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

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

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ABSTRACT

Process performance guarantees were met or exceeded as confirmed by Acceptance Testing which began on 29 August 1977 and ended on 14 September 1977. The Acceptance Test consisted of two test periods. The Design Load test period was to be a 12-day period during which the FGD plant was to be operated at the design condition of a boiler flue gas output rate equivalent to 80% of the maximum boiler load of 115 megawatts gross. The High Load test period was to be an 83-hour period during which the FGD plant treated flue gas volumes equivalent to 95% of maximum boiler load.

Specific performance criteria were met or exceeded as follows:

(a) SO_2 removal of 90% or better was achieved at Design Load conditions and at High Load conditions.

(b) Particulate emissions did not exceed 0.1 $lb/10^6$ Btu of boiler heat input at either Design Load or High Load conditions.

(c) The consumption of steam, natural gas and electrical power was less than the performance guarantee requirements at Design Load conditions.

(d) Soda ash consumption was less than the limit set by the performance guarantees.

(e) Sulfur product purity was greater than 99.5% at both Design Load and High Load conditions.

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Process performance guarantees were met or exceeded as confirmed by Acceptance Testing which began on 29 August 1977 and ended on 14 September 1977. The Acceptance Test consisted of two test periods. The Design Load test period was to be a 12-day period during which the FGD plant was to be operated at the design condition of a boiler flue gas output rate equivalent to 80% of the maximum boiler load of 115 megawatts gross. The FGD plant was actually operated for 265 hours at this load condition. The High Load test period was to be an 83-hour period during which the FGD plant treated flue gas volumes equivalent to 95% of maximum boiler load. Actual operating time was 86 hours at this load condition.

Specific performance criteria were met or exceeded as follows:

(a) SO_2 removal of 90% or better was achieved for 261 hours of the 265 hours of operation at Design Load conditions and was achieved for 84 hours of the 86 hours of operation at High Load conditions.

(b) Particulate emissions did not exceed 0.1 lb./10^6 Btu of boiler heat input at either Design Load or High Load conditions.

(c) The consumption of steam, natural gas and electrical power averaged 76% of the performance guarantee requirements at Design Load conditions.

(d) Soda ash consumption averaged less than 6.6 tons of Na_2CO_3 per day which was the limit set by the performance guarantees not to be exceeded during the Design Load period.

(e) Sulfur product purity was greater than 99.5% at both Design Load and High Load conditions. As

a check to ensure that the sulfur product was acceptable for burning in a contact acid plant, impurities in the sulfur were compared with bright sulfur purchase specifications. All impurities were less than specified.

During the Design Load period, a SO_2 removal efficiency of 90% or better, based on two hour averages, was achieved for all but four hours of the 265 hour operating period. SO_2 removal was 88% and 89% two hour averages, two two-hour periods. Four hours were added to the 12-day test period for these failures. During the High Load period, there was one two hour period during which SO_2 removal was 89%. Three hours were added to the 83-hour test period for this failure.

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 (WL) 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 (Allied) 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. For the remainder of this report, we will refer to this configuration 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 (NIPSC). The EPA is sharing 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.

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, 1976. 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 reasons for the delays have been explained in some detail elsewhere(1)(2).

The Acceptance Test is to verify that the process performance guarantees have been met. The performance guarantees are a contractual requirement placed on Davy by NIPSCO and EPA. Over a period totaling more than 15 days, the FGD plant must meet the minimum SO_2 removal requirements of the performance guarantees at two specified levels of boiler load, and must not exceed the specified amounts of raw materials and utilities consumption.

TRW, under contract to EPA, is providing the test services required for evaluating the performance of the FGD plant, including its ability to meet the performance guarantees during acceptance testing. Preceding the Acceptance Test, a Test Plan(3) was prepared based on the performance requirements specified in EPA's contract with NIPSCO (EPA Contract No. 68-02-0621).

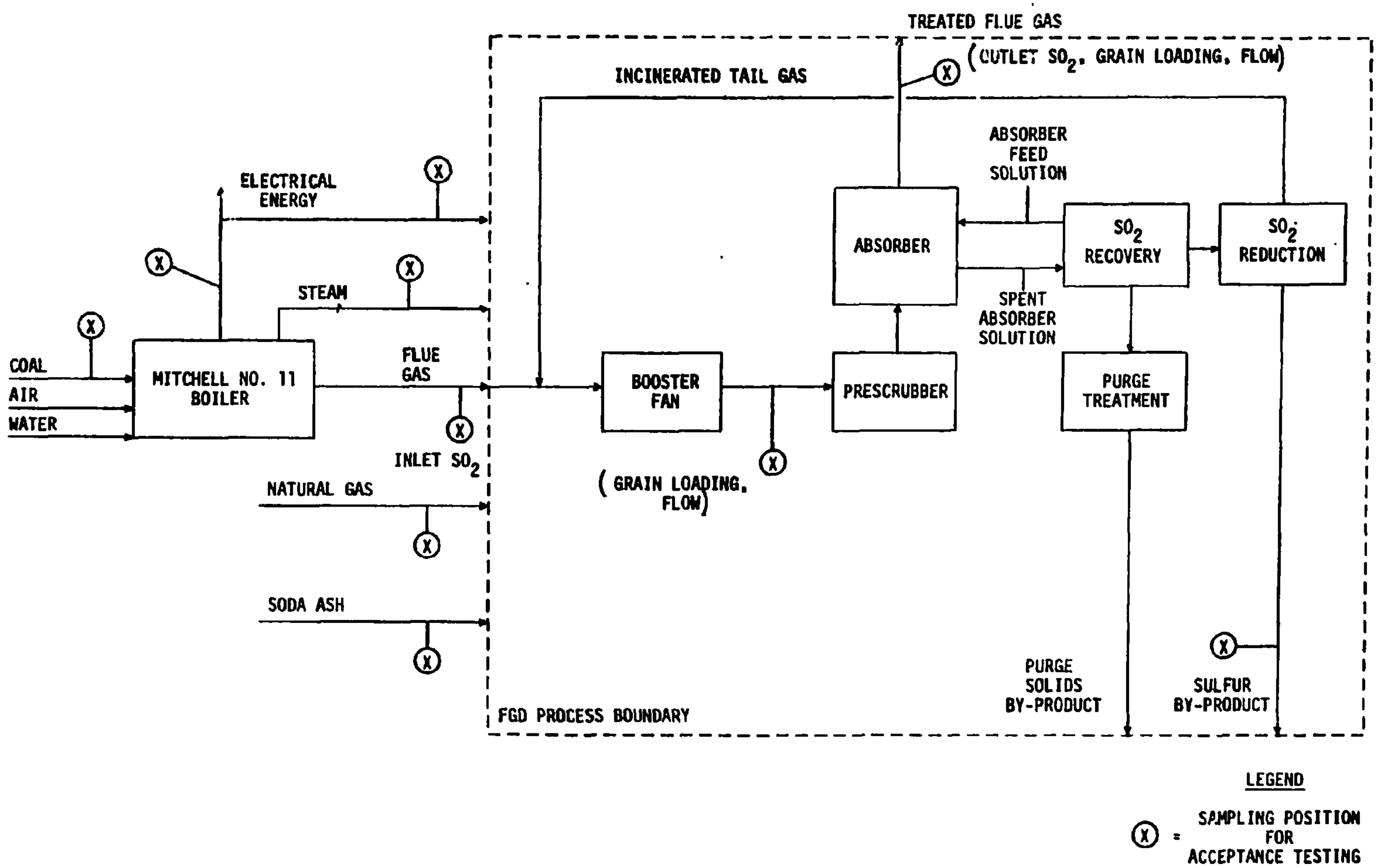
PROCESS DESCRIPTION

The process employs sodium sulfite scrubbing of the flue gas to remove SO_2 with thermal regeneration of the scrubbing solution to recover the SO_2 and subsequent reduction of the SO_2 to produce marketable sulfur in molten form. The block diagram (Figure 1-1) shows the major process steps.

Mitchell No. 11 is a 115 MW pulverized coal fired boiler, balanced draft, with cold end electrostatic precipitator particle controls. The FGD plant accepts the total flue gas from the discharge of the boiler's induced draft (ID) fans. A booster fan is used to force the flue gas through the prescrubber and the absorber. The prescrubber is expected to remove additional particulate matter such that the New Source Performance Standard of 0.1 lb particulate matter emitted from the absorber /10^6 Btu heat input is met if particulate matter out of the ESP does not exceed 0.2 lb/ACF or that 80% removal is achieved if inlet grain loading exceeds 0.2 lb/ACF.

Cooled, humidified flue gas leaves the prescrubber and enters the bottom of a multistage absorber and is contacted with sulfite solution fed to the top

FIGURE 1-1. BLOCK FLOW DIAGRAM OF MAJOR PROCESS STEPS. LOCATION OF SAMPLING POSITIONS FOR ACCEPTANCE TESTING



stage of the absorber tower. SO_2 is absorbed by the sulfite solution and the treated flue gas is discharged from the top of the absorber tower through a stack to the atmosphere. The spent sulfite solution is removed from the bottom stage of the tower and sent to a surge tank for storage prior to regeneration in the SO_2 recovery step. The absorber is designed to remove 90% of the incoming SO_2 continuously from the volume of flue gas expected (320,000 acfm) at 80% of full load (92 MWG). Thus, the performance guarantees require an extended test period (12 days) at this flue gas rate to show continuous SO_2 removal capability. Because SO_2 removal performance is a function of the SO_2 levels at the inlet to the absorber, the performance guarantees require the level of sulfur in the coal to be within specific limits.

During the SO_2 recovery step, the spent sulfite solution is regenerated in a steam-heated evaporator and returned to the absorber feed tank. SO_2 is recovered from the evaporator overhead. The SO_2 recovery area was not designed for recovery of all of the SO_2 removed from the flue gas at boiler loads in excess of 80% because the boiler is normally not operated for extended periods in excess of 80% load. However, surge capacity was provided in the form of surge tank and absorber feed tank capacity to allow for a limited period of operation at full load. The performance guarantees require that SO_2 and particle removal requirements be met during an 83 hour period when accepting flue gas equivalent to a 110 MWG load.

A purge stream from the SO_2 recovery area is processed in the purge treatment area to produce a dry sodium sulfate by-product. The sodium values lost in the purge stream must be made up by adding Na_2CO_3 to the regenerated sodium sulfite solution. The performance guarantees limit the amount of Na_2CO_3 make-up during the 12 day test period.

The SO_2 which was recovered in the SO_2 recovery step is sent to the SO_2 reduction area. The reduction step is a proprietary process developed by Allied Chemical which utilizes natural gas for the reduction of SO_2 to H_2S and finally elemental sulfur in molten form. A small stream of tail gas is returned after incineration to the inlet of the booster fan. The performance requirement is to produce a sulfur product of high purity and of a quality which can be used to make sulfuric acid, the major market for sulfur.

Limits on the consumption of utilities and natural gas are also a performance requirement. Natural gas is used as a reductant of SO_2 and for incineration of the tail gas. The major use of steam is in the SO_2 recovery area for evaporation but steam is also used in the purge treatment area and for steam turbine drives. Electrical energy is consumed to drive pumps and auxiliaries, for line tracing, for instrumentation and for lighting.

The Sections of EPA Contract No. 68-02-0621 which set forth the performance requirements are given in the next section of this report.

PERFORMANCE REQUIREMENTS

The EPA/NIPSCO Contract No. 68-02-0621 specifies that an acceptance test be performed in accordance with the specified performance guarantees. Article XIX, Paragraphs A.1 and A.2, of the Contract is quoted as follows:

"ARTICLE XIX - PROCESS PERFORMANCE GUARANTEE

A. Performance Guarantee

1. The Contractor (NIPSCO) guarantees that during the acceptance testing the system will perform on Unit No. 11 as follows:

   (a) The system when operated with 3.15 to 3.5% sulfur in the coal shall achieve 90% sulfur removal from the flue gas or no more than 200 ppm of SO_2 in the outlet gas stream from the absorber, (which shall be the only source of SO_2 emissions from the system to the atmosphere during normal operations) whichever is the lesser. For fuels containing less than 3.15% sulfur the absorber outlet stream shall contain no more than 200 ppm SO_2. For fuels containing more than 3.5% sulfur the absorber outlet stream will achieve no less than 90% sulfur removal from the flue gas.

   (b) The system shall be capable of producing by-product sulfur having a sulfur assay of 99.5% minimum and shall be suitable for use in a sulfur burning contact acid plant.

   (c) Based on the following costs, the net operating cost per hour shall not exceed $56.00/hour.

Electric Power	$0.007 per KWH
Steam	$0.50 per 1,000 lb. at 550 psig & 750°F
Natural Gas	$0.55 per 1,000,000 Btu

   (d) The system's particulate emission rate shall not exceed the Federal New Source Performance Standard for Fossil-Fuel Fired Steam Generators that is current at the completion of Phase I.

   (e) The average chemical make-up over a twelve (12) day operating period at an average of 92 MW shall be no greater than 6.6 tons per day of

Na_2CO_3. The value of antioxidant used during the 12-day period shall not exceed an average of $400 per day.

2. The Guarantees in paragraphs (a) - (e) hereof, shall be demonstrated in accordance with paragraph D of Phase II in the Scope of Work."

Paragraph D of Phase II in the Scope of Work cites the provisions by which the unit will be operated during an acceptance test. This paragraph states that:

"NIPSCO shall hold Davy Powergas responsible for this Phase of the project; accordingly, Davy Powergas shall be required to maintain technical staff available until such time as the performance guarantees have been fulfilled in an acceptance test as follows:

The test period shall consist of 12 days operation at an average load of 92 MW followed by 83 hours operation at an average load of 110 MW. During the test period the average sulfur content of the coal will be 3.16% S. Interruptions totalling less than 24 hours will not be considered as a break in continuous operation except that the test period will be extended by this period of interruption. Furthermore, if, for reasons beyond Contractor's control, there is either a reason to separate the 92 MW and 110 MW test runs, having completed no less than 10 days of the 92 MW test, or else the 110 MW test portion of the test has not been completed, then the 110 MW test can be restarted preceded by 3 days at 92 MW operation.

Should, for reasons beyond Contractor's control, it becomes necessary to adjust the basis for the guarantee run, then Davy Powergas will prepare new guarantee procedures consistent with the guarantees in this contract. In no event will the emission guarantees be changed."

TEST CRITERIA

Except for the particle emission rate, the performance guarantees do not specify the criteria or methodology for determining performance or the penalties to be assessed in case of performance failure. Thus, specific criteria were established and included in the Acceptance Test Plan. The criteria of the Test Plan were then used as a guide for final criteria selection acceptable to the contractual parties (EPA, NIPSCO, Davy). These final criteria are detailed as follows.

Specific changes were made in these performance guarantees and agreed to by the contractual parties. However, they do not reflect a contract change. The specific changes are described in the following paragraphs.

Sulfur Removal

Sulfur removal was designated to mean SO_2 removal. The FGD plant was to remove 90% of the inlet SO_2 at the inlet flow conditions at 92 MWG and 110 MWG (flue gas volume equivalents) with sulfur in the coal between 3.0% and 3.5%. If the sulfur in the coal exceeded 3.5% during any two hour period that period was treated as an inlet stream interruption and the results discarded without adding the interruption period to the end of the test. The official test results were by the TRW SO_2 analyzer or manual sampling except in the case of an instrument failure, at which time the FGD plant analyzer results were to be used provided that the SO_2 removal results of both instruments complement each other for the time period preceding the failure. The SO_2 removal guarantees were based on twelve two-hour averages per day. Any sequential two hour period failure to meet SO_2 removal performance guarantees was added to the end of the Acceptance Test. This applied to both the 92 MWG (Design) and 110 MWG (High Load) test periods.

Due to the unpredictability of flue gas dilution levels, it was decided to limit sulfur removal criteria to that of 90% removal efficiency alone without any requirement for meeting a concentration level of 200 ppm.

Sulfur in Coal

A sample was collected each hour of each test period. A composite was created for each 24-hour period and analyzed to determine if the percent sulfur was within the range of 3.0-3.5% set forth in the performance requirements. However, each one hour increment was retained for possible analysis if requested by any of the contractual parties.

Operating Levels

The FGD plant was designed to remove better than 90% of the SO_2 continuously when the boiler is burning coal of 3.15% sulfur content and is developing flue gas volumes of 320,000 acfm (at 300°F) at a gross generating output of 92 MW. Pre-acceptance testing indicated that the flue gas volume was much higher than 320,000 acfm at 92 MW gross. Therefore, instead of testing at 92 MWG and 110 MWG, flue gas volume equivalents were set as the operating levels. These were 320,000 acfm for the design (92 MWG) test period and

380,000-390,000 acfm for the High Load (110 MWG) test period, without corrections for temperature or air dilution.

