ENVIRONMENTAL PROTECTION AGENCY
OFFICE OF ENFORCEMENT

EPA-330/2-77-023

Evaluation Of Particulate Control System
Cherokee Station
Public Service Company Of Colorado
Denver, Colorado

(July 27 - August 31, 1977)

NATIONAL ENFORCEMENT INVESTIGATIONS CENTER
AND
REGION VIII
DENVER, COLORADO

NOVEMBER 1977

ENVIRONMENTAL PROTECTION AGENCY
Office of Enforcement
EPA 330/2-77-023

EVALUATION OF PARTICULATE CONTROL SYSTEM

CHEROKEE STATION
PUBLIC SERVICE COMPANY OF COLORADO
DENVER, COLORADO

(July 27 - August 31, 1977)

November 1977

National Enforcement Investigations Center - Denver
and
Region VIII - Denver

CONTENTS

Tables

Figures

I. INTRODUCTION

The Cherokee Station powerplant in suburban North Denver is owned and operated by Public Service Company of Colorado (PSCC). It has four base-loaded coal- and/or gas-fired steam generators with a total electrical generating capacity (gross) of 775 megawatts (MW).

BACKGROUND

The Colorado Air Pollution Control Regulation No. 1.A.1 requires that *no person shall emit an air contaminant in excess of 20% opacity.* It also allows for a condition called 'upset' which is *an unpredictable equipment failure or other malfunction which results in the violation of an emission control regulation, and which is not due to improper or careless operation.* An 'upset' is not considered a violation of the Regulation if it is immediately reported to the Air Pollution Control Division of the State of Colorado Department of Health.

Although equipped with extensive air pollution control equipment such as mechanical collectors, electrostatic precipitators (ESP's), and scrubbers, the Cherokee plant has a long history of opacity excursions.* The Company attributes these excursions to control equipment operation and maintenance problems and states that every reasonable effort is made on a continuing basis to correct and prevent such problems. However, the opacity excursions have continued.

In June 1977, the Environmental Protection Agency's (EPA's) Region VIII in Denver requested that the National Enforcement Investigations

* *This report uses the term 'excursion' to describe an emission in excess of 20% opacity.*

Center (NEIC) evaluate the design, operation and maintenance of the Company's air pollution control equipment. Region VIII also notified the Public Service Company of Colorado that NEIC would conduct visible emission observations (VEO's) of the Cherokee Station powerplant (off the property) for 1 1/2 months. In a conference between Company officials and attorneys and EPA representatives, NEIC personnel explained that a process evaluation would be conducted concurrent with the VEO's; the Company thus granted EPA permission to enter the plant.*

STUDY OBJECTIVES

The objectives of the NEIC evaluation were as follows:

First, determine the cause of reported emissions of >20% equivalent opacity by evaluating the design, operation, and maintenance of the air pollution control equipment.

Second, determine the accuracy of the in-stack opacity monitors by evaluating the meter capabilities, their location, and the Company procedures in calibrating and maintaining the meters.

Third, conduct visible emission observations (VEO) in conjunction with the above objectives.

Fourth, suggest ways to improve reliability of the particulate control system.

---

* *The Company allowed plant entry at any time under the following conditions: during normal working hours, those entering were to sign the plant's visitor book, contact the senior results engineer or his assistant; on off-duty hours, they were to sign in and then report to the shift supervisor.*

The evaluation involved an intensive in-plant observation period in July-August 1977 to collect data on boiler operation, air pollution control equipment, opacity meters, and visible emissions. Additional VEO's were taken in October 1977. (Evaluation data are in Appendix A, and the visible emission data are summarized in Appendix B.) NEIC personnel also observed routine adjustment of the control equipment by the Company and inspected the ESP's and scrubbers when they were removed from service. To further evaluate scrubber operation, design and operating data were compared with literature references.

This report uses the terms availability and reliability to describe operation of the particulate control equipment. Availability, as defined by PSCC is:

$$\text{Availability} = \frac{\text{Scrubber hours operation - hours boiler burning 100\% gas}}{\text{Boiler hours operation - hours boiler burning 100\% gas}}$$

Reliability, as used in the report is defined as the percent of time the boiler is on-line that the particulate control systems are operating and meeting applicable particulate regulations.

II. SUMMARY AND CONCLUSIONS

The National Enforcement Investigations Center (NEIC) evaluated in detail the design, operation and maintenance of the Cherokee Station air pollution control equipment during July and August 1977. The evaluation included equipment inspections and in-plant observations of the electrostatic precipitators, scrubbers, and opacity meters, as well as visible emission observations.* NEIC also suggested ways to improve the reliability of Cherokee's particulate control equipment.

ELECTROSTATIC PRECIPITATOR EVALUATION

Evaluation of the ESP's was hampered because NEIC was not able to determine if, or to what extent, the gas conditioning agent was being added to the boiler offgases. This made it difficult to interpret the electrical operating parameters, such as the cause of low power input. However, information was obtained on the design, operation and maintenance of the ESP's, along with results of tests run by PSCC between 1965 and 1976.

The ESP's were designed for collection efficiencies of 87 to 94% and the design parameters are comparable to other fly ash ESP's designed in the late 1960's for collection efficiencies of 80 to 90%. A review of the design and operating data indicates these precipitators are undersized if more efficient collection (>90%) of the fly ash is required.

Early test results on the ESP efficiencies indicated that these units are operating at lower than design efficiencies (shown in parentheses), with typical values reported by PSCC as:

---

* *Additional VEO's were made in October 1977, and are included in the VEO summaries contained in Section VI and Appendix B of this report.*

Unit 1 - 50% (90%)	Unit 3 - 51% (87%)
Unit 2 - 89% (94%)	Unit 4 - 42% (87%)

These values are five years old, and data on present ESP efficiencies were not available for this study.

Since the outlet loadings from recent tests conducted by the Company are in the same range as the previous efficiency tests, an increase in ESP efficiency is unlikely. Thus, the efficiencies reported above are considered representative of the ESP operations. Because the coal quality and the effectiveness of the gas conditioning system would affect these efficiencies, additional tests would be needed to update these ESP efficiencies.

The electrical operating data indicate that the ESP's are operating at lower power inputs than typical fly ash precipitators, and of the four ESP's at Cherokee, the Unit 1 ESP had the lowest power input. Possibly the Sulfan system on Unit 1 was not operating properly. This was indicated by the Unit 1 ESP controls which appeared to be spark rate limited, causing a reduction in power input. Higher power inputs typically would increase the ESP collection efficiencies.

Although the precipitators are tuned every day during the normal work week, the effectiveness of this procedure could not be determined for two reasons. First, Company representatives indicated that no data is recorded by the electricians during tuning; second, specific values of the normal and abnormal conditions were not identified. In addition, the meter readings on Unit 3 ESP are suspect, since the power efficiencies of the transformer-rectifier sets were greater than "1" in most cases.

The maintenance of the ESP's was adequate. Most of the maintenance on both ESP's and mechanical collectors is done as needed. The maintenance is conducted during Unit outages unless the opacity meters read

>20% as a result of the problem, then a priority is placed on the maintenance for immediate repair. When a wire in an ESP is grounded, a load reduction is scheduled, usually within a week, and the wire is removed.

The internal inspections on the Unit 3 and 4 ESP's did not reveal any severe mechanical problems such as misaligned electrodes, warped plates, corroded internals, etc. The Company personnel conducted the inspection in a knowledgeable and thorough manner.

SCRUBBER EVALUATION

Wet scrubbers were installed on Units 1, 3 and 4 to supplement particulate control of the existing mechanical collectors and electrostatic precipitators. The scrubbers are Turbulent Contact Absorbers (TCA) designed by Universal Oil Products, Air Correction Division. PSCC incorporated significant improvements in the Unit 4 scrubbers after installing Unit 1 and 3 scrubbers. These included indirect reheat, individual scrubber booster fans for each scrubber section, three recirculating slurry pumps per scrubber section, and weather enclosures. Unit 4 is also operated so that at least one scrubber section is always available as a spare. Units 1 and 3 have scrubber sections with only one recirculating slurry pump, and operate without spare scrubber sections. The effect of these improvements has been that Unit 4 normally meets the opacity regulation and with better reliability than Units 1 and 3.

PSCC is required by Colorado regulations to report air pollution control equipment upsets. Although the availability of previous upset data was limited, some generalizations on scrubber upsets can be made. Scrubber availabilities, i.e. scrubber operating time as a percentage of boiler operating time, from startup date to May 1977 were: Unit 1 (65%), Unit 3 (63%) and Unit 4 (84%). The major areas of malfunction for the Unit 1 and 3 scrubbers, in approximate order of importance are the in-line reheaters, scrubber internals, recirculating slurry system, and recirculating slurry pumps. Most of the Unit 4 scrubber upsets were caused by the scrubber booster fans. The differences in scrubber availabilities and major problem areas between units are mainly due to the differences in the scrubber system design.

To further document existing scrubber conditions a thorough internal inspection was made of the Unit 3 scrubber during a scrubber outage in August 1977. Numerous problems were observed in the inspection, including: large accumulations of solids in the presaturator, poor mobile ball distribution, numerous plugged recirculating slurry nozzles, and extensive corrosion in the outlet ductwork. Many of these deficiencies would result in reduced particulate removal and create the possibility of exceeding particulate regulations. In addition, it was observed that scrubber instrumentation data taken prior to the inspection may not adequately indicate problems such as solids deposits, ball migration, or pluggage of recirculating slurry nozzles. Therefore, it appears that the scrubbers could be operated at reduced particulate removal before the need for scrubber internal repairs was recognized.

An evaluation of the performance of the scrubbers was made from operating data accumulated in previous tests and during the in-plant inspections. Based on visible emission observations, stack tests, and particulate removal efficiency results, the scrubbers on all units are capable of meeting particulate regulations, however, they do not meet these standards on a continuous basis. This is due in part to the fact that scrubbers are frequently operated at higher-than-design gas velocities, at low pressure drops indicative of gas channeling, and with low liquid flow rates.

Effects of operation outside of design conditions are difficult to quantify but can be discussed in qualitative terms. At high gas velocities, increased liquid entrainment and overall particulate emissions can be expected. When gas channeling is occurring, the scrubbers' particulate removal efficiency is reduced, which will result in increased particulate emissions. Low liquid flows are especially significant when the only recirculating slurry pump in a single-pump scrubber section is out of service. Continued operation without recirculating slurry drastically reduces particulate removal and can damage scrubber internals. It is expected that the opacity standard is more stringent than the process weight standard and that maintaining consistent compliance with the opacity standard will require operating closer-to-design requirements.

With minor exceptions, the thoroughness of scrubber maintenance appeared acceptable. Company personnel conducted the scrubber inspections in a knowledgeable and thorough manner, and the required repairs appeared to be adequately carried out. However, the frequency of maintenance (for Unit 1 and 3 scrubbers) depends to a major degree on operation of the boilers. Since scrubber instrumentation may not reliably indicate internal scrubber problems, limited maintenance frequency could result in scrubbers operating under conditions where particulate removal is low and standards are not being met. Furthermore, it is expected that the frequency of maintenance required to keep the scrubbers in good operating condition will vary with the type of coal being burned, the operation of the boiler, and the effectiveness of the gas conditioning system. It would be difficult to define an optimum maintenance schedule.

Based on the upset reports and equipment inspections, the following areas account for major operating problems in the scrubbers: breakage and migration of mobile ball contactors; malfunctions with the guillotine dampers, recirculation pumps, reheater sections, recirculation piping and nozzles, scrubber booster fans, and mist eliminators; presaturator buildup; weather related problems; and outlet ductwork. It is difficult to evaluate the exact impact of each of these since many are interrelated or one can affect another. It is important to note, however, that most of these problems have existed from startup and, so far, the Company's attempts to eliminate them have met with little success. Furthermore, the Company's ongoing efforts will probably have minimal effect on increasing scrubber reliability.

OPACITY METERS EVALUATION

Daily operation and maintenance for all the opacity meters follow manufacturers' recommendations. However, even with proper operation and maintenance, the Bailey Bolometers on Units 1, 2 and 3 were out of calibration because the span was foreshortened on all three meters. In addition, these meters are not reading exit stack opacities because of the path length difference at the meter and at the stack exit.

The Lear-Siegler meter on Unit 4 was not calibrated by NEIC, but the meter readings compared closely to the stack opacity readings.

The recording and reporting of excursions over the 20% limit of the Colorado regulation is hampered by having opacity meter readings that do not reflect stack exit opacities. Any reliability requirement for the particulate control equipment depends on accurate operation of the opacity meters to read stack exit opacities and detailed reporting requirements and record keeping by PSCC and the control agencies involved.

VISIBLE EMISSION OBSERVATIONS

The Colorado Air Pollution Control Regulation No. 1.A.1 requires that *no person shall emit an air contaminant in excess of 20% opacity.* An upset condition is defined as *an unpredictable equipment failure or* *malfunction which results in the violation of an emission control regulation, and which is not due to improper or careless operation.* Upset conditions are deemed not to be in violation of these regulations if immediately reported to the State Air Pollution Control Division.

VEO's were taken during the July - August evaluation period with additional observations taken in October 1977.

The NEIC procedure used in all observations made in July and August was as follows: A member of the Process Control Branch entered the plant and recorded the operation of the equipment before and after a VEO was taken. A member of the Field Operations Branch would take a VEO following Method 9 from a location outside the plant's property at a scheduled time established in advance with the Process Control member.

Of the 92 VEO's taken for a period of 6 minutes or more, 51 were recorded in excess of 20% average opacity. There were 1,374 individual readings (a reading is taken every 15 seconds during a VEO), taken during the 51 observations of which 1,135 (83%) exceeded 20% opacity, the limit prescribed by the Colorado Air Pollution Control Regulations. Of the readings in excess of 20%, 605 were recorded on the Unit 1 and 2 stack, 334 on the Unit 3 stack and 196 on the Unit 4 stack. Although the fewest observations were made on the Unit 3 stack, most of the readings were in excess of 20% opacity because the scrubber was not operating during the entire period of the evaluation.

Of the 1,135 readings greater than 20% opacity, 727 readings were taken during equipment failures in the particulate control system.

Information reported in PSCC upset reports has shown violations of the 20% opacity standards (as measured by the opacity meters) due to ESP malfunctions. Since these violations occurred when the scrubber was in survice, it must be concluded that the scrubber outlet particulate loading can exceed standards even when the scrubber is not in an upset condition. Therefore, it is important that the mechanical collector/ESP efficiency be improved and maintained at optimum conditions. Operation of the ESP's at 40 to 60% efficiency is not acceptable.

