09 grams/m^3 (0.04 grains/acf). This cost item includes an orifice contactor for additional flyash removal and for cooling and saturation of the gas prior to SO_2 absorption. This cost item also includes all equipment for SO_2 recovery and all equipment for soda ash storage and handling.

[2] Forced draft booster fan.

[3] The natural gas-fired reheater for the absorber exit gas has not been operated due to natural gas restrictions.

[4] Included in this cost item are a 2,000 KVA transformer, natural gas lines, power lines, steam lines, and water lines.

(5) The stack is erected atop the absorber. The top of the stack is 51.2 meters (168 feet) above grade.

(6) Extensive modifications, primarily for winterizing, were made following a winter freeze-up.

(7) Administrative and overhead costs.

TABLE 3.8 PROJECTED ANNUAL OPERATING COST

Variable Costs	Cost, $
Operating labor	750,000
Maintenance labor and supplies	853,000
Utilities:(1)	
(a) Steam @ $2.~~35~~/1,000 lb	1,222,000
(b) Electric power @ $~~0.0~~16/kWh	126,000
(c) City water	7,000
(d) Treated water	30,000
Utilities subtotal	1,385,000
Raw Materials:	
(a) Natural gas @ $1.60/$10^6$ Btu	216,000
(b) Sodium carbonate, 2,317 tons	204,000
(c) Other(2)	86,000
Raw materials subtotal	506,000
By-product credits(3)	(323,000)
Overhead	837,000
Total variable costs	4,008,000
Fixed Charges	
Interest	1,925,623
Annual depreciation	1,813,204
Taxes	1,465,069
Total fixed charges	5,230,896
Total Annual Operating Cost	9,211,896
Unit operating cost, mills/kWh(4)	14.86

(1) No funds included for reheat fuel

(2) Includes operating supplies

(3) Based on 7754 metric tons (7632 LT) of sulfur ($35.56/metric tons)($35/LT) & 1128 metric tons (1244 tons) of sodium sulfate ($40.82/metric tons)($~~45~~/ton)

(4) Based on 6.2×10^8 kWh. This is based on a projected load factor of 76.9% of a FGD plant capacity of 92 MW.

TABLE 3.9 ACTUAL ANNUAL OPERATING COST

Item Description	Cost Basis: Projected	Cost Basis: Actual	Cost, $: Projected	Cost, $: Actual
VARIABLE COSTS				
Utilities:				
(a) Steam @ \$2.35/1,000 lbs	$520,000 \times 10^3$ lbs	$224,138 \times 10^3$ lbs	1,222,000	526,724
(b) Electric power @ \$0.016/kWh	7,875,000 kWh	2,813,000 kWh	126,000	45,008
(c) City water	\$7,000	\$7,000 (assumed)	7,000	7,000
Utilities subtotal			1,355,000	578,732
Raw materials:				
(a) Natural gas @ \$1.60/10^6 Btu	$130,814 \times 10^3$ cf, 1,032 Btu/cf	$27,393 \times 10^3$ cf, 1,025 Btu/cf	216,000	44,925
(b) Sodium carbonate @ \$88.04/ton(1)	2,317 tons	1,431 tons	204,000	125,925
Raw materials subtotal			420,000	170,910
Sulfur credit \$35/LT(1)	7,623 LT	1,456 LT	(267,120)	(50,960)
Sodium sulfate credit @ \$45/ton(1)	1,244 tons	282.5 tons	(55,980)	(12,713)
By-product credits subtotal			(323,100)	(63,673)
All other costs(2)	-	-	2,556,000	3,440,117
Total variable costs			4,007,900	4,126,086
TOTAL FIXED COSTS			5,203,896	5,203,896
TOTAL ANNUAL OPERATING COSTS			9,211,796	9,329,982
Unit operating cost, mills/kWh	6.2×10^8 kWh	5.9×10^8 kWh	14.86	15.81

(1) At year end, raw material and product values were as follows: Soda ash - \$82.28/metric tons (\$90.70/ton)
Sulfur - \$33.53/metric tons (\$33/LT)
Sodium sulfate - \$12.33/metric tons (\$13.59 ton)

(2) Includes some estimate due to billing lags.

TABLE 3.10 FGD PLANT ENERGY USAGE

Heat input to boiler(1)	786.2×10^6 Btu/hr
Hours of boiler operation	7,800
Hours of absorber/evaporator operation	3,836
Average heat rate(1)	10,400 Btu/kWh
Total steam consumed(2)	$224,138 \times 10^3$ lbs
Total electric power consumed(2)	2,813,280 kWh
Average energy equivalent of steam(3,4)	87.6×10^6 Btu/hr
Average energy equivalent of electricity(4)	7.6×10^6 Btu/hr
Average energy supplied by boiler	95.2×10^6 Btu/hr
Total natural gas consumed(5)	27,392,711 cf
Average energy equivalent	7.3×10^6 Btu/hr
Total energy consumed	102.5×10^6 Btu/hr

(1) For hours of boiler operation.
(2) For hours of absorber/evaporator operation.
(3) Approximated, using an enthalpy of 3,073 J/gram (1,320 Btu/lb).
(4) Referred to heat input of boiler.
(5) Average heating value, 38.220 MJ/m^3 (1,025 Btu/cf).

BOILER PERFORMANCE

Boiler capacity factor was 0.585 (actual kilowatt hours generated per maximum possible at a nameplate rating of 115.6 MWG) for an average of 68 MW of power produced. The boiler was operated 7,800 hours. Average load was 76 MW for this operating time. The gross heat rate averaged 11,000 kJ/kWh (10,400 Btu/kWh) which was somewhat higher than a design heat rate of around 9700 kJ/kWh (9,200 Btu/kWh). However, heat rate during the Baseline Test (years 1974 and 1975) was 10,700 kJ/kWh) (10,100 Btu/kWh) at 92 MWG load.

Operating Problems

The major boiler operating problems have been described in a preceding section of this report. Operating problems that limited boiler capacity are summarized herein:

- Coal quality and associated coal feeding problems were a factor until Period 8 (April 1978) when burning of a better quality coal (Captain) was started (overhaul and modifications to the coal mills had also been partially completed by that time).

- Boiler operation was interrupted or limited due to high silica levels in the boiler feed water. Although a boiler-related problem, the effect on boiler operation was compounded by the inadvertent loss of returned condensate from the FGD plant.

- Operation was also interrupted for turbine, precipitator, and ID fan repairs. None of these interruptions were extensive but there was an overall effect on capacity.

The boiler was taken down nearly at the end of the demonstration year (September 12, 1978) for a scheduled three week period for routine maintenance. Three days of operation were lost as a result of this outage. Unscheduled outages amounted to a total of 37 days.

Retrofit Effects

The FGD plant affected boiler operation in two ways. First, boiler load was limited by a FGD plant capacity limitation of about 2,300 kg/hr (5,000 lb/hr) of SO_2. This equates to about 9,100 am^3/m (320,000 acfm) of flue gas at 150°C (300°F), 5% O_2, and a coal sulfur level slightly above 3%. With the boiler operating efficiently, this limits its capacity to 92 MWg or 80% of full capacity. The FGD absorber is designed to take full boiler capacity but the SO_2 recovery system was designed for the 92 MW of equivalent boiler load. With surge capacity provided, the FGD plant will operate above 92 MW for a limited time. However, the average gross power output experienced during the demonstration year was 76 MW for 7,800 hours of boiler operation but was 79 MW during the 3,836 hours that the absorber/evaporator were operating. Therefore, on the average, the boiler operated substantially below the 92 MW level whether the FGD plant was operating or not. But boiler operation was not typical, given the numerous interruptions and unstable operation of the boiler largely as a result of coal and water quality problems. After correction of these problems, the FGD plant was operated with minimal interruption for 1,028 hours (Periods 12 & 13, August-September 1978). Boiler load history is shown (Table 3.11).

TABLE 3.11 BOILER LOAD DISTRIBUTION[(1)]

Gross Megawatts	% of Time
72	0.3
73	0.3
74	1.4
75	3.1
76	6.8
77	13.3
78	16.6
79	23.7
80	17.1
81	9.2
82	5.0
83	1.5
84	1.4
85	0.1
86	0
87	0.2
	100.0

[(1)]Based on 1,000 hours of data during the period July 31-September 22, 1978.

This is more typical of expected operation. Also, the boiler was in better condition than earlier in the year and, without the FGD plant, probably would have exceeded the 92 MW capacity limitation if required to by power demand. The average load of 79 MWg reflects further derating of the boiler due to the energy consumed by the FGD plant.

There is also a lower limit of operation below which the SO_2 reduction unit will not operate. This establishes minimum limits on boiler load or on coal sulfur.

The second major effect further limits boiler capacity to below 92 MW due to the energy demands of the FGD plant. For Periods 12 & 13, with the FGD plant operating, steam consumption averaged 28,000 kg/hr (61,000 lb/hr). FGD electric power usage averaged 774 kW. The steam and electric power consumption represent direct derating of the boiler output. The loss of available generating capacity from FGD steam consumption is 10 MW. Thus, 89 MW of power could have been generated from the same boiler heat input during Periods 12 & 13, had the FGD plant not been there. Including nearly one megawatt of electrical power consumed, this amounts to a boiler derating of 9% of nameplate capacity.

Flue Gas Characteristics

Flue gas characteristics which affect FGD operation are primarily SO_2 mass rate, flue gas volume and temperature. Grain loading may also be troublesome if excessive. Volume is a function of boiler load; however, volume as well as temperature will also be a function of the excess air carried by the flue gas. Obtaining a complete description of these characteristics has been hampered by lack of reliable flue gas flow and moisture measurements and by sporadic problems with the data acquisition system (DAS), resulting in an incomplete record of some parameters. The most stable period of operation occurred from July 31 to September 12, 1978 (Table 3.12).

TABLE 3.12 FLUE GAS CHARACTERISTICS 7/31/78 to 9/12/78

Average load, MWG	79
Average load (including steam equivalent), MWG	89
Average coal rate, lb/hr	74,517
Average sulfur in coal, %	3.26
SO_2 in flue gas, ppm ave.	2,109
Average flue gas volume, acfm	(1)
Flue gas temperature range, °F	(2)
Oxygen in flue gas, %	(2)

(1) Not measured.
(2) Data on strip charts, not accessed.

The DAS was not operating during this period, preventing access of the data for determining the flue gas temperature and the level of oxygen in the flue gas. Spot checks of temperature data for other periods of operation are presented (Table 3.13). The oxygen data are being further analyzed before reporting.