Interruptions

Interruptions were defined as the loss of any feed stream to the FGD plant from the moment a stream is lost to the time that the plant is back to the original operating conditions. Interruptions of less than 24 hours were to be added to the end of the respective test periods. However, since actual interruptions during the Design Test Phase totaled less than 24-hours, the contractual parties agreed to waive the extensions. There were no interruptions of any kind during the High Load Test Phase. Available performance data during interruptions were not included in the performance results.

By-Product Sulfur

Sulfur purity requirements were determined on composites created from samples of each sulfur shipment (about one a day). Sulfur purity was determined for both the Design test period and the High Load test period. The criteria for suitability for use in a sulfur burning contact acid plant were Allied Chemical's sulfur purchase specifications. Penalties for failure to meet the performance requirements were to be by agreement among the contractual parties.

Operating Costs

Since cost performance guarantees had to be set far in advance of the Acceptance Test period, it was intended that these performance requirements reflect utility and natural gas consumptions rather than the current costs for these items. Consumption performance, reported in dollars per hour based on the specified unit costs, was determined as the total consumptions divided by the total uninterrupted hours operated during the Design (12-day) test period. Consumptions during periods of interruption were excluded. Daily measurements of natural gas heating value of gas being fed to NIPSCO's gas distribution system were obtained from NIPSCO. Penalties for any overrun were to be by agreement among the contractual parties.

Particle Emissions

EPA Method 5 was the procedure used with only the catch up to and including the filter catch considered to be particulate matter. One test a day, averaging in excess of three hours per test, was used to determine particulate control performance. Alternative performance criteria were used. If the inlet particle concentration was greater than 0.2 grain/ACF, the FGD plant particle controls must remove an average of 80% or more of the particulate matter. If the inlet concentration was 0.2 grain/ACF or less, the particle emissions must meet the New Source Performance Standards (NSPS) of 0.1 lb/10^6 Btu heat input. One day was to be added to the test for each three hour test failed.

Chemical Make-Up

Following adoption of the initial performance guarantees, Davy determined that oxidation rates could be controlled without feeding an antioxidant. Thus, the only chemical make-up during the Acceptance Test was soda ash. Average soda ash consumption for the Design (12-day) test period was determined from measurements provided by Allied. Total consumption was determined from inventories at the start and end of the 12-day period plus shipments. Soda ash as Na_2CO_3 was determined from an analysis certificate supplied by Allied. Davy had the option to either include or exclude the soda ash consumption during periods of interruption but had to explain their choice in writing. There was to be no penalty for violations.

METHODS SUMMARY

The test methods are described in detail in Appendix B. However, in order to completely understand the test results and their significance, brief descriptions of the more significant methodologies are needed.

To the extent possible, continuous high frequency test data were used. The TRW continuous monitoring system was utilized to accomplish this. The continuous monitoring system samples each flue gas composition parameter (SO_2, CO_2, O_2, H_2O) every six minutes (alternating every three minutes between inlet and outlet of the absorber). All other high frequency data sampling was done every three minutes. The data were collected and stored by the data acquisition system (DAS) and hourly averages were computed and printed out. Strip chart backup was provided in case of DAS failure. Annubars are installed in the absorber stack to measure the flue gas flow every three minutes. However, attempts to calibrate the Annubars were unsuccessful, and other means of estimating flue gas flows had to be found. The flue gas flow measurement problem and its solution are treated in detail in Section 3.0.

The test parameters that were not amenable to continuous monitoring are briefly described as follows:

(a) Particulate matter concentration in the flue gas was from tests performed for a limited period no more than once a day. Tests were run simultaneously at the inlet and outlet of the absorber using EPA Method 5 (impinger train catch discarded). Outlet sampling had to be done downstream of tail gas and tank vent returns and of the booster fan. It was assumed that any increase or decrease in grain loading contributed by the FGD plant tail gas stream and tank vents were negligible.

(b) Totalizer readings were taken only at the beginning of each day, the beginning and end of each grain loading test, the beginning and end of each interruption, and the beginning and end of the Design and High Load test periods. These were for:

- Coal feed rate
- Natural gas and kWh consumptions
- Generator total gross energy output in megawatts (Power output was also measured every three minutes).

Booster fan speed and outlet pressure, for validating flue gas flow, was also read at these frequencies.

(c) Average coal compositions and heating values were restricted to each 24-hour period and each period of particle sampling. However, coal samples were available for determining averages of each two hour period.

(d) Soda ash feed rates were determined from inventory and shipments data supplied by Allied.

(e) The heating value of natural gas, determined daily, was obtained from NIPSCO.

To correct for dilution in the determination of the percentage SO_2 removal, relative mass rates of SO_2 at the inlet and outlet of the absorber were calculated. The calculations were based on a CO_2 balance; that is, it was assumed that any differences in CO_2 mass rates inlet and outlet the absorber were negligible. A dilution factor, f, was calculated:

$$f = \frac{a}{b} \frac{(100-c)}{(100-d)}$$

where a = CO_2 inlet, vol. % of dry flue gas

b = CO_2 outlet, vol. % of dry flue gas

c = H_2O inlet, vol. % of wet flue gas

d = H_2O outlet, vol. % of wet flue gas

The dilution factor was then used to correct outlet SO_2 to the same relative mass rate basis as the inlet SO_2 as follows:

$$\%\ SO_2\ \text{Removal} = \frac{(SO_2\ \text{in, ppmv}) - (SO_2\ \text{out, ppmv})\ (f)}{SO_2\ \text{in, ppmv}} \times 100\%$$

Coal was sampled once every hour throughout the Acceptance Test except during particle sampling periods when higher frequency sampling was employed. Sample increments, about one pound each, were kept separate by placing each increment in a plastic bag which was sealed to prevent moisture loss. Composites were created by mixing equal portions of each sample increment, using a riffler.

Test days began and ended at 0800 hours and were cross referenced with calendar dates for the day ending at 0800. Thus, Test Day No. 1 beginning at 0800 on August 29th was assigned a day ending date of August 30th.

SECTION 2

TEST RESULTS

Test results are divided into two test periods - a 12 day test with the boiler flue gas flow rate held constant at about 320,000 acfm (8,960 cubic meters per minute) and an 83 hour test with the boiler flue gas output maintained at about 388,000 acfm (10,864 cubic meters per minute); both flow rates were at about 300°F and one atmosphere pressure.

Performance requirements for SO_2 removal efficiency; particle emission rate; natural gas, electrical, and steam consumptions; soda ash consumption; and sulfur product purity were all met in both phases of the Acceptance Test. The performance results are summarized at the end of this section (Table 2-3). Detailed test results are appended.

TEST LENGTHS AND INTERRUPTIONS

The 12-day test commenced at 0800 on 29 August 1977 and ended at 1200 on 10 September 1977. Operating time totaled 265 hours out of an elapsed time of 292 hours. Performance guarantees for SO_2 removal were not met during two 2-hour periods. Thus, the test was extended four hours. A total of 27 hours qualified as interruptions (Table 2-1). Of these hours, 10 hours were boiler interruptions and 17 hours were FGD plant interruptions. In addition, the boiler feed water pump went down on Day 11 from 1830 to 0800 causing a load reduction to about 60 megawatts. This was not considered to be an interruption for determining SO_2 removal performance. However, data collected during this period was not used for determining consumption of utilities.

TABLE 2-1. INTERRUPTIONS DURING DESIGN LOAD (12-DAY) TEST

DAY	TIME OF INTERRUPTION	HOURS CHARGED	CHARGED TO	NATURE OF INTERRUPTION
3	0120-0415	3	Boiler	Booster fan tripped
4	1450-1555	1	FGD	Booster fan tripped; bypass damper opened
4	1645-2240	6	FGD	Booster fan tripped
5	0240-0545	3	FGD	Reduction area down, Claus bed plugging
6	1005-1300	3	FGD	Reduction area down to burn sulfur off Claus bed
7	0900-1630	7	Boiler	Boiler interruption; boiler feed water pump repairs
7	0330-0545	2	FGD	Reduction area down to rake Claus bed
10	0845-1100	2	FGD	Reduction area down, incinerator trip solenoid unable to be reset after releasing

The 83-hour test commenced at 0800 on 11 September 1977 and ended at 2200 on 14 September 1977. Operating time totaled 86 hours out of an elapsed time of 86 hours. Performance guarantees for SO_2 removal were not met during one 2-hour period. The test was extended two hours plus one additional hour to assure sequential two hour averages. No interruptions were experienced.

SO_2 REMOVAL PERFORMANCE

Test failures occurred on only two days - one day of the Design Load test and one day of the High Load test (Figure 2-1). During the fifth day of the Design Load test, the absorber failed to meet the 90% SO_2 removal

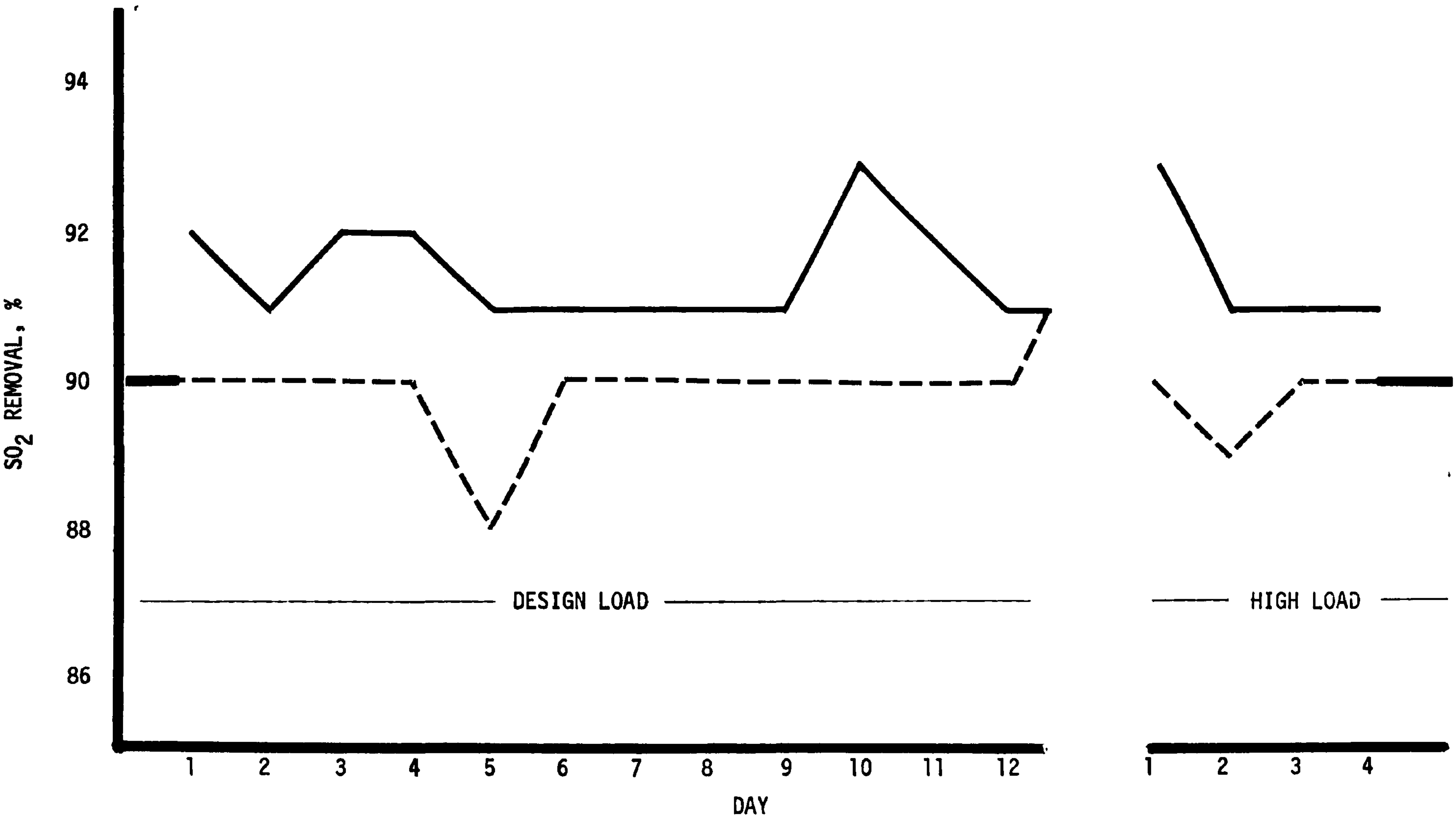


FIGURE 2-1. DAILY MINIMUM AND MAXIMUM SO_2 REMOVAL EFFICIENCIES - TWO HOUR AVERAGES

performance requirement during two 2-hour periods - from 0800 to 1000 hours and 1000 to 1200 hours. In addition, the absorber did not satisfy the 90% removal guarantee for one 2-hour period during the High Load test. This occurred from 0200 to 0400 hours on the second day of the High Load test. Each test series was extended for the hours failed and performance guarantees were met during the test extensions. When performance guarantees were met, SO_2 removal varied within the 90 to 93% band. The percentage of two hour averages at each incremental level of SO_2 removal was as follows:

	2-HOUR AVERAGES, %	
SO_2 REMOVAL, %	DESIGN LOAD	HIGH LOAD
88	0.7	0.0
89	0.7	2.3
90	33.4	44.2
91	56.3	39.6
92	8.2	11.6
93	0.7	2.3

PARTICLE EMISSION PERFORMANCE

Inlet particulate matter did not exceed 0.2 gr/acf for either test phase. Therefore, absorber emissions were required not to exceed the NSPS of 0.1 lb/10^6 Btu of boiler heat input. A total of 8 samples during the 12-day test and 3 samples during the High Load test were taken for grain loading both at the inlet and outlet of the absorber. For the 12-day test, valid samples were obtained on test days 1, 2, 5, 6, 8, 9, 10, and 11 while, for the High Load test, useful data were obtained on days 1, 2, and 4. At no time during either test period was the inlet grain loading greater than 0.2 gr/acf or the outlet particle emissions rate greater than 0.1 lbs/10^6 Btu input.

UTILITY AND NATURAL GAS CONSUMPTION

Utility and natural gas consumptions averaged only 76% of the performance guarantee for the 12-day test period. Furthermore, the maximum single day average during the 12-day period was only 79% of the performance requirement..

Based on consumption costs of $0.007 per kWh for electricity, $0.50 per 1000 lb of steam (550 psig and 750°F), and $0.55 per 1,000,000 Btu for natural gas, the average cost for utilities and natural gas during the 12-day test period was \$42.74/hour of operation. The average heating value of the natural gas was 1029 Btu/scf.

Utility and natural gas consumptions for the 12-day test were as follows:

Electric Consumption:	186,640 kWh for 246.3 hours
Natural Gas Consumption:	2,793,720 ft^3 for 249.3 hours
Steam Consumption:	15,442,518 lbs for 248.3 hours

It should be noted that the number of hours for each parameter is less than the 261 hours which make up the 12-day test. This is due to exclusion of certain hourly averages on account of invalid data as well as exclusion of data received during an interruption (see interruption schedule earlier in this section) or during the period of low power plant output (from 1830 to 0800 hours during test day 11).

ANALYSIS OF DEMONSTRATION PLANT STEAM CONSUMPTION

Steam usage, steam temperature and pressure, and the range for each of these parameters is given for the Design test period:

	STEAM CONSUMPTION (lbs/hr)	STEAM TEMPERATURE (°F)	STEAM PRESSURE (psig)
AVERAGE VALUE	62,139	724	551
95% CONFIDENCE LIMITS	± 6,134	± 7	± 23
RANGE OF VALUES	55,720 - 65,510	711 - 730	518 - 573

RAW MATERIAL CONSUMPTION

Soda ash consumption was determined by Allied Chemical personnel by measuring the decrease in volume of stored soda ash, taking into account shipments received over the duration of the 12-day test. Daily soda ash consumption figures were not computed because the performance guarantee was based on a maximum quantity consumed over the 12-day test period.

Over the 12-day test, an average of 6.2 tons of Na_2CO_3 per day was consumed. the performance guarantee required that no more than 6.6 tons per day be consumed. The soda ash assay was 99.79% as Na_2CO_3.

SULFUR PRODUCT PURITY

Sulfur analyses were performed on composites of samples of product sulfur shipped from the sulfur recovery plant for both the Design Load test and the High Load test. The composite samples were made up by thoroughly mixing equal portions of representative samples taken from every shipment of product sulfur. Product purity exceeded the guarantee of 99.5% sulfur assay. For analyses for the impurities, the laboratory first determined that the product did not meet the impurities specifications for carbon and As_2O_3. One of these samples was sent to a second independent laboratory which found that these components were well below the impurities specifications. Based on the results from the second laboratory, it was concluded that the sulfur was suitable for burning in a contact sulfuric acid plant. Complete analytical results are included in Appendix A.