RELIABILITY

Based on visible emission observations and Company stack tests, the particulate control system appears to be able to meet SIP particulate regulations. The problem is one of how consistently the particulate control system can meet these regulations. Numerous improvements should be investigated to improve the reliability of the particulate control equipment at Cherokee Station.

The particulate removal performance of the scrubbers will vary with gas velocity, liquid flowrate, inlet particulate loading, gas flow imbalances, etc. For those units with scrubbers, improving the collection efficiency of the ESP's would reduce the inlet grain loading to the scrubbers, thus reducing the solids accumulation, fly ash erosion, and required particulate removal in the scrubbers. Potential areas of improvement in the existing electrostatic precipitators include upgrading the gas conditioning system, upgrading the automatic control system, adding more electrical sections, and adding more collecting plate area. Of immediate concern, the efficiency of the ESP's should be optimized, including upgrading the gas conditioning system and performing ESP efficiency tests. This would indicate if further improvements are necessary, such as upgrading the automatic controls, or adding electrical sections.

There are several potential areas for improving reliability in the scrubber system: adding spare scrubber capacity, replacing direct reheaters with indirect reheaters, adding spare recirculating slurry pumps, and providing weather enclosures. These changes can be evaluated and adopted with minimal preliminary study. Further improvements can be made to the scrubber packing and mist eliminators; however, these would probably require significant modifications, such as using stationary packing, two-stage mist eliminators, or vertically positioned mist eliminators. These modifications would also require lengthy research and development efforts for successful application. Finally, reliability can be improved by more frequent inspection and repair of the Unit 1 and 3 scrubbers. But, how practical this approach is for a base-loaded plant with a limited natural gas supply is questionable.

An alternative to upgrading the existing ESP's and scrubbers would be to replace them with more efficient ESP's (+99% efficiency) or to replace the scrubbers with baghouses.

The areas of potential improvement of the particulate collection system for each unit at Cherokee are summarized in Table 1. The final means of improving reliability will be specific to each unit and will depend on the reliability at which the particulate control equipment is required to operate. Economics and the use of proper techniques to compare reliability improvement alternatives must be considered.

Table 1

POTENTIAL AREAS FOR IMPROVING PARTICULATE CONTROL SYSTEM RELIABILITY
CHEROKEE STATION
PUBLIC SERVICE COMPANY OF COLORADO

Parameters	Unit 1	Unit 2	Unit 3	Unit 4
Electrostatic Precipitators				
Install SO_3 flow meters	Yes	Yes	Yes	Exist
Add gas conditioning	NA	NA	Yes	NA
Optimize ESP operation	Yes	Yes	Yes	Yes
Upgrade the automatic controls	Yes	Yes	Yes	Yes
Add more electrical sections	Yes	NA	Yes	Yes
Add more collecting plate area	Yes	Yes	Yes	Yes
Scrubbers (TCA)				
Add spare scrubber capacity	Yes	NA	Yes	Exist
Replace direct reheat with indirect reheat	Yes	NA	Yes	Exist
Add spare recirculating pumps	Yes	NA	Yes	Yes
Provide weather enclosures	Yes	NA	Yes	Exist
Improve mobile bed packing	Yes	NA	Yes	Yes
Improve mist eliminator design	Yes	NA	Yes	Yes
Increase frequency of inspections and cleaning	Yes	NA	Yes	Yes
Replace Scrubber with Baghouse	Yes	Yes†	Yes	Yes

† *Add to existing particulate control system.*

III. RECOMMENDATIONS

ADMINISTRATIVE

It is recommended that responsible regulatory agencies convey to PSCC an acceptable "percent reliability," i.e. a required percentage of boiler on-line time that the particulate control equipment is operating and meeting particulate regulations.

Public Service Company of Colorado should then be required to conduct a reliability study. Preferably, the Company should consider having a reliability analysis performed by an outside consultant acceptable to the regulatory agencies. From this study and control alternatives evaluated by PSCC, a control plan should be developed by PSCC for review and approval of the appropriate control agencies.

TECHNICAL

In order to monitor compliance with the regulations, it is recommended that the opacity meters be operated and maintained to indicate exit stack opacities and that any readings >20% opacity be reported to the control agencies. This will require that the Bailey meter readings must be calibrated and the readings adjusted to relate the opacities to the different path lengths associated with each stack. The Bailey meters should be calibrated using an opacity plate or filter in the 40% opacity range. As an alternative, the meters could be replaced with more up-to-date equipment that can be calibrated to read and automatically record the stack exit opacities.

The monitoring controls for the Sulfan system are limited and should be upgraded, as a minimum, to monitor SO_3 flow to each ESP. Additionally, a gas conditioning system should be added to Unit 3 and measures should be taken to prevent pluggage in the gas conditioning lines. Further technical recommendations for improving particulate control equipment reliability will depend on the results of the reliability study in which alternatives will be rated according to cost, impact, and degree of expected improvement to the overall system reliability.

IV. PLANT DESCRIPTION

The Cherokee Station powerplant is owned and operated by the Public Service Company of Colorado, a privately owned utility. It is a base-loaded installation with a normal operating schedule of 24 hr/day, 7 days/week, 52 weeks/year. The plant consists of four primary gas- and/or coal-fired units and two diesel-fired peaking units. Unit 1 began commercial operation in 1957, Unit 2 in 1959, Unit 3 in 1962 and Unit 4 in 1968. A general layout of the plant is shown in Figure 1.

COAL SUPPLY

The Cherokee Station currently receives coal from two primary sources -- the Energy Reserves Mine in Colorado and the Rosebud Mine in Wyoming. Representative analyses of the coal from these sources is shown as follows:

Source	Heating Value J/kg	Heating Value Btu/lb	Sulfur % by weight	Ash % by weight	Moisture % by weight
Energy Reserve Mine	2.58×10^7	11,100	0.47	9.34	8.77
Rosebud Mine	Not available				

The coal is delivered to the plant by train and stored in 30- to 90-day storage piles. Although less than 0.1% of the coal used at Cherokee Station during 1976 was from the Rosebud Mine, it is anticipated that more Rosebud coal could be used in the future and that at any given time the plant would burn coal from either source.

SCALE: 1" = 134'

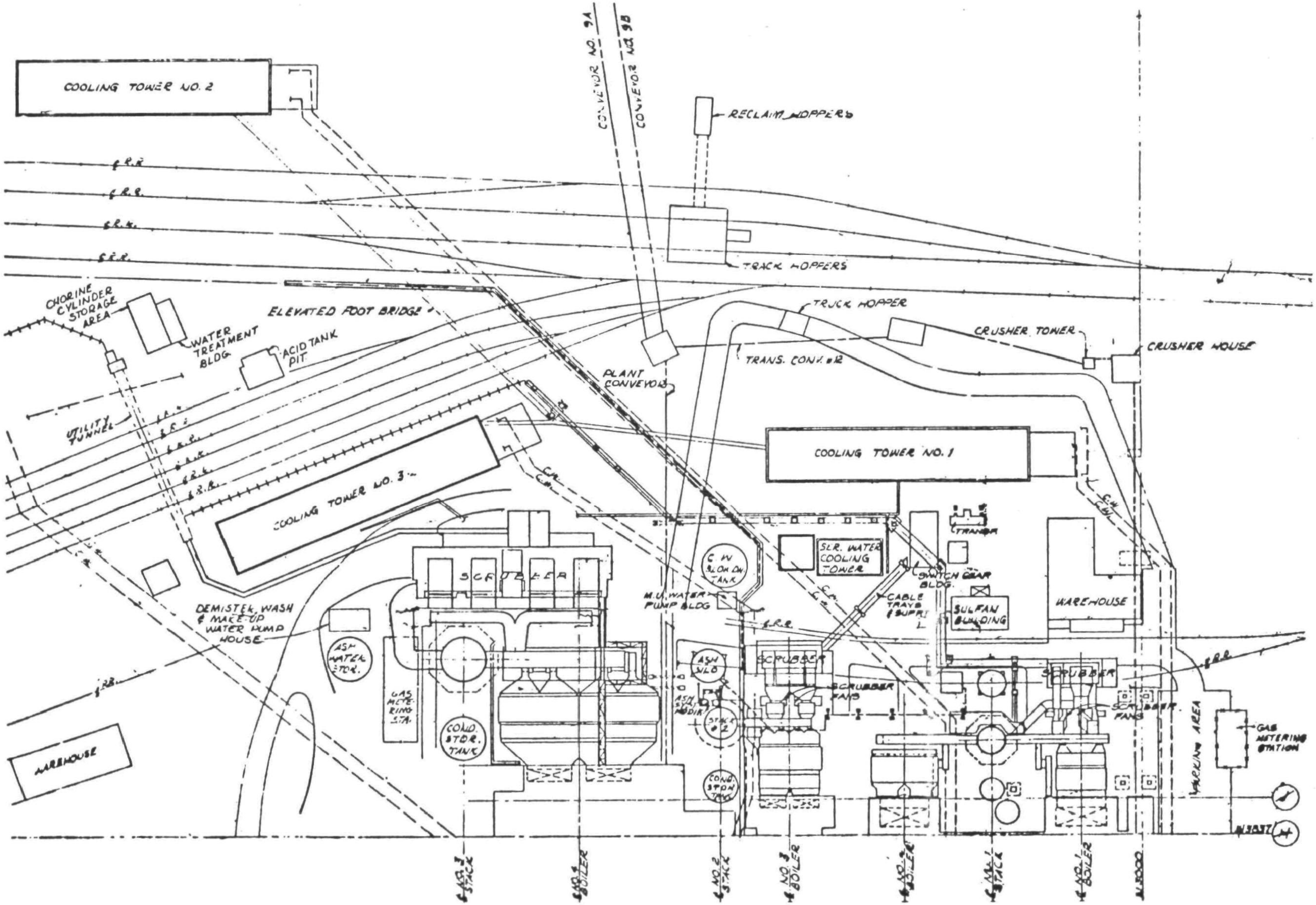

Figure 1. Plot Plan, Cherokee Station
Public Service Company of Colorado

Coal is conveyed to each unit by conveyor belts. The coal is transferred first to crusher houses (one for Units 1-3 and one for Unit 4), and then to coal silos which feed the individual pulverizers for each unit. Coal samples are withdrawn from the conveyor belts upstream of the silos. During this investigation, typical coal values were (as measured by weight) 8.86% moisture, 9.73% ash, 0.53% sulfur, and 2.52×10^7 J/kg (10,840 Btu/lb) heating value.

The coal is routed from the coal silos through counters that weigh the coal fed to the pulverziers. Each Unit is equipped with Riley Stoker Corporation pulverizers that reduce the coal to <50 mesh. From the pulverizer, primary combustion air conveys the coal to the combustion zone of the steam generators. Here it is mixed with secondary air and burned to produce superheated steam which drives the turbine-generators.

STEAM GENERATING UNITS

The four primary steam generating units are balanced draft, radiant-type boilers that burn pulverized coal as the primary fuel. Design parameters for the Units are listed in Table 2.

PARTICULATE CONTROL SYSTEM

After exiting the air preheater section of the boilers, the flue gas is mixed with a gas conditioning agent, SO_3. The SO_3 is injected into the gas stream to improve the collection efficiency of the electrostatic precipitators. As indicated in the flow diagram [Figure 2], the gas conditioning system for Unit 3 is not in operation.

The conditioned flue gases are treated by the particulate control system shown in Figure 2. For Units 1, 3, and 4, the system consists of

Table 2

DESIGN PARAMETERS - STEAM GENERATING UNITS
CHEROKEE STATION
PUBLIC SERVICE COMPANY OF COLORADO

Design Data	Unit 1	Unit 2	Unit 3	Unit 4
Initial Year of Operation	1957	1959	1962	1968
Boiler Manufacturer	Babcock and Wilcox	Babcock and Wilcox	Babcock and Wilcox	Babcock and Wilcox
Boiler Type	Balanced draft, radiant type	Balanced draft, radiant type	Balanced draft, radiant type	Balanced draft, radiant type
Steam Capacity, kg(lb)/hr, $x10^3$	387 (852)	387 (852)	517 (1,140)	1,170 (2,587)
Steam Pressure, kg/cm^2 (psig)	109 (1,550)	109 (1,550)	135 (1,925)	180 (2,500)
Steam Temperature, °C (°F)	540 (1,005)	540 (1,005)	540 (1,005)	540 (1,005)
Gross Electrical Generating Capacity,MW	115	115	170	375
Coal Pulverizer Manufacturer	Riley Stoker Corp.	Riley Stoker Corp.	Riley Stoker Corp.	Riley Stoker Corp.
Number of Mills	4	4	4	5
Design Capacity, kg(lb)/hr, each	16,400 (36,250)	16,400 (36,250)	16,800 (37,000)	30,000 (65,000)