TABLE 3.13 BOILER OUTLET FLUE GAS TEMPERATURES

	FGD	Min. Temperature			Max. Temperature		
	Operated	°F	°C	Load, MWg	°F	°C	Load, MWg
9/16/77-9/19/77	yes	244	118	61	280	138	85
11/5/77-11/23/77	yes	212	100	62	304	151	61
12/10/77-12/23/77	no	235	113	60	309	154	95

Results of Special Tests

Tests were conducted from November 16 to November 22, 1977, to measure the performance variables that are not measured by the continuous monitoring system. The FGD performance with respect to possible flyash and SO_3 removal are particularly of interest.

Flyash concentrations at the inlet and outlet of the absorber are reported in Table 3.14, together with flue gas flowrates measured at the time that a particle stack test was conducted. The flyash removal rates ranged from 40% to 96%, depending on the inlet particle loading.

TABLE 3.14 FLY ASH LOADING

DATE & POSITION	GAS FLOWRATE(1) (ACFM)	LOADING(2) gm/m^3 (Std.)	kg/hr
11/16, Inlet	279,150	0.065	21.53
11/16, Outlet		0.044	10.50
11/18, Inlet	332,578	0.093	36.45
11/18, Outlet		0.079	27.85
11/19, Inlet	321,618	0.093	35.16
11/19, Outlet		0.76	21.16
11/21, Inlet	258,869	0.115	35.26
11/21, Outlet		0.034	20.74
11/21, Inlet	401,412	0.331	157.35
11/21, Outlet		0.014	6.14
11/22, Inlet	348,286	0.087	35.63
11/22, Outlet		0.047	13.43
11/22, Inlet	424,443	0.232	116.06
11/22, Outlet		0.028	11.53

(1) Corrected to 150°C (300°F)
(2) Std. conditions 21°C, 29.92 in.Hg.

TABLE 3.15 SO_3 AND SO_2 REMOVAL

DATE	GAS FLOWRATE (ACFM)	SO_2, ppm IN	SO_2, ppm OUT	SO_3, ppm IN	SO_3, ppm OUT
11/16	279,150	2280	193	33	1
11/17	326,037	1987	140	80	2
11/18	332,578	2893	245	11	2
11/19	321,618	2777	257	4	3
11/21	258,869	2526	96	5	1
11/21	401,412	2185	264	6	2
11/22	348,286	2514	215	7	7
11/22	424,443	2259	199	18	2

(1)Corrected to 150°C (300°F).

A pattern of SO_3 reduction is evident, although at these low concentrations there is potential for considerable error.

SECTION 4

EVALUATION METHODS

EVALUATION GOALS

Evaluation was in response to the test objectives and proceeded in six steps:

1. Collect applicable data and operating information.

2. Define hours of operation within each operating mode.

3. Process the raw data and accumulate for each 30-day elapsed period and for specific periods according to the mode of operation.

4. Assess performance with regard to pollutant removal, dependability, energy consumption, and costs.

5. Assess the response of selected dependent variables to changes or fluctuations in the major independent variables.

6. Assess the effect of upsets and transients on SO_2 removal capability.

The evaluation goals were dependent on a variety of measurement techniques which provided the basis for reporting SO_2 removal efficiency, operating load, FGD energy consumption, and cost of utilities. In addition, manual records were used to establish bulk materials consumption and by-product production. The operating status of the boiler and the FGD plant was an equally important evaluation goal, leading to some rather detailed determinations of the dependability of the two units.

THE TEST SYSTEM

The core test system (Figure 4.1) consisted of sensors for various boiler and flue gas operating variables (with emphasis on the FGD inlet and outlet flue gas parameters) and accumulation of the sensor analog signals by a data acquisition system (DAS). The frequency of analog signal scan by the DAS was three or six minutes, from which one-hour averages were computed. The DAS had the capability for storing the data on magnetic tape. However, hardware difficulties with the tape transport unit were experienced throughout the demonstration year, so that very little automated data reduction was possible. Backup storage was available on teletype printouts or on charts taken from strip chart recorders. These data sources had to be utilized at considerable penalty in the excessive time required to access the data and reduce it manually.

It was essential that the test system data be correlated with operational disruptions or limitations. Daily meetings were scheduled with NIPSCO and Allied Chemical representatives to receive reports on the operating status of the boiler and the FGD plant. Use was also made of NIPSCO and Allied reports to obtain raw material rates, product rates and costs.

The parameters to be measured at each sampling position are shown on a matrix (Table 4.1). The numbered data items represent the DAS data channels sampled every three or six minutes. The X's indicate less frequent sampling, at frequencies of every 24 hours, every 6 days, every 30 days, or for special tests at least once during the test program. The sampling positions are located as shown (Figure 4.2 & Figure 4.3).

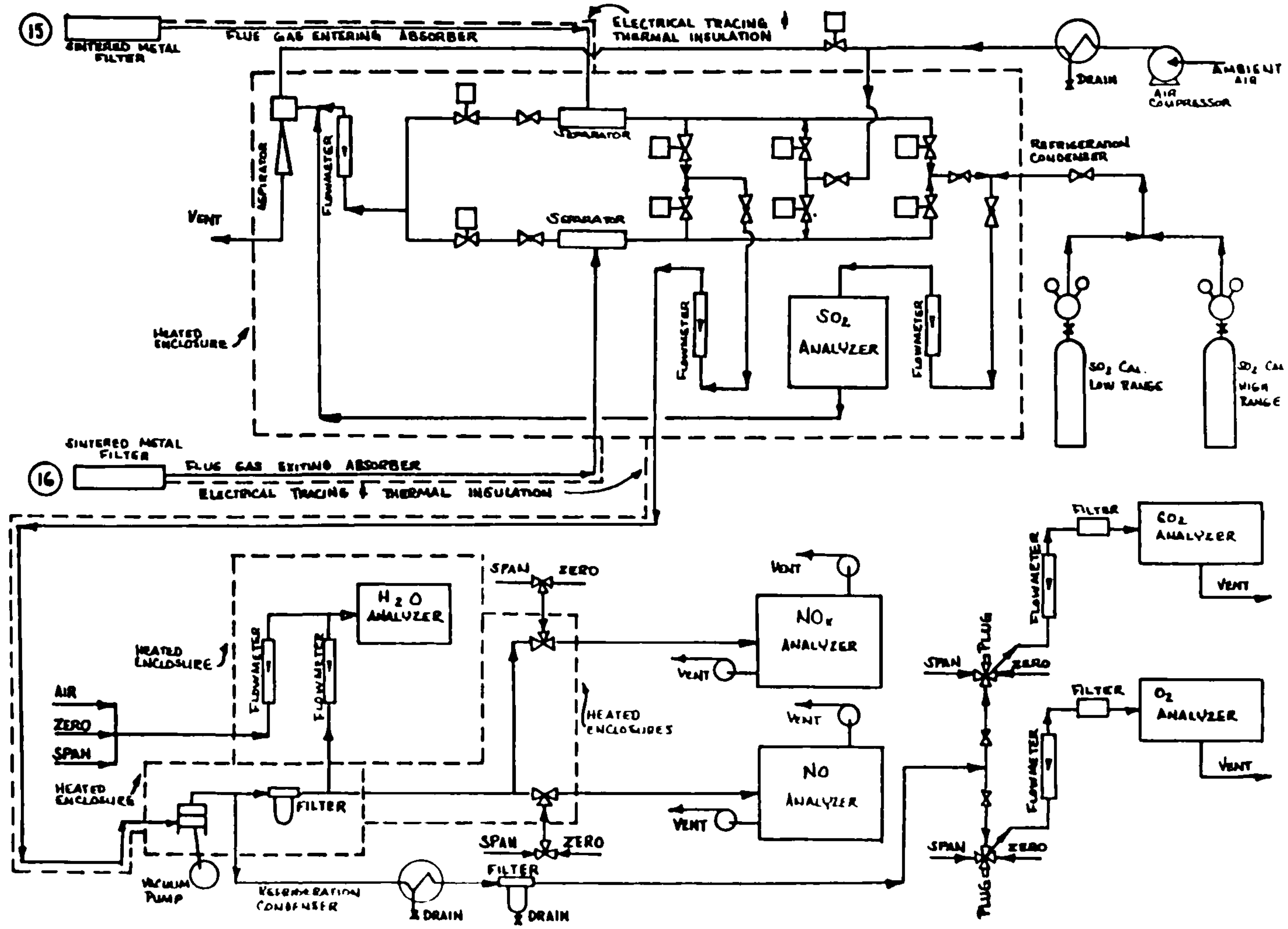


FIGURE 4.1 SCHEMATIC DIAGRAM OF MEASURING SYSTEM

TABLE 4.1 TEST PARAMETERS

Parameters \ Sampling Position	Raw Coal 1	Coal As Fired 2	Ambient Air 3	Combustion Air Boiler 4	Fly Ash (Special) 7	Steam Drum 8	Secondary S.H. Outlet 9	Cold Reheat Inlet 10	Hot Reheat Outlet 11A	No. 4 Extraction 11B	BFW Inlet-Economizer 12A	BFW Lvg. Heater No. 3 12B	BFW Lvg. Heater No. 4 12C	Heater No. 4 Drain 12D	Heater No. 5 Drain 12E	Super Heater Interstage Spray 12F	Reheat Attemperation Spray 12G	RIPSCO Load Gross 13A	RIPSCO Load Net 13B	Flue Gas Inlet APH 14	Booster Fan Inlet 15	Booster Fan Outlet 15A	Booster Fan 15B	Absorber Outlet 16	Fly Ash Purge 17	Soda Ash Feed 18	Total Natural Gas 21	Purge Solids 22	Sulfur 23	Demo Steam 24	Demo Electricity 25	Electrostatic Precipitator 30	Flue Gas Exit APH 31	Boiler Gas Side 33	Auxiliary Amperages 34
1. SO_2																					00			00											
2 SO_3																					X			X											
3 Particle Mass																				X		X		X	X										
4 Particle Size																						X		X											
5 Proximate	X	X																																	
6 Ultimate	X	X																																	
7 H_2O																																			
8 Trace Metals																																			
9 Halogens	X	X			X																				X	X									
10 Pressure						07	08	09	10	11										X							X			X				X	
11 Volume							X													X							X			X					
12 Temperature		X	X	X			49	41	42	51	47	48	33	55	50					X							X			X			X		
13 Weight	X	X			X							X				X	X								X	X		X	X						
14 CO_2																				X	02			02											
15 O_2																				03	04			04											
16 Booster Fan ΔP																					17	17													
17 NO/NOx																					05/06			05/06											
18 Booster Fan RPM																							18												
19 Total Sulfur	X	X																							X			X	X						
20 Heating Value	X	X																									X								
21 Combustibles/Sulfur					X																														
22 Relative Humidity				X																															
23 Barometer				X																															
24 Sulfur Species																												X							
25 Total N																									X										
COD																									X										
27 Gross kWh																	38														X				
28 Net kWh																		39																	
29 Voltage																																X			
30 Current																																X			X
31 Soot Blower Status																																		X	