DATA RECOVERY

Various problems were encountered with the continuous sampling instrumentation which required the acquisition of data from other sources (either other instrumentation or manual sampling). The use of supplemental data sources during short periods of instrument downtime made it possible to report SO_2 removal for a total of 336 hours out of 351 total operating hours (96%). Data recovery from the TRW operated analyzers for obtaining the primary test data was as follows:

DATA CHANNEL	PERCENT DATA RECOVERY
SO_2 Inlet/Outlet	95
H_2O Vapor Inlet/Outlet	94
CO_2 Inlet/Outlet	95
O_2 Inlet/Outlet	89
Static Pressure FGD Inlet	100
Gas Temperature FGD Inlet	100
Demo Steam Temperature	100
Demo Steam Pressure	100
Demo Steam Flow	100
Power to Demo Plant	100

Specific outages of instruments as well as the source of supplementary data is given (Table 2-2). In addition to the downtime experienced by these instruments, the DAS was down less than 10% of the total operating time during which data was extracted from strip chart recorders.

TABLE 2-2. INSTRUMENT DOWNTIME

DAY	TIME	INSTRUMENT	SUPPLEMENTAL SOURCE
1	0800-1000	SO_2	Allied Analyzer
1	1900-2000	H_2O, CO_2, O_2	Average of 1800-1900 and 2000-2100
1	2000-2100	SO_2	Average of 2100-2200
3	0000-0120	SO_2	None
3	0000-0120	H_2O, CO_2, O_2	None
5	0600-0700	H_2O	Average of 0700-0800
6	2100-0800	SO_2	Allied Analyzer
6	2100-0800	H_2O, CO_2	Manual Sample
6	2100-0400	O_2	Manual Sample
10	1100-1400	SO_2	Allied Analyzer
10	1100-1400	H_2O, CO_2, O_2	Manual Sample
11	0900-1000	O_2	Average of 0800-0900 and 1000-1100
11	1500-1900	H_2O, CO_2	Average of 1400-1500 and 1900-2000
11	1500-1700	O_2	Average of 1400-1500 and 2000
2 (High Load)	0100-0200	O_2	Average of 0000-0100 and 0200-0300

TABLE 2-3. SUMMARY OF PERFORMANCE RESULTS

DAY	HOURS UNIT PASSED ACCEPTANCE TEST	SO_2 REMOVAL (% REMOVAL)	PARTICULATE EMISSION RATE (POUNDS/ MILLION BTU)	COST OF UTILITIES ($/HOUR)	SODA ASH CONSUMPTION (TONS/DAY)	SULFUR PRODUCT PURITY (% PURE)	COAL FEED RATE (POUNDS/ HOUR)	BOILER HEAT INPUT (MILLION BTU/HOUR)	BOILER OUTPUT (MEGAWATTS)
1	24	90.6	.01	43.05	AVERAGE 6.2	COMPOSITE ANALYSIS 99.76	83,000	880	71.5
2	24	90.3	.03	38.91			82,400	866	70.8
3	21	90.9	INVALID SAMPLE	41.59			81,500	871	71.1
4	17	90.6	NO TEST	39.44			82,200	863	70.1
5	21	90.3	.08	43.78			84,400	886	71.2
6	17	90.1	.07	44.50			86,300	908	71.4
7	15	90.5	NO TEST	42.46			83,700	883	71.4
8	24	90.8	.03	44.22			91,200	970	73.8
9	24	90.5	.04	43.96			83,900	893	72.8
10	22	90.9	.05	43.91			81,500	873	72.8
11	24	91.2	.04	43.07			74,700	780	65.6
12	24	90.8	NO TEST	43.39			79,800	853	71.7
13	4	90.9	NO TEST	42.09			78,400	847	72.2
1 HL	24	91.3	.04	42.20	DATA NOT COLLECTED DURING HIGH LOAD TEST	COMPOSITE ANALYSIS 99.91	94,000	998	84.8
2 HL	22	90.2	.05	44.03			103,600	1,072	90.2
3 HL	24	90.3	NO TEST	44.45			100,300	1,036	89.5
4 HL	14	90.3	.03	42.06			99,700	1,066	88.7

SECTION 3

DATA VALIDATION

INTRODUCTION

In this section, calibration procedures are described and the accuracy and precision of the test results are quantified to the extent possible. The limitations affecting the quality of the data are discussed. In particular, validation of the flue gas flow determinations was a major problem. The action taken to assure that the flue gas flows were not less than the performance requirements are described in detail.

DATA ACCURACY

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 once each day 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 3-1).

TABLE 3-1. 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 summarized (Table 3-2). 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 and at the beginning and end of manual sampling of the flue gas and at the beginning and end of each interruption.

TABLE 3-2. INSTRUMENT CALIBRATIONS

ITEM	CALIBRATED	CALIBRATED BY
COAL SCALES	ONCE OR TWICE/YEAR	NIPSCO
FGD INLET TEMPERATURE	PRECEDING TEST	TRW
FGD INLET STATIC PRESSURE	PRECEDING TEST	TRW
FGD OUTLET TEMPERATURE	PRECEDING TEST	TRW
FGD OUTLET STATIC PRESSURE	PRECEDING TEST	TRW
STEAM FLOW METER	APRIL 1976	
STEAM FLOW TRANSMITTER	PRECEDING TEST	TRW
STEAM PRESSURE	APRIL 1976	
STEAM TEMPERATURE TRANSMITTER	PRECEDING TEST	TRW
STEAM PRESSURE TRANSMITTER	PRECEDING TEST	TRW
NATURAL GAS FLOW METERS (2)	APRIL 1976	
KILOWATT-HOUR METER	NOVEMBER 1976	NIPSCO

Samples of coal and particulate matter were collected manually and laboratory analyses were performed. One-hour sample increments of coal were collected continuously, whereas particulate matter was collected once a day, weather conditions permitting, for a 4-5 hour period. During the same 4-5 hour period, SO_2 concentrations were determined by manual methods to help in verifying the accuracy of the continuous analyzer. A modified version of EPA Method 6[4] was used for the SO_2 measurements. Calibrations for manual particulate matter and SO_2 measurements are necessary for verifying the accuracy of duct flow and sample flow measurements. Dry gas meters for sample flow were calibrated in August 1977 and pitot tubes for duct flow were last calibrated in September 1976.

Agreement Between Methods

Comparison of results by different methods was limited to the determination of SO_2 concentrations and of flue gas flow. For SO_2, comparison of the continuous analyzer output was made with EPA Method 6 results. These comparisons were made both on the standard calibration gas prior to the Acceptance Test and on samples of flue gas collected during the Acceptance Test. Both of these investigations were done to help validate the accuracy of the SO_2 measurements and results are described in following subsections. Flue gas flow comparisons will be discussed separately.

Accuracy Verification of the Calibration Standard--

The high range and low range standard gases, certifiable as traceable to NBS standards, were analyzed by EPA Method 6 during June-July, 1977. The bottle labels were 2690 ppm SO_2 and 244 ppm SO_2. Results are presented as follows (Table 3-3).

TABLE 3-3. SO_2 SPAN GASES CONCENTRATION BY EPA METHOD 6

	HIGH RANGE	LOW RANGE
LABEL, PPM	2690	244
ANALYSIS, PPM	2579	236
	2726	242
	2546	242
	2648	232
	2530	235
	2672	
	2729	
	2628	
AVERAGE	2632	237

Confidence limits were calculated for the analytical results. For the high range, the confidence range was 2568 to 2696 ppm or only $\pm$ 2.4% of the sample mean. Confidence limits are statistical parameters which in this case tell us that there is a 95% probability that the true mean value of the results is within the confidence limits. This indicates acceptable precision for the analytical method. Also, for the low range span gas, confidence limits of 231 ppm and 243 ppm ($\pm$ 2.5% of the sample mean) were an indication of acceptable precision. However, averages for the analytical results tend to be slightly lower than the span gas bottle labels:

	HIGH RANGE	LOW RANGE
SPAN GAS LABEL, PPM	2690	244
ANALYSIS AVERAGE, PPM	2632	237

Since span gas concentrations were only 4 to 6% higher than the lower confidence limits and only 2 to 3% higher than the means of the Method 6 results, it was concluded that the method comparisons tended to verify the accuracy of calibrations.

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. 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

Method Comparisons of Actual Flue Gas Samples--

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 (Table 3-4).

VALIDATION OF FLUE GAS FLOW RATES

Just prior to the Acceptance Test, it was found that the apparent flue gas rates at 92 MWG (FGD design load) were much higher than expected. As a consequence, it was necessary to test FGD performance during the Acceptance Test at the design flue gas rate of 320,000 acfm rather than at 92 MWG load. The resulting gross load was only 72 MW. Adding the steam consumed by the FGD plant to the steam equivalent of 72 MWG, the load equivalent of the total steam produced by the boiler was 81 MWG or only 88% of the design load.

TABLE 3-4. COMPARISON OF METHODS FOR MEASURING SO_2 CONCENTRATIONS

	SO_2, PPM				SO_2 REMOVAL, %	
	CONTINUOUS ANALYZER		METHOD 6		CONTINUOUS ANALYZER	METHOD 6
DAY	INLET	OUTLET	INLET	OUTLET		
1	2158	161	2137	162	92.5	92.3
2	2036	176	2123	187	91.0	90.6
3	----	---	----	---	----	----
4	----	---	----	---	----	----
5	2525	259	2146	272	89.5	86.3
6	2385	204	2481	235	91.2	90.1
7	----	---	----	---	----	----
8	2169	180	2296	193	90.9	90.8
9	2051	190	2147	203	89.4	89.3
10	----	---	----	---	----	----
11	2246	190	2246	218	91.2	90.1
12	----	---	----	---	----	----
13	----	---	----	---	----	----
1 HL	1987	141	2098	144	92.2	92.4
2 HL	2278	183	2315	197	91.4	90.9
3 HL	----	---	----	---	----	----
4 HL	2615	228	2703	250	91.2	90.7
				MEAN	91.1	90.4

Furthermore, during the Acceptance Test, it was necessary to rely on flow estimates derived from the fan curves for the booster fan. This was necessary because of an apparent bias error in the flow measurements which was a result of limited lengths of straight duct available for measurement. These uncertainties have brought into question whether or not enough gas was being treated during the Acceptance Test to provide a fair test of the performance of the FGD process.

Simultaneous flow measurements at inlet and outlet the absorber were contradictory. Flow measurements at the inlet appeared to be in error on the high side whereas the measurements at the outlet showed apparent errors on the low side. As soon as coal analyses were available following start of the Acceptance Test, flows were calculated from the coal compositions and rates and the flue gas excess oxygen levels. Calculated values were at least as high as the flows estimated from the fan curve (Table 3-5).

TABLE 3-5. CALCULATED FLUE GAS FLOW RATES(1)

DESIGN LOAD DAY NO.	FLOW 10^3 ACFM	HIGH LOAD DAY NO.	FLOW 10^3 ACFM
1	349	1	393
2	---	2	380
3	337	3	376
4	344	4	391
5	374	AVERAGE	385
6	357	MEDIAN	385
7	351		
8	387		
9	372		
10	387		
11	320		
12	328		
13	324		
AVERAGE	353		
MEDIAN	354		

(1)AT 300°F, 29.92 in. Hg.

All flue gas rates reported in this section are corrected to 300°F and 29.92 in. Hg.

In an effort to further validate the flue gas flow measurements, a limited series of flue gas measurements were made, after completion of the Acceptance Test, with the FGD plant completely isolated from the boiler. The objective was to compare present day flue gas rates with those obtained during the Baseline Test[5]. Measurements were made at the same location as the Baseline Test. However, the upstream duct had been redesigned to include the louvered bypass damper and the elimination of an expansion transition of the portion of the duct collecting flue gas from the two induced draft fans of the boiler. The test results are summarized as follows:

(a) At a gross load on the boiler of 92 MW, the flue gas flow was 400×10^3 CFM compared to an average of 369×10^3 CFM during the Baseline Test in 1974, an increase of about 7% after correcting for load differences. The increase seems to be largely due to an increase in heat input to the boiler, which was 12% higher than during the Baseline Test, and the corresponding increase in fuel rate.

(b) At a gross load of 81 MW, which is the megawatt equivalent of total main steam produced by the boiler during the design load phase of the Acceptance Test, the measured values averaged 399 MCFM which was virtually the same as the flue gas volume measured at 92 MWG. However, flows calculated from fuel composition and rate and excess air levels correlated fairly well with load. Using calculated values, flow rates during the Acceptance Test were slightly higher but within 5% of the Baseline Test measurements.

(c) It is concluded from these results that actual flow rates during the Acceptance Test were higher than the 320×10^3 CFM and 388×10^3 CFM specified for the performance runs and also were not less than the flue gas volumes experienced during the Baseline Test.

(d) The data collected to determine boiler heat input during these flow tests and during the Acceptance Test suggest a loss of boiler efficiency since the baseline testing in 1974. Increased flue gas flows would be one result of a decrease in efficiency. The combined data of the flow tests and the Acceptance Test show that heat input is about 7% higher than during the Baseline Test.

(e) Based on samples of ash collected from the precipitator hoppers, heat losses due to unburned carbon were found to be less than 0.5% of the total heat input.

Results of these tests were reported on November 1, 1977[6]. The full report is appended (Appendix C).

While these investigations tend to confirm that flue gas volumes were at least as high as those required for meeting the performance guarantees, they did not provide a very accurate measure of the actual flue gas volumes. Actually, the error in the flue gas flow measurements did not affect any of the performance parameters except particle emission rates. Inlet grain loading was less than 0.2 gr/ACF throughout the Acceptance Test. Therefore, the performance requirement was that the mass rate of 0.1 $lb/10^6$ Btu not be exceeded. To calculate a mass rate from the measured grain loadings, the flue gas volume must be known. It was suspected and later confirmed that the outlet flue gas rates were in error on the low side and the inlet flue gas rates were in error on the high side. The particle emission rates calculated from the outlet flue gas rates and reported were thus in error on the low side. Flow rates calculated from coal rates and compositions are believed to be a more accurate measure of the true flows. The mass rates have been recalculated from the higher flue gas rates obtained by calculation (Table 3-6).

TABLE 3-6. REVISED ESTIMATES OF PARTICULATE MATTER EMISSION RATES

TEST DAY	MEASURED ACFM	CALCULATED[1] MACFM	Δ MACFM	$lb/10^6$ BTU REPORTED	$lb/10^6$ BTU REVISED
1	234,973	269	+ 34	0.01	0.02
2	233,056	226	- 7	0.03	0.04
3	235,976	277	+ 41	----	----
5	237,756	309	+ 71	0.08	0.10
6	237,756	---	----	0.07	0.10
8	233,350	---	----	0.03	0.04
9	243,641	321	+ 77	0.04	0.05
10	234,470	307	+ 73	0.05	0.07
11	239,841	269	+ 29	0.04	0.05
			$\bar{x}$ = + 45		
			σ = 30		
			CL = + 45 $\pm$ 28		
1 (HIGH LOAD)	280,360	318	+ 38	0.04	0.05
2 (HIGH LOAD)	280,417	303	+ 23	0.045	0.05
4 (HIGH LOAD)	279,533	802	+ 22	0.033	0.04
			$\bar{x}$ = + 28		
			σ = 9		
			CL = + 28 $\pm$ 22		

(1) ADJUSTED TO OUTLET TEMPERATURES AND WATER CONTENTS.

The revised estimates do not exceed the performance limit of 0.1 $lb/10^6$ Btu. The correction was made out to the upper confidence limit (95% probability) of the average difference between the measured and calculated flue gas flow. Therefore, there is a low probability that the revised estimate would ever be as high as indicated.

TEST PRECISION

Precision in this case refers to the repeatability of the data. That is, it is a measure of the variability of measurements on the same sources of data made by a single test team with the same equipment over a short period of time. The expected maximum instrument errors and the expected maximum procedural errors in sampling and analysis have been used to estimate variabilities expressed as the standard deviation of a mean value. The variabilities for SO_2 removal, particle emission control, and operating costs have been estimated.

SO_2 Removal

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 concentrations 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.

Particle Emission Control

The variability in particulate matter emission rates from random errors was smaller compared to the inaccuracies in the flue gas flow measurements, the effects of which have been discussed earlier. Considerable work has been done by EPA in an attempt to define the accuracy and precision of the EPA method (Method 5) and errors and expected variabilities for every step of the procedure have been estimated[7]. Standard deviations determined from expected errors have been estimated for each measurement parameter and can be used to estimate a probable error of the method as follows:

$$\sigma^2_m = \sigma^2_1 + \sigma^2_2 + \cdot \cdot \cdot + \sigma^2_n$$

where,

σ_m = repeatability standard deviation of the method

$\sigma(1,2,n)$ = repeatability standard deviation of each measurement parameter.

To put each standard deviation on a common basis, the Coefficient of Variation (CV), which is the standard deviation expressed as a percentage, is substituted. Thus, for particulate matter emission rate, as $lb/10^6$ Btu heat input, the probable error is estimated as follows:

$$CV^2_{pmrhv} = CV^2_{hr} + CV^2_{cr} + CV^2_{pmr}$$

Where,

pmrhv = emission rate, $lb/10^6$ Btu

pmr = emission rate, lb/hr

hr = heating value of coal, 10^6 Btu/lb

cr = coal rate, lb/hr

CV = coefficient of variation and probable error, %

CV's were estimated based on the mean values of the measurements of the Acceptance Test (Table 3-7).