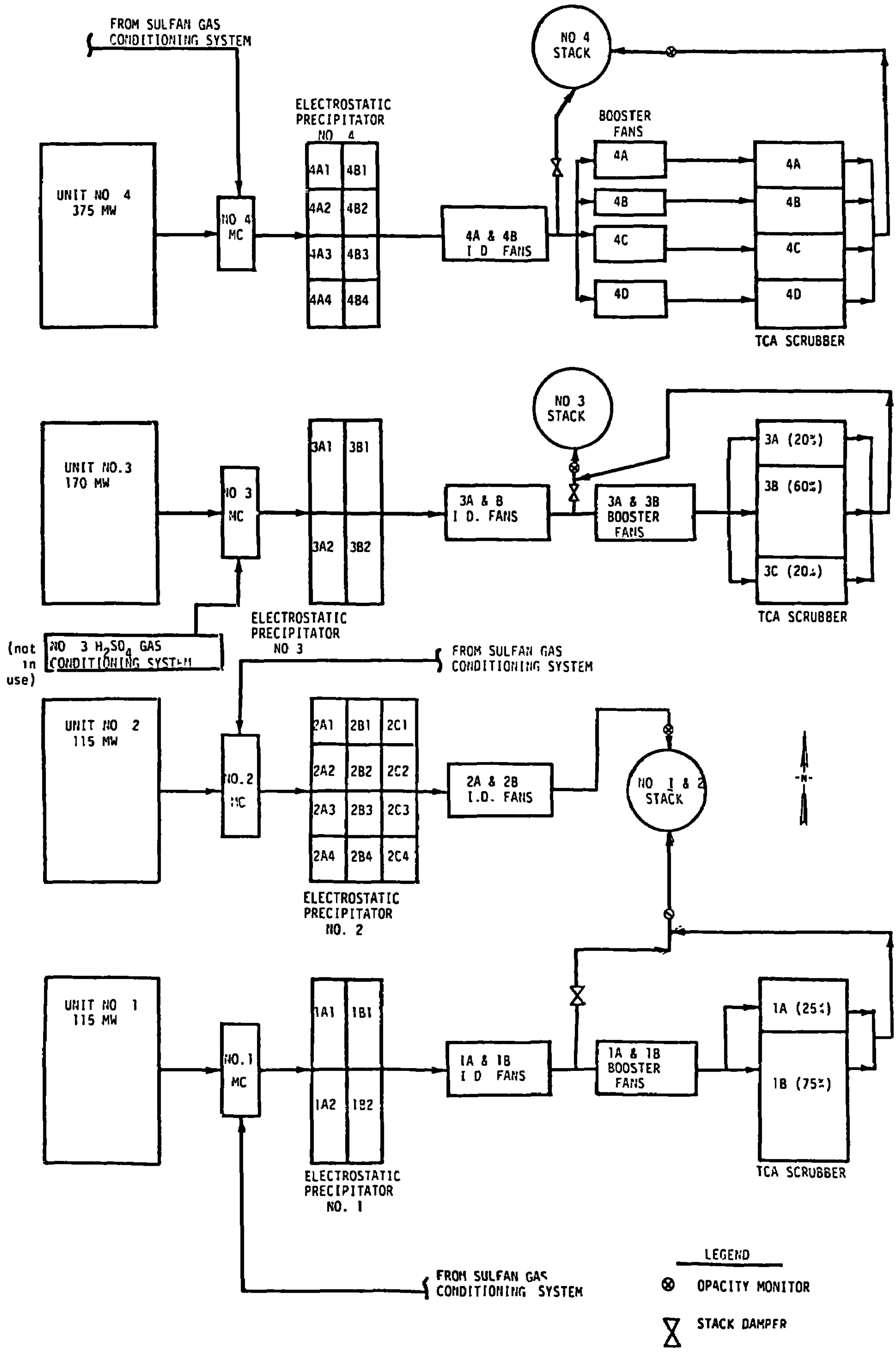

Figure 2. Flow Diagram of Particulate Removal System
Cherokee Station
Public Service Company of Colorado

mechanical collectors, electrostatic precipitators, and a turbulent contact absorber (TCA). For Unit 2, the system consists of a mechanical collector and an upgraded electrostatic precipitator. From the particulate control system, the cleaned flue gases are ducted to stacks for release to the atmosphere. Units 1 and 2 are ducted to a common stack, and Units 3 and 4 are ducted to individual stacks. The scrubbers on Units 1, 3 and 4 can be bypassed so that gas is ducted directly from the respective precipitators to the stack.

V. ELECTROSTATIC PRECIPITATORS

All of the electrostatic precipitators (ESP's) are followed by TCA scrubbers except for the Unit 2 ESP which exhausts directly to the common stack for Units 1 and 2. The ESP's installed at Cherokee are cold-side precipitators installed between 1964 and 1968. The ESP's are all preceded by a mechanical collector that precleans the flue gas before entering the precipitators.

The fly ash collected in the ESP hoppers is pneumatically conveyed to ash collecting silos and then hauled off the site by a private contractor for disposal.

ESP operation and control are monitored on the ESP control panels. Metering is provided to monitor primary and secondary voltage, primary and secondary current, and spark rate. The power input to the ESP can be automatically or manually controlled. In the automatic mode, the power input is controlled by saturable core reactors that monitor the spark rate and decrease the applied voltage during excessive sparking or increase the voltage in the absence of sparking. Optimum applied voltage levels occur at a level where sparking is less than 100 sparks per minute.

DESIGN

Unit 1 ESP

The electrostatic precipitator manufactured by Western Precipitation Division of Joy Manufacturing Company was installed in 1965. The two-chamber, two-field precipitator is designed to handle a gas flow of

229 m^3/sec (485,000 ft^3/min) at 140°C (285°F). The approximate dimensions of the active collection area for the ESP are shown in Figure 3. The ESP has two electrical fields, A and B, each powered by one transformer-rectifier (T-R) set which is energized and controlled from control panels in the ESP control room.

The flue gas enters the ESP through plenum chambers connected to the outlet of the mechanical collectors. The original gas distribution pans at the inlet of each chamber were modified in 1974 by adding a 40% open perforated plate with horizontal and vertical spoilers for proper gas distribution. The collecting surfaces in each field are vertically hung steel plate panels. The panels are hung parallel to each other with the surface of the panel parallel to the gas flow. The gas passage space between the plates is 23 cm (9 in). The discharge elements (stainless steel wire electrodes) are hung in the center of the gas passage from a steel framework that prevents horizontal movement of the wires. The general design parameters for the ESP are given in Table 3.

Unit 2 ESP

The ESP for Unit 2 was manufactured by Research-Cottrell, Inc. and was installed in 1968. The precipitator was modified in 1976 by splitting the electrical sections in half and adding three transformer-rectifier sets rated at 35 kVa each. These new T-R sets and controls were manufactured by Buell Emission Control, Division of Envirotech Corporation. This modification increased the number of fields from 2 to 3 and increased the precipitator design efficiency from 90 to 94%. The approximate dimensions of the active collection area are shown in Figure 4.

The precipitator has two chambers and three electrical fields, A, B, and C, and was designed to handle 234 m^3/sec (495,000 ft^3/min) of

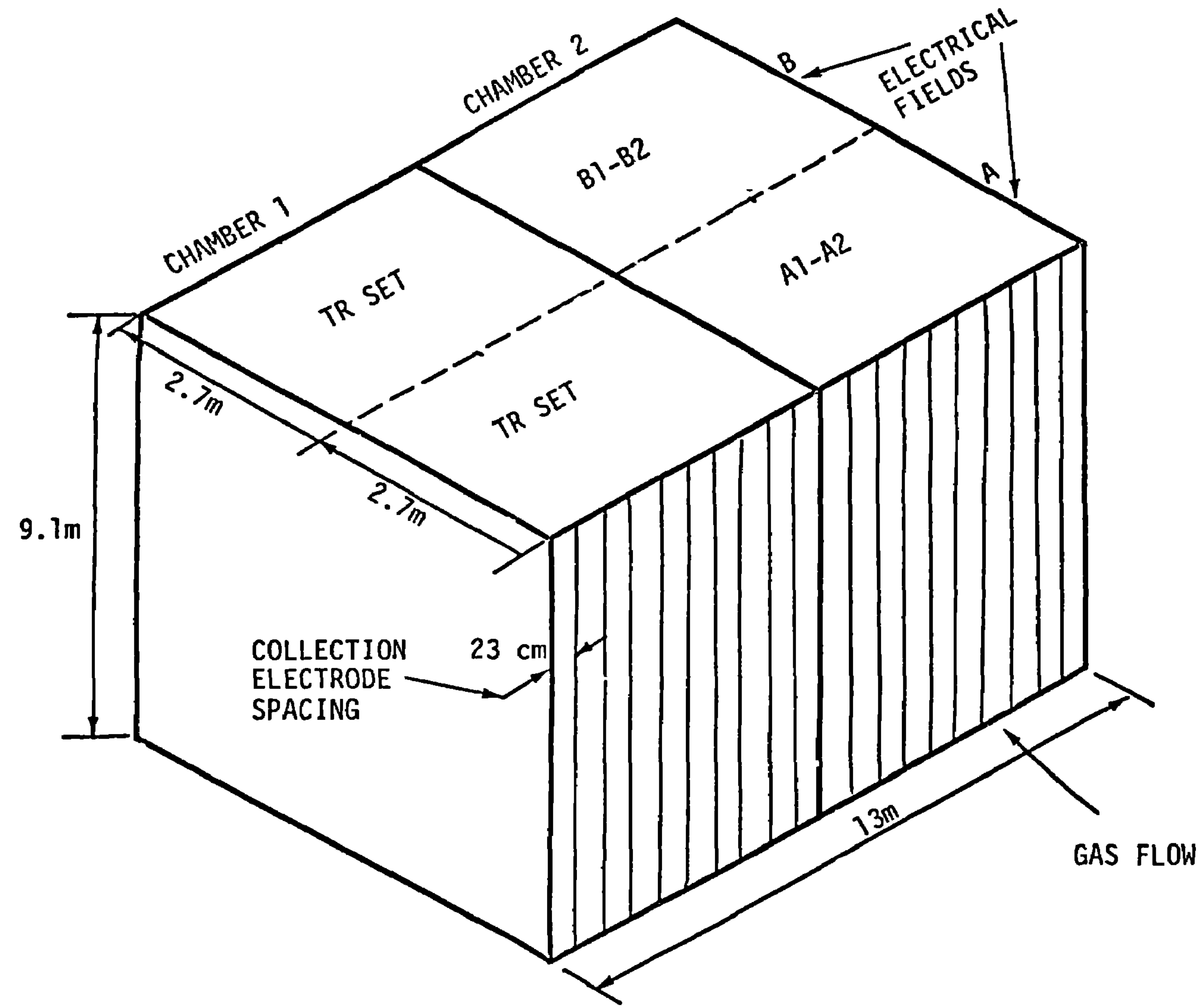

Figure 3. Approximate Dimensions of the Electrostatic Precipitator Active Area
Unit 1 - Cherokee Station
Public Service Company of Colorado

Table 3

DESIGN DATA FOR ELECTROSTATIC PRECIPITATOR - UNIT 1
CHEROKEE STATION
PUBLIC SERVICE COMPANY OF COLORADO

Parameter	Design Value
Manufacturer	Western Precipitation, Division of Joy Manufacturing, Inc.
Date Installed†	1965
Design Efficiency	90%
Outlet Loading @ 21°C, 1 atm (optional)	0.09 gm/m³ (0.04 gr/ft³)
Gas Volume (V)	229 m³/sec (485,000 ft³/min)
Average Gas Velocity	1.97 m/sec (6.47 ft/sec)
Gas Temperature	140°C (285°F)
Collection Electrode Area (A)	5,418 m² (58,320 ft²)
Specific Collection Electrode Area (A/V)	24 m²/m³/sec (120 ft²/10³ft³/min)
No. of Collector Electrodes	112
Aspect Ratio (L/H)	0.6
Type of Discharge Electrode	Shrouded Wire, 430 SS
Diameter of Discharge Electrode	0.268 cm (0.1055 in)
Type of Rapper and Number	Wire - Eriez Vibrator - 8 Plate - Eriez Rapper - 24
Rapping Frequency	5 sec/20 min
No. of Electrical Fields	2
No. of Chambers	2
No. of Electrical Energizing Sets	2
Transformer Rating	63.6 kVa (each)
Rectifier Wave Form	Full-wave
Rectifier D.C. Voltage	45 kV
Rectifier D.C. Milliamperes	900 mA (each)
Type of Control	Saturable Reactor
H.T. Bus Sections per 10² m³/sec (10⁵ ft³/min)	1.7 (0.8)
Treatment Time	2.9 sec
Migration Velocity	9.45 cm/sec (3.7 in/sec)
Chemical Additive	SO_3 Injection

† *In 1975-1976, inlet ductwork was modified by adding 40% open perforated plate and horizontal and vertical spoilers. Inlet electrical section A wire discharge electrode was replaced with the Western Mast electrode.*

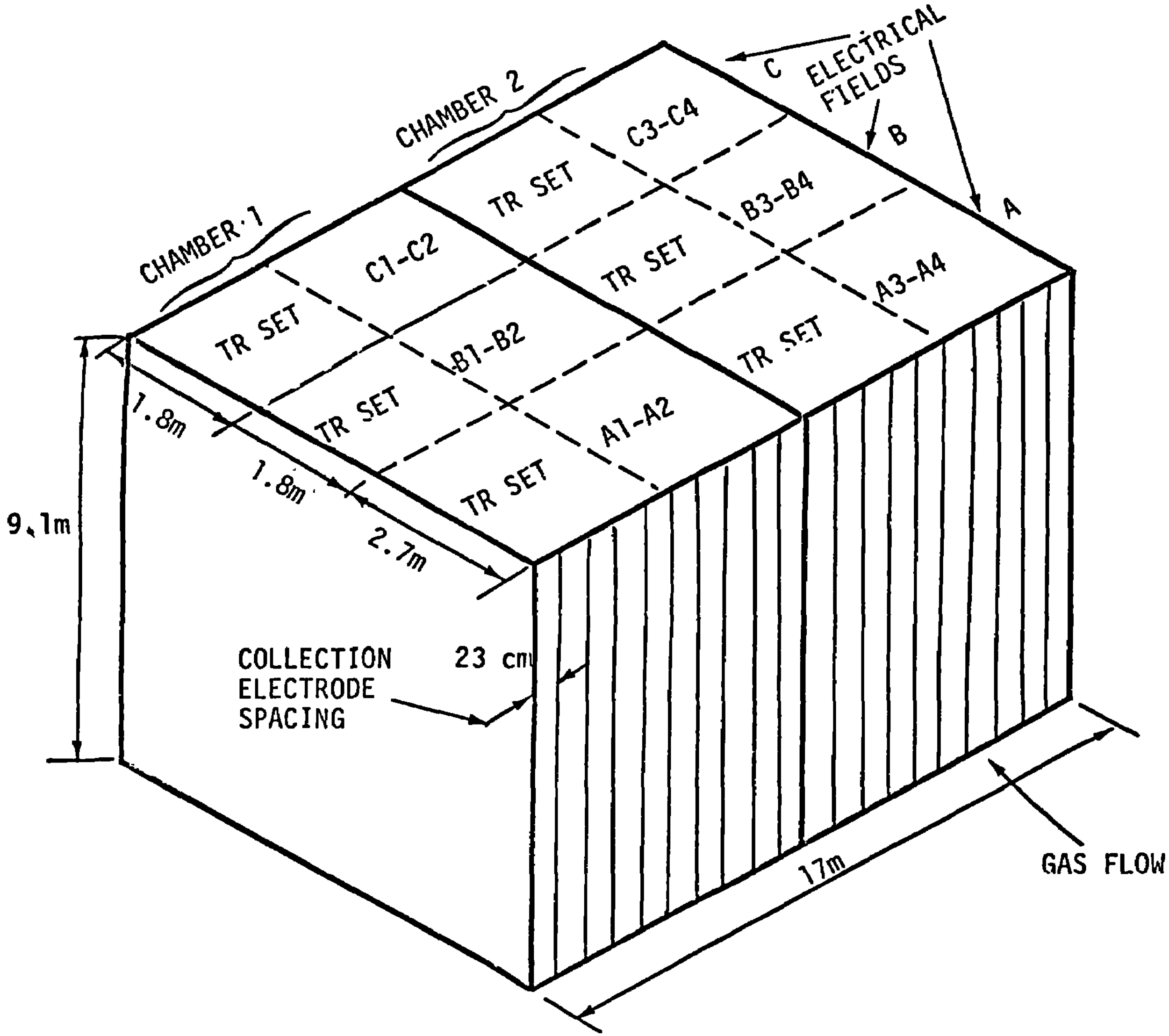

Figure 4. Approximate Dimensions of the Electrostatic Precipitator Active Area
Unit 2 - Cherokee Station
Public Service Company of Colorado

flue gas at 143°C (290°F). Each inlet section of the two chambers consists of 37 gas passage ducts which are 23 cm (9 in) wide, 9 m (30 ft) high, and 3 m (9 ft) long. The remaining sections are 23 cm (9 in) wide, 9 m (30 ft) high, and 2 m (6 ft) long. The flue gas is precleaned by a mechanical collector, then enters the inlet flue for each chamber. For uniform gas distribution, the inlet duct for each chamber is equipped with turning vanes and perforated distribution plates. The treated flue gases are ducted directly to the stack servicing both Units 1 and 2. Table 4 contains the general design parameters for the Unit 2 ESP.