Notes (1) Numbered items of data denote DAS channels.
(2) X's denote non-DAS sampling

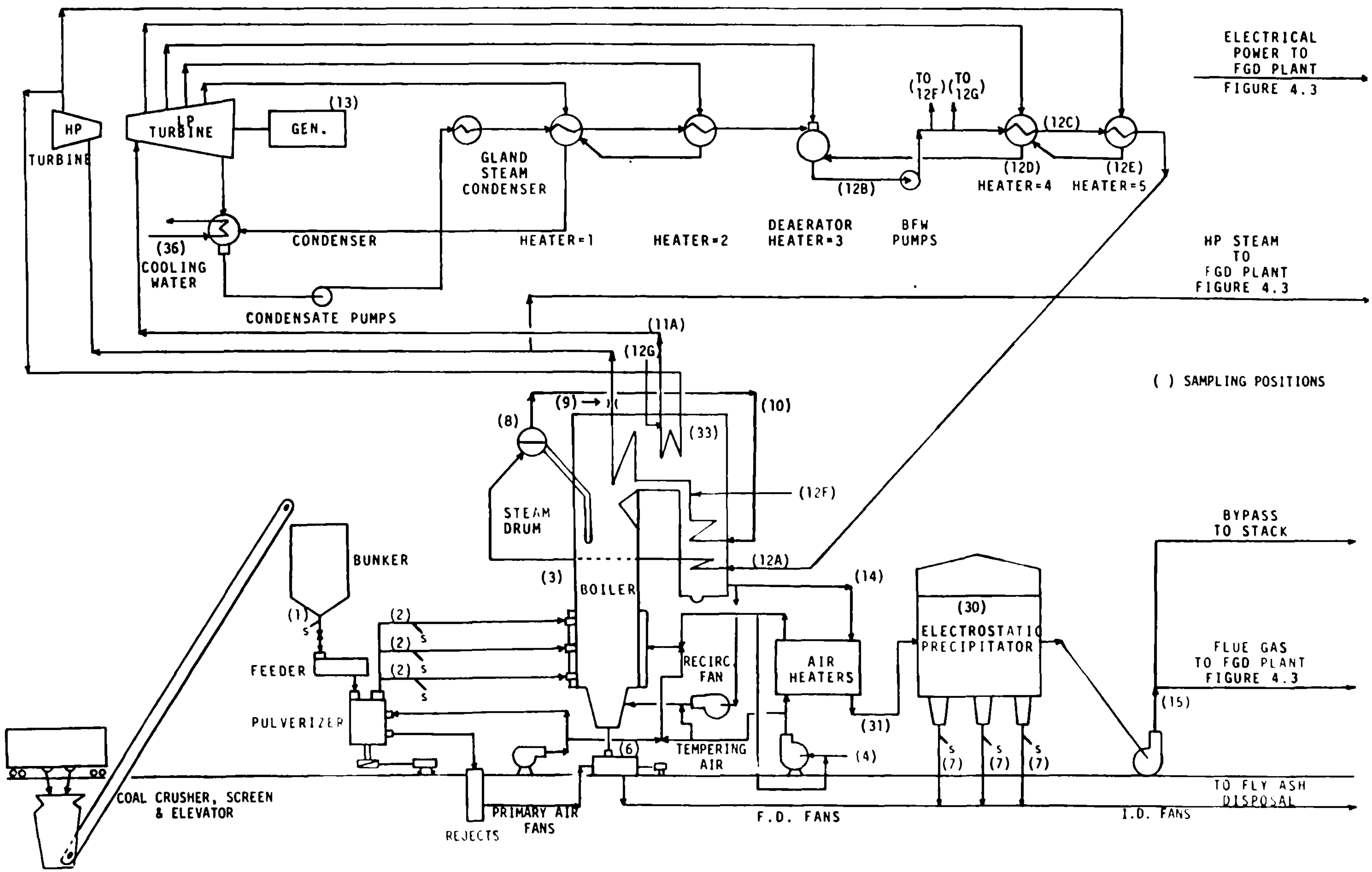
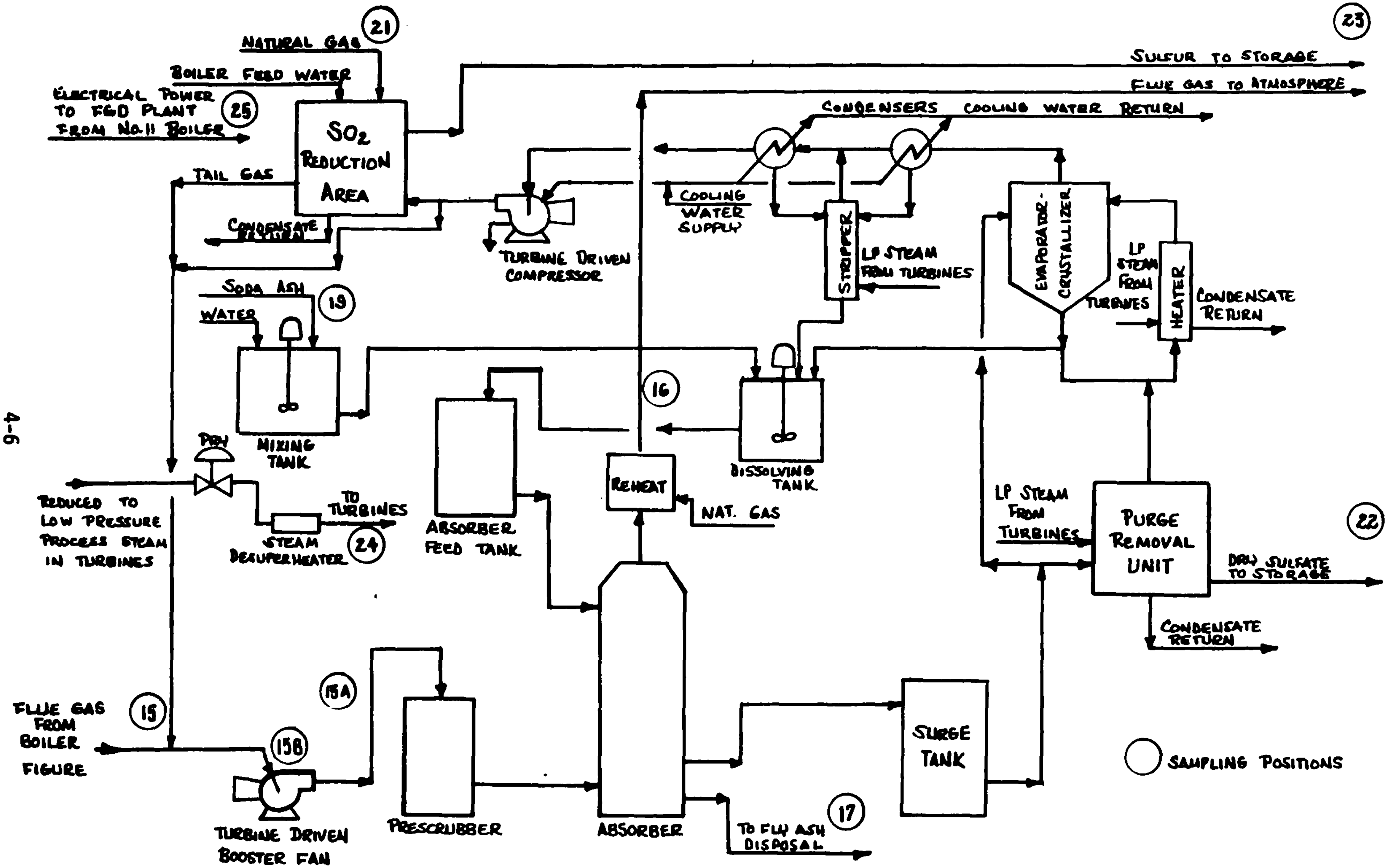


FIGURE 4-2 MITCHELL NO. 11 BOILER SAMPLING POSITIONS

FIGURE 4.3 SCHEMATIC DIAGRAM OF FGD PLANT



METHODOLOGY

The evaluation data flow is shown schematically on Figure 4.4 and the data inputs are summarized in Table 4.2 with respect to measurement type, frequency of recording and utilization. The three or six minute values stored by the DAS were used to determine one-hour averages. The basic time interval was one hour and SO_2 removal performance was assessed on the basis of a one-hour averaging time. Not all of the operating variables were measurable at one-hour intervals. To make the necessary comparisons; one-hour data were accumulated, evaluated and reported for each 30-day period and when possible according to operating mode status (FGD plant down, FGD plant full operation, FGD plant partial operation). The Demonstration year reporting periods are shown in Table 2.1.

Data Reduction Procedures & Problems

Most of the data were manually reduced from the DAS backup teletype hard copy or from strip charts, and project logs. Coal feed rates were obtained from the NIPSCO coal scale totalizers. FGD natural gas consumption was also determined from daily totalizer readings. Electrical energy consumption was scanned by the DAS. The other consumables and products were taken from the Allied monthly summaries. The intent was to do most data reduction automatically, as described in the Demonstration Test Plan.[6] Data obtained on the DAS were stored on magnetic tape for subsequent processing by a batch computer program. Hardware difficulties with the tape drive and controller were experienced throughout most of the demonstration year so that very little automated data reduction was possible. Hardware failures occurred with the DAS and its analog signal interface occasionally, but these were corrected as soon as possible for acceptable data recovery. In one case of extended DAS downtime, data were taken from backup recorder strip charts. Therefore, the only periods of complete data loss were during sensor failures.

(6) TRW Inc., Environmental Engineering Division. Program for Test and Evaluation of the NIPSCO/Davy/Allied Demonstration Plant. Demonstration Test Plan. Prepared for Control Systems Laboratory, Office of Research and Monitoring, Environmental Protection Agency, Research Triangle Park, NC April 8, 1975.