TABLE 3-7. VARIABILITY OF PARTICULATE MATTER EMISSION RATES

VARIABLE	MEAN	σ	CV
pmr	39 lb/hr[(1)]	3.5	8.9%
CR	83,300 lb/hr[(1)]	83.3	0.1%
hr	0.0104×10^6 Btu/lb[(2)]	31 Btu lb	0.3%
pmrhv	0.06 lb/10^6 Btu[(2)]	0.005	8.9%

(1) DESIGN LOAD SERIES.

(2) DESIGN LOAD AND HIGH LOAD SERIES.

The data indicates a probable error of about 9% versus as much as a 31% error due to flow inaccuracies.

Operating Costs

Measurements subject to error include:

	Maximum Expected Error
Kilowatt-hours by meter	1.0%
Natural gas flow (2 meters)	5.0%
Natural gas heating value	0.3%
Steam flow by meter	5.6%
Steam temperature	2.0%
Steam pressure	11.0%

The performance result was a 12-day average of a combined cost performance not to exceed $56.00/hour based on individual utility rates as follows:

Electric Power	$0.007 per kWh
Steam	$0.50 per 1000 lb.
Natural Gas	$0.55 per 1,000,000 Btu

Thus, each utility consumption variable was determined by accumulating hourly values over the 12-day period and dividing by the total operating hours. By applying the maximum expected errors to each of the measurement parameters, a probable error in operating costs can be estimated by the same method used for particle emission control. In this case, standard deviations for the natural gas, electricity and steam consumptions can be expressed in dollars (Table 3-8).

TABLE 3-8. VARIABILITY IN OPERATING COSTS

VARIABLE	CUMULATIVE TOTALS	PROBABLE ERROR %	PROBABLE ERROR $/HR
ELECTRICITY	186,640 kWh	1.0	0.05
NATURAL GAS	2,875 x 10^6 BTU	7.0	0.44
STEAM	15,442.5 x 10^3 LBS	12.5	3.89
TOTAL COSTS	----	----	3.92

A probable error of $3.92/hr., added to reported costs of $42.72, is still well within the performance requirement of $56.00/hr.

SECTION 4

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3. TRW, Inc., Transportation & Environmental Engineering Operation. Program for Test and Evaluation of the NIPSCO/Davy/Allied Demonstration Plant. Acceptance Test Plan. Prepared for Control Systems Laboratory, Office of Research and Monitoring, Environmental Protection Agency, Research Triangle Park, N.C. April 8, 1975.

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APPENDIX A

TEST RESULTS

REPORT NO. 2 - SULFUR

Sulfur Removal

TEST PERIOD: Design

OPERATING TIME:

Test Day No. 1 Day Ending 0800 8/30/77

Hrs. Operation (Cumulative) 24 Hrs. Operation (This Day) 24

Hrs. Interrupted None Hrs. Boiler Availability 24

CONTINUOUS DATA SEQUENTIAL 2 HR. AVERAGES, LBS/HR.

2-Hr. Averages

SO_2

Time	Inlet	Outlet	% Removal
0800-1040	No data	No Data	No Data
1040-1200	4929	420	92
1200-1400	4861	403	92
1400-1600	4942	381	92
1600-1800	4897	411	92
1800-2000	4928	452	91
2100-2200	4682	475	90
2200-2400	4637	477	90
0000-0200	4500	456	90
0200-0400	4482	454	90
0400-0600	4655	471	90
0600-0800	4831	503	90

REMARKS: Period 0800 to 1040 is assumed to be >90% by agreement of EPA Project Officer.

8/31/77
Date

R. C. Adams
Test Director

REPORT NO. 3 - ASH

Particulate Control

TEST PERIOD: Design

OPERATING TIME:

Test Day No.	1	Day Ending 0800	8/30/77
Hrs. Operation (Cumulative)	24	Hrs. Operation (This Day)	24
Hrs. Interrupted	None	Hrs. Boiler Availability	24

PERFORMANCE:

	Inlet	Outlet
Particulate 3-Hr. Avg., Lb/Hr.		12.1
Gr./Acf	0.01	0.006
Emission Rate / $\frac{\text{lb.}}{10^6 \text{ Btu}}$	0.01	

REMARKS: Test passed based on lb/10^6 Btu value.

9/01/77
Date

R. C. Adams
Test Director

REPORT NO. 4 - COST

Operating Costs

TEST PERIOD: Design

OPERATING TIME:

Test Day No. 1

Day Ending 0800 8/30/77

Hrs. Operation (Cumulative) 24

Hrs. Operation (This Day) 24

Hrs. Interrupted 0

Hrs. Boiler Availability 24

PERFORMANCE:

	Daily	Cumulative
Electric Energy, KWH/hr.	755	755
Steam, mlbs./hr.	63.119	63.119
Total Natural Gas, mcf./hr.	11.046	11.046
Avg. Daily Cost, $	43.05	43.05

(HOURLY STEAM PRESSURE AND TEMPERATURE ATTACHED)

REMARKS:

9/13/77
Date

R. C. Adams
Test Director

REPORT NO. 4 - COST

(Continued)

TEST DAY NO. 1

SEQUENTIAL HOURLY DEMONSTRATION

PLANT STEAM PRESSURES AND TEMPERATURES

	Pressure PSIG	Temperature °F
1	550	730
2	549	730
3	548	730
4	548	729
5	548	729
6	549	728
7	552	726
8	551	727
9	550	726
10	549	726
11	548	727
12	548	726
13	548	727
14	548	728
15	548	728
16	549	728
17	549	728
18	548	727
19	548	726
20	547	727
21	548	729
22	540	720
23	548	720
24	548	720

REPORT NO. 2 - SULFUR

Sulfur Removal

TEST PERIOD: Design

OPERATING TIME:

Test Day No. 2

Day Ending 0800 8/31/77

Hrs. Operation (Cumulative) 48

Hrs. Operation (This Day) 24

Hrs. Interrupted None

Hrs. Boiler Availability 24

CONTINUOUS DATA SEQUENTIAL 2 HR. AVERAGES, LBS/HR.

2-Hr. Averages

SO_2

Time	Inlet	Outlet	% Removal
0800-1000	4684	459	90
1000-1200	4691	467	90
1200-1400	4675	452	90
1400-1600	4719	458	90
1600-1800	4443	422	91
1800-2000	4576	457	90
2000-2200	4587	437	91
2200-2400	4592	457	90
0000-0200	4806	487	90
0200-0400	4743	461	90
0400-0600	4814	457	91
0600-0800	4840	455	91

REMARKS:

9/01/77
Date

R. C. Glaser
Test Director

REPORT NO. 3 - ASH

Particulate Control

TEST PERIOD: Design

OPERATING TIME:

Test Day No. 2 — Day Ending 0800 8/31/77

Hrs. Operation (Cumulative) 48 — Hrs. Operation (This Day) 24

Hrs. Interrupted None — Hrs. Boiler Availability 24

PERFORMANCE:

	Inlet	Outlet
Particulate 3-Hr. Avg., Lb/Hr.		22.5
Gr./Acf	0.02	0.01
Emission Rate / $\frac{\text{lb.}}{10^6\text{ Btu}}$	0.03	

REMARKS: Test passed based on lb/10^6 Btu value.

9/03/77
Date

R. C. Adams
Test Director

REPORT NO. 4 - COST

Operating Costs

TEST PERIOD: Design

OPERATING TIME:

Test Day No. 2 — Day Ending 0800 8/31/77

Hrs. Operation (Cumulative) 48 — Hrs. Operation (This Day) 24

Hrs. Interrupted 0 — Hrs. Boiler Availability 24

PERFORMANCE:

	Daily	Cumulative
Electric Energy, KWH/hr.	744	750
Steam, mlbs./hr.	56.198	59.659
Total Natural Gas, mcf./hr.	10.004	10.525
Avg. Daily Cost, $	38.91	40.98

(HOURLY STEAM PRESSURE AND TEMPERATURE ATTACHED)

REMARKS:

9/13/77
Date

R. C. Adams
Test Director

REPORT NO. 4 - COST

(Continued)

TEST DAY NO. 2

SEQUENTIAL HOURLY DEMONSTRATION

PLANT STEAM PRESSURES AND TEMPERATURES

	Pressure PSIG	Temperature °F
1	548	720
2	548	720
3	548	720
4	548	711
5	548	711
6	548	711
7	548	720
8	548	720
9	548	720
10	548	720
11	548	720
12	548	720
13	548	720
14	540	720
15	540	720
16	540	720
17	540	720
18	540	720
19	540	720
20	540	720
21	540	720
22	540	720
23	540	720
24	540	720

REPORT NO. 2 - SULFUR

Sulfur Removal

TEST PERIOD: Design

OPERATING TIME:

Test Day No. 3 — Day Ending 0800 9/01/77

Hrs. Operation (Cumulative) 69 — Hrs. Operation (This Day) 21

Hrs. Interrupted 3 — Hrs. Boiler Availability 21

CONTINUOUS DATA SEQUENTIAL 2 HR. AVERAGES, LBS/HR.

2-Hr. Averages

SO_2

Time	Inlet	Outlet	% Removal
0800-1000	4741	425	91
1000-1200	4818	445	91
1200-1400	4831	451	91
1400-1600	4801	443	91
1600-1800	4797	401	92
1800-2000	4774	462	90
2000-2200	4790	453	91
2200-2400	4763	449	91
0000-0200	----	---	--
0200-0400	----	---	--
0400-0600	4856	443	91
0600-0300	4959	431	91

REMARKS: 0000 to 0120: Invalid SO_2 data.
0120 to 0415: Boiler interruption.

9/02/77
Date

R. C. Adams
Test Director

REPORT NO. 3 - ASH

Particulate Control

TEST PERIOD: Design

OPERATING TIME:

Test Day No. 3

Day Ending 0800 9/01/77

Hrs. Operation (Cumulative) 69

Hrs. Operation (This Day) 21

Hrs. Interrupted 3

Hrs. Boiler Availability 21

PERFORMANCE:

	Inlet	Outlet
Particulate 3-Hr. Avg., Lb/Hr.		---
Gr./Acf	0.05	---
Emission Rate / $\frac{\text{lb.}}{10^6 \text{ Btu}}$	---	

REMARKS: Outlet sample invalid.

9/05/77
Date

R. C. Adams
Test Director

REPORT NO. 4 - COST

Operating Costs

TEST PERIOD: Design

OPERATING TIME:

Test Day No. 3	Day Ending 0800 9/01/77
Hrs. Operation (Cumulative) 69	Hrs. Operation (This Day) 21
Hrs. Interrupted 3	Hrs. Boiler Availability 21

PERFORMANCE:

	Daily	Cumulative
Electric Energy, KWH/hr.	749	749
Steam, mlbs./hr.	60.460	59.894
Total Natural Gas, mcf./hr.	10.850	10.621
Avg. Daily Cost, $	41.59	41.17

(HOURLY STEAM PRESSURE AND TEMPERATURE ATTACHED)

REMARKS:

9/13/77
Date

R. C. Adams
Test Director

REPORT NO. 4 - COST

(Continued)

TEST DAY NO. 3

SEQUENTIAL HOURLY DEMONSTRATION

PLANT STEAM PRESSURES AND TEMPERATURES

	Pressure PSIG	Temperature °F
1	540	719
2	540	719
3	540	719
4	540	711
5	540	711
6	544	711
7	540	711
8	540	711
9	540	719
10	540	719
11	540	720
12	540	720
13	518	720
14	518	720
15	518	720
16	518	720
17	518	720
18	---	---
19	---	---
20	---	---
21	540	720
22	540	720
23	540	720
24	540	720

REPORT NO. 2 - SULFUR

Sulfur Removal

TEST PERIOD: Design

OPERATING TIME:

Test Day No. 4 | Day Ending 0800 9/02/77

Hrs. Operation (Cumulative) 86 | Hrs. Operation (This Day) 17

Hrs. Interrupted 7 | Hrs. Boiler Availability 24

CONTINUOUS DATA SEQUENTIAL 2 HR. AVERAGES, LBS/HR.

2-Hr. Averages

SO_2

Time	Inlet	Outlet	% Removal
0800-1000	5203	470	91
1000-1200	5101	455	91
1200-1400	5490	485	91
(1)1400-1500	5579	464	92
1450-1555		FGD Interruption	
1600-1700		Invalid Data	
1645-2240		FGD Interruption	
(1)2300-2400	5530	509	91
0000-0200	5855	537	91
0200-0400	5710	512	91
0400-0600	5710	591	90
0600-0800	5824	596	90

REMARKS: (1)One hour average.

9/03/77
Date

R C Adams
Test Director

REPORT NO. 3 - ASH

Particulate Control

TEST PERIOD: Design

OPERATING TIME:

Test Day No. 4 | Day Ending 0800 9/02/77
Hrs. Operation (Cumulative) 86 | Hrs. Operation (This Day) 17
Hrs. Interrupted 7 | Hrs. Boiler Availability 24

PERFORMANCE:

	Inlet	Outlet
Particulate 3-Hr. Avg., Lb/Hr.		
Gr./Acf		
Emission Rate / $\frac{\text{lb.}}{10^6\ \text{Btu}}$		

REMARKS: Test not run - rain.

9/05/77
Date

R. C. Adams
Test Director

REPORT NO. 4 - COST

Operating Costs

TEST PERIOD: Design

OPERATING TIME:

Test Day No. 4	Day Ending 0800 9/02/77
Hrs. Operation (Cumulative) 86	Hrs. Operation (This Day) 17
Hrs. Interrupted 7	Hrs. Boiler Availability 24

PERFORMANCE:

	Daily	Cumulative
Electric Energy, KWH/hr.	750	749
Steam, mlbs./hr.	56.762	59.295
Total Natural Gas, mcf./hr.	10.238	10.544
Avg. Daily Cost, $	39.44	40.83

(HOURLY STEAM PRESSURE AND TEMPERATURE ATTACHED)

REMARKS:

9/13/77
Date

R. C. Adams
Test Director

REPORT NO. 4 - COST

(Continued)

TEST DAY NO. 4

SEQUENTIAL HOURLY DEMONSTRATION

PLANT STEAM PRESSURES AND TEMPERATURES

	Pressure PSIG	Temperature °F
1	ND	720
2	543	720
3	543	720
4	543	720
5	543	720
6	543	720
7	543	720
8	---	---
9	543	716
10	---	---
11	---	---
12	---	---
13	---	---
14	---	---
15	---	---
16	546	724
17	547	720
18	546	720
19	546	720
20	544	722
21	544	720
22	546	720
23	543	722
24	543	722

ND - data not available

REPORT NO. 2 - SULFUR

Sulfur Removal

TEST PERIOD: Design

OPERATING TIME:

Test Day No. 5

Day Ending 0800 9/03/77

Hrs. Operation (Cumulative) 107

Hrs. Operation (This Day) 21

Hrs. Interrupted 3

Hrs. Boiler Availability 24

CONTINUOUS DATA SEQUENTIAL 2 HR. AVERAGES, LBS/HR.

2-Hr. Averages

SO_2

Time	Inlet	Outlet	% Removal
0800-1000	6322	755	88
1000-1200	6250	663	89
1200-1400	6218	636	90
1400-1600	5879	564	90
1600-1800	5767	531	91
1800-2000	5764	496	91
2000-2200	5520	486	91
2200-2400	5301	492	91
0000-0200	5109	472	91
0240-0545		FGD Interruption	
0600-0800	4891	448	91

REMARKS: Test failed 0800-1200 (4 hours).