Unit 3 ESP

The ESP for Unit 3, manufactured by Western Precipitation Division of Joy Manufacturing Company, was installed in 1964. The two-chamber, two-field precipitator is designed to handle a gas flow of 257 m^3/sec (545,000 ft^3/min) at 133°C (272°F). The approximate dimensions of the active collection area for the ESP are shown in Figure 5. The Unit 3 ESP is similar to the ESP on Unit 1 with two electrical fields, A and B. One transformer-rectifier set provides the power for each field and is monitored and operated from control panels adjacent to the maintenance offices. Each of the inlet sections consists of 34 gas passage ducts which are 23 cm (9 in) wide, 7.3 m (24 ft) high, and 3 m (9 ft) long; the outlet sections have the same dimensions. The flue gas is precleaned by mechanical collectors, then enters the inlet flue for each chamber which is equipped with a perforated plate of 44% open area for uniform gas distribution. The general design parameters for the Unit 3 ESP are given in Table 5.

Unit 4 ESP

The Unit 4 ESP, manufactured by Koppers Company, Inc., was installed in 1968. It was designed for a gas flow of 656 m^3/sec

Table 4

DESIGN DATA FOR ELECTROSTATIC PRECIPITATOR - UNIT 2
CHEROKEE STATION
PUBLIC SERVICE COMPANY OF COLORADO

Parameter	Design Value
Manufacturer	Research-Cottrell, Inc.
Date Installed	1968†
Design Efficiency	94%
Outlet Loading @ 21°C, 1 atm (optional)	0.07 gm/m^3 (0.03 gr/ft^3)
Gas Volume (V)	234 m^3/sec (495,000 ft^3/min)
Average Gas Velocity	1.51 m/sec (4.95 ft/sec)
Gas Temperature	143°C (290°F)
Collection Electrode Area (A)	8,662 m^2 93,240 ft^2)
Specific Collection Electrode Area (A/V)	37 m^2/m^3/sec (188 ft^2/10^3 ft^3/min)
No. of Collector Electrodes	76 nine ft and 152 six ft
Aspect Ratio (L/H)	0.7
Type of Discharge Electrode	Loop-ring smooth coppered Bessemer
Diameter of Discharge Electrode	0.277 cm (0.109 in)
Type of Rappers and Number	Wire - Syntron Vibrators - 12 Plate - Magnetic Impulse, gravity impact - 32
Rapping Frequency	6 sec/15 min
No. of Electrical Fields	3
No. of Chambers	2
No. of Electrical Energizing Sets	6†
Transformer Rating	3 @ 64 kVa, 3 @ 35 kVa
Rectifier Wave Form	Half-wave
Rectifier D.C. Voltage	45 kV
Rectifier D.C. Milliamperes	3 @ 1,000 mA, 3 @ 550 mA
Type of Control	Saturable Reactor
H.T. Bus Sections per 10^{2}m^3/sec (10^5 ft^3/min)	5.1 (2.4)
Treatment Time	4.24 sec
Migration Velocity	7.7 cm/sec (3.0 in/sec)
Chemical Additive	SO_3 Injection

† *In 1976 the electrical sections were split in half, making 12 separate sections. Three 35 kVa transformer-rectifier units were added.*

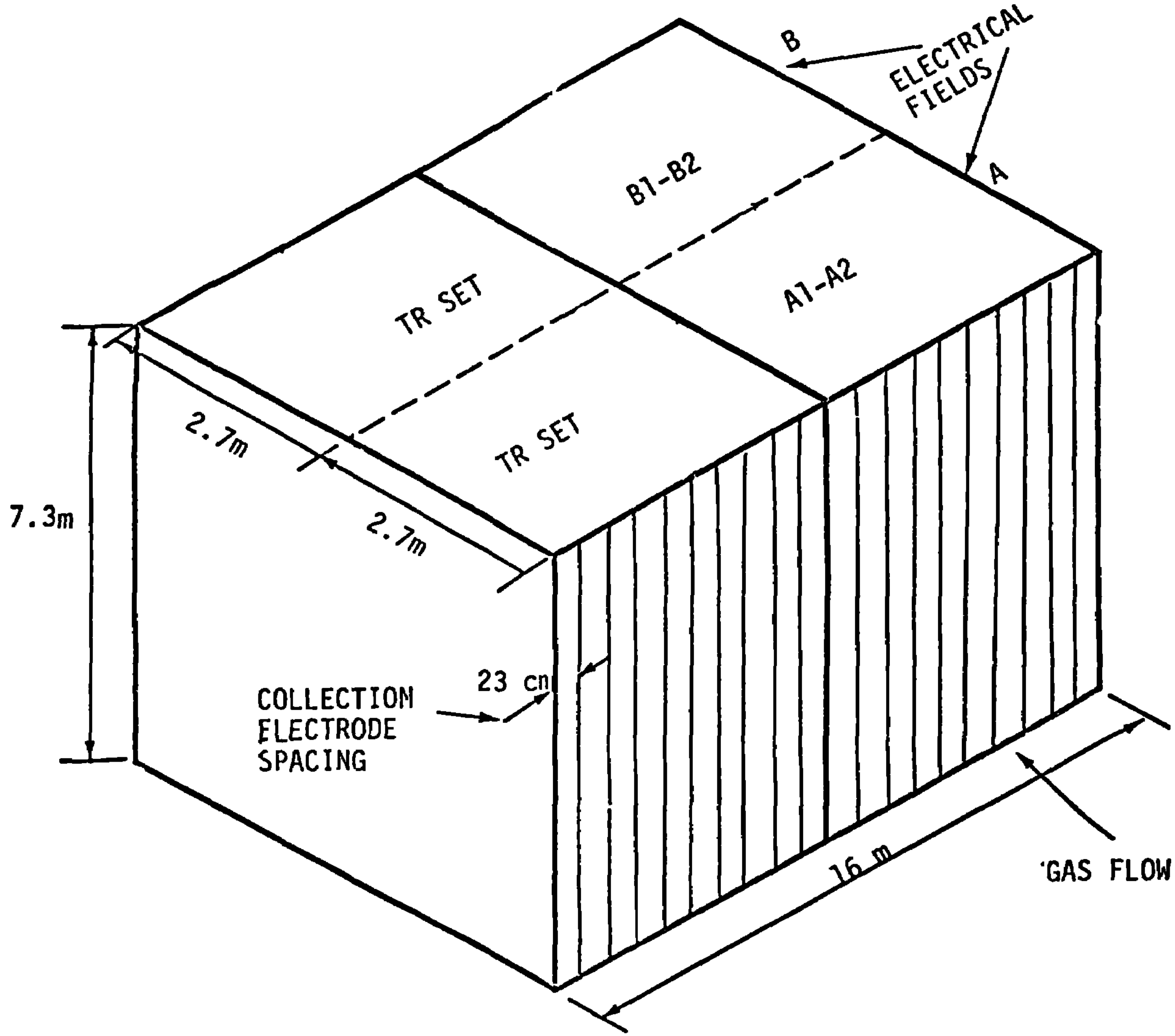

Figure 5. Approximate Dimensions of the Electrostatic Precipitator Active Area
Unit 3 - Cherokee Station
Public Service Company of Colorado

Table 5

DESIGN DATA FOR ELECTROSTATIC PRECIPITATOR - UNIT 3
CHEROKEE STATION
PUBLIC SERVICE COMPANY OF COLORADO

Parameter	Design Value
Manufacturer	Western Precipitation - Division of Joy Manufacturing, Inc.
Date Installed	1964
Design Efficiency	87%
Outlet Loading @ 21°C, 1 atm (optional)	0.046 g/m^3 (0.02 gr/ft^3)
Gas Volume (V)	257 m^3/sec (545,000 ft^3/min)
Average Gas Velocity	2.3 m/sec (7.44 ft/sec)
Gas Temperature	133°C (272°F)
Collection Electrode Area (A)	5,458 m^2 (58,752 ft^2)
Specific Collection Electrode Area (A/V)	21 m^2/m^3/sec (108 $ft^2/10^3$ ft^3/min)
No. of Collector Electrodes	134
Aspect Ratio (L/H)	0.75
Type of Discharge Electrode	Shrouded Wire - 430 SS
Diameter of Discharge Electrode	0.268 cm (0.1055 in)
Type of Rappers and Number	Wire - MD 60 Electrical - 8 Plate - MD 60 Electrical - 28
Rapping Frequency	Adustable
No. of Electrical Fields	2
No. of Chambers	2
No. of Electrical Energizing Sets	2
Transformer Rating	57.5 kVa each
Rectifier Wave Form	Full-Wave
Rectifier D.C. Voltage	45 kV
Rectifier D.C. Milliamperes	900 mA each
Type of Control	Saturable Reactor
H.T. Bus Sections per $10^2 m^3$/sec (10^5 ft^3/min)	1.6 (0.7)
Treatment Time	2.4 sec
Migration Velocity	9.6 cm/sec (3.8 in/sec)
Chemical Additive	SO_3 Injection

(1,390,000 ft^3/min) at 130°C (267°F) and a collection efficiency of 87%. The approximate dimensions of the active collection area for the ESP are shown in Figure 6. The one-chamber, two-field precipitator is powered by four transformer-rectifier sets. After being precleaned, the flue gas enters the inlet sections of the ESP which consist of 78 gas passage ducts 25 cm (10 in) wide, 3 m (9 ft) long, and 9.9 m (32 ft) high; the outlet sections have the same dimensions. The fly ash is handled dry and collected in the #4 Ash Collecting Silo. Table 6 contains the general design parameters for the Unit 4 ESP.

OPERATING AND MAINTENANCE PRACTICES

The operation and control of the ESP's are monitored on the ESP control panels. Metering is provided to monitor primary and secondary voltage, primary and secondary current and spark rate. The power inputs to the ESP's can be automatically or manually controlled. The ESP's are tuned every day during the normal five-day work week. As part of the adjustment, an electrician checks the meters which monitor current, voltage and spark rate. Both the value of the meter readings and the fluctuation of those readings are observed. If any "abnormal" readings were observed, corrective action or adjustments would be made to the Sulfan system, and/or to the set points for the automatic controls, etc. During discussions with Company representatives, specific values of normal conditions or abnormal conditions were not identified. A Company representative indicated that "by experience" they knew what was "abnormal." No data is recorded by the electricians, however, a strip chart continuously records the precipitator (secondary) current.

Besides the daily checks, the powerplant operator has ground and trip alarms to indicate problems. An electrician is assigned to periodically check the meter readings to minimize the tripping-out of sections.

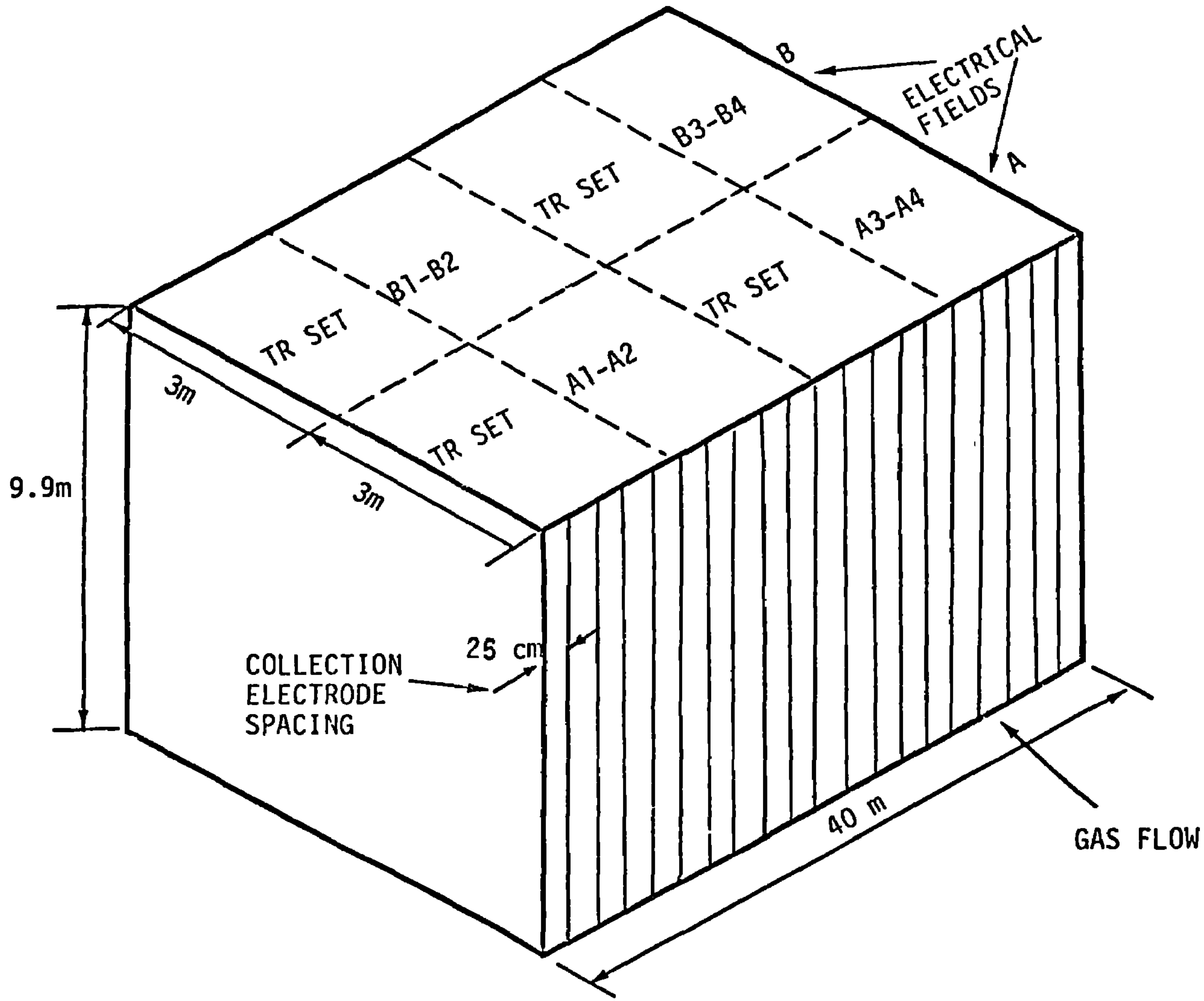

Figure 6. Approximate Dimensions of the Electrostatic Precipitator Active Area Unit 4 - Cherokee Station Public Service Company of Colorado