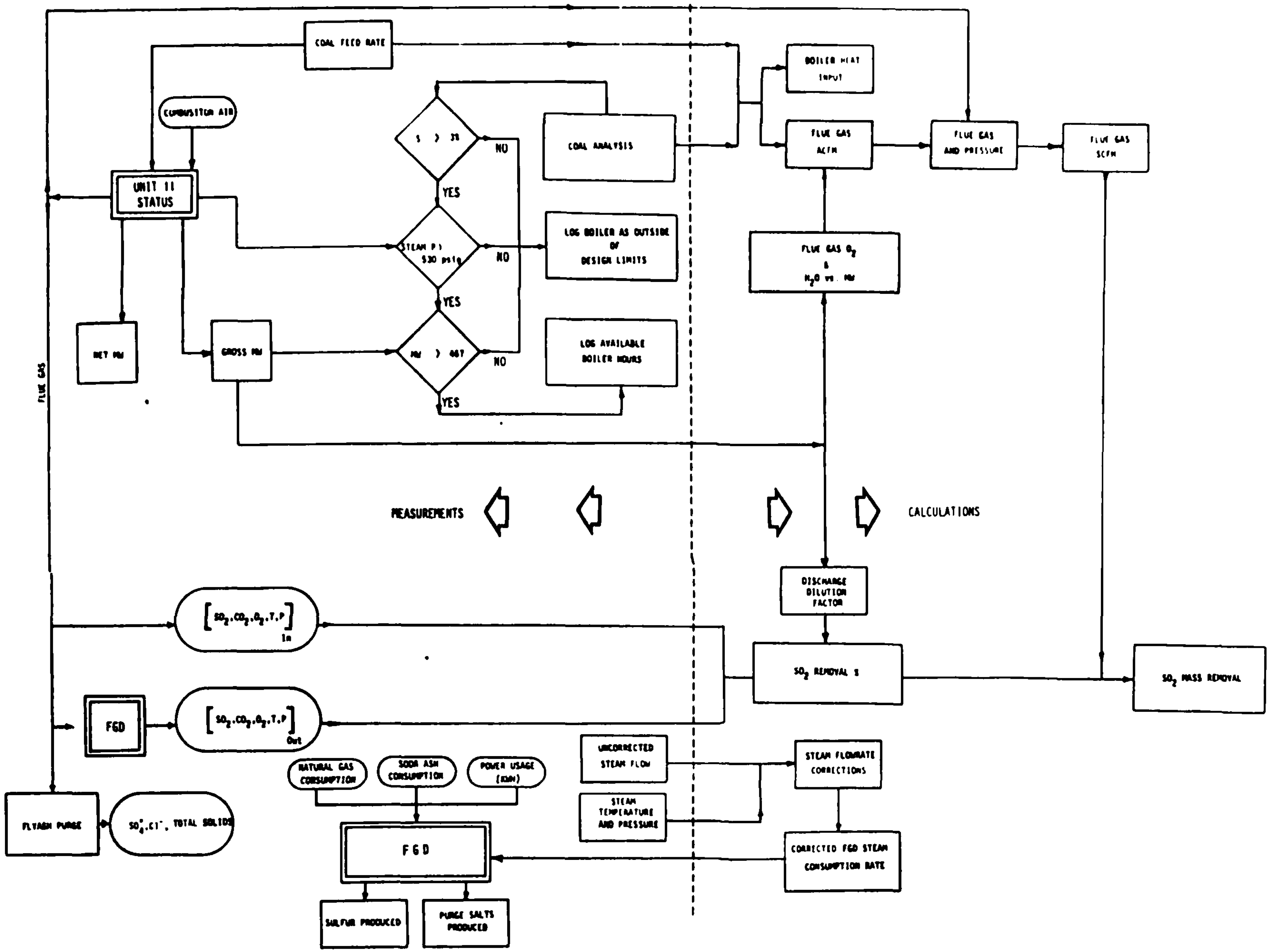


FIGURE 4.4 DATA FLOW FOR EVALUATION

TABLE 4.2 EVALUATION DATA INPUTS

Measurement Type	Sampling Frequency	Utilization
Coal feed rate (belt weigher)	Daily total	Flue gas volume, boiler heat input
Coal analysis (laboratory)	6-day composite & spot check	Flue gas volume, design limit check
Boiler load (gross MW)	Hourly average	Design limit check, flue gas corrections
Inlet flue gas SO_2 conc.	Hourly average	SO_2 removal, FGD loading
Inlet flue gas CO_2 conc.	Hourly average	Flue gas volume & dilution
Inlet flue gas O_2 conc.	Hourly average	Flue gas volume & dilution
Flue gas temp. & pressure	Hourly average	Flue gas volume & characterization
FGD stack SO_2 conc.	Hourly average	SO_2 removal, SO_2 emissions
FGD stack CO_2 conc.	Hourly average	Flue gas dilution
FGD stack O_2 conc.	Hourly average	Flue gas dilution
FGD stack temp. & pressure	Hourly average	Relative humidity of stack gas
FAP sulfate (lab analysis)(1)	Spot tests	Sulfur balance, water medium effects
FAP chlorides (lab analysis)	Spot tests	Chloride removal, water medium effects
FAP total solids (lab analysis)	Spot tests	Flyash removal, water medium effects
FGD steam rate (uncorrected)	Hourly average	Economics, energy consumption, boiler derating
FGD steam pressure	Hourly average	Design limit check, correct steam flow
FGD steam temperature	Hourly average	Correct steam flow
FGD power use	Hourly average	Economics, energy consumption
FGD soda ash use	Monthly inventory	Economics
FGD natural gas use	Daily total	Economics, energy consumption
Purge salts production	Monthly inventory	Economics
Sulfur production	Monthly inventory	Economics

(1)FAP: Flyash Purge

Measurement and Estimating Techniques

The mass rate of SO_2 at the inlet or outlet of the absorber was determined by,

$$SO_2 \text{ mass rate, lb/hr} = \frac{(\text{volume fraction } SO_2)(\text{SCFH of flue gas})(f)}{(\text{CF/mol})(\text{mol/lb } SO_2)}, \text{ where}$$

f is a factor correcting for the dilution resulting from saturation of the flue gas with respect to water. The factor was found to be a function of boiler load. This correlation was necessary as moisture measurements of flue gas were not reliable. The flue gas flowrate was estimated from known coal firing rates and coal analyses. The details of this calculation are given in Appendix C. Another aspect of data estimation involved the values which were used for time periods shorter than those actually observed. Daily coal feed rates, for example, were spread over the course of a day by making each hourly coal feed rate estimate be proportional to MW generation by the boiler for a given hour. Six-day coal composite analyses were assumed to be representative of their respective period of operation (Table 4.3).

TABLE 4.3 FLUE GAS COMPOSITION

MW Range (gross)	60-70	70-80	80-90	90-100
Parameters				
H_2O in	8.52	9.23	8.62	8.68
H_2O out	11.93	12.51	13.64	14.08
CO_2 in	11.66	12.61	12.64	12.93
CO_2 out	11.26	11.69	11.95	12.21
O_2 in	7.66	7.51	6.41	5.60

FGD energy consumption calculations were all measurable, including electric power, steam, and natural gas. FGD steam rates were corrected for temperature and pressure as indicated in Appendix C.

QUALITY CONTROL

Calibration of instruments using a known standard was the predominant method employed for validating data accuracy. Comparison of data obtained by different methods and of the test data with a known standard was also employed.

Calibration Procedures

In order to ensure valid data measurements, the continuous analyzers were calibrated routinely with known calibration gases for both zeroing and spanning the instruments. The following table illustrates the gas compositions for both the zero gas and span gas for the respective analyzer (Table 4.4).

TABLE 4.4 CONTINUOUS ANALYZER CALIBRATION

ANALYZER	RANGE OF ANALYZER	ZERO GAS	SPAN GAS
SO_2 (Low Range)	0-500 PPMV	N_2	260 PPMV SO_2 in N_2
SO_2 (High Range)	0-5000 PPMV	N_2	2690 PPMV SO_2 in N_2
CO_2	0-20 Volume Percent	N_2	15% Volume CO_2 in N_2
H_2O	0-25 Volume Percent	N_2	100% C_2H_6 gives instrument span of 15.625%
O_2	0-25 Volume Percent	N_2	Ambient Air (21% O_2 by volume)

The SO_2 calibration gases are traceable to NBS standards.

Certain other information was needed for determining performance. The source of these data and the calibration records are shown in Table 4.5. The instruments installed for the acceptance and demonstration tests were the major sources of data. Other sources were coal scales, steam flow meters, steam pressure, natural gas flow meters, and kilowatt-hour meter. Steam flow, steam pressure and electrical energy consumption were transmitted to the DAS. Therefore, continuous real time data were available for analysis from all instruments except the coal scales and the natural gas flow meters. Totalized readings of coal and natural gas feed rates were taken at 0800 each day.

TABLE 4.5 INSTRUMENT CALIBRATIONS

ITEM	CALIBRATED BY
Coal Scales	NIPSCO
FGD Inlet Temperature	TRW
FGD Inlet Static Pressure	TRW
FGD Outlet Temperature	TRW
FGD Outlet Static Pressure	TRW
Steam Flow Meter	
Steam Flow Transmitter	TRW
Steam Pressure	
Steam Temperature Transmitter	TRW
Steam Pressure Transmitter	TRW
Natural Gas Flow Meters (2)	
Kilowatt-Hour Meter	NIPSCO

Accuracy Verification of the Calibration Standard

These verifications have been described in the Acceptance Test report.[7] For SO_2, the standard gases were analyzed by EPA Method 6. It was found that the span gases, traceable to NBS standards were only 2 to 3% higher than the mean value of repetitive Method 6 analyses.

[7] Adams, R. C., S. J. Lutz, and S. W. Mulligan. Demonstration of Wellman-Lord/Allied Chemical FGD Technology: Acceptance Test Results. EPA-600/7-79-014a. TRW, Inc., Durham, NC January 1979.