9/03/77
Date

R. C. [illegible]
Test Director

REPORT NO. 3 - ASH

Particulate Control

TEST PERIOD: Design

OPERATING TIME:

Test Day No. 5	Day Ending 0800 9/03/77
Hrs. Operation (Cumulative) 107	Hrs. Operation (This Day) 21
Hrs. Interrupted 3	Hrs. Boiler Availability 24

PERFORMANCE:

	Inlet	Outlet
Particulate 3-Hr. Avg., Lb/Hr.		67.9
Gr./Acf	0.04	0.03
Emission Rate / $\frac{\text{lb.}}{10^6 \text{ Btu}}$	0.08	

REMARKS:

9/05/77
Date

R. C. Ahems
Test Director

REPORT NO. 4 - COST

Operating Costs

TEST PERIOD: Design

OPERATING TIME:

Test Day No. 5	Day Ending 0800 9/03/77
Hrs. Operation (Cumulative) 107	Hrs. Operation (This Day) 21
Hrs. Interrupted 3	Hrs. Boiler Availability 24

PERFORMANCE:

	Daily	Cumulative
Electric Energy, KWH/hr.	756	751
Steam, mlbs./hr.	63.184	60.069
Total Natural Gas, mcf./hr.	12.163	10.863
Avg. Daily Cost, $	43.78	41.41

(HOURLY STEAM PRESSURE AND TEMPERATURE ATTACHED)

REMARKS:

9/13/77
Date

R. C. Adams
Test Director

REPORT NO. 4 - COST

(Continued)

TEST DAY NO. 5

SEQUENTIAL HOURLY DEMONSTRATION

PLANT STEAM PRESSURES AND TEMPERATURES

	Pressure PSIG	Temperature °F
1	544	720
2	542	720
3	542	720
4	544	720
5	542	720
6	543	720
7	545	721
8	547	728
9	547	724
10	545	721
11	545	723
12	544	720
13	544	724
14	545	726
15	546	724
16	547	724
17	546	726
18	535	725
19	546	724
20	---	---
21	---	---
22	---	---
23	530	723
24	546	724

REPORT NO. 2 - SULFUR

Sulfur Removal

TEST PERIOD: Design

OPERATING TIME:

Test Day No. 6 — Day Ending 0800 9/04/77

Hrs. Operation (Cumulative) 128 — Hrs. Operation (This Day) 21

Hrs. Interrupted 3 — Hrs. Boiler Availability 24

CONTINUOUS DATA SEQUENTIAL 2 HR. AVERAGES, LBS/HR.

2-Hr. Averages

SO_2

Time	Inlet	Outlet	% Removal
0800-1000	5301	496	91
1000-1300		FGD Interruption	
(1)1300-1400	5296	531	90
1400-1600	5423	505	91
1600-1800	5698	509	90
1800-2000	5488	566	90
(2)2000-2200	5363	562	90
(2)2200-2400	5218	540	90
(2)0000-0200	5126	517	90
(2)0200-0400	5104	464	91
(2)0400-0600	5241	529	90
(2)0600-0800	5152	509	90

REMARKS: Total test hours failed to date: 4

(1)One hour average

(2)Invalid SO_2 data. Allied analyzer used.

9/06/77
Date

R. C. Adams
Test Director

REPORT NO. 3 - ASH

Particulate Control

TEST PERIOD: Design

OPERATING TIME:

Test Day No. 6 — Day Ending 0800 9/04/77

Hrs. Operation (Cumulative) 128 — Hrs. Operation (This Day) 21

Hrs. Interrupted 3 — Hrs. Boiler Availability 24

PERFORMANCE:

	Inlet	Outlet
Particulate 3-Hr. Avg., Lb/Hr.	----	----
Gr./Acf	0.04	0.03
Emission Rate / $\frac{lb.}{10^6 \text{ Btu}}$	0.07	

REMARKS:

9/07/77
Date

R. C. Adams
Test Director

REPORT NO. 4 COST

Operating Costs

TEST PERIOD: Design

OPERATING TIME:

Test Day No. 6 Day Ending 0800 9/04/77

Hrs. Operation (Cumulative) 128 Hrs. Operation (This Day) 21

Hrs. Interrupted 3 Hrs. Boiler Availability 24

PERFORMANCE:

	Daily	Cumulative
Electric Energy, KWH/hr.	775	755
Steam, mlbs./hr.	63.995	60.723
Total Natural Gas, mcf./hr.	12.481	11.131
Avg. Daily Cost, $	44.50	41.92

(HOURLY STEAM PRESSURE AND TEMPERATURE ATTACHED)

REMARKS:

9/13/77
Date

R. C. Adams
Test Director

REPORT NO. 4 - COST

(Continued)

TEST DAY NO. 6

SEQUENTIAL HOURLY DEMONSTRATION

PLANT STEAM PRESSURES AND TEMPERATURES

	Pressure PSIG	Temperature °F
1	544	728
2	545	728
3	---	---
4	---	---
5	---	---
6	546	725
7	547	724
8	546	725
9	546	723
10	546	723
11	544	723
12	544	724
13	543	726
14	544	727
15	545	726
16	545	726
17	545	726
18	545	727
19	545	727
20	546	726
21	546	727
22	546	727
23	547	727
24	547	727

REPORT NO. 2 - SULFUR

Sulfur Removal

TEST PERIOD: Design

OPERATING TIME:

Test Day No. 7 | Day Ending 0800 9/05/77

Hrs. Operation (Cumulative) 143 | Hrs. Operation (This Day) 15

Hrs. Interrupted 9 | Hrs. Boiler Availability 17

CONTINUOUS DATA SEQUENTIAL 2 HR. AVERAGES, LBS/HR.

2-Hr. Averages

SO_2

Time	Inlet	Outlet	% Removal
0800-0900	4953	429	91
0900-1630	Boiler Interruption		
1630-1800	5246	477	91
1800-2000	5157	514	90
2000-2200	5315	510	90
2200-2400	5349	529	90
0000-0200	4982	495	90
0200-0330	4877	479	90
0330-0545		FGD Interruption	
0545-0800	5037	448	91

REMARKS: Total test hours failed to date: 4

9/06/77
Date

R. C. Adams
Test Director

REPORT NO. 3 - ASH

Particulate Control

TEST PERIOD : Design

OPERATING TIME:

Test Day No. 7	Day Ending 0800 9/05/77
Hrs. Operation (Cumulative) 143	Hrs. Operation (This Day) 15
Hrs. Interrupted 9	Hrs. Boiler Availability 17

PERFORMANCE:

	Inlet	Outlet
Particulate 3-Hr. Avg., Lb/Hr.	---	---
Gr./Acf	---	---
Emission Rate / $\frac{\text{lb.}}{10^6 \text{ Btu}}$	---	

REMARKS: No test - boiler interruption.

9/06/77
Date

R. C. Adams
Test Director

REPORT NO. 4 - COST

Operating Costs

TEST PERIOD: Design

OPERATING TIME:

Test Day No. 7	Day Ending 0800 9/05/77
Hrs. Operation (Cumulative) 143	Hrs. Operation (This Day) 15
Hrs. Interrupted 9	Hrs. Boiler Availability 17

PERFORMANCE:

	Daily	Cumulative
Electric Energy, KWH/hr.	778	757
Steam, mlbs./hr.	61.174	60.769
Total Natural Gas, mcf./hr.	11.292	11.147
Avg. Daily Cost, $	42.46	41.98

(HOURLY STEAM PRESSURE AND TEMPERATURE ATTACHED)

REMARKS:

9/13/77
Date

R. C. Adams
Test Director

REPORT NO. 4 - COST

(Continued)

TEST DAY NO. 7

SEQUENTIAL HOURLY DEMONSTRATION

PLANT STEAM PRESSURES AND TEMPERATURES

	Pressure PSIG	Temperature °F
1	548	725
2	---	---
3	---	---
4	---	---
5	---	---
6	---	---
7	---	---
8	---	---
9	544	722
10	543	ND
11	543	725
12	543	725
13	543	726
14	542	726
15	542	728
16	543	728
17	545	726
18	549	723
19	552	722
20	551	723
21	---	---
22	---	---
23	543	725
24	542	722

ND - data not available.

REPORT NO. 2 - SULFUR

Sulfur Removal

TEST PERIOD: Design

OPERATING TIME:

Test Day No. 8 | Day Ending 0800 9/6/77

Hrs. Operation (Cumulative) 167 | Hrs. Operation (This Day) 24

Hrs. Interrupted None | Hrs. Boiler Availability 24

CONTINUOUS DATA SEQUENTIAL 2 HR. AVERAGES, LBS/HR.

2-Hr. Averages

SO_2

Time	Inlet	Outlet	% Removal
0800-1000	4966	426	91
1000-1200	4991	448	91
1200-1400	4923	445	91
1400-1600	4950	480	90
1600-1800	4929	459	91
1800-2000	4954	449	91
2000-2200	4899	448	91
2200-2400	4833	438	91
0000-0200	4885	459	91
0200-0400	4819	458	91
0400-0600	4836	454	91
0600-0800	4897	457	91

REMARKS: Total hours test failed to date: 4

9/06/77
Date

R. C. Adams
Test Director

REPORT NO. 3 - ASH

Particulate Control

TEST PERIOD: Design

OPERATING TIME:

Test Day No. 8

Day Ending 0800 9/06/77

Hrs. Operation (Cumulative) 167

Hrs. Operation (This Day) 24

Hrs. Interrupted None

Hrs. Boiler Availability 24

PERFORMANCE:

	Inlet	Outlet
Particulate 3-Hr. Avg., Lb/Hr.	95.3	29.7
Gr./Acf	0.07	0.01

Emission Rate / $\frac{\text{lb.}}{10^6 \text{ Btu}}$ 0.03

REMARKS:

9/09/77
Date

R.C. Adams
Test Director

REPORT NO. 4 - COST

Operating Costs

TEST PERIOD: Design

OPERATING TIME:

Test Day No. 8 | Day Ending 0800 9/06/77

Hrs. Operation (Cumulative) 167 | Hrs. Operation (This Day) 24

Hrs. Interrupted 0 | Hrs. Boiler Availability 24

PERFORMANCE:

	Daily	Cumulative
Electric Energy, KWH/hr.	781	761
Steam, mlbs./hr.	64.310	61.286
Total Natural Gas, mcf./hr.	11.618	11.215
Avg. Daily Cost, $	44.22	42.30

(HOURLY STEAM PRESSURE AND TEMPERATURE ATTACHED)

REMARKS:

9/13/77
Date

R. C. Adams
Test Director

REPORT NO. 4 - COST

(Continued)

TEST DAY NO. 8

SEQUENTIAL HOURLY DEMONSTRATION

PLANT STEAM PRESSURES AND TEMPERATURES

	Pressure PSIG	Temperature °F
1	542	724
2	543	725
3	544	726
4	543	727
5	544	726
6	544	726
7	544	726
8	543	726
9	543	727
10	544	727
11	546	726
12	547	726
13	547	726
14	547	726
15	546	726
16	544	726
17	543	726
18	544	726
19	544	725
20	544	726
21	543	728
22	543	728
23	546	728
24	545	727

REPORT NO. 2 - SULFUR

Sulfur Removal

TEST PERIOD: Design

OPERATING TIME:

Test Day No. 9

Day Ending 0800 9/07/77

Hrs. Operation (Cumulative) 191

Hrs. Operation (This Day) 24

Hrs. Interrupted None

Hrs. Boiler Availability 24

CONTINUOUS DATA SEQUENTIAL 2 HR. AVERAGES, LBS/HR.

2-Hr. Averages

SO_2

Time	Inlet	Outlet	% Removal
0800-1000	4810	419	91
1000-1200	4722	473	90
1200-1400	4732	483	90
1400-1600	4679	486	90
1600-1800	4581	454	90
1800-2000	4796	465	90
2000-2200	4674	430	91
2200-2400	4644	430	91
0000-0200	4694	425	91
0200-0400	4722	433	91
0400-0600	4847	444	91
0600-0800	4880	449	91

REMARKS: Total hours test failed to date: 4

9/08/77
Date

R. C. Adams
Test Director

REPORT NO. 3 - ASH

Particulate Control

TEST PERIOD : Design

OPERATING TIME:

Test Day No. 9	Day Ending 0800 9/07/77
Hrs. Operation (Cumulative) 191	Hrs. Operation (This Day) 24
Hrs. Interrupted None	Hrs. Boiler Availability 24

PERFORMANCE:

	Inlet	Outlet
Particulate 3-Hr. Avg., Lb/Hr.	----	35.41
Gr./Acf	0.02	0.02
Emission Rate / $\frac{\text{lb.}}{10^6\ \text{Btu}}$	0.04	

REMARKS:

9/09/77
Date

R. C. Adams
Test Director

REPORT NO. 4 - COST

Operating Costs

TEST PERIOD: Design

OPERATING TIME:

Test Day No. 9	Day Ending 0800 9/07/77
Hrs. Operation (Cumulative) 191	Hrs. Operation (This Day) 24
Hrs. Interrupted None	Hrs. Boiler Availability 24

PERFORMANCE:

	Daily	Cumulative
Electric Energy, KWH/hr.	777	763
Steam, mlbs./hr.	63.943	61.625
Total Natural Gas, mcf./hr.	11.529	11.255
Avg. Daily Cost, $	43.96	42.52

(HOURLY STEAM PRESSURE AND TEMPERATURE ATTACHED)

REMARKS:

9/13/77
Date

R.C. Adams
Test Director

REPORT NO. 4 - COST

(Continued)

TEST DAY NO. 9

SEQUENTIAL HOURLY DEMONSTRATION

PLANT STEAM PRESSURES AND TEMPERATURES

	Pressure PSIG	Temperature °F
1	545	726
2	546	726
3	547	726
4	548	725
5	546	727
6	544	727
7	547	725
8	548	726
9	547	724
10	547	724
11	548	725
12	547	725
13	545	726
14	543	726
15	546	726
16	547	725
17	546	725
18	546	724
19	547	722
20	546	725
21	546	725
22	546	724
23	547	724
24	547	725

REPORT NO. 2 - SULFUR

Sulfur Removal

TEST PERIOD : Design

OPERATING TIME:

Test Day No. 10

Day Ending 0800 9/08/77

Hrs. Operation (Cumulative) 213

Hrs. Operation (This Day) 22

Hrs. Interrupted 2

Hrs. Boiler Availability 24

CONTINUOUS DATA SEQUENTIAL 2 HR. AVERAGES, LBS/HR.

2-Hr. Averages

SO_2

Time	Inlet	Outlet	% Removal
0800-0845	4849	460	91
0845-1100		FGD Interruption	
1100-1200	4951	488	90
1200-1400	4940	475	90
1400-1600	4854	432	91
1600-1800	4733	423	91
1800-2000	4729	437	91
2000-2200	4664	418	91
2200-2400	4643	417	91
0000-0200	4687	430	91
0200-0400	4676	343	93
0400-0600	4705	422	91
0600-0800	4819	472	90

REMARKS: Total test hours failed to date: 4

9/08/77
Date

R. C. Adams
Test Director

REPORT NO. 3 - ASH

Particulate Control

TEST PERIOD: Design

OPERATING TIME:

Test Day No. 10 — Day Ending 0800 9/08/77

Hrs. Operation (Cumulative) 213 — Hrs. Operation (This Day) 22

Hrs. Interrupted 2 — Hrs. Boiler Availability 24

PERFORMANCE:

	Inlet	Outlet
Particulate 3-Hr. Avg., Lb/Hr.	----	44.0
Gr./Acf	0.02	0.02
Emission Rate / $\frac{\text{lb.}}{10^6 \text{ Btu}}$	0.05	

REMARKS:

9/10/77
Date

Test Director

REPORT NO. 4 - COST

Operating Costs

TEST PERIOD: Design

OPERATING TIME:

Test Day No. 10	Day Ending 0800 9/08/77
Hrs. Operation (Cumulative) 213	Hrs. Operation (This Day) 22
Hrs. Interrupted 2	Hrs. Boiler Availability 24

PERFORMANCE:

	Daily	Cumulative
Electric Energy, KWH/hr.	781	765
Steam, mlbs./hr.	64.110	61.885
Total Natural Gas, mcf./hr.	11.292	11.259
Avg. Daily Cost, $	43.91	42.66

(HOURLY STEAM PRESSURE AND TEMPERATURE ATTACHED)

REMARKS:

9/13/77
Date

R. C. Adams
Test Director

REPORT NO. 4 - COST

(Continued)

TEST DAY NO. 10

SEQUENTIAL HOURLY DEMONSTRATION

PLANT STEAM PRESSURES AND TEMPERATURES

	Pressure PSIG	Temperature °F
1	547	725
2	---	---
3	---	---
4	566	722
5	567	722
6	567	722
7	567	723
8	566	723
9	567	722
10	567	722
11	566	723
12	565	723
13	565	723
14	565	723
15	565	723
16	567	723
17	566	723
18	566	723
19	566	723
20	566	723
21	566	724
22	565	724
23	564	725
24	565	725

REPORT NO. 2 - SULFUR

Sulfur Removal

TEST PERIOD: Design

OPERATING TIME:

Test Day No. 11 Day Ending 0800 9/09/77

Hrs. Operation (Cumulative) 237 Hrs. Operation (This Day) 24

Hrs. Interrupted None Hrs. Boiler Availability 24

CONTINUOUS DATA SEQUENTIAL 2 HR. AVERAGES, LBS/HR.

2-Hr. Averages

SO_2

Time	Inlet	Outlet	% Removal
0800-1000	4870	486	90
1000-1200	4935	474	90
1200-1400	4783	440	91
1400-1600	4796	411	91
1600-1800	4675	396	92
1800-2000	4438	367	92
2000-2200	4424	369	92
2200-2400	4415	372	92
0000-0200	4426	380	91
0200-0400	4431	387	91
0400-0600	4588	384	92
0600-0800	4674	398	91

REMARKS: Total test hours failed to date: 4

One boiler feed pump down from about 1830 to 0800. Load at about 60 MW.