Table 6

DESIGN DATA FOR ELECTROSTATIC PRECIPITATOR - UNIT 4
CHEROKEE STATION
PUBLIC SERVICE COMPANY OF COLORADO

Parameter	Design Value
Manufacturer	Koppers
Date Installed	1968
Design Efficiency	87%
Outlet Loading @ 21°C, 1 atm (optional)	0.046 g/m^3 (0.02 gr./ft^3)
Gas Volume (V)	656 m^3/sec (1,390,000 ft^3/min)
Average Gas Velocity	1.81 m/sec (5.94 ft/sec)
Gas Temperature	130°C (267°F)
Collection Electrode Area (A)	17,400 m^3 (187,250 ft^2)
Specific Collection Electrode Area (A/V)	26 m^2/m^3/sec (135 ft^2/ft^3/min)
No. of Collector Electrodes	640
Aspect Ratio	0.62
Type of Discharge Electrode	Round coppered mild steel
Diameter of Discharge Electrode	0.277 cm (0.109 in)
Type of Rappers and Number	Wire - Vibrator 24 Plate - Impulse 80
Rapping Frequency	Adjustable
No. of Electrical Fields	2
No. of Chambers	1
No. of Electrical Energizing Sets	4
Transformer Rating	96.3 kVa each
Rectifier Wave Form	Half-wave
Rectifier D.C. Voltage	45 kV
Rectifier D.C. Milliamperes	1,500 mA each
Type of Control	Saturable Reactor
H.T. Bus Sections per 10^2 m^3/sec (10^5 ft^3/min)	0.6 (0.3)
Treatment Time	3.37 sec
Migration Velocity	7.7 cm/sec (3.0 in/sec)
Chemical Additive	SO_3 Injection

Maintenance practices for the ESP's and mechanical collectors are essentially performed on an as-needed basis. When a grounded wire in the ESP is indicated, a load reduction is scheduled, usually within a week, and the wire is removed (note: on Unit 2, if the shorted wire causes an opacity reading of >20% on the opacity meter, immediate action is taken). For ESP problems noted during Unit operation that do not cause opacity of >20%, a Station Service Request (SSR) is originated. An SSR is a request to maintenance that indicates an equipment problem that needs to be checked and repaired during the next shutdown. The mechanical collectors are monitored by reading the differential pressure across the collectors. A high reading would indicate pluggage.

The bulk of the maintenance on both the ESP's and mechanical collectors is conducted during unit outages. For the ESP's, this consists of an inspection and cleaning, if so indicated. Cleaning is accomplished by a combination of vacuuming, scraping and water washing. The mechanicals are inspected during minor and major unit outages. If pluggage has occurred, the collector is cleaned by routing out with poles and/or air lances. Areas of collector found to be excessively worn are also replaced at this time.

PHYSICAL INSPECTIONS

An internal inspection of the Unit 3 electrostatic precipitator was conducted by EPA and Company personnel on August 14, 1977. The inspection was conducted from the top of the collection plates and from a walkway located just above the hoppers between the first and second fields. The following observations were made.

Unit 3 ESP

Discharge Electrodes

Some of the discharge electrodes (approximately 2 to 5%) had a whisker-like buildup of ash over a significant length of the wire. The buildup in some cases reached thicknesses of up to 1 cm. This was not considered a major problem because of the number involved, but would indicate that specific discharge electrode rappers needed to be checked for proper operation. The electrode alignment was good as most electrodes were straight and centered in the gas passages.

Collection Plates

The collection plates were also straight, properly spaced and had no signs of warpage. The dust deposits on the plates did not appear excessive (<1 cm). Most of the dust present on the plates could be dislodged with gentle tapping.

Hoppers

The hoppers were clean and there was no indication of dust buildup. Corrosion of the hopper walls was not observed.

Other

The perforated plate, flow distribution device had no significant (>1 cm) solids deposits. The insulators were not closely inspected, but significant (>3 cm) ash buildup was not seen. Company personnel conducted the inspection in a knowledgeable and thorough manner.

Unit 4 ESP

The internals of the Unit 4 electrostatic precipitator were inspected on August 24, 1977. The inspection was conducted from the top of the collection plates and from a walkway located just above the hoppers between the front half and back half of the ESP. The following observations were made.

Discharge Electrodes

Some of the discharge electrodes (approximately 2 to 5%) had a whisker-like buildup of ash over a significant length (8 to 10 ft) of the wire. The buildup in some cases reached thicknesses of up to 1 cm. The whisker deposits were easily dislodged by tapping, indicating that the operation of the discharge electrode vibrators could be improved. The electrodes were observed to be straight, hung evenly and centered in the gas passages. There did not appear to be many missing wires.

Collection Plates

The alignment of the collection plates appeared satisfactory with little or no noticeable warpage. There was one section (approximately 1 m^2) of one plate which was warped to the point of touching an adjacent plate. This may have been initiated by corrosion of the plate. Overall, however, corrosion of collector plates did not appear to be a problem. There were very few large (>2 cm) ash buildups on the collector plates but, in general, it was found that more ash was sticking to the plates on the north half than on the south half. In addition, some of the deposits on the north half of the ESP tenaciously clung to the plates and formed very hard deposits. These may have been due to more predominant $CaSO_4$ formation at these locations caused by reaction of SO_3 with CaO present in the ash.

Other

The hoppers were clean with no signs of corrosion or dust buildup that would interfere with precipitator operation. The inlet flow perforated plate showed no signs of dust accumulation. The insulators were not inspected. Company personnel conducting the inspection were knowledgeable and thorough in their procedures.

SULFAN SYSTEM

The high resistivity ash associated with low-sulfur western coal severely limits the performance of an ESP by limiting the voltage and current at which the ESP operates. The purpose of the Sulfan system is to provide sulfur trioxide (SO_3) for mixing with the powerplant fly ash particles. The SO_3 conditions the surface of the fly ash particles by increasing the surface conductivity and, thus, reducing the ash resistivity. This improves the collection of the fly ash particles by increasing the current density and voltages at which the ESP can operate.

The Sulfan system presently is installed on Units 1, 2 and 4 and was initially put in operation in June 1971. It consists of a heated tank, piping and manual control valves through which the SO_3 is transferred to each unit, a nozzle distribution system injects SO_3 into the individual gas streams. A diagram of the Sulfan system is shown in Figure 7.

The Sulfan system is designed to provide a maximum of 0.9 m^3/min (32 ft^3/min) of SO_3. This should result in a SO_3 concentration in the powerplant offgas of about 20 ppmv, assuming design gas rates inputs to the ESP's and appropriate distribution of SO_3 to each unit. The actual injection rate is controlled by the temperature maintained in the Sulfan tank by an external heat source. The amount of SO_3 used is

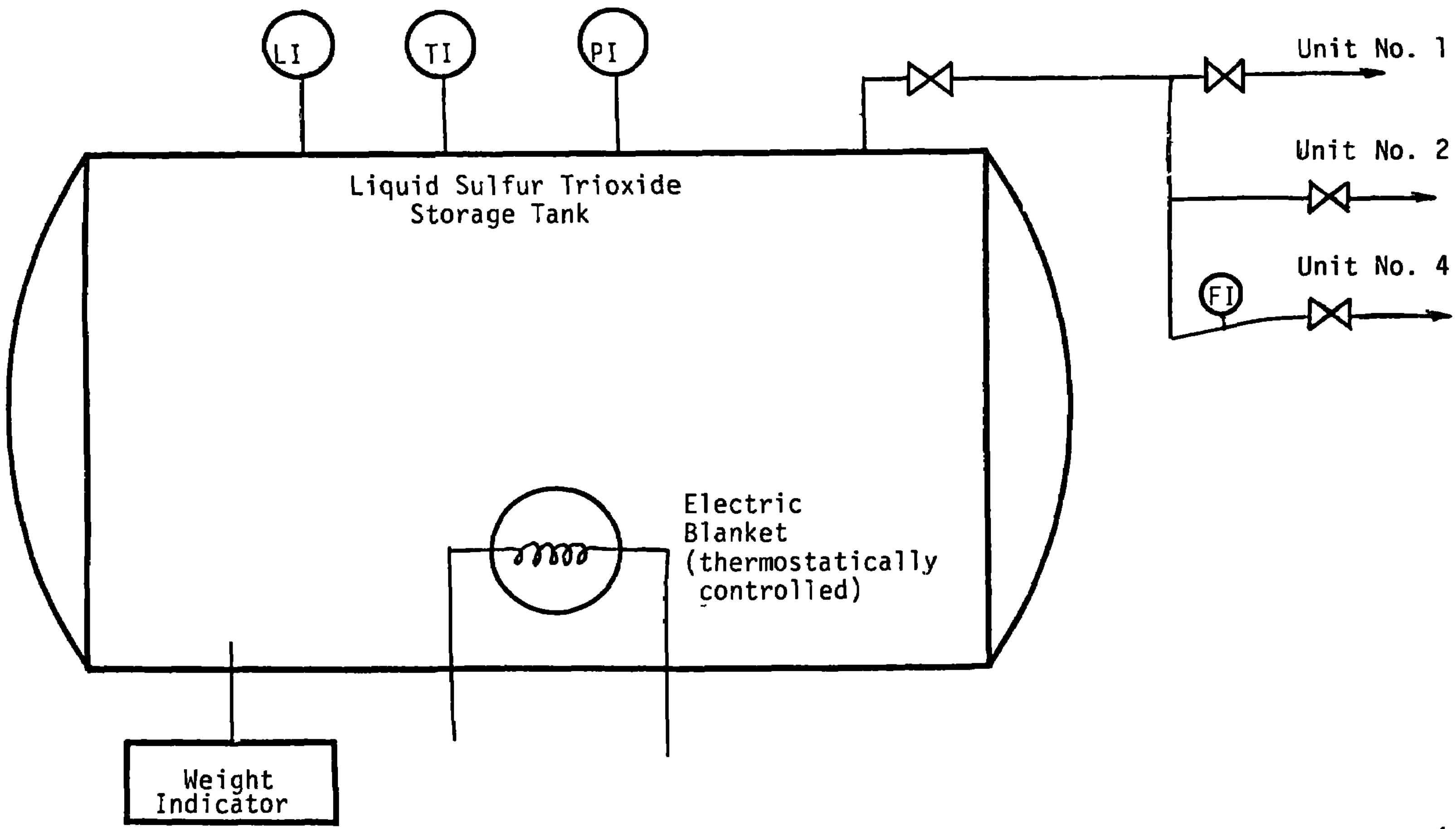

Figure 7: Schematic Drawing of Sulfan Sulfur Trioxide Conditioning System
Cherokee Station
Public Service Company of Colorado

monitored daily by recording the tank weight. There is also a flow meter recording SO_3 flow rate to the Unit 4 ESP but no flow rate indicator exists for the other ESP's.*

The SO_3 flow is not normally adjusted unless an ESP problem is indicated such as excessive sparking. When current/voltage inputs to the ESP are low, the first consideration is to further open the valve controlling the SO_3 to the individual ESP unit. If this does not improve the power input, the spark rate control is adjusted. Additional adjustments are based on specific problems indicated by the ESP instrumentation.

The monitoring controls for the Sulfan system are very limited and the amount of SO_3 injected to each unit could not be determined. Knowing how much SO_3 flows to the ESP's is critical to the proper operation of the Sulfan system and the ESP's. Without SO_3 flow data, the Sulfan system could not be evaluated and the effect of the gas conditioning system on ESP operation was only speculative. No test results were available to determine the effectiveness of the gas conditioning system.

ESP OPERATING DATA AND EVALUATION

To evaluate the operation of the precipitators, the electrical operating levels of the ESP's were monitored periodically during the entire study period. The electrical parameters monitored were primary and secondary voltage, primary and secondary current and spark rate. From these readings the power levels in and out of the rectifier sets were calculated along with the power efficiencies and current densities for each electrical section. These calculations are contained in

---

* *The Unit 4 flow meter was not in operation during the investigation as a result of pluggage difficulties. In September 1977, the Company installed a heat lamp to remedy this problem.*

Appendix C and are summarized in Table 7. Table 8 compares the normal operating conditions to the conditions that were observed during the study period. The normal operating conditions were provided by PSCC. These values are for normal operation at full load and 100% coal. During the period of the study, Unit 1 was operated on 100% coal, Unit 2 on 75% coal, Unit 3 on 25 to 75% coal and Unit 4 on 100% coal.

Unit 1 ESP

The electrical operating data indicates that the Unit 1 ESP was operating at lower power inputs than the ESP's on the other units. Although the voltages and currents were in the normal operating ranges, the majority of the values were at the lower end of the scale, also indicating low power inputs. The spark rate for the Unit 1 ESP is normally 100 to 150 sparks per minute (spm), but was observed to be greater than 200 spm for the majority of the time. Because of this condition, the automatic controls appeared to be spark rate limited, causing the low power inputs. The high spark rate and low power indicate unstable electrical conditions in the precipitator. One possible explanation could be the failure of the Sulfan system to adequately condition the flue gas. The lines or nozzles could have been plugged, but this could not be determined since metering was not available to monitor the SO_3 flow. Before further evaluation of the power inputs can be made, the Sulfan system needs to be upgraded to monitor flow so that the levels of gas conditioning needed for maximum power input to the precipitator can be determined.

At various times during the study, the secondary current was abnormally low with no spark rate indication. Probable cause could be misadjustment of current and/or voltage limit controls. This condition was usually corrected by the next day and the exact cause of the problem could not be identified.