The accuracy of the span gases was also verified against a standard gas supplied by Research Triangle Institute in conjunction with their quality assurance program for EPA. This gas was analyzed by the continuous analyzer after calibration with the following results:

Analyzer Reading, ppm	1275
Actual Gas Analysis, ppm	1262 1264
Apparent Error, %	+0.95

During the Acceptance Test, a modified version of EPA Method 6 was used to determine SO_2 concentration entering and leaving the absorber. The effect of the method modification was to extend the sampling time to coincide with particulate matter sampling (4-5 hours per day). The average removal efficiency determined by the continuous analyzer was less than one percent higher than the comparable average of Method 6 results.

Instrument Reliability

Most of the problems affecting data acquisition were associated with the flue gas sampling and analysis system. The parameters needed for determining SO_2 removal performance are flow and the concentrations of SO_2, CO_2 or O_2, and H_2O.

The test program was hampered by the lack of a dependable measurement of two of these flue gas parameters: flow rate and moisture content. Annubars placed in the FGD stack did not provide a dependable or accurate flow measurement. Accuracy was poor due to unidentified disturbances that dictated more than the eight traverse points available with the Annubars. Also, signal resolution was lost due to inherent instability of the sensor signals. The water analyzer was a non-dispersive infrared (NDIR) type. Stable operation was never achieved after the Acceptance Test and the instrument was finally abandoned as not suitable for the application intended. Without reliable flow and moisture measurements, estimating techniques were resorted to for determining SO_2 removal. System uptime for SO_2 content and O_2 or CO_2 content was 80% of the hours of absorber operation (Appendix A). Either O_2 or CO_2 absorber inlet and outlet values along with H_2O inlet and outlet values are used to determine the amount of flue gas dilution during absorption. The SO_2 analyzer, at 89% uptime, was somewhat more reliable.

Variability in SO_2 Removal Result

The removal performance, expressed as a percentage was determined as follows:

$$SO_2 \text{ Removal} = \frac{SO_2 \text{ in} - SO_2 \text{ out} \times f}{SO_2 \text{ in}}$$

where f is a factor to correct for dilution effects:

$$f = \frac{CO_2 \text{ in}}{CO_2 \text{ out}} \times \frac{(1 - H_2O \text{ in})}{(1 - H_2O \text{ out})}$$

The same instruments used for measuring the inlet concentration also measured the outlet concentrations. If it is assumed that the instruments are in error in one direction only, the errors tend to compensate. Therefore, it is probable that the variability of the SO_2 removal results were quite small. However, it is true that sampling errors would not necessarily be compensating since inlet and outlet samples are collected and conditioned by separate sampling systems. No attempt has been made to estimate the magnitude of sampling errors, but these types of errors have been minimized in the design and operation of the sampling systems.

APPENDIX A. DATA BASE

TABLE A.1 BOILER PERFORMANCE DATA

DATE	COAL USAGE (lbs/hr)	HEATING VALUE (BTU/lb)	BOILER HEAT INPUT (10^6 BTU/HR)	HEAT RATE (BTU/KWH)
9/16/77	95833	9890	947.79	11465
9/17	93779	9890	927.47	11808
9/18	71467	9890	706.81	11904
9/19	35521	9890	351.30	9184
9/20	39679	9890	392.43	10349
9/21	51541	9890	509.74	15564
9/22	30842	9890	305.03	4386
9/23	9842	9890	97.34	10716
9/24	20533	9890	203.07	32930
9/25	34629	9890	342.48	74722
9/26	27600	9890	272.96	9851
9/27	26096	9890	258.09	8473
9/28	38938	9890	385.10	9577
9/29	53946	9890	533.53	9722
9/30	87696	9890	867.31	11197
10/01/77	86167	9890	852.19	11620
10/02	77108	9890	762.60	11439
10/03	93325	9890	922.98	11159
10/04	90558	9890	895.61	7174
10/05	90358	9890	893.64	10793
10/06	87621	9890	866.57	24099
10/07	94933	9890	938.89	11449
10/08	90242	9890	892.49	10884
10/09	88888	9890	879.10	10720
10/10	91629	10527	964.58	11763
10/11	96529	10527	1016.16	12224
10/12	80150	10527	843.74	12865
10/13	70621	10527	743.43	13672
10/14	77504	10527	815.88	13311
10/15	66442	10527	699.43	14094
10/16	74600	10581	788.60	13635
10/17	78942	10571	934.50	7384
10/18	101129	10571	1069.03	24411
10/18	98950	10571	1046.00	11908
10/20	89979	10571	951.17	12078
10/21	74058	10571	782.87	11967
10/22	75829	10571	801.59	12253
10/23	81038	10571	856.55	12481
10/24	111817	10571	1182.02	11771
10/25	138929	10571	1468.62	14928
10/26	75021	10571	793.05	8061
10/27	76067	10571	804.10	12229
10/28	86450	10571	913.86	12104
10/29	37675	10571	398.26	10727
10/30	97450	10571	1030.14	11846
10/31	0	10571	-	(Boiler Down)

DATE	COAL USAGE (lbs/hr)	HEATING VALUE (BTU/lb)	BOILER HEAT INPUT (10^6 BTU/HR)	HEAT RATE (BTU/KWH)
11/01/77	83867	10571	886.56	12291
11/02	68417	10571	723.24	12829
11/03	81792	10571	964.62	7806
11/04	73783	15071	779.96	34536
11/05	83958	10571	887.52	11588
11/06	88400	10571	934.48	11501
11/07	82858	10571	875.89	12039
11/08	78208	10571	826.76	11035
11/09	83804	10271	860.75	11489
11/10	80650	10271	828.36	10752
11/11	83538	10271	858.02	10758
11/12	56475	10271	580.05	9262
11/13	97596	10271	1002.41	12071
11/14	73813	10271	758.13	10895
11/15	73646	11011	810.92	11932
11/16	80921	11011	891.02	12353
11/17	87817	11011	966.95	12578
11/18	66142	11011	728.29	9942
11/19	67042	11011	738.20	11177
11/20	69538	11011	765.68	11689
11/21	78475	9653	757.52	10033
11/22	79625	9653	768.62	9960
11/23	36683	9653	354.10	9463
11/24	85696	9653	827.22	9689
11/25	0	9653	0	(Boiler Down)
11/26	0	9653	0	(Boiler Down)
11/27	79508	9653	767.49	9745
11/28	80758	9653	777.36	9888
11/29	77658	9653	749.63	9667
11/30	70388	9653	674.46	9973
12/01/77	76713	9653	740.51	9967
12/02	71142	9653	686.73	10653
12/03	86850	10556	916.79	11376
12/04	80600	10556	850.81	11275
12/05	74429	10556	785.67	11575
12/06	79463	10556	838.81	11490
12/07	19350	10556	837.62	11243
12/08	55308	10556	503.83	11182
12/09	55308	10118	559.61	10718
12/10	15800	10118	159.36	9837
12/11	0	10118	0	(Boiler Down)
12/12	70383	10118	712.14	9936
12/13	87821	10118	888.57	10078
12/14	88550	10118	895.95	10407
12/15	91567	10064	921.53	10159
12/16	49563	10064	498.80	5496
12/17	253.63	10064	255.25	85083
12/18	78602	10064	791.05	12539
12/19	78602	10064	791.05	12539
12/20	75308	10064	171.90	10898

DATE	COAL USAGE (lbs/hr)	HEATING VALUE (BTU/lb)	BOILER HEAT INPUT (10^6 BTU/HR)	HEAT RATE (BTU/KWH)
12/21/77	87758	10097		10288
12/22	84033	10097	273.43	10667
12/23	57488	10097	580.46	10015
12/24	60292	10097	608.77	9772
12/25	56075	10097	566.19	9940
12/26	59204	10097	597.78	9956
12/27	39329	9637	379.01	10186
12/28	45867	9637	442.02	9514
12/29	49429	9637	476.35	9080
12/30	53571	9637	516.26	5391
12/31	69733	9637	672.02	29112
1/01/78	57025	9637	549.55	10784
1/02	63367	10457	662.63	11499
1/03	64933	10457	679.00	11070
1/04	59746	10457	624.76	10960
1/05	62708	10457	655.74	10891
1/06	27288	10457	285.35	9714
1/07	71108	10457	743.58	11077
1/08	0	10457	0	(Boiler Down)
1/09	0	10457	0	(Boiler Down)
1/10	80858	10457	845.53	10156
1/11	54488	10457	569.78	10069
1/12	67917	10457	110.21	9779
1/13	80100	10457	837.61	9839
1/14	81279	10690	868.87	10704
1/15	33879	10690	896.62	7275
1/16	86592	10690	925.67	20251
1/17	97133	10690	1038.35	10366
1/18	88775	10690	949.00	10118
1/19	107488	10690	1149.05	9959
1/20	102767	10341	1062.71	10197
1/21	47833	10341	494.64	9167
1/22	13229	10341	136.80	16751
1/23	106796	10341	1104.36	10066
1/24	93408	10341	965.93	9603
1/25	114800	10341	1137.15	10223
1/26	104167	9953	1036.77	10884
1/27	92900	9953	924.63	10179
1/28	87379	9953	869.68	10530
1/29	87717	9953	873.05	10625
1/30	103079	9953	1025.95	10178
1/31	94004	9953	935.62	10006
2/01	91629	10922	100.77	11181
2/02	104308	10922	1139.25	11256
2/03	85563	10922	934.52	11186
2/04	36004	10922	393.24	11709
2/05	16100	10922	175.84	10343
2/06	99233	10922	1084	8661
2/07	99233	10122	1084	8661
2/08	110908	10122	1122.61	15127
2/09	62063	10122	628.20	10024