9/09/77
Date

R. C. Adams
Test Director

REPORT NO. 3 - ASH

Particulate Control

TEST PERIOD: Design

OPERATING TIME:

Test Day No. 11 | Day Ending 0800 9/09/77

Hrs. Operation (Cumulative) 237 | Hrs. Operation (This Day) 24

Hrs. Interrupted None | Hrs. Boiler Availability 24

PERFORMANCE:

	Inlet	Outlet
Particulate 3-Hr. Avg., Lb/Hr.	----	31.0
Gr./Acf	0.018	0.015
Emission Rate / $\frac{\text{lb.}}{10^6 \text{ Btu}}$	0.04	

REMARKS:

9/10/77
Date

R.C. Adams
Test Director

REPORT NO. 4 - COST

Operating Costs

TEST PERIOD: Design

OPERATING TIME:

Test Day No. 11 — Day Ending 0800 9/09/77

Hrs. Operation (Cumulative) 237 — Hrs. Operation (This Day) 24

Hrs. Interrupted None — Hrs. Boiler Availability 24

PERFORMANCE:

	Daily	Cumulative
Electric Energy, KWH/hr.	732	763
Steam, mlbs./hr.	62.932	61.932
Total Natural Gas, mcf./hr.	11.449	11.268
Avg. Daily Cost, $	43.07	42.68

(HOURLY STEAM PRESSURE AND TEMPERATURE ATTACHED)

REMARKS:

9/13/77
Date

R. C. Adams
Test Director

REPORT NO. 4 - COST

(Continued)

TEST DAY NO. 11

SEQUENTIAL HOURLY DEMONSTRATION

PLANT STEAM PRESSURES AND TEMPERATURES

	Pressure PSIG	Temperature °F
1	567	726
2	567	725
3	567	726
4	569	725
5	569	725
6	571	725
7	571	725
8	569	724
9	569	725
10	570	726
11	571	725
12	571	726
13	568	727
14	569	727
15	570	727
16	570	727
17	568	727
18	567	727
19	568	727
20	569	725
21	573	727
22	572	727
23	573	727
24	573	726

REPORT NO. 2 SULFUR

Sulfur Removal

TEST PERIOD: Design

OPERATING TIME:

Test Day No. 12 | Day Ending 0800 9/10/77

Hrs. Operation (Cumulative) 261 | Hrs. Operation (This Day) 24

Hrs. Interrupted None | Hrs. Boiler Availability 24

CONTINUOUS DATA SEQUENTIAL 2 HR. AVERAGES, LBS/HR.

2-Hr. Averages

SO_2

Time	Inlet	Outlet	% Removal
0800-1000	4714	426	91
1000-1200	4712	443	91
1200-1400	4732	411	91
1400-1600	4767	428	91
1600-1800	4787	464	90
1800-2000	4853	455	91
2000-2200	4819	464	90
2200-2400	4810	448	91
0000-0200	4906	422	91
0200-0400	4872	438	91
0400-0600	4872	444	91
0600-0800	4886	452	91

REMARKS: Test is being extended four additional hours to make up four hours failure.

9/10/77
Date

R. C. Adams
Test Director

REPORT NO. 3 - ASH

Particulate Control

TEST PERIOD: Design

OPERATING TIME:

Test Day No. 12 | Day Ending 0800 9/10/77

Hrs. Operation (Cumulative) 261 | Hrs. Operation (This Day) 24

Hrs. Interrupted None | Hrs. Boiler Availability 24

PERFORMANCE:

	Inlet	Outlet
Particulate 3-Hr. Avg., Lb/Hr.	---	---
Gr./Acf	---	---
Emission Rate / $\frac{\text{lb.}}{10^6 \text{ Btu}}$	---	

REMARKS: No test. High winds - unsafe test conditions.

9/10/77
Date

R.C. Adams
Test Director

REPORT NO. 4 - COST

Operating Costs

TEST PERIOD: Design

OPERATING TIME:

Test Day No. 12 — Day Ending 0800 9/10/77

Hrs. Operation (Cumulative) 261 — Hrs. Operation (This Day) 24

Hrs. Interrupted None — Hrs. Boiler Availability 24

PERFORMANCE:

	Daily	Cumulative
Electric Energy, KWH/hr.	708	758
Steam, mlbs./hr.	64.560	62.191
Total Natural Gas, mcf./hr.	10.875	11.229
Avg. Daily Cost, $	43.39	42.75

(HOURLY STEAM PRESSURE AND TEMPERATURE ATTACHED)

REMARKS:

9/13/77
Date

R. C. Adams
Test Director

REPORT NO. 4 - COST

(Continued)

TEST DAY NO. 12

SEQUENTIAL HOURLY DEMONSTRATION

PLANT STEAM PRESSURES AND TEMPERATURES

	Pressure PSIG	Temperature °F
1	572	726
2	572	725
3	572	724
4	563	725
5	567	724
6	568	724
7	569	723
8	568	723
9	568	723
10	567	723
11	566	724
12	566	724
13	566	725
14	565	724
15	565	725
16	564	725
17	563	725
18	563	726
19	562	726
20	561	726
21	566	726
22	565	726
23	567	727
24	572	727

REPORT NO. 2 - SULFUR

Sulfur Removal

TEST PERIOD: Design

OPERATING TIME:

Test Day No. 13

Day Ending 0800 9/11/77

Hrs. Operation (Cumulative) 265

Hrs. Operation (This Day) 4

Hrs. Interrupted None

Hrs. Boiler Availability 4

CONTINUOUS DATA SEQUENTIAL 2 HR. AVERAGES, LBS/HR.

2-Hr. Averages

SO_2

Time	Inlet	Outlet	% Removal
0800-1000	4890	449	91
1000-1200	4918	439	91

REMARKS: Four hour test to makeup four hours failure. Design test period completed.

9/11/77
Date

R. C. Adams
Test Director

REPORT NO. 4 - COST

Operating Costs

TEST PERIOD: Design

OPERATING TIME:

Test Day No. 13 | Day Ending 0800 9/11/77

Hrs. Operation (Cumulative) 265 | Hrs. Operation (This Day) 4

Hrs. Interrupted None | Hrs. Boiler Availability 4

PERFORMANCE:

	Daily	Cumulative
Electric Energy, KWH/hr.	768	758
Steam, mlbs./hr.	62.340	62.193
Total Natural Gas, mcf./hr.	9.808	11.206
Avg. Daily Cost, $	42.09	42.74

(HOURLY STEAM PRESSURE AND TEMPERATURE ATTACHED)

REMARKS:

9/13/77
Date

R. C. Adams
Test Director

REPORT NO. 4 - COST

(Continued)

TEST DAY NO. 13

SEQUENTIAL HOURLY DEMONSTRATION

PLANT STEAM PRESSURES AND TEMPERATURES

	Pressure PSIG	Temperature °F
1	571	725
2	572	725
3	571	724
4	572	724
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		

REPORT NO. 4 - COST

Operating Costs

12-DAY AVERAGE COSTS

TEST PERIOD: Design

OPERATING TIME:

Test Day No. 1-13	Day Ending 0800 9/11/77
Hrs. Operation (Cumulative) 265	Hrs. Operation (This Day) 4
Hrs. Interrupted 27	Hrs. Boiler Availability 282

PERFORMANCE:

	Daily	Cumulative
Electric Energy, KWH/hr.		757.8
Steam, mlbs./hr.		62.193
Total Natural Gas, mcf./hr.		11.206
Avg. Daily Cost, $		43

(HOURLY STEAM PRESSURE AND TEMPERATURE ATTACHED)

REMARKS:

9/11/77	J. S. C. [illegible]
Date	Test Director

REPORT NO. 6 PRODUCT

By-Product Sulfur Assay

12-DAY AVERAGE

TEST PERIOD: Design

OPERATING TIME:

Test Day No. 1-12	Day Ending 0800 9/11/77
Hrs. Operation (Cumulative) 265	Hrs. Operation (This Day) 4
Hrs. Interrupted 27	Hrs. Boiler Availability [illegible]

PERFORMANCE:

Sulfur Assay, Wt. %S	99.76
Wt. % Ash	0.007
As_2O_3	<5 ppm
Wt. % Carbon	0.11
Wt. % Chlorides	<0.0002
Wt. % Acidity as H_2SO_4	0.0005

REMARKS:

10/3/77
Date

R. C. [illegible]
Test Director

REPORT NO. 5 - SODA

Soda Ash Feed Rate
12-DAY AVERAGE

TEST PERIOD: Design

OPERATING TIME:

Test Day No. 13 | Day Ending 0800 9/11/77

Hrs. Operation (Cumulative) 265 | Hrs. Operation (This Day) 4

Hrs. Interrupted None | Hrs. Boiler Availability 4

PERFORMANCE:

Avg. Soda Ash Consumed, Tons/Day 6.2

REMARKS:

9/11/77
Date

R. C. Adams
Test Director

REPORT NO. 2 - SULFUR

Sulfur Removal

TEST PERIOD: High Load

OPERATING TIME:

Test Day No. 1

Day Ending 0800 9/12/77

Hrs. Operation (Cumulative) 24

Hrs. Operation (This Day) 24

Hrs. Interrupted (1)

Hrs. Boiler Availability 24(1)

CONTINUOUS DATA SEQUENTIAL 2 HR. AVERAGES, LBS/HR.

2-Hr. Averages

SO_2

Time	Inlet	Outlet	% Removal
0800-1000	5665	491	91
1000-1200	5554	419	93
1200-1400	5467	433	92
1400-1600	5513	442	92
1600-1800	5647	469	92
1800-2000	5825	495	92
2000-2200	5778	502	91
2200-2400	5806	551	91
0000-0200	5879	590	90
0200-0400	5860	586	90
0400-0600	6029	548	91
0600-0800	5782	435	93

REMARKS: (1) Boiler down to 55-60 MW for about one hour, 0600-0700. No interruption is charged.

9/13/77
Date

R. C. Adams
Test Director

REPORT NO. 3 - ASH

Particulate Control

TEST PERIOD: High Load

OPERATING TIME:

Test Day No. 1	Day Ending 0800 9/12/77
Hrs. Operation (Cumulative) 23	Hrs. Operation (This Day) 23
Hrs. Interrupted 1	Hrs. Boiler Availability 23

PERFORMANCE:

	Inlet	Outlet
Particulate 3-Hr. Avg., Lb/Hr.	----	41.1
Gr./Acf	0.04	0.02
Emission Rate / $\frac{\text{lb.}}{10^6 \text{ Btu}}$	0.04	

REMARKS:

9/14/77
Date

R. C. Adams
Test Director

REPORT NO. 2 - SULFUR

Sulfur Removal

TEST PERIOD: High Load

OPERATING TIME:

Test Day No. 2 — Day Ending 0800 9/13/77

Hrs. Operation (Cumulative) 48 — Hrs. Operation (This Day) 24

Hrs. Interrupted None — Hrs. Boiler Availability 24

CONTINUOUS DATA SEQUENTIAL 2 HR. AVERAGES, LBS/HR.

2-Hr. Averages

SO_2

Time	Inlet	Outlet	% Removal
0800-1000	6163	553	91
1000-1200	6239	577	91
1200-1400	6568	655	90
1400-1600	7058	660	91
1600-1800	7232	678	91
1800-2000	7218	682	91
2000-2200	7153	713	90
2200-2400	7210	722	90
0000-0200	7213	704	90
0200-0400	7010	775	89
0400-0600	7319	729	90
0600-0800	7469	764	90

REMARKS: Test failed two hours, 0200-0400.

9/13/77
Date

R. C. Adams
Test Director

REPORT NO. 3 - ASH

Particulate Control

TEST PERIOD: High Load

OPERATING TIME:

Test Day No. 2 — Day Ending 0800 9/13/77

Hrs. Operation (Cumulative) 47 — Hrs. Operation (This Day) 24

Hrs. Interrupted None — Hrs. Boiler Availability 24

PERFORMANCE:

	Inlet	Outlet
Particulate 3-Hr. Avg., Lb/Hr.	----	51.9
Gr./Acf	0.05	0.02
Emission Rate / $\frac{\text{lb.}}{10^6 \text{ Btu}}$	0.05	

REMARKS:

9/14/77
Date

R. C. Adams
Test Director

REPORT NO. 2 - SULFUR

Sulfur Removal

TEST PERIOD : High Load

OPERATING TIME:

Test Day No. 3

Day Ending 0800 9/14/77

Hrs. Operation (Cumulative) 72

Hrs. Operation (This Day) 24

Hrs. Interrupted None

Hrs. Boiler Availability 24

CONTINUOUS DATA SEQUENTIAL 2 HR. AVERAGES, LBS/HR.

2-Hr. Averages

SO_2

Time	Inlet	Outlet	% Removal
0800-1000	7199	724	90
1000-1200	7169	723	90
1200-1400	7013	688	90
1400-1600	6937	670	90
1600-1800	6871	652	91
1800-2000	6790	623	91
2000-2200	6639	632	91
2200-2400	6485	632	90
0000-0200	6693	654	90
0200-0400	6880	681	90
0400-0600	7094	673	91
0600-0800	7394	712	90

REMARKS:

9/14/77
Date

R. C. Adams
Test Director

REPORT NO. 3 - ASH

Particulate Control

TEST PERIOD: High Load

OPERATING TIME:

Test Day No. 3	Day Ending 0800 9/14/77
Hrs. Operation (Cumulative) 71	Hrs. Operation (This Day) 24
Hrs. Interrupted None	Hrs. Boiler Availability 24

PERFORMANCE:

	Inlet	Outlet
Particulate 3-Hr. Avg., Lb/Hr.		
Gr./Acf		
Emission Rate / $\frac{\text{lb.}}{10^6 \text{ Btu}}$		

REMARKS: No sample collected - rain.

9/14/77
Date

R. C. Adams
Test Director

REPORT NO. 2 - SULFUR

Sulfur Removal

TEST PERIOD: High Load

OPERATING TIME:

Test Day No. 4

Day Ending 0800 9/15/77

Hrs. Operation (Cumulative) 85

Hrs. Operation (This Day) 14

Hrs. Interrupted None

Hrs. Boiler Availability 14

CONTINUOUS DATA SEQUENTIAL 2 HR. AVERAGES, LBS/HR.

2-Hr. Averages

SO_2

Time	Inlet	Outlet	% Removal
0800-1000	7401	755	90
1000-1200	7253	711	90
1200-1400	7079	675	91
1400-1600	6695	625	91
1600-1800	6428	612	91
1800-2000	6481	605	91
2000-2200	6448	631	90

REMARKS:

9/14/77
Date

B. C. Adams
Test Director

REPORT NO. 3 - ASH

Particulate Control

TEST PERIOD: High Load

OPERATING TIME:

Test Day No. 4	Day Ending 0800 9/15/77
Hrs. Operation (Cumulative) 85	Hrs. Operation (This Day) 14
Hrs. Interrupted None	Hrs. Boiler Availability 14

PERFORMANCE:

	Inlet	Outlet
Particulate 3-Hr. Avg., Lb/Hr.	----	35.8
Gr./Acf	0.04	0.01
Emission Rate / $\frac{\text{lb.}}{10^6\text{ Btu}}$	0.03	

REMARKS:

9/15/77
Date

R. C. Adams
Test Director

REPORT NO. 6 - PRODUCT

By-Product Sulfur Assay

TEST PERIOD: High Load

OPERATING TIME:

Test Day No. 1-4	Day Ending 0800 9/15/77
Hrs. Operation (Cumulative) 85	Hrs. Operation (This Day) 14
Hrs. Interrupted None	Hrs. Boiler Availability 85

PERFORMANCE:

		Corrected
Sulfur Assay, Wt. %S	99.61	99.99
Wt. % Ash	0.005	0.004
As_2O_3	<5 ppm	Not detected
Wt. % Carbon	0.11	0.004
Wt. % Chlorides	0.0002	-
Wt. % Acidity as H_2SO_4	0.0005	-

REMARKS:

10/3/77
Date

R. C. Adams
Test Director

COAL ANALYSIS

Test Period	Test Day	Day Ending 0800	C (Wt. %)	H (Wt. %)	N (Wt. %)	O (Wt. %)	S (Wt. %)	H_2O (Wt. %)	Btu/Lb. HHV	Wt. % Ash
Design	1	8/30/77	59.50	4.10	1.14	7.55	2.61	15.62	10614	9.47
Design	Spot	8/30/77	58.87	4.22	1.12	8.19	2.75	14.48	10566	10.31
Design	2	8/31/77	58.88	4.04	0.76	7.60	2.64	14.88	10509	11.16
Design	Spot	8/31/77	56.41	3.72	0.66	7.51	2.33	13.66	9980	15.67
Design	3	9/01/77	60.07	4.12	1.21	7.50	2.91	13.06	10692	11.09
Design	Spot	9/01/77	60.30	4.04	0.82	7.58	2.94	13.23	10735	11.05
Design	4	9/02/77	59.09	4.01	1.20	6.56	3.20	12.78	10506	13.13
Design	5	9/03/77	58.78	3.97	1.00	7.21	3.23	13.50	10491	12.27
Design	Spot	9/03/77	58.30	3.97	1.18	6.42	3.38	12.23	10351	14.49
Design	6	9/04/77	59.29	4.11	1.03	7.15	2.77	14.95	10524	10.67
Design	Spot	9/04/77	57.71	3.99	1.06	7.77	2.93	14.75	10387	11.76
Design	7	9/05/77	59.29	4.04	1.05	7.55	2.59	14.98	10546	10.47
Design	8	9/06/77	59.42	4.11	1.12	7.58	2.80	15.46	10637	9.48
Design	Spot		59.25	4.12	0.83	7.99	2.67	15.68	10594	9.43
Design	9	9/07/77	59.91	4.08	1.01	7.53	2.75	14.75	10642	9.94
Design	Spot	9/07/77	59.20	4.07	1.01	7.48	2.74	15.76	10540	9.71
Design	5	1000-1200	59.09	4.07	0.78	10.23	2.83	12.60	10569	10.37
Design	5	0800-1000	59.03	4.11	0.97	7.03	3.21	13.39	10527	12.23
Design	10	9/08/77	60.34	4.06	0.74	4.50	3.20	14.26	10708	12.87
Design	Spot	9/08/77	60.09	3.99	0.76	7.17	2.81	14.18	10616	10.98
Design	11	9/09/77	58.81	3.79	1.08	7.17	2.45	15.34	10441	11.35
Design	Spot	9/09/77	60.12	4.16	1.04	7.25	2.87	15.00	10756	9.56
Design	12	9/10/77	60.09	4.09	1.02	7.34	2.60	14.74	10678	10.09

COAL ANALYSIS (CONTINUED)

			Wt. %						Btu/Lb.	Wt. %
	Test	Day	C	H	N	O	S	H_2O	HHV	Ash
Test Period	Day	Ending								
		0800								
High Load	1	9/12/77	60.19	4.15	1.04	7.68	2.76	14.15	10624	10.00
High Load	Spot	9/12/77	59.78	4.09	0.85	7.90	2.75	14.31	10600	10.29
Design	13	9/11/77	60.46	4.04	1.11	7.80	2.84	13.40	10807	10.32
High Load	2	9/13/77	57.79	3.85	1.01	7.44	3.11	11.98	10350	14.80
High Load	Spot	9/13/77	58.41	4.06	1.01	7.66	2.66	13.48	10422	12.69
High Load	3	9/14/77	57.81	3.99	1.01	6.84	3.31	13.02	10321	14.00
High Load	Spot	9/15/77	58.09	4.09	0.80	7.63	3.05	12.67	10413	13.65
High Load	4	9/15/77	59.68	4.10	0.80	7.24	3.20	13.19	10696	11.77

INDUSTRIAL CHEMICALS DIVISION

ANALYSIS CERTIFICATION

Allied Chemical

FROM - LABORATORY Green River Works	DATE SAMPLE RECEIVED July 20, 1977	REFERENCE NO.
Soda Ash Analysis	ANALYSIS DATE July 26, 1977	NO. SAMPLES 2
Allied Chemical Corporation Industrial Chemicals Division PO Box 2006 Hammond IN 46323 Attn; Mike McCoy	SOURCE Railroad Car Loaded ☒ SAMPLE PROPERLY TAKEN ☒ SAMPLE SAID TO REPRESENT MARKED CRDX 6456	

Screen Analysis

U. S. Screen	% Retained
20	.1
30	3.0
40	23.3
60	54.7
100	17.1
200	1.6
-200	.2

TOTAL.................................. 100.0

Density................................ 1024 GPL

Color.................................. 96

Assay as Na_2CO_3.................... 99.79

Impurities

Sodium Chloride (as NaCl)........... .0067 %

Soluble Silica (as SiO_2)............ .0155 %

Organic Matter (as C)............... .0153 %

Iron (as Fe)........................ .0003 %

CERTIFIED BY: L. O. Johnson

DATE 7-26-77

APPENDIX B

TEST METHODS

I. SO_2 REMOVAL EFFICIENCY DETERMINATION

A) Analysis methods used by continuous analyzers to measure gaseous components which determine the removal efficiency:

1. SO_2 (in/out) was determined by using a split beam ultraviolet photometric detector.

2. CO_2 (in/out) was determined by non-dispersive infrared detection using nitrogen as the reference gas.

3. H_2O (in/out) was determined by non-dispersive infrared detection using nitrogen as the reference gas.

B) Sulfur in coal analysis was done using ASTM Standard Method D271.

C) Calibration of the three continuous analyzers used to determine SO_2 removal efficiencies was performed on a daily basis using the following calibration gases:

	Zero	Span
SO_2	N_2	260 ppmv SO_2 in N_2 (low span) 2690 ppmv SO_2 in N_2 (high span)
CO_2	N_2	75% by volume CO_2 in N_2
H_2O	N_2	Pure C_2H_6 giving 62.5% of full scale

D) Manual sampling of the inlet flue gas stream (sample point was at the discharge of the boiler ID fans) was done using a modified EPA Method 6 testing procedure whereby one point, non-isokinetic sampling was used for SO_2 determination.

E) FGD plant analyzer was calibrated daily using ambient air as the source of zero gas and an optical filter system for spanning the instrument.

F) Calculation of the SO_2 removal efficiency for the Design Test was performed using the following method:

1. Average gas concentrations were calculated for inlet and outlet SO_2, inlet and outlet CO_2, and inlet and outlet H_2O for each 2-hour period, beginning at 0800 hours each day.

2. Average stack temperatures and static pressures were found for the same 2-hour periods.

3. Flue gas flow rates (assumed to be at the measured inlet conditions to the scrubber) were corrected to 70°F and 29.92" Hg. for each 2-hour period.

4. SO_2 mass rates at the inlet for each 2-hour period were calculated by multiplying the average inlet SO_2 concentration by the corresponding flue gas flow rate and then multiplying this quantity by the density of SO_2 (0.1665 lb/ft^3 @ 70° F and 1 atm.)

5. Flue gas flow rates at the outlet for each 2-hour period were corrected for air inleakage and water pickup by using the following equation:

$$VSTD = \frac{(VSTDI)\ (CO_2I)\ (100-H_2OI)}{(CO_2O)\ (100-H_2OO)}$$

where:

VSTD = outlet flow rate, ft^3/hr
VSTDI = inlet flow rate, ft^3/hr
CO_2I = inlet CO_2 concentration, vol. %

CO_2O = outlet CO_2 concentration, vol. %
H_2OI = inlet H_2O concentration, vol. %
H_2OO = outlet H_2O concentration, vol. %

6. SO_2 mass rates at the outlet for each 2-hour period were calculated by multiplying the average outlet SO_2 concentration by the corresponding flue gas flow rate and then multiplying this quantity by the density of SO_2 (0.1655 lb/ft^3 @ 70°F, 1 atm.).

7. SO_2 removal efficiency for any 2-hour period was then given by:

$$\% \text{ removal} = 1 - \frac{(SO_2 \text{ mass rate, outlet})}{(SO_2 \text{ mass rate, inlet})}$$

II. PROCESS CONSUMABLES

A) Natural gas flow rates were measured using the FGD plant factory-calibrated flow nozzles and pressure differential transducers which were calibrated on a routine basis. Natural gas heating values were obtained from NIPSCO from calorimetric analysis.

B) Kilowatt-hour measurements were taken from the FGD plant meter which were calibrated by the NIPSCO Meter Department.

C) Steam flow rates were measured using pressure differential transducers and factory-calibrated flow nozzles. The transducers were calibrated by applying known pressure differentials across the transducer and verifying correct output.

D) Steam temperature and pressure were measured using thermocouples and differential pressure sensors, respectively. Temperature sensors were calibrated by thermocouple disconnect at the recorder input, application of a known DC potential across the input, and verifying correct output. Pressure sensor calibration was performed using dead weight testers.

E) Steam temperature, pressure, and flow were reported on an hourly basis derived from twenty 3-minute averages taken during the hour.

F) A correction to steam flow rate based on measured temperature and pressure was derived empirically. The equation for determining corrected steam flow, in lb/hr., is as follows:

$$W_c = W \frac{(-1.3759 \times 10^{-6}\ T^2) + (2.3391 \times 10^{-3}\ T) + .11237}{\sqrt{(1.25 \times 10^{-3}\ T) - (2.21 \times 10^{-3}\ p) + 1.5525}}$$

where:

W_c = corrected flow rate, lb/hr

W = indicated flow rate, lb/hr

T = steam temperature, °F

p = steam pressure, psig

III. SODA ASH

A) Soda ash consumption figures were provided by Allied Chemical along with a certificate of analysis for Na_2CO_3 content. Based on this analysis, the soda ash consumption rate was converted to a pure Na_2CO_3 consumption rate and reported as Na_2CO_3 consumed.

IV. SULFUR PRODUCT PURITY

A) A sample from each truck shipment was collected by Allied Chemical personnel. Shipments were at a frequency of about one a day. To prepare a laboratory sample; portions from each sample increment were split off, pulverized, and mixed by quartering. Two samples were prepared in this fashion; one for the Design Load phase and one for the High Load phase.

B) The samples were analyzed by Commercial Test and Engineering Company laboratories, using methods for bright sulfur supplied by Allied Chemical.

V. PARTICULATE MATTER

A) Sampling was done both at the inlet and outlet of the absorber in accordance with EPA Method 5, Federal Register, August 18, 1977 using 24 traverse points.

B) Sampling during both the Design Load test and the High Load test was normally scheduled to begin between 0800 and 0900 hours with completion usually 4.5 hours after commencement. During the period of manual sampling, coal samples were taken every 7.5 minutes with a composite sample made up at the end. Also, boiler and FGD process readings were taken both at the beginning and end of the manual sampling period.

C) Particulate matter was determined by the following methodology:

1. Dessicate needed quantity of Gelman, Type A-E, Glass-Fiber filter paper for at least 24 hours.
2. Weigh each filter and obtain weight to nearest 0.0001 gram.
3. Place weighed filter in labeled holder.
4. Transport filters and holders in dessicator to sampling site, avoiding any contamination of filter.
5. After use in sampling train, dessicate filter for at least 24 hours.
6. Weigh filter and obtain weight to nearest 0.0001 gram.
7. Obtain subtotal of particle weight by difference.
8. Add to this, weight of particulate matter washed out of sampling line from probe inlet to the filter using acetone (acetone was driven off by heating on hot plate set to 40°C).

VI. SO_2 BY MANUAL METHODS

A) Sampling was carried out by a modified EPA Method 6 (42 FR 41754, August 18, 1977). The method was modified to increase the absorbing reagent supply so that the sampling could cover the entire period of particulate matter sampling, about 4.5 hours. The collecting hardware was modified from a midget impinger train to a full sized impinger train in order to use the Method 5 EPA train for both particulate and sulfur oxides. Instead of distilled water in the impingers, the first impinger contains 80% isopropanol (SO_3 absorption), the second and third impingers contain 3% hydrogen peroxide (SO_2 absorption), and a fourth impinger is for silica gel.

B) The analysis for SO_2 is a barium-perchlorate titration with thorin end-point indicator after the SO_2 is oxidized to SO_3 by the peroxide absorbing solution.

C) Flow determination was accomplished in accordance with EPA Method 2, Federal Register, August 18, 1977.

D) Moisture and dry molecular weight determinations were performed by gas chromatograph analysis (using an AID GC-TC) which is an accepted substitute method for both EPA Methods 4 and 3, Federal Register, August 18, 1977.

VII. FLUE GAS SAMPLING BY THE CONTINUOUS SAMPLING TRAIN

A) Flue gas was sampled at both the NIPSCO outlet and the absorber outlet. In-stack filters, with a filter surface of a porous metal removed particulates of 5 micron diameter or greater. To prevent degradation of the gaseous sample, the sample was delivered to the sensor system in a heated process line. At the NIPSCO outlet, the line was mainteined at 300°F. At the absorber outlet, a temperature of 150°F was maintained. The sample line was 3/8" TFE. The chemical inactivity of this line prevented degradation of the flue gas. The electrically traced process line interfaced with the in-stack filter at the duct and interfaced with the SO_2 analyzer in the continuous monitor installation. Blowback of the sample lines was initiated at the SO_2 analyzer to occur once every 6 minutes.

B) Flow control through the continuous sampling system was on a dual-pressure basis. The SO_2 and H_2O vapor analyzers operated on a partial vacuum flow system, while the remainder of the instruments used a positive pressure flow system. Wet sample gas was supplied to the SO_2 analyzer at a rate of 5 scfh and was pressure-controlled internally at the analyzer to ensure proper readings. Wet sample gas was supplied to the H_2O vapor analyzer at the rate of 10 scfh and flow to the analyzer was controlled internally by a separate pump. The sample gas stream not used by the H_2O vapor analyzer then was pumped under positive pressure through a condenser and then supplied to the CO_2 and O_2 analyzers on a dry basis.

VIII. COAL SAMPLING

A) Coal was sampled by the NIPSCO coal handler from the coal hoppers to make composites of raw coal, using sampling probes designed by NIPSCO. One gross sample per 4-hour spot test was composited from increments taken every 7.5 minutes, while one gross sample per 24-hour period was composited from increments taken every hour over the 24-hour sampling period, except the hours when a manual sample was being run. During the hours of manual sampling, the hourly increment for the 24-hour composite was made up of equal portions of the sample taken at 7.5 minutes after the hour and the sample taken at 22.5 minutes after the hour. Each incremental sample taken was stored in a plastic bag and sealed with ties to minimize moisture loss. To make the composite sample, equal quantities from each incremental sample were riffled together, forming a composite sample. Portions of the composite were then stored in mason jars, one of which was submitted for analysis. The coal handler was instructed when to begin and end the manual test period, thus ensuring continuous sampling even when the manual testing took longer than the planned time frame.

APPENDIX C

FLUE GAS FLOW COMPARISONS

DEMONSTRATION OF WELLMAN-LORD/ALLIED CHEMICAL FGD TECHNOLOGY: Flue Gas Flow Comparisons

by

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SECTION 1

SUMMARY AND CONCLUSIONS

A limited series of flue gas measurements were made with the FGD plant completely isolated from the boiler. The objective was to compare present day flue gas rates with those obtained during the Baseline Test. These data would be of help in confirming that the flows during the Acceptance Test were providing a fair test of the performance of the FGD unit.

Test results are summarized as follows:

(a) At a gross load on the boiler of 92 MW, the flue gas flow was 400 MCFM compared with an average of 369 MCFM during the Baseline Test in 1974, an increase of about 7% after correcting for load differences. The increase seems to be largely due to an increase in heat input to the boiler, which was 12% higher than during the Baseline Test, and the corresponding increase in fuel rate.

(b) At a gross load of 81 MW, which is the megawatt equivalent of total main steam produced by the boiler during the design load phase of the Acceptance Test, the measured values averaged 399 MCFM which was virtually the same as the flue gas volume measured at 92 MWG. However, flows calculated from fuel composition and rate and excess air levels correlated fairly well with load. Using calculated values, flow rates during the Acceptance Test were slightly higher but within 5% of the Baseline Test measurements.

(c) It is concluded from these results that actual flow rates during the Acceptance Test were higher than the 320 MCFM and 388 MCFM specified for the performance runs and also were not less than the flue gas volumes experienced during the Baseline Test.

(d) The data collected to determine boiler heat input during these flow tests and during the Acceptance Test suggest a loss of boiler efficiency since the baseline testing in 1974. Increased flue gas flows would be one result of a decrease in efficiency. The combined data of the flow tests and the Acceptance Test show that heat input is about 7% higher than during the Baseline Test.

(e) Based on samples of ash collected from the precipitator hoppers, heat losses due to unburned carbon were found to be less than 0.5% of the total heat input.

SECTION 2

TEST RATIONALE

The flow measurements were made to compare present flue gas flow rates with the baseline flue gas flow rates. Just prior to the Acceptance Test, it was found that the apparent flue gas rates at 92 MW (FGD design load) were much higher than expected. As a consequence, it was necessary to test FGD performance during the Acceptance Test at the design flue gas rate of 320,000 acfm rather than at 92 MW load. The resulting gross load was only 72 MW. Adding the steam consumed by the FGD plant to the steam equivalent of 72 MW, the load equivalent of the total steam produced by the boiler was 81 MW or only 88% of the design load. Furthermore, during the Acceptance Test, it was necessary to rely on flow estimates derived from the speed and fan curves of the booster fan. This was necessary because of an apparent bias error in the flow measurements which was a result of limited lengths of straight duct available for measurement. These uncertainties have brought into question whether or not enough gas was being treated during the Acceptance Test to provide a fair test of the performance of the FGD process.