Table 7

SUMMARY OF OBSERVED ELECTRICAL CONDITIONS FOR THE ELECTROSTATIC PRECIPITATORS CHEROKEE STATION PUBLIC SERVICE COMPANY OF COLORADO

Unit	Primary Power (kw)	Secondary Power (kw)	Power Efficiency (%)	Current Density	
				μA/ft^2	mA/m^2
Unit 1					
A-field	4-12	1-6	14-79	1-7	0.015-0.063
B-field	1-10	-	-	1-8	0.007-0.083
Unit 2					
A-field	3-23	1-14	22-79	2-15	0.023-0.162
B-field	3-26	1-21	30-78	3-41	0.035-0.437
C-field	10-25	11-21†	71-87†	11-41	0.097-0.445
Unit 3††	No data				
A-field					
B-field					
Unit 4					
A-field	12-38	†††	†††	6-15	0.068-0.161
B-field	12-50	7-20†††	52-69†††	5-19	0.055-0.2

† *No secondary voltage data on Unit 2 C1 and C2 field.*
†† *Secondary power was higher than primary power. Exact cause of problem was not identified.*
††† *No secondary voltage data on Unit 4 A field and B1-B2 fields.*

Table 8

COMPARISON OF
NORMAL AND OBSERVED OPERATING CONDITIONS†
ELECTROSTATIC PRECIPITATORS
CHEROKEE STATION
PUBLIC SERVICE COMPANY OF COLORADO

Operating Conditions	Unit 1	Unit 2	Unit 3††	Unit 4
Spark Rate (SPM)				
Normal	100-150	50-150	100-150	250-300
Observed	0->500	0->200	0-280	20->200
Primary Voltage (V)				
Normal	180-200	50-75	150-175	175-200
Observed	155-200	170-370	50-235	190-320
Primary Current (A)				
Normal	45-55	150-200	100-125	60-75
Observed	25-68	10-95	65-135	55-150
Secondary Voltage (kV)				
Normal	34-40	35-45	38-40	30-35
Observed	33-41	20-45	8-51	29-36
Secondary Current (mA)				
Normal	100-125	500-600	400-500	400-500
Observed	20-225	40-550	280-740	230-865

† *Normal operating conditions were provided by PSCC. Precipitator operation varies with unit, load, fuel and sulfan treatment. Values stated are normal operation, full load, 100% coal. Observed readings were taken by NEIC during study period.*

†† *Power efficiencies were greater than 1, exact cause of problem was not identified therefore meter readings are suspect.*

$$\text{Power efficiency} = \frac{\text{primary voltage (V) X primary current (A)}}{\text{secondary voltage (kV) X secondary current (mA)}} \text{ X } 100\%$$

Under normal conditions, the inlet sections (A sections) are usually operated at lower current densities due to space charge effect and higher particulate concentrations. However, the data taken during the study period [Appendix A] showed that the outlet sections (B sections) operated at much lower current densities than the inlet sections. From this observation, it appears that the outlet sections could be operated at even higher power levels once the spark rate was optimized, thus increasing efficiency. It could also be inferred that the SO_3 injection is too low, since this would effect current densities. However, this is only speculative since the SO_3 rates were not monitored. Once the SO_3 rate can be monitored, the effect of increasing the SO_3 rate on current densities should be investigated.

Unit 2 ESP

In 1976, the electrical sections of this precipitator were split in half and new lower-rated T-R sets were added for greater sectionalization with an estimated increase in efficiency from 90 to 94%. The added sets and controls were manufactured by Buell and were rated lower than the original T-R sets. The new lower rated sets were placed on the northside of the ESP to energize cells 1 and 2 and the original T-R sets were placed on the southside to power cells 3 and 4. Convenience and the ease of installation dictated arranging the T-R sets in this manner. Normally when mixing different rated T-R sets, the best arrangement would be to place the higher rated units at the outlet fields because they can handle higher current densities, thus improving the collection efficiency of the precipitator. Placing the lower rated sets on one side of the ESP would probably lower the overall efficiency since half of the precipitator is operating at lower power inputs and current densities.

The electrical operating data monitored during the study period showed this condition to exist in the precipitator. One side of the precipitator, cells 1 and 2, had very low power inputs, power efficiencies, and current densities when compared to the cells 3 and 4. This condition was consistent in each field (A, B and C) of the precipitator. Although the lower power inputs and current densities were expected, the magnitude of the difference was not expected. A possible explanation of this would be severe flow and particulate loading imbalances in the two sides of the precipitator. In addition, the voltage and current limiting controls should be checked for misadjustment.

It was also noted that the power efficiencies of the T-R sets for cells 1 and 2 had lower calculated power efficiencies than the T-R sets on cells 3 and 4. Assuming the meter readings are accurate, the operation of the T-R sets should also be checked, since the arrangement of the T-R sets should not affect the power efficiencies of the sets.

The power levels, power efficiencies and current densities for cells 3 and 4 are within the normal operating ranges for the precipitator and are higher than the other Cherokee precipitators. The power levels, power efficiencies, and current densities for cells 1 and 2 are lower than the normal operating ranges. As previously discussed, the cause of this problem was not apparent. The current densities for the outlet sections are higher than the inlet sections, even for the low powered cells 1 and 2 as would be expected.

Unit 3 ESP

Unit 3 boiler was operated on varying amounts of coal for the first half of the study period because the scrubber was down for major maintenance. The entire unit was down for its annual outage (maintenance) during the last half of the study period. Although the

ESP was operating while the boiler was on-line, the data collected could not be evaluated because the power efficiencies of the T-R sets were greater than one in most cases and the exact cause of the problem could not be identified. The meter readings are suspect, therefore, further analysis of the data was not done.

Unit 4 ESP

Analysis of the electrical operating data indicated that cells 1 and 2 of the precipitator were operating at lower power levels than the 3 and 4 cells. This is the same situation that was found in the Unit 1 ESP, although not as severe. Possible cause of this problem could be imbalances in gas flow and/or particulate loadings. Since this ESP is only a one-chamber precipitator, this condition is not as likely to occur as may be the case with the Unit 1 precipitator, which has two chambers. For the cells 3 and 4, the outlet sections (B3 and B4) had lower current densities than the inlet sections (A3 and A4), which indicates that the B3 and B4 sections could be operated at higher power inputs. For the other side of the precipitator (cells 1 and 2), the current densities were, as expected, higher for the outlet sections. Although secondary currents were high, the actual current densities were relatively low; that would cause a drop in particulate collection efficiency. For example, the ESP on Unit 2 had secondary currents around 500 mA with current densities about 40 $\mu A/ft^2$ while the Unit 4 secondary currents were around 700 mA, and the current densities were about 15 $\mu A/ft^2$. Because the secondary currents are operating at relatively high levels, the power input cannot be adjusted to significantly improve the current densities. The most probable way of increasing the current density would be to add more T-R sets and increase the sectionalization of the precipitator.

PSCC is experimenting with full-wave and half-wave energization on the Unit 4 ESP to improve its efficiency. PSCC indicated that sections 4A1 and 4A2 were on full-wave rectification, but an analysis of the optimum voltage wave form was not available for review.

Use of full-wave energization for the collection of high resistivity dust is not typical because full-wave energization is electrically more unstable than half-wave energization. Half-wave energization produces longer decay periods for the voltage between current pulses, thus allowing ample time for sparks to extinguish. For high resistivity dusts associated with low sulfur coal, which is the case at Cherokee, the optimum voltage wave form is usually with half-wave energization.

There are times when combinations of half-wave and full-wave sets are useful, but usually on precipitators with higher sectionalization, i.e., >3 fields. The usual arrangement is to have the full-wave rectifiers on the outlet sections of the precipitator. The principle involved is that the inlet sections have the highest particle concentration and collection which means relatively high operating voltages but low currents, while the outlet sections have relatively clean gas which means lower voltages and higher currents for these sections.

The use of half-wave rectification for Units 1 and 3 should be investigated by PSCC. Units 2 and 4 are on half-wave rectification.

COMPARISON OF DESIGN PARAMETERS

The design parameters for the ESP's at the Cherokee Station were compared to the range of values typically found in fly ash precipitators [Table 9]. The values were compiled from precipitators with collection efficiencies from 90 to 99%. The design parameters for the Cherokee

Table 9

COMPARISON OF
ELECTROSTATIC PRECIPITATOR DESIGN PARAMETERS
CHEROKEE STATION
PUBLIC SERVICE COMPANY OF COLORADO

Parameters	Range of Values for Fly Ash Precipitators†	Unit 1	Unit 2	Unit 3	Unit 4
Precipitation Rate					
m/sec	0.015-0.18	0.09	0.08	0.1	0.08
ft/sec	0.05-0.6	0.31	0.25	0.32	0.25
Specific Collection Area (SCA)					
m^2/m^3/sec	20-157	24	37	21	27
ft^2/1,000 ft^3/min	100-800	120	188	108	135
Gas Velocity					
m/sec	1.2-2.4	1.97	1.51	2.3	1.8
ft/sec	4-8	6.47	4.95	7.44	5.94
Aspect Ratio (L/H)	0.5-1.5	0.06	0.7	0.75	0.62
Corona Power					
watts/m^3/sec	106-1,060	6-26	4-94	No data	11-31
watts/1,000 ft^3/min	50-500	3-12	2-44	-	5-14
Corona Current Density					
mA/m^2	0.054-0.075	0.01-0.063	0.02-0.45	No data -	0.055 0.18
μA/ft^2	5-70	1-7	2-41	-	5-17
Plate Area/Electrical Set					
m^2	465-7,430	2,709	3,712†† 1,237†††	2,729	4,349
ft^2	5,000-80,000	29,160	19,980†† 13,320†††	29,376	46,812
Degree of Sectionalization					
Bus sections/100 m^3/sec	0.8-8.4	1.7	5.1	1.6	1.2
Bus sections/100,000 ft^3/min	0.4-4.0	0.8	2.4	0.7	0.6
No. of Fields	4-8	2	3	2	2

† *Taken from reference 3. Design efficiencies are from 90 to 99%. The larger number is generally associated with the more efficient precipitators except for gas velocities.*
†† *Inlet sections*
††† *Outlet sections*

precipitators are typical for the fly ash precipitators operating at medium efficiencies (80 to 90%). The specific collection electrode area (SCA) is used to calculate theoretical collection efficiencies in the Deutsch equation.* The specific collection electrode area is defined as the collection electrode surface area divided by the gas flow rate. For design purposes the SCA is usually expressed in $ft^2/1{,}000$ acfm. This term is used directly in the calculation of collection efficiencies as previously shown in the Deutsch equation. The SCA's for the Cherokee precipitators are at the low range for fly ash precipitators. Higher performance ESP's (99+%) are now being designed with SCA's of up to 157 $m^2/m^3/sec$ (800 $ft^2/10^3$ ft^3/min). The SCA's for the Cherokee precipitators are much lower and can only be increased by enlarging the precipitator (i.e., increasing the collection electrode area).

The aspect ratio is defined as the ratio of the effective length of the gas passages to the height of the gas passages. As the re-entrained dust is carried forward by the flow of the gas, sufficient gas passage length must be provided to prevent dust from being carried out of the ESP before the dust reaches the dust collection hoppers. If the aspect ratio is too small, dust losses from re-entrainment will increase. Higher performance ESP's usually have aspect ratios greater than 1. As shown in Table 9, all the Cherokee precipitators have aspect ratios less than 1.

Power consumption is another important design parameter that affects the collection efficiency. The ranges of corona power and current density as compared in Table 8 show that the Cherokee precipitators have lower power inputs than typical fly ash precipitators. Precipitators installed in the late 1960's were typically found to be undersized

---

* *Deutsch equation is* $n = 1 - e^{-(A/V)w}$ *where n is the efficiency, w is the migration velocity, A is the collecting electrode surface area, and V is the gas flow rate. The precipitation rate parameter is considered equivalent to the performance migration velocity for actual operating data.*

especially for units collecting high resistivity ash. This is the case for the precipitators installed at Cherokee. The Unit 2 ESP was upgraded in 1976 by adding T-R sets and increasing the electrical sectionalization. This modification is reflected in the power comparisons, where corona power and current density are much larger than the other three precipitators.

Electrical sectionalization and number of fields is important in maintaining the collection efficiency near design. This is especially true when sections are taken out of service for broken corona wires or some other reason. If a precipitator cell only had two fields and one field was out of service, the efficiency of this cell would decrease by as much as 30 to 50%. However, if there were three or four fields and one was taken out of service, then the cell would probably lose less than 20 to 30% in collection efficiency.

Reviewing the design parameters, it appears that the precipitators are undersized for efficient collection (>90%) but are typical for precipitators that were installed in the late 1960's for collection efficiencies of 80 to 90%.

More efficient precipitators have a higher degree of sectionalization and a larger number of fields. The degree of sectionalization and number of fields for three of the Cherokee precipitators are low when compared to typical fly ash precipitators. The recent modification of the Unit 2 ESP increased the degree of sectionalization and number of fields, thus increasing its efficiency.

ESP EFFICIENCY TEST RESULTS

In response to a request for stack test data, PSCC submitted a summary of test results performed by PSCC on the electrostatic precipitators at Cherokee [Appendix D].

Most of the data were outlet grain loadings only, but there were efficiency tests done on the Units about five years ago. These tests are summarized as follows.

ESP	Tested Efficiency Range %	Typical Efficiency† %
Unit 1	24-73	50
Unit 2	76-97	89
Unit 3	48-58	51
Unit 4	28-55	42

† *Typical efficiencies were reported by PSCC, with the most frequently tested efficiency reported as typical.*

These test results indicate that the ESP's are operating well below their design efficiencies. More recent data indicates the same range of outlet grain loadings as when these efficiency tests were done, therefore, these efficiencies are considered typical of the present ESP efficiencies.

UPSET REPORTING

As part of the upset reporting requirements, PSCC has reported day-to-day malfunctions of the particulate control equipment to the State of Colorado. Prior to May 1975, the Company reported all equipment outages of 24 hours or longer. From May 1975 to April 1977, the Company reported all major outages that occurred when the opacity was greater than 20%. As of May 1977, the Company reports only those malfunctions which prevent all the flue gas from being treated in each scrubber. The data generated in these reports on ESP problems* is

* *Scrubber data is discussed in the following section.*

summarized in Table 10. Because of the limited amount of data on ESP's only the data from July 1975 to May 1977 were summarized. The availabilities are relatively good except for Unit 3 where the major cause of downtime was broken electrode wires. A possible explanation would be the lack of gas conditioning to this Unit. The high resistivity ash, with no gas conditioning, could cause excessive sparking at the electrodes causing the wires to burn out. If this happens, the section would have to be taken out of service until the wire is removed or replaced.

The major upset problems associated with the ESP's are broken electrode wires, but as discussed previously, they are immediately removed or replaced if the opacity exceeds 20%. An important observation was made from reviewing the upset reports. There are times when an ESP section or sections are down, with the scrubber operating normally and the opacity exceeding 20%. It is therefore, very important that the ESP efficiencies are maintained and downtime minimized.