DATE	COAL USAGE (lbs/hr)	HEATING VALUE (BTU/lb)	BOILER HEAT INPUT (10^6 BTU/hr)	(BTU/KWH)
2/10/78	59433	10122	601.58	3246
2/11	0	10122	0	(Boiler Down)
2/12	0	10122	0	" "
2/13	0	10122	0	" "
2/14	0	10122	0	" "
2/15	0	10122	0	" "
2/16	0	10122	0	" "
2/17	86835	10122	878.94	50647
2/18	86835	10122	878.94	50647
2/19	93671	10122	948.14	11371
2/20	87838	10367	910.62	11156
2/21	67075	10367	695.37	12408
2/22	85467	10367	886.04	10989
2/23	87779	10367	910.00	11205
2/24	99942	10367	1036.10	7630
2/25	105075	10159	1067.46	17643
2/26	102192	10159	1038.17	10283
2/27	103379	10159	1050.23	10200
2/28	97700	10159	992.53	10214
3/1/78	63021	10159	649.23	10340
3/2	52700	10159	535.38	10213
3/3	67488	10691	721.51	10108
3/4	64033	10691	684.58	10565
3/5	64533	10691	189.92	10361
3/6	73275	10691	783.38	11450
3/7	72483	10691	774.92	11257
3/8	68763	10691	735.15	9818
3/9	72096	10691	770.78	7017
3/10	71717	10711	768.16	30573
3/11	71075	10711	761.78	11174
3/12	69263	10711	741.88	11479
3/13	67863	10711	726.88	11545
3/14	66938	10711	716.97	11372
3/15	37038	10711	396.71	11161
3/16	17479	10711	187.22	10188
3/17	0	10711	0	(Boiler Down)
3/18	68692	10711	735.76	10961
3/19	67913	10711	727.42	11014
3/20	74146	10711	794.18	10897
3/21	81800	9633	787.98	6278
3/22	75621	9633	728.45	22299
3/23	59075	9633	569.06	99038
3/24	74529	9633	717.93	10052
3/25	53221	9633	512.67	7680
3/26	48213	9633	464.43	8437
3/27	85783	10885	933.74	10049
3/28	58129	10885	632.73	12013
3/29	66292	10885	721.58	11491
3/30	78242	10885	851.66	10803
3/31	42058	10885	457.80	10605

DATE	COAL USAGE (lbs/hr)	HEATING VALUE (BTU/lb)	BOILER HEAT INPUT (10^6 BTU/hr)	(BTU/KWH)
4/1/78	8745	10885	95.29	10490
4/2	0	10885	0	(Boiler Down)
4/3	72017	10885	783.91	10337
4/4	53842	10885	586.07	9836
4/5	52479	10885	571.23	24051
4/6	53562	10885	583.02	9097
4/7	72001	10885	783.73	10443
4/8	72001	10097	726.99	9687
4/9	72001	10097	726.99	9687
4/10	72001	10097	726.99	9687
4/11	72001	10097	726.99	9687
4/12	72001	10097	726.99	9687
4/13	72001	10097	726.99	9687
4/14	15467	10990	169.97	10459
4/15	0	10990	0	(Boiler Down)
4/16	0	10990	0	" "
4/17	0	10990	0	" "
4/18	0	10990	0	" "
4/19	74600	10990	818.85	10100
4/20	70504	10990	774.84	4725
4/21	77553	10990	852.30	15025
4/22	77553	10990	852.30	15025
4/23	77553	10990	852.30	15025
4/24	59988	10990	659.26	9784
4/25	51542	10990	566.44	9614
4/26	57596	10867	625.89	9318
4/27	59796	10867	646.80	9169
4/28	64799	10867	704.17	10180
4/29	64799	10867	704.17	10180
4/30	64799	10867	704.17	10180
5/1	74025	10867	804.43	9915
5/2	79617	10483	834.62	9435
5/3	31229	10483	327.38	4224
5/4	0	10483	0	(Boiler Down)
5/5	0	10483	0	" "
5/6	0	10483	0	" "
5/7	0	10483	0	" "
5/8	64275	10483	673.79	8694
5/9	79929	10483	837.90	10339
5/10	78258	10483	820.38	10619
5/11	80575	10483	844.67	10754
5/12	81729	10483	856.77	10726
5/13	84895	10483	889.96	11078
5/14	81954	10828	887.40	12100
5/15	74958	10828	811.65	11451
5/16	63296	10828	685.37	11312
5/17	62258	10828	674.13	11401
5/18	77675	10828	841.06	14225
5/19	79738	10828	863.40	10975
5/20	79121	10828	856.72	10960

DATE	COAL USAGE (lbs/hr)	HEATING VALUE (BTU/lb)	BOILER HEAT INPUT (10^6 BTU/hr)	(BTU/KWH)
5/21/78	79125	10900	862.46	11027
5/22	80504	10900	877.50	10974
5/23	79942	10900	871.36	10943
5/24	83963	10900	915.19	10341
5/25	83304	10900	908.02	11512
5/26	79113	10255	811.30	10324
5/27	81946	10255	840.35	10460
5/28	82125	10255	842.19	10599
5/29	79100	10255	811.17	10483
5/30	72938	10255	747.97	10522
5/31	77125	10255	790.92	
6/1/78	-	10255	-	No data
6/2	-	10329	-	sheet for
6/3		10329	-	days 6/1
6/4	-	10329		thru 6/6
6/5	-	10329		
6/6	-	10329		
6/7	77596	10779	836.41	10903
6/8	76590	10779	825.56	10116
6/9	76590	10779	825.56	10116
6/10	100796	10779	1086.48	13399
6/11	47613	10779	513.22	6336
6/12	75021	10779	808.65	10155
6/13	67404	10779	726.55	10067
6/14	66750	11083	739.79	10209
6/15	64125	11083	122.83	1702
6/16	70858	11083	785.32	10210
6/17	65825	11083	629.54	9776
6/18	71342	11083	790.68	11007
6/19	69471	10740	746.12	9992
6/20	69646	10740	748.00	9890
6/21	71292	10740	765.68	10158
6/22	71029	10740	762.85	10126
6/23	68007	10740	730.40	10327
6/24	68007	10740	730.40	10327
6/25	68007	10740	730.40	10327
6/26	65788	10740	706.56	10172
6/27	70954	10740	762.05	10076
6/28	67413	10740	724.02	10067
6/29	56463	10740	606.41	10432
6/30				
7/1/78	-	10740	-	No data
7/2	-	10740	-	sheet for
7/3	-	10740	-	days 7/1
7/4	-	10740	-	thru 7/4
7/5	58238	10740	625.48	9459
7/6	5588	10740	60.02	9667
7/7	-	10740		No data
7/8	-	10740	-	sheet for
7/9	-	10740	-	days 7/8
7/10	-	10740		thru 7/10

DATE	COAL USAGE (lbs/hr)	HEATING VALUE (BTU/lb)	BOILER HEAT INPUT (10^6 BTU/hr)	(BTU/KWH)
7/11/78	71142	10740	764.07	12290
7/12	62767	10740	674.12	10374
7/13	62767	10740	674.12	10374
7/14	69525	10740	746.70	11517
7/15	75975	10740	815.97	11261
7/16	68450	10740	735.15	11427
7/17	74658	10740	801.83	11072
7/18	71079	10740	763.39	11144
7/19	62913	10740	675.69	11168
7/20	63404	10740	680.96	11388
7/21	64083	10854	695.56	10917
7/22	61292	10854	665.26	10658
7/23	54467	10854	591.18	10651
7/24	55563	10854	603.08	9779
7/25	63838	10854	692.90	10605
7/26	74167	10854	805.01	10540
7/27	69792	10854	757.52	10490
7/28	77904	10854	845.57	10951
7/29	74825	10854	812.15	10610
7/30	76225	10854	827.35	11314
7/31	77054	10854	836.34	10873
8/1/78	78721	10854	854.44	10873
8/2	78521	10854	852.27	10880
8/3	79779	10854	865.92	10801
8/4	74129	10854	804.60	10775
8/5	75383	10854	818.21	10678
8/6	73017	10741	784.28	10616
8/7	74029	10741	795.15	10631
8/8	73642	10741	790.99	10767
8/9	76546	10741	822.18	10841
8/10	73413	10741	788.53	11080
8/11	77029	10741	827.37	11168
8/12	74221	10741	797.21	10611
8/13	74221	10741	797.21	10611
8/14	73488	10741	789.33	10472
8/15	75000	10741	805.58	10629
8/16	77379	10741	831.13	10730
8/17	75871	10741	814.93	9784
8/18	74871	10952	819.99	11645
8/19	80613	10952	882.89	11623
8/20	72125	10952	789.91	8448
8/21	74058	10952	811.08	13527
8/22	77142	10952	844.86	11366
8/23	75600	10952	837.97	10900
8/24	76375	10952	836.46	10928
8/25	76329	10796	824.05	10807

DATE	COAL USAGE (lbs/hr)	HEATING VALUE (BTU/lb)	BOILER HEAT INPUT (10^6 BTU/hr)	(BTU/KWH)
8/26/78	76683	10796	827.87	10659
8/27	76050	10796	821.04	10785
8/28	75067	10796	810.42	10687
8/29	77996	10796	842.04	11073
8/30	74096	10796	799.94	10272
8/31	74729	11379	850.34	11269
9/1/78	78196	11379	889.79	11198
9/2	76669	11379	872.42	11247
9/3	76669	11379	872.42	11247
9/4	74108	11379	850.10	10268
9/5	73546	11379	836.88	12085
9/6	74525	11379	848.02	10954
9/7	74408	11379	846.69	10954
9/8	73525	11379	836.64	11014
9/9	75446	11379	858.50	10017
9/10	75250	11379	856.22	12124
9/11	71638	11379	815.17	(Data up to 9/11/78)

TABLE A.2 BY-PRODUCT PRODUCTION AND RAW MATERIAL CONSUMPTION

PERIOD	1	2	3	4	5	6	7	8	9	10	11	12	13
Natural Gas, MM Btu	10.4	7.4	10.3	--	--	--	--	--	10.8	1.2	2.1	11.1	10.1
Steam, MM Btu	77.9	69.3	74.5	72.0	--	68.0	75.4	--	84.9	79.6	73.2	82.1	78.3
Soda ash, consumed, tons(1)	19	87	171	97	--	34.7	212	22.8	243	53	106.5	262.5	123.5
Sulfur produced,(1) tons	39	91	285	0	--	0	135	0	191	0	8.5	504.5	202
Purge salts produced, tons(1)	4	9	50	11.5	--	0	0	0	44	40	25.7	58	40.3

(1) From Allied Chemical summary reports.