The testing described in this report was designed to determine if at a given load the flue gas flow rates of the Baseline Test could be repeated. This was accomplished by completely isolating the FGD plant from the boiler and then making the flow measurements at the location used for baseline testing. At the same time, coal rates and compositions, steam and feed water rates, and other pertinent boiler operating data were collected with the assistance of NIPSCO's Results Department personnel. The Results Department also collected data for a boiler heat balance and for air heater inleakage tests but these results are not a part of this report. Fly ash samples were also collected to determine the amount of unburned carbon present.

SECTION 3

RESULTS AND DISCUSSION

RESULTS AT 92 MEGAWATTS GROSS

Flue gas flow measurements were made at two levels of load; about 92 MW (FGD design load) and about 81 MW. The latter load represents the Acceptance Test design load operating condition. At 91.3 MW gross, the flue gas rate was 400 MCFM. (All flue gas rates in this report are corrected to 300°F and 29.92" Hg absolute pressure.) For six tests during the Baseline Test, the flue gas rate varied from 297 MCFM to 411 MCFM at an average load of 90.0 MWG. Of this data, the measurements made in conjunction with ASME particulate matter sampling were more consistent and varied from 357 MCFM to 385 MCFM for an average value of 369 MCFM. The present operating condition at a nominal 92 MWG compared with the baseline condition are summarized in Table 1:

TABLE 1. PRESENT OPERATING CONDITIONS VS. BASELINE AT 92 MW GROSS

	Average of Six Baseline Tests (1974)	Present Condition (10/5/77)	Percent Diff.
Flue Gas Rate, MCFM (300°F, 29.92 in. Hg)	369	400	+8.4
Gross Load, MW	90.0	91.3	+1.4
Coal Rate, lb/hr.	81,000	96,800	+19.5
Boiler Heat Input, MM Btu/hr.	908	1016	+11.9

The data of Table 1 show that more fuel is being consumed now than during the Baseline Test. It is apparent that flue gas volumes would have to increase with the fuel rates. How much increase is dependent on the combustible component and water contents of the coal and on the amount of excess air. The

Baseline Test flue gas rates have been calculated from the measured coal compositions and excess air levels and plotted on Figure 1. For 91.3 MWG, the baseline flue gas rate is calculated to be 350 MCFM compared to a calculated rate of 412 MCFM at 91.3 MWG during the recent flow tests. The corresponding measured values agree within 10% of these calculated flue gas rates.

RESULTS AT 81 MEGAWATTS GROSS

Flows were also measured at about 81 MW which was the operating level for performance testing at the design rate of the FGD plant. The average of two flow measurements at 81.8 MWG was 399 MCFM, or virtually the same as the flow measured at 91.3 MWG. Obviously, there should be a decrease in flue gas rate with decreasing load. However, we were attempting to measure flows at two levels which varied by only about ten percent and a measurement error band of ± 10% is to be expected for the method used. Table 2 compares the operating conditions at the two load levels.

TABLE 2. PRESENT OPERATING CONDITIONS AT TWO LOAD LEVELS

	Baseline Test Comparison	12-Day Acceptance Test Comparison	Percent Diff.
Gross Load, MW	91.3	81.8	-10.4
Flue Gas Rate, MCFM	400	399	<1.0
Coal Rate, lb/hr.	96,800	87,900	-9.2
Boiler Heat Input, MM Btu/hr.	1016	898	-11.6

Better correlation at varying operating levels is obtained with calculated flue gas flows, see Figure 2. Both measured and calculated flue gas rates are plotted as functions of the measured heat input to the boiler. These correlations show that present flue gas rates are not substantially greater than the Baseline Test results but that all flue gas volumes, including the baseline results, are substantially above the 320 MCFM and 388 MCFM specified for the Acceptance Test. For example, the average boiler heat input during the

FIGURE 1. BASELINE TEST FLUE GAS FLOWS - CALCULATED

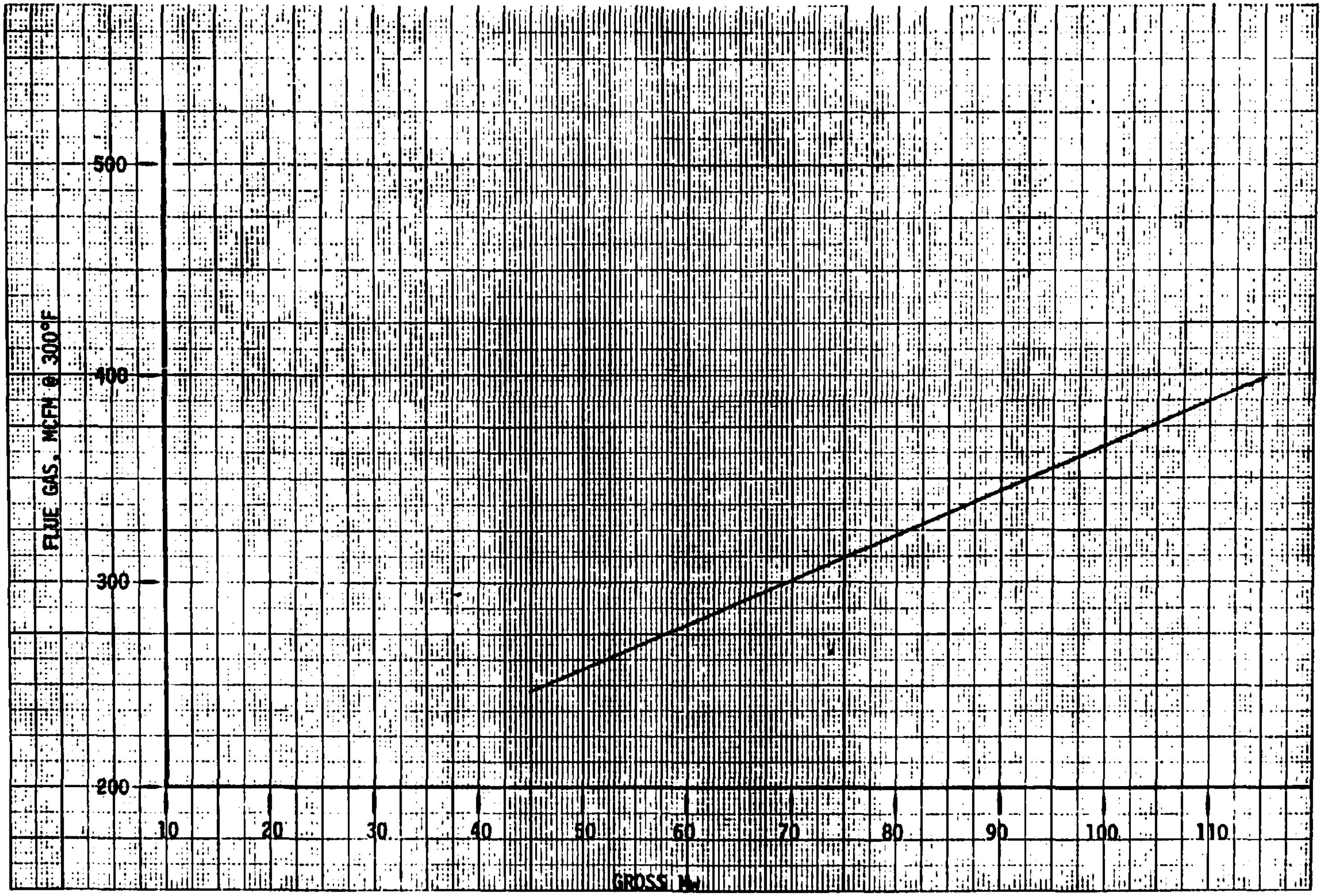
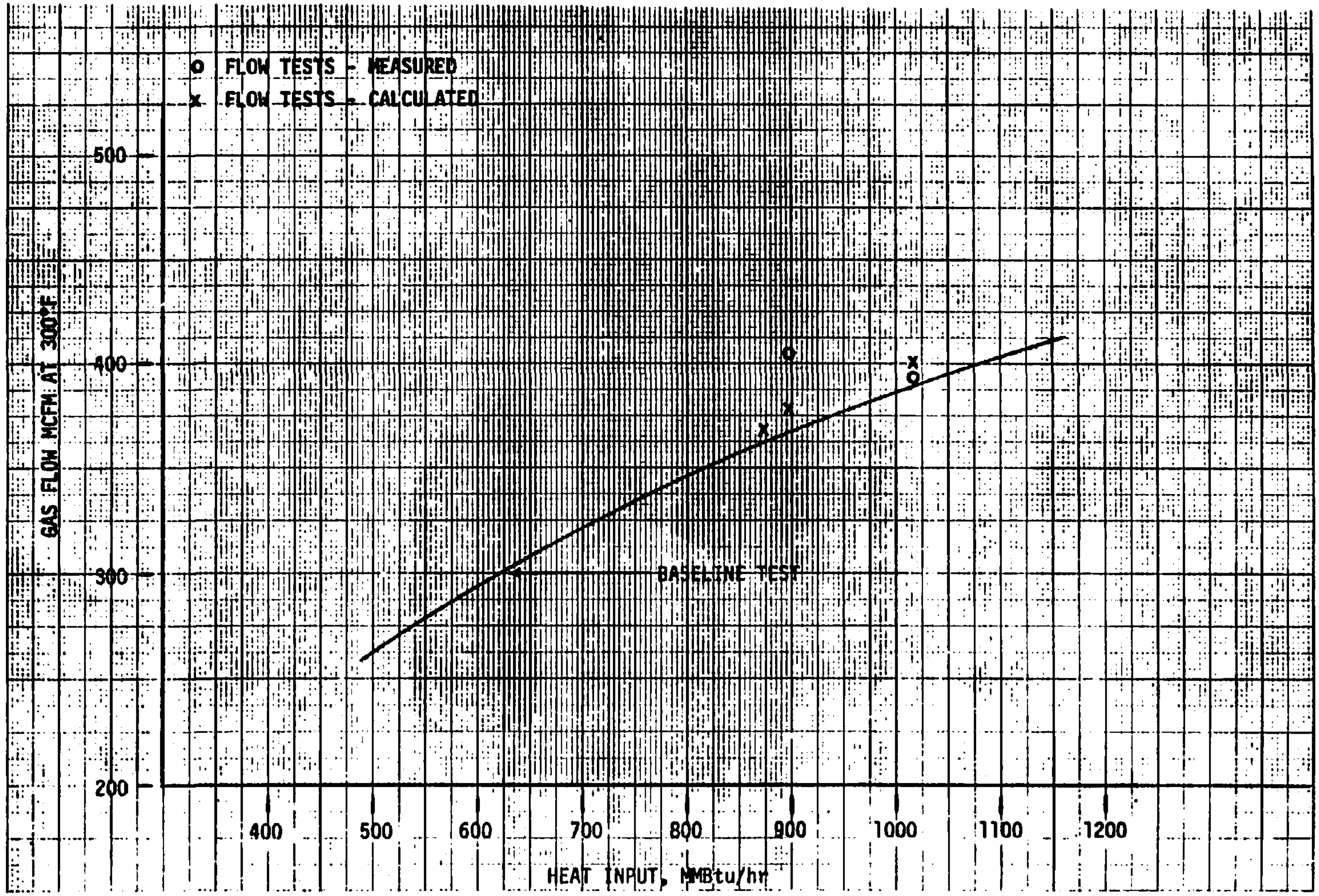


FIGURE 2. FLUE GAS FLOW VERSUS BOILER HEAT INPUT



Acceptance Test at design load was 885 MM Btu/hour. At this boiler heat input, baseline flue gas flow rate was 365 MCFM and present flow rates are slightly higher but within 5% of the baseline value.

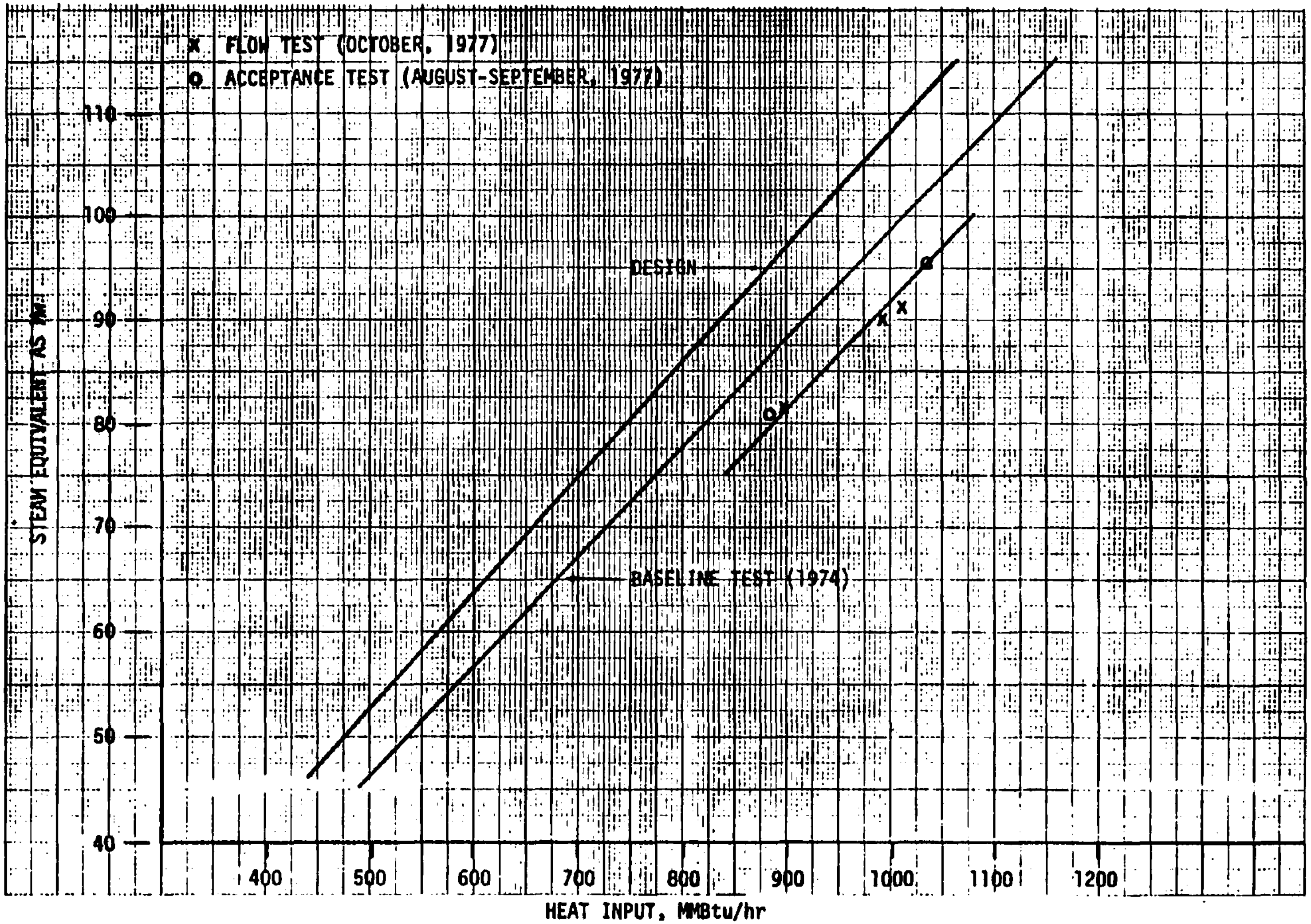
BOILER PERFORMANCE

The higher than expected flue gas rates are due in part to a higher than expected input heat requirement for the level of megawatts generated. The gross megawatts as a function of heat input are shown on Figure 3. On the average, the combined flow test and Acceptance Test heat input data are about 7% higher than the boiler heat inputs encountered in 1974 during the baseline testing.

HEAT LOSSES DUE TO UNBURNED CARBON

To determine if there was a significant loss of heating value due to unburned fuel, two samples of ash were collected from the precipitator hopper and analyzed for combustible content. Loss on ignition was 1.4% and 2.9% of the ash for the two ash samples. Assuming that the corresponding combustible content is carbon, the associated heat loss would be less than 0.5% of the total heat input.

FIGURE 3. MEGAWATTS GENERATED VERSUS BOILER HEAT INPUT



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16. ABSTRACT The report gives results of acceptance tests of Wellman-Lord/Allied Chemical flue gas desulfurization (FGD) technology. Process performance guarantees were met or exceeded. During the 12-day Design Load test, the plant was operated at the design condition of a boiler flue gas output rate equivalent to 80% of the maximum boiler load of 115 MW gross. During the 83-hour High Load test, the plant treated flue gas volumes equivalent to 95% of maximum boiler load. SO2 removal of 90% or better was achieved. Particulate emissions did not exceed 0.1 lb/million Btu of boiler heat input. The consumption of steam, natural gas, and electrical power was less than the performance guarantee requirements at Design Load conditions. Soda ash consumption was less than the limit set by the performance guarantees. Finally, sulfur product purity was greater than 99.5%.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Air Pollution	Air Pollution Control	13B
Flue Gases	Stationary Sources	21B
Desulfurization	Particulate	07A,07D
Dust	Wellman Lord	11G
Sodium Carbonates	Allied Chemical	07B

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