Table 10

SUMMARY OF ESP AVAILABILITY BY UNIT[a]
CHEROKEE STATION
PUBLIC SERVICE COMPANY OF COLORADO

Unit No.	ESP Availability[b] %	ESP Downtime[c] hrs	Major Reported Downtime Causes[d]
1	91	958	Broken electrode wires - 98% breakage or control circuit failure - 2%
2	*e*	1,367	Broken wires-37%, unknown 32%, high ash buildup-17% control system failure-6%
3	75	3,299	Broken electrode wires-87% Control system failure-8% Unknown grounds-5%
4	94	648	Low power-48%, broken wire-30%, ash buildup-22%

a *Data taken from PSCC monthly upset reports for July 1975 to May 1977.*

b $\% \text{ Availability} = \frac{A - B - C}{A - B} \times 100\%$

A = Hours boiler operating
B = Hours boiler burning 100% gas
C = Hours ESP had 1 or more sections out of service.

c *Hours ESP had 1 or more sections out of service as reported by PSCC to the State of Colorado in their monthly upset reports.*

d *Expressed as percentage of hours ESP was down.*

e *Data were not available on hours of boiler operation.*

VI. SCRUBBERS

DESIGN

Turbulent Contact Absorber (TCA) scrubbers were installed on Cherokee Units 1, 3 and 4 to supplement control of particulate by the electrostatic precipitators and mechanical collectors on those units. The TCA scrubbers were designed by Universal Oil Products (UOP), Air Correction Division. A drawing of the TCA scrubber is shown in Figure 8.

Flue gas exiting from the precipitators enters a scrubber booster fan which discharges into the presaturator section of the scrubber. In this section, scrubber makeup water is sprayed into the gas, reducing the temperature to approximately 52°C (125°F). From the presaturator, the gas enters the scrubber.

Each scrubber consists of three stages of beds packed to a 15 cm (6 in) depth with 5 gm balls (approximately 3 to 4 cm diameter). The mobile packing creates a high gas-side pressure drop across the scrubber and provides liquor-to-gas contact for effective particulate removal. The mobile spheres, when in constant action, also tend to be self-cleaning, thus reducing the potential for plugging. By design, the spheres remain mobile when liquor-to-gas flows balance each other. As a result, gas and liquor rate must be properly controlled within specified limits to insure scrubber effectiveness. Gas velocities in the scrubber should be maintained between 550 and 750 fmp.

The scrubber liquor is pumped to spray headers located above the packing in the top stage. After being contacted with gas flowing up through the scrubber, the scrubber liquor is collected in a hopper at the bottom of the scrubber from where it is recirculated. Slurry is

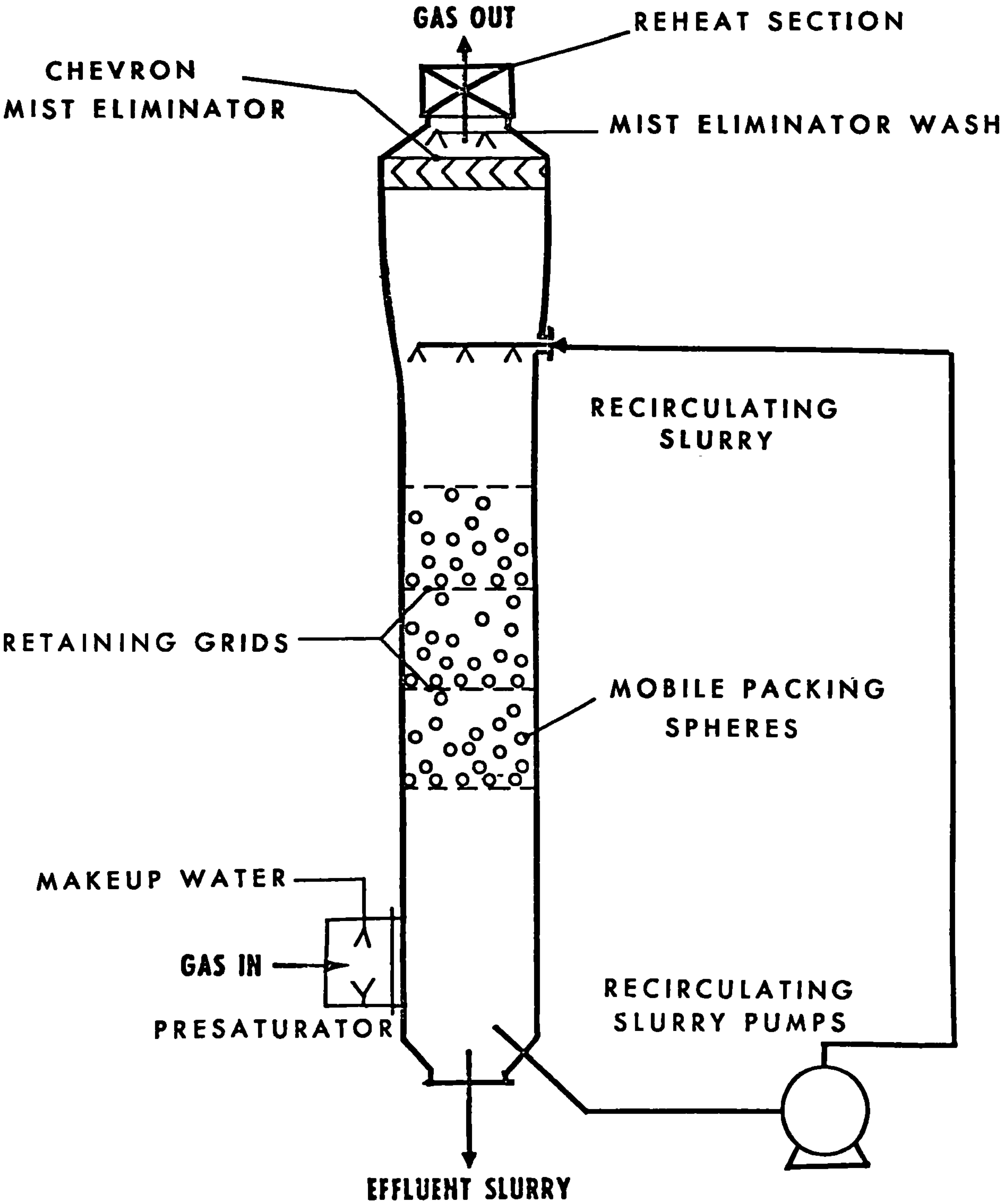

Figure 8. Schematic Drawing of Turbulent Contact Absorber (TCA)
Cherokee Station
Public Service Company of Colorado

purged from the scrubber system to prevent buildup of excessive solids in the recirculated liquor. The slurry from the scrubber is pumped to an ash pond for disposal.

The scrubbed gas passes through mist eliminator and reheater sections prior to being discharged through a stack. The mist eliminator consists of a single section of chevron-type blades and is designed to remove entrained droplets carried over from the scrubber. Deposits which accumulate on the mist eliminator blade are washed off by intermittently operated spray nozzles located above the mist eliminator. After passing through the mist eliminator, the gas is heated by direct in-line steam coils (Units 1 and 3) or by hot air injection (Unit 4). The resulting gas is at a temperature which should prevent corrosion of the stack and duct work and provide plume buoyancy.

The design specifications for the scrubbers on Units 1, 3 and 4 are presented in Table 11.

Unit 1

A model 5600 TCA scrubber was installed on Unit 1 in 1973. It has two parallel sections: section 1A handles 25% of the gas flow, and section 1B handles 75% of the flow. The sections receive gas flow from two common parallel scrubber booster fans but are designed to operate independently. Section 1A has one recirculating slurry pump (27,000 lpm or 7,000 gpm) while section 1B has three recirculating slurry pumps (80,000 lpm or 21,000 gpm). The designed particle collection efficiency is 97.5% with three scrubbing stages and a liquid-to-gas ratio (L/G) of 8.1 l/m^3 (60 gal/1,000 ft^3). Direct stack gas reheat to 93°C (200°F) is provided by in-line steam coils arranged in two tube bundles equipped with soot blowers to remove deposits from tube surfaces.

Table 11

DESIGN SPECIFICATIONS FOR TCA SCRUBBERS
CHEROKEE STATION
PUBLIC SERVICE COMPANY OF COLORADO

Specifications	Unit 1	Unit 3	Unit 4
Scrubber Manufacturer	UOP-ACD	UOP-ACD	UOP-ACD
Model No.	5600	6700	4200
Date Installed	1973	1972	1974
No. Sections	1-25% flow	1-60% flow	
	1-75% flow	2-20% flow	4-25% flow
No. Stages	3	3	3
Mobile Packing	Variable	Variable	Variable
Gas Flowrate			
m^3/hr @ 138°C, 627 mm Hg	880,000	1,040,000	2,600,000
ft^3/min @ 280°F, 24.7in Hg	520,000	610,000	1,520,000
Turndown ratio†	0.45-1.05	0.45-1.05	0.45-1.05
Pressure drop†† cm W.C.	30	28	30
in W.C.	12	11	12
Particulate removal eff.	97.5%	93%	97%
Inlet particle concen.			
g/std m^3	1.8	0.69	1.6
gr/std ft^3	0.8	0.3	0.7
Outlet particle concen.			
g/std m^3	0.046	0.046	0.046
gr/std ft^3	0.02	0.02	0.02
Particle size distr.	Not specified	Not specified	Not specified
Scrubbing Liquid	Water	Water	Water
Recirculate flowrate			
liter/min	106,000	114,000	319,000
gal/min	28,000	30,000	84,000
Liquid-to-gas ratio (L/G)			
liter/m^3	8.1	7.4	8.3
gal/1,000 ft^3	60	55	62
Suspended Solids Content			
Max. wt %	3.0	3.0	3.0
Mist eliminator type	Chevron-3 pass	Chevron-3 pass	Chevron-3 pass
No. sections	1	1	1
Efficiency	Not available	Not available	Not available
Reheater Type	Direct	Direct	Indirect
No. Tube banks	2	3	3
Tube type	bare/finned	bare/finned	bare
No. Sootblowers	8	10	N/A
Reheat Temperature °C	93	85	79
°F	200	185	175

† *Ratio of acceptable gas flowrates in scrubber expressed as a function of design flowrate.*

†† *Pressure drop includes mist eliminator as well as scrubber.*

Since its initial operation in 1973, the TCA scrubber on Unit 1 has undergone a number of modifications. These include removing all finned tube steam reheat coils (1975), installing additional soot blowers (1974), replacing the original Fiberglass reinforced plastic (FRP) mist eliminators with stainless steel (1976), and adding turning vanes to the ESP outlet and scrubber inlet ductwork (1974).

Future changes to the scrubber will depend on mist eliminator tests being conducted for the Unit 3 scrubber. A decision will be made on whether to replace all of the mist eliminator sections with a newer design or to expand present reheat capacity.

Unit 3

A model 6700 TCA scrubber was installed on Unit 3 in 1975. It has three parallel sections: sections 3A and 3C each handle 20% of the gas, and section 3B handles the remaining 60%. The sections receive gas flow from two common parallel scrubber booster fans but are designed to operate independently. Section 3A and 3C each have one recirculating slurry pump (19,000 lpm or 5,000 gpm) while section 3B has three recirculating slurry pumps (57,000 lpm or 15,000 gpm). Particle collection efficiency is 93% with three scrubbing stages and an L/G of 7.4 l/m^3 (55 gal/1,000 ft^3). Direct stack reheat to 85°C (185°F) is provided by in-line steam coils arranged in three tube bundles equipped with soot blowers to remove deposits from tube surfaces.

Since its initial operation in 1972, the TCA scrubber has gone through a number of modifications. These include replacing all finned tube steam reheat coils with plain coils (1975-76), installing additional soot blowers (1973), and replacing the original FRP mist eliminators with stainless steel (1977). In August, 1977, the Company replaced the stainless steel mist eliminators in Sections 3A and 3C with plastic assemblies manufactured by Heil (Heilex Model EB-4) and Munters (Euroform Model 271), respectively. The Company will observe the mist removal efficiency of these assemblies and, based upon the test outcome, will decide whether to replace all of the mist eliminator sections with one of these newer designs or to expand present scrubber reheat capacity.

Unit 4

Four model 4200 TCA scrubbers were installed on Unit 4 in 1974. The scrubbers, designated as sections 4A, 4B, 4C, and 4D, were each designed to handle 25% of the gas flow. Each section receives gas flow from an individual scrubber booster fan. There are three recirculating pumps per section designed to provide a total recirculating flow of 80,000 lpm (21,000 gpm). The design particle collection efficiency is 97% with three scrubbing stages and an L/G of 8.3 l/m^3 (62 gal/1,000 ft^3). Indirect stack gas reheat to 79°C (175°F) is provided by mixing the scrubbed gas with heated ambient air in a venturi type mixing chamber.

Since its initial operation in 1974, the Unit 4 TCA scrubber has gone through a number of modifications. These include adding a second reheat air fan to each scrubber reheat system (1976) and installing outlet damper purge air systems (1976).

OPERATION AND MAINTENANCE

The operation of the scrubbers is, for the most part, monitored and controlled from panels located in the respective boiler unit control rooms. The data that is monitored is shown in Table 12. The essential areas of control are the gas flows, recirculating slurry, mist eliminators and reheaters.