TABLE A.3 NATURAL GAS CONSUMPTION
FOR THE MONTH OF DECEMBER 1977

DATE	$(CF \times 10^5)$
12/1	.972
12/2	1.067
12/3	1.102
12/4	.909
12/5	.975
12/6	.989
12/7	.986
12/8	.995
12/9	.995
12/10	.952
12/11	.952
12/12	.956
12/13	1.013
12/14	.950
12/15	.930
12/16	.935
12/17	.945
12/18	.932
12/19	.932
12/20	.988
12/21	1.092
12/22	.990
12/23	.922
12/24	1.002
12/25	1.062
12/26	.995
12/27	1.059
12/28	1.087
12/29	1.033
12/30	1.001
12/31	1.069
1/1	.818
1/2	.952

TABLE A.4 NATURAL GAS CONSUMPTION

FOR THE MONTH OF AUGUST 1978

DATE	(CF X 10^5)
7/31	2.10
8/1	2.401
8/2	2.356
8/3	2.360
8/4	2.272
8/5	2.477
8/6	2.354
8/7	2.414
8/8	2.326
8/9	2.410
8/10	2.266
8/11	2.531
8/12	2.254
8/13	2.254
8/14	2.362
8/15	2.196
8/16	2.337
8/17	2.403
8/18	2.467
8/19	2.353
8/20	2.345
8/21	2.384
8/22	2.364
8/23	2.361
8/24	2.363
8/25	2.383
8/26	2.396
8/27	2.451
8/28	2.523
8/29	2.565
8/30	2.508

TABLE A.5 ANALYTICAL RESULTS - PURGE SOLIDS

Date Sampled	% Sodium Sulfate	% Sodium Sulfite	% Sodium Pyrosulfite	% Sodium Thiosulfate	% Moisture
5/22/78	93.16	6.54	1.9	.03	.11
5/23/78	96.64	8.00	1.9	.03	.18
5/24/78	93.56	7.43	1.14	.06	.12
5/25/78	94.28	8.52	1.14	.13	.09
5/26/78	96.25	9.15	.38	.06	.06
5/28/78	92.48	10.08	.76	>.03	.10
5/29/78	94.95	10.20	.57	.09	.10
5/30/78	93.83	13.21	.38	.09	.04
5/31/78	81.98	12.02	.72	.09	.23
6/1/78	82.52	12.13	.57	.06	.18
6/2/78	86.43	11.40	1.06	.09	.13
6/3/78	89.73	9.52	.61	0	.20
6/4/78	84.07	10.28	.61	0	.05
6/5/78	90.29	9.28	1.18	0	.03
6/6/78	83.99	9.55	.68	0	.19
	73.40	14.46	.51	0	.02
6/7/78	91.87	-	-	.06	.13
6/8/78	79.69	9.53	.38	.10	.13
6/9/78	92.19	9.43	.30	0	.09
6/10/78	92.47	11.13	.15	0	.06
6/11/78	68.25	10.03	.22	0	.17
6/12/78	90.48	9.81	.19	.03	.26
6/13/78	92.49	11.09	.19	0	.05
6/14/78	90.17	11.01	.34	.03	.09
6/15/78	92.48	10.70	.22	.025	.15
6/16/78	92.19	10.36	.23	.05	.16
6/17/78	80.99	9.99	.32	.05	.04
6/18/78	93.19	9.84	.30	.05	.17
6/20/78	93.49	11.04	.21	.05	.09
6/21/78	91.17	10.11	.51	.25	.09

TABLE A.6 SIGNIFICANCE AND SOURCE OF DATA LISTED IN TABLE 3.1

Start/End - Period length, dates are shown. The hour, 0800 CST or CDT is implicitly a part of all entries except substitute 0000 CDT for the initial 9/16 and 2400 CDT for the final 9/15. Comes from schedule.

Hrs. Total - Elapsed hours per operating period. Comes from schedule.

Hrs. Boiler Operated - Entire hours boiler is fired per operating period. Calculated from the daily status report.

Hrs. Boiler Operated <46 MW - Hours per operating period when generator output is less than 46 MW. Calculated from DAS teletype printout or strip chart records.

Hrs. FGD Operated - Hours per operating period when the absorber and evaporator ran. Calculated from the daily status report.

Avg. Load, MWG - Overall average hourly power production of the generator. Calculated from DAS teletype printout or strip chart records.

Avg. Load, MWG - Avg. load MWG above reduced by the overall average hourly power requirements of the boiler auxiliaries and the FGD. Calculated from DAS teletype printout or strip chart records.

Avg. Load, MWG, FGD Down - Average hourly power production of the generator. Calculated from daily status reports and DAS teletype printout or strip chart records.

Avg. Load, MWG, FGD Down - Avg. load, MWG, FGD down above reduced by average hourly power requirements of the boiler auxiliaries only. Calculated from daily status reports and DAS teletype printout or strip chart records.

Net/Gross - Overall average fraction of generated power delivered to transmission network. Calculated from above data.

Net/Gross, FGD Down - Average fraction of generated power delivered to transmission network when the absorber and evaporator are not running. Calculated from above data.

FGD Avg. Steam Usage, Lb/Hr - Average hourly steam usage of FGD plant when absorber and evaporator are running. Calculated from the daily status report and DAS teletype printout or strip chart records.

Avg. Coal Rate, Lb/Hr - Overall average hourly coal usage of boiler. Calculated from totalized coal usage meter readings for the four boiler coal mills collected once a day.

MW Equiv. of FGD Steam Usage (Condensate Returned) & (Condensate Not Returned) - Power equivalent of the average FGD hourly steam usage. Calculated from above data and using a rounded boiler efficiency of 88% calculation method:

S_u = FGD hourly average steam usage, lbs.
E_b = Boiler efficiency, fraction & dimensionless
H_g = Gross heat rate, BTU/KWH
H_{is} = Boiler heat loss in steam, BTU/lb
P_e = Equivalent power loss as FGD steam, MW

$P_e = \frac{S_u}{E_b} \frac{H_{is}}{H_g}$ Note: H_{is} = 1370.7 BTU/lb with condensate returned, 1480.4 BTU/lb without

% Derating (Condensate Returned) & (Condensate Not Returned) - Percentage that steam power equivalent represents of boiler gross generation capability with no FGD operation. Calculated as 100 times the quotient of the respective power equivalent and the sum of the respective power equivalent plus the gross power generated.

Coal HHV, Btu/Lb - Average heating value of the wet coal fired. Calculated from laboratory analyses reported for composite samples taken during 6-day subintervals in the period.

Boiler Heat Input Rate, 10^6 Btu/Hr - Overall average hourly heat supplied to boiler. Calculated as product of coal usage and heating value described above.

Gross Heat Rate, Btu/KWH - Overall average heat supplied to boiler for each kilowatt-hour of power generated. Calculated from above data.

Net Heat Rate, Btu/KWH - Overall average heat supplied to boiler for each kilowatt-hour of power delivered to transmission network. Calculated from above data.

Avg. Inlet SO_2, PPM by Vol. - Average SO_2 inlet flue gas concentration. Calculated from DAS teletype printout or strip chart records.

Max. Inlet SO_2, PPM by Vol. - Highest hourly averaged inlet SO_2 concentration existing in the period. Directly taken from DAS teletype printout or strip chart records.

Min. Inlet SO_2, PPM by Vol. - Lowest hourly average inlet SO_2 concentration existing in the period. Directly taken from DAS teletype printout or strip chart records.

Avg. Outlet SO_2, PPM by Vol. - Average SO_2 outlet flue gas concentration. Calculated from DAS teletype printout or strip.

Max. Outlet SO_2, PPM by Vol. - Highest hourly averaged inlet SO_2 concentration existing in the period. Directly taken from DAS teletype printout or strip chart records.

Min Outlet SO_2, PPM by Vol. - Lowest hourly averaged outlet SO_2 concentration existing in the period. Directly taken from DAS teletype print-out or strip chart records.

Avg. SO_2 Rate in, Lbs/Hr - Average hourly weight of SO_2 fed to FGD plant by flue gas while absorber and evaporator were operating. Calculated from hourly inlet flue gas flow rates derived from daily coal usage rates of the four mills, the elemental analysis of 6-day period coal composite sample, and the DAS readings for inlet SO_2 and oxygen.

Avg. SO_2 Rate Out, Lbs/Hr - Average hourly weight of SO_2 rejected by FGD in effluent flue gas while absorber and evaporator were operating. Calculated from hourly outlet flue gas flow rates derived from the inlet flow rates above adjusted for air in-leakage using DAS inlet and outlet CO_2 concentrations and DAS reading for outlet SO_2.

Avg. % SO_2 Removal = $\frac{100\ (\text{Avg. } SO_2 \text{ Rate in} - \text{Avg. } SO_2 \text{ Rate Out})}{\text{Avg. } SO_2 \text{ Rate in}}$ - Calculated from above values.

Electricity, MWh - Average hourly FGD plant electrical usage. Calculated from DAS channel reading.

Natural Gas 10^6Btu/hr Equiv. Average hourly thermal heating value equivalent of process and incinerator usage of natural gas. Calculated from Allied data and daily reported gas heating value.

Steam 10^6Btu/hr Equiv. (With & Without Condensate Returned) Average hourly heat loss of boiler from FGD steam. Calculated from steam usage above. Calculation mode:

Definitions:

H_e* = Equivalent heat in steam, 10^6 Btu/hr
S_u = Steam usage, Lbs/Hr.
H_o* = Heat in steam leaving boiler system, Btu/Lb.
H_r* = Heat in condensate entering boiler system, Btu/Lb.

Equation:

$$H_e^* = S_u (H_o^* - H_r^*)$$

*Referred to heat content of liquid water at 32°F under atmsopheric pressure as 0 Btu/Lb.

Note: If condensate is returned, H_r = 0.93 X (150 - 32) = 109.74* Btu/Lb. based on estimate that 93% is returned at 150°F and 14.696 PSIG. From NIPSCO design data, H_o = 1480.4* Btu/Lb. H_r = 0 for no return.

$$\left.\begin{array}{l}\text{Soda Ash Consumed, Tons}\\ \text{Sulfur Produced, Long Tons}\\ \text{By-Product Salt Produced, Tons}\end{array}\right\}\ \text{Taken directly from Allied's summary report.}$$

APPENDIX B. INSTRUMENT RELIABILITY

TABLE B.1 INSTRUMENT DOWN TIME - SO_2 REMOVAL

	TIME DOWN		HOURS DOWN		
DATE	SO_2	O_2 & CO_2	SO_2	O_2 & CO_2	SYSTEM
9/16/77	-	1030-1150	-	-	-
9/16/77	1505-1805	1430-1800	3	5	3
9/17/77	1030-1145	1030-1145	1	1	1
10/10/77	0800-0900	0800-0900	1	1	1
10/12/77	0805-0905	0805-0905	1	1	1
10/14/77	1115-1310	1115-1250	2	2	2
11/7/77	0945-1040	0945-1040	-	-	-
	1105-1140	1105-1140	1	1	1
11/11/77	1200-0800	-	20	0	20
11/12/77	0800-0800	-	24	0	24
11/13/77	0800-0800	-	24	0	24
11/14/77	0800-0800	-	24	0	24
11/15/77	0800-1012	-	2	0	2
11/16/77	0800-0800	0800-0800	24	24	24
11/17/77	0800-0800	0800-0800	24	24	24
11/18/77	0800-1602	0800-1602	8	8	8
11/20/77	1403-1433	-	1	0	1
2/26/78	1300-0800	2300-0800	19	9	19
2/27/78	0800-1200	0800-0800	4	24	24
2/27/78	0100-0800	-	7	-	-
2/28/78	0800-1300	0800-1300	5	5	5
3/14/78	1400-1458	1400-1458	1	1	1
3/21/78	-	0800-0800	0	24	24
3/22/78	-	0800-0800	0	24	24
3/23/78	-	0800-0800	0	24	24
3/24/78	-	0800-1530	0	8	8
5/6/78	0800-0800	0800-0800	24	24	24
5/7/78	0800-0800	0800-0800	24	24	24
5/8/78	0800-0800	0800-0800	24	24	24
5/9/78	0800-0800	0800-0800	24	24	24
5/10/78	0800-0800	0800-0800	24	24	24
5/11/78	0800-0800	0800-0800	24	24	24
5/12/78	0800-0800	0800-0800	24	24	24
5/13/78	0800-1905	0800-0800	11	24	24
5/14/78	-	0800-0800	0	24	24
5/15/78	-	0800-0800	0	24	24
5/16/78	-	0800-0800	0	24	24
5/17/78	-	0800-0800	0	24	24
5/18/78	-	0800-0800	0	24	24
5/19/78	-	0800-0800	0	24	24
5/20/78	-	0800-0800	0	24	24
5/21/78	-	0800-0800	0	24	24
5/22/78	-	0800-0800	0	24	24

TABLE B.1 INSTRUMENT DOWN TIME SO_2 REMOVAL (CONTINUED)

DATE	TIME DOWN SO_2	TIME DOWN O_2 & CO_2		HOURS DOWN SO_2	HOURS DOWN O_2 & CO_2	HOURS DOWN SYSTEM
5/23/78	-	0800-0800		0	24	24
5/24/78	0900-1405	0900-1405		5	5	5
5/30/78	-	0905-1010		0	1	1
8/1/78	1800-0800	-		14	0	14
8/2/78	0900-1100	-		3	0	2
8/6/78	0900-2200	-		13	0	13
8/7/78	0900-1000	-		1	0	1
8/16/78	0800-1130	0800-1130		4	4	4
8/22/78	NA	-		2	0	2
8/23/78	-	0800-1530		0	8	8
8/27/78	0415-0800	0415-0800		4	4	4
8/28/78	0800-1352	0800-1352		6	6	6
			Totals	427	646	781

NA - Not Available

TABLE B.2 INSTRUMENT DOWN TIME - WATER ANALYZER

Date	Down Time
9/16/77	1030-1150, 1430-1800
9/17/77	0830-1145
10/10/77	0800-1403
10/12/77	0805-1202
10/14/77	1115-1250
10/16/77	1005-0900
10/17/77	0800-1005
11/7/77	0945-1040, 1105-1140
11/11/77	1200-0900
11/12/77	0800-0800
11/13/77	0800-0800
11/14/77	0800-0800
11/16/77	0800-0800
11/17/77	0800-0800
11/18/77	0900-1602
2/26/78	2300-0900
2/27/78	0900-0800
2/28/78	0800-1300
3/14/78	1400-1458
3/21/78	0800-0800
3/22/78	0800-0800
3/23/78	1900-0900
3/24/78	0900-1530
3/26/78	0905- *

* As of 3/26, H_2O analyzer not operating satisfactorily and it was determined not to repair it for the remainder of demonstration year.

TABLE B.3 DAS CHANNEL DOWN TIME

Parameter	Channel No.	Date & Down Time
Steam Drum Pressure	07	∼3/19/78 to 3/21/78
Gross Load	38	3/1/78, 0905 to 3/2/78, 0900
Net Load	39	2/16/78, 1100 to 3/8/78, 1630
Flue Gas Inlet Temperature	45	11/7/77, ∼0800 to 11/19/78, ∼1440

APPENDIX C

METHOD FOR ESTIMATING FLUE GAS VOLUME

Flue gas volumes were calculated based on the coal ultimate analysis, quantity of coal burned and percentage of oxygen contained in the flue gas. The required data are listed below:

DATA	SYMBOL
Coal (lb/hr)	COAL
Ultimate Analysis (%):	
- Carbon	C
- Sulfur	S
- Hydrogen	H
- Water	H_2O
- Oxygen	O
- Nitrogen	N
Percent O_2 in Flue Gas	O_2

The calculation procedure is shown below. The first step is the flue gas volume calculation. These procedures were followed:

1. Calculation of dry, excess air free flue gas (Mole/Hr). This was accomplished by calculating the quantities of CO_2, SO_2, and N_2 resulting from the carbon, sulfur and nitrogen contained in the coal. In addition, nitrogen associated with the stoichiometric quantity of combustion oxygen is included.

2. Calculation of dry flue gas with excess air (Mole/Hr). Based on the excess oxygen contained in the flue gas, the quantity of excess air is computed.

3. Calculation of flue gas with water and excess air (Mole/Hr). Water contained in this flue gas resulting from: The hydrogen and water content of the coal and atmospheric humidity is added giving the total flue gas flow rate in moles per hour.

4. Calculation of flue gas volume (SCFM). The total flow rate (in moles/hr) is converted to a volumetric flow rate (SCFM).

Equations are as follows:

1. Flue Gas (FGD), mol/hr., excess air free, dry

$$MCO2\text{, mol/hr.} = \frac{.03665}{44} \times C \times COAL$$

$$MSO2\text{, mol/hr.} = \frac{.019}{64} \times S \times COAL$$

$$MN2\text{, mol/hr.} = \frac{.01}{28} \times N \times COAL$$

Stoichiometric Air:

$$MO2S = \frac{[.02665C + 0.019S + .07936H - .01(0)]\ COAL}{32}$$

$$MN2S = 3.762 \times MO2S$$

$$FGD\text{ mol/hr.} = MCO2 + MSO2 + MN2 + MN2S$$

2. Flue Gas (FGDX), mol/hr., with excess air, dry

$$MO2X\text{, mol/hr.} = \frac{.01 \times 02}{1 - (4.762(02) \times .01)} \times FGD$$

$$FGDX\text{, mol/hr.} = FGD + MO2X + 3.762\ MO2X$$

3. Flue Gas (FGWX), mol/hr., wet

Assume abs. Humidity = $\frac{0.013\ lb\ H_2O}{lb\ dry\ air}$

Total Dry Air (TDA) mol/hr., = MO2S + MN2S + 4.762 MO2X

$$MH2OA = 0.013 \times \frac{29}{19}\ TDA$$

$$MH2O = (0.08936H + 0.01\ H_2O)\ \frac{COAL}{18}$$

$$FGWX\text{, mol/hr.} = FGDX + MH2OA + MH2O$$

4. Flue Gas (KVSTD), scfm wet

at 70°F,

$$KVSTD\text{, mscfm} = \frac{386.7}{60} \times FGWX$$

REFERENCES

1. Adams, R. C., S. J. Lutz, and S. W. Mulligan. Demonstration of Wellman-Lord/Allied Chemical FGD Technology: Acceptance Test Results. EPA-600/7-79-014a. TRW Inc., Durham, NC January 1979.

2. Adams, R. C., T. E. Eggleston, J. L. Haslbeck, R. C. Jordan and Ellen Pulaski. Demonstration of Wellman-Lord/Allied Chemical FGD Technology: Boiler Operating Characteristics. EPA-600/7-77-014. TRW Inc., Vienna, Va. February 1977.

3. 40 CFR Part 60, Vol. 43 No. 182, 42154-42184 (Federal Register).

4. Laske, B., et al. EPA Utility FGD Survey. EPA-600/7-78-051d, U. S. Environmental Protection Agency, Research Triangle Park, NC 1978.

5. Same as 4.

6. TRW Inc., Environmental Engineering Division. Program for Test and Evaluation of the NIPSCO/Davy/Allied Demonstration Plant. Demonstration Test Plan. Prepared for Control Systems Laboratory, Office of Research and Monitoring, Environmental Protection Agency, Research Triangle Park, NC April 8, 1975.

7. Same as 1.

TECHNICAL REPORT DATA
(Please read Instructions on the reverse before completing)

1. REPORT NO. EPA-600/7-79-014b	2.	3. RECIPIENT'S ACCESSION NO.
4. TITLE AND SUBTITLE Demonstration of Wellman-Lord/ Allied Chemical FGD Technology: Demonstration Test First Year Results		5. REPORT DATE September 1979 6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S) R.C. Adams, J. Cotter, and S.W. Mulligan		8. PERFORMING ORGANIZATION REPORT NO.
9. PERFORMING ORGANIZATION NAME AND ADDRESS TRW, Inc. 201 N. Roxboro Street, Suite 200 Durham, North Carolina 27701		10. PROGRAM ELEMENT NO. EHE624A 11. CONTRACT/GRANT NO. 68-02-1877
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15. SUPPLEMENTARY NOTES IERL-RTP project officer is Charles J. Chatlynne, Mail Drop 61, 919/541-2915.

16. ABSTRACT The report gives results of the first year of a comprehensive test program to demonstrate the capabilities of a full-scale plant using the Wellman-Lord/Allied Chemical process for desulfurizing flue gas. The FGD unit is retrofitted to Northern Indiana Public Service Company's 115 MW coal-fired unit No. 11 at the Dean H. Mitchell Station. During the demonstration, which began in September 1977, operating experience was limited by boiler- and FGD-related operating problems. The FGD plant had a 50% reliability factor (hours operated/hours called upon to operate). SO2 removal efficiency averaged 89%. Economic performance was distorted by considerable off-normal boiler operation (which limited use of the FGD plant) and by partial operation of the FGD plant during which operating costs were not substantially less than costs during full operation. A major effect on boiler operation from retrofit of the FGD plant was a boiler derating of 9% resulting from the consumption of steam by the FGD plant, a value that will be reduced by design changes at future Wellman-Lord installations. At least 1 year of additional testing will follow completion of a number of design improvements that will eliminate or minimize the problems that have limited FGD plant use.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Pollution	Pollution Control	13B
Flue Gases	Stationary Sources	21B
Desulfurization	Wellman-Lord Process	07A,07D
Coal	Allied Chemical Process	21D
Combustion		
Boilers		13A

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