Normal scrubber operation requires all scrubber sections in service on Units 1 and 3, and three of four sections in service on Unit 4. When one of the smaller sections of the scrubbers on Units 1 and 3 require repair, the Company treats all the gas flow from that unit in the

SCRUBBER LOG
CHEROKEE STATION
PUBLIC SERVICE COMPANY OF COLORADO

		UNIT	NO 1				NO 3				NO 4				
		SHIFT	12-8	8-4	4-12		12-8	8-4	4-12		12-8	8-4	4-12		UNITS
1	[illegible]	SH STEAM FLOW													M Lbs
2		SH STEAM TEMP													°F
3		SH STEAM PRESS													P
4	SECTION A	PRESAT WATER FLOW													GPM
5		OUTLET GAS TEMP													°F
6		BED DIFF													"H_2O
7		DEMISTER DIFF													"H_2O
8		RH DIFF													"H_2O
9		GAS OUTLET FLOW													"H_2O
10		SLURRY DRAW OFF FLUSH													TIME
11															
12	SECTION B	PRESAT WATER FLOW													GPM
13		OUTLET GAS TEMP													°F
14		BED DIFF													"H_2O
15		DEMISTER DIFF													"H_2O
16		RH DIFF													"H_2O
17		GAS OUTLET FLOW													"H_2O
18		SLURRY DRAW OFF FLUSH													TIME
19															
20	SECTION C	PRESAT WATER FLOW													GPM
21		OUTLET GAS TEMP													°F
22		BED DIFF													"H_2O
23		DEMISTER DIFF													"H_2O
24		RH DIFF													"H_2O
25		GAS OUTLET FLOW													"H_2O
26		SLURRY DRAW OFF FLUSH													TIME
27															
28	SECTION D	PRESAT WATER FLOW													GPM
29		OUTLET GAS TEMP													°F
30		BED DIFF													"H_2O
31		DEMISTER DIFF													"H_2O
32		RH DIFF													"H_2O
33		GAS OUTLET FLOW													"H_2O
34		SLURRY DRAW OFF FLUSH													TIME
35															
36	RECIRC PUMPS	RECIR PUMP A1													Amps
37		RECIR PUMP A2													Amps
38		RECIR PUMP A3													Amps
39		RECIR PUMP B1													Amps
40		RECIR PUMP B2													Amps
41		RECIR PUMP B3													Amps
42		RECIR PUMP C1													Amps
43		RECIR PUMP C2													Amps
44		RECIR PUMP C3													Amps
45		RECIR PUMP D1													Amps
46		RECIR PUMP D2													Amps
47		RECIR PUMP D3													Amps
48															
49	FANS	FAN A INLET PRESS													"H_2O
50		FAN B INLET PRESS													"H_2O
51		FAN C INLET PRESS													"H_2O
52		ID DISCHG PRESS													"H_2O
53		FAN A OUTLET PRESS													"H_2O
54		FAN B OUTLET PRESS													"H_2O
55		FAN C OUTLET PRESS													"H_2O
56		FAN D OUTLET PRESS													"H_2O
57		STACK DAMP POS A													% Open
58		STACK DAMP POS B													% Open

REMARKS

SHIFT	AUXILIARY TENDER
MID-8:00 A.M.	
8:00 A.M.-4:00 P.M.	
4:00 P.M.-MID	

CHEROKEE STATION

DAY__________ DATE______________ 19_____

SCRUBBER LOG

remaining scrubber sections. If the larger scrubber section on Units 1 or 3 is removed from service, part of the gas is bypassed to the stack.

The gas flow to the scrubber is automatically controlled by maintaining the inlet scrubber booster fan pressure to within proper limits (e.g., -1.0 to -2.5 cm W.G.). When the inlet pressure deviates from this range, the fan dampers are automatically adjusted accordingly. No attempt is made to shift scrubber sections in or out of service during increasing or decreasing load conditions. When the booster fan control is unable to keep the fan inlet pressure within the proper range (a situation which exists when there is a high pressure drop across the scrubber) the stack bypass damper is activated and gas flow is bypassed to the stack. Pressure and pressure drop information are monitored and recorded once per shift.

The recirculating slurry flow is manually controlled by maintaining the slurry pump motor amps within a predetermined operating range (e.g., 11-16 amps for recirculating slurry pumps on Unit 4). This is accomplished by adjusting the slurry pump discharge valve. No attempt is made to vary the slurry flow with gas flow or unit load. When the slurry pump motor amps are low (out of the control range), the Company tries to backflush the line. If no improvement is noted, a Station Service Request (SSR) is prepared to initiate proper corrective action. When a slurry pump is taken out of service the affected scrubber section is not removed from service. In the case of scrubber sections 1A, 3A and 3C which have one recirculating slurry pump each, the Company maintains a limited flow of water in the section by running the mist eliminator wash.

The blowdown of recirculating slurry is dictated by the scrubber water balance requirements. During each shift, an operator takes a sample of the slurry and measures settleable solids and pH. If the settleable solids concentration is higher than is to be allowed (i.e. 3.0 weight %), adjustments are made to the fresh water inlet rate and/or an SSR is initiated to check the drawoff lines and other potential trouble areas.

The operation of the mist eliminator wash system varies between units. On Units 1 and 3, a manual wash system has been installed. Once each shift, an operator sequentially opens the mist eliminator wash header valves and each header is left on for two minutes. On Unit 4, an automatic wash system sequentially operates each wash header for a period of three (3) minutes each shift. The timing of the mist eliminator wash system can be adjusted according to changes in operating conditions.

The control of the reheat system is based on maintaining the exit gas temperature within proper limits. The operator adjusts the set point on a pressure control valve which supplies steam to the reheat steam coils. At full load conditions, the control valves are set at maximum design values [21 kg/cm^2 (300 psi) for Units 1 and 3; 28-35 kg/cm^2 (400-500 psi) for Unit 4]. At low loads, the operator reduces the set point of the pressure control valve accordingly.

Maintenance practices that are reported in effect for the TCA scrubbers can be divided into two categores: daily or routine inspection checks conducted when the scrubbers are in operation; and major and/or minor repairs conducted when the scrubber is taken out of service. Moreover, the differences between the Unit 4 scrubbers and those on Units 1 and 3 must also be recognized. Since the Unit 4 scrubbers are operated with three of the four equal-size modules in service, it is possible to rotate the operating modules every 3 to 4 months so that frequent internal maintenance can be performed. It is also possible to switch modules when one of the operating modules is performing poorly. This approach is not possible on Units 1 and 3.

Daily maintenance checks are performed on the slurry and recirculation pumps. These are checked for leaky packings, oil level, oil leaks, abnormal noise and vibration. Other pieces of equipment are monitored by Plant Operations and include data collected from instrument readouts. When instrument values are outside of the appropriate range, Operations personnel initiate a Station Service Request (SSR), which details an equipment or instrument problem that is to be checked and repaired by Maintenance. Then, depending on the urgency of the SSR, immediate action is taken or action is scheduled for the next scrubber outage.

The bulk of the scrubber maintenance work is conducted during major or minor outages. In this case, a major outage is defined as a boiler unit outage exceeding four to six weeks, whereas a minor outage is any other time the scrubber is brought out of service. Besides repairing SSR items, the scrubber is inspected for ball wear and pluggage by solids. The balls are inspected and weighed periodically. If a representative number of balls (100 balls) have lost more than 20% of the weight of an equivalent number of new balls, then the balls are replaced with new balls. If there are a lot of broken balls or balls have migrated, then new balls are added. Solids pluggage is removed with a jackhammer, by manual washing, or through chiseling by hand as required. In general, if anything is found during an inspection that reduces efficiency, i.e., ball migration or missing spray nozzles, repairs are made at that time.

During a major outage, a complete overhaul program is undertaken. The guillotine gates are inspected, shafts are repacked and any item that is not working properly is repaired as time permits. The reheat coils (Units 1 and 3) are cleaned and tested for leaks. The duct work is inspected and cleaned. The recirculation system is inspected for wear, pluggage and failures. The mist eliminators and mist eliminator spray nozzles are inspected and cleaned. The vertical dividers and grid bars are inspected and repaired or replaced as necessary. The presaturator area and hoppers are cleaned and the pump screens are checked and repaired. The presaturator nozzles are inspected and replaced as needed. The scrubber booster fans are checked and repaired as necessary. The fan bearing oil is changed and new shaft seals are installed. All soot blowers (Units 1 and 3) are inspected and checked for proper operation.

SCRUBBER INSPECTIONS

Unit 3

An inspection of the Unit 3 scrubber was conducted on August 5, 1977. The unit had been shut down for a scheduled outage in which a scrubber overhaul was planned. The last previous major scrubber overhaul had occurred in August - September, 1976. The results of the inspection were as follows.

Presaturator

The presaturator had large solids deposits in the area of the wet-dry interface. Section C had the largest accumulation of solids forming a layer as much as two meters deep. Sections A and B had solids accumulations of about one meter in depth. There were also solid formations projecting from the top spray nozzles. The solids on both the floor and ceiling of the presaturator formed a very hard deposit. The solid-cone presaturator spray nozzles that were inspected did not appear to be plugged or covered with solids but in some cases solids had accumulated around the nozzle, possibly restricting the spray coverage.

Scrubber Sumps

The scrubber sumps had accumulated solids at the bottom but the solids level did not appear to reach the spray pump intake lines. All the pump intake lines have screens. Broken balls had accumulated on most of the screens, but none of the screens were completely plugged.

Packing Stages

There was evidence throughout the mobile ball sections of ball migration and poor gas flow distribution. This typically appeared as maldistribution of balls and deposition of solids on the bottom of the packing stages. Generally, it appeared that the majority of the gas tended to flow from the presaturator section up the "back side" of the scrubber. (The "back side" of the scrubber is the east side or side opposite the presaturator section.) This could have resulted from the high velocities resulting from restriction in the presaturator section

In section 3A, the ball migration problem was very evident, since it was possible to look up from the eastside of the scrubber sump to the mist eliminator blades because of ball migration. In all three stages, the layer of balls (nominally at 20-30 cm depth) varied from zero thickness for the east one-third of the stage to as much as 1 m near the west end of the scrubber. There did not appear to be any significant solids buildup in the 3A section.

Section 3B showed a less consistent pattern of ball migration. In the first stage (which was made up of twelve wire-grid compartments), two of the compartments on the east side and one compartment on the west side had less than one layer of balls, whereas two middle compartments had 0.5 m and 1 m ball depths. A couple of breaks were noted in the grids separating the far east and middle compartments where ball migration could occur. The second stage had a uniform distribution of balls. The third stage of this section, however, had poor distribution. The south one-third of the stage had less than one layer of balls and the depth of the balls became progressively deeper toward the southwest corner of the scrubber stage. The only significant solids buildup noted was on the bottom of the first stage. Scaled areas covering about one-fourth and one-sixteenth of the cross-sectional area were seen in the middle of the bottom stage and of the northwest corner of the first grid, respectively.

Section 3C had the most significant solids accumulations. Approximately three-fourths of the bottom of the first stage was scaled over. A large mass (0.5-1 m diameter) of a very hard deposit of accumulated solids and balls was found in the east compartment of this stage. The bottom of the west compartment on the second stage was also scaled over. The third stage did not have significant solid deposits. Ball migration problems were not as evident in this section. The first stage had less balls on the east side of each compartment, varying by as much as 10 to 20 cm (4 to 8 in), while the second and third stages had reasonably good ball distribution.

The physical condition of the ball grids and scrubber liner was reasonably good. The most prevalent ball types found were a solid black rubber ball and a hollow green plastic ball. Less than 5% of the balls appeared to be broken or grossly worn. The support grids were intact with the exception of those noted above. However, it was observed that at the point of contact, overlapping grid wires apparently were "cutting" into one another. In many cases for the first stage, as much as 0.5 to 1 cm wear was observed. This is apparently due to vibration and movement of the strands when the scrubber is in service. The rubber scrubber liner, although found to be in fairly good condition overall, had some bubbles or blisters where the liner had popped off the steel underneath, especially in section 3B stage 1 and section 3C stage 2. There were also a couple of areas in section 3B stage 1 and section 3C stage 1 where pieces of the liner had come off, exposing the underlying metal.

Recirculating Slurry Pumps and Nozzles

The impellers of the slurry pumps were inspected from the suction side of the pump which had been opened for each pump. The rubber-covered impellers seemed to be intact and in good condition. Inspection was also made of the recirculating nozzles. Several of the nozzles were plugged: 7 of 14 in section 3A, 9 of 42 in section 3B and 7 of 14 in section 3C. The material causing the pluggage was mostly 0.6 to 1.0 cm rubber liner, possibly eroded from the recirculating lines. The orifices of several of the recirculating slurry nozzles were measured and did not show significant wear.

Mist Eliminator

The mist eliminator area was observed to be in very good condition with the exception of wash nozzle which had broken loose from its header. The chevrons, which were 316 SS, had very little solids deposit and did not show any gross signs of pitting or corroding. The alignment of the mist eliminator blades was also good.

Reheater Area

At the time of the inspection, only sections 3A and 3C had reheater coils in place. The coils were reasonably clean. There was a thin solids layer (<2 to 4 mm) on most of the coils with significant deposits (1 to 2 cm) found only on the bottom of the tubes in the lowest tube bundles. No pitting of the 316 tubes was observed. There was evidence of severe rusting and corrosion of the ducting which surrounds the coils. In section 3B, in which the reheater coils had been absent, there were several holes in the reheat duct area caused by excessive corrosion.

Ductwork and Dampers

The ductwork downstream of the scrubbers, the isolation dampers, and the bypass ductwork were inspected. The downstream ductwork was badly rusted for all three sections and large pieces of the corroded carbon steel ductwork could be easily pulled off by hand. The ductwork was set and in section 3C there was a wet solids accumulation as deep as 10 cm throughout. The inlet guillotine gates were closed and from a limited inspection appeared to be in good condition. The outlet dampers were rusted and corroded. None appeared capable of providing a tight seal and the bottom louver blade in 3C was mired in solids in a half open position (the other blades of the damper were closed). The bypass ductwork was found to have extensive, very hard deposits. The buildups were as much as 1 m deep throughout.

The Company representative who accompanied NEIC personnel on the inspections was knowledgeable of the problems present and how they would be fixed.

A follow-up inspection of the Unit 3 scrubber was conducted on August 24, 1977. The purpose of the inspection was to determine the thoroughness of the scrubber overhaul in light of the problems noted from the previous inspection and to inspect the new mist eliminator assemblies that were to be installed in sections 3A and 3C.

The solids in the presaturator and scrubber sump had been thoroughly removed. The pump intake lines were clear. The recirculating slurry nozzles had been cleaned. The new mist eliminator assemblies were in place and appeared to be properly installed. The reheat ductwork in 3B had had a plate installed to cover the corroded areas. The bypass ductwork area had been thoroughly cleaned out.

The ball sections had not been cleaned and balls had not been redistributed or added, although the Company representative stated that this would be done prior to startup. The areas where the scrubber liner had fallen off were not repatched.

Unit 4

A very limited inspection of the C section of the Unit 4 scrubber was conducted on August 14, 1977. The boiler unit had been brought down to inspect a leak in the boiler tubes. The only areas open for inspection were the presaturator area and the scrubber sump.

A layer of soft solids approximately 0.5 m deep was present on the presaturator floor. The presaturator nozzles, however, were clear and, in general, the presaturator area was in good shape. A small section (approximately 2 ft square) of rubber liner had come loose from one wall just downstream of the presaturator spray nozzles. The scrubber sump on the north side had its pump intake screen clogged with balls. The other two sumps were filled with water and their intake screens were not visible. The bottom of the first stage of the scrubber had significant solids buildup across approximately 15% of the cross-section. These deposits were noted on the presaturator side of the scrubber.

UPSET REPORTING

As discussed in the previous section, Public Service Company of Colorado has reported day-to-day malfunctions of the particulate control equipment. The data generated in these upset reports were used to review scrubber availability and the major sources of scrubber malfunctions.

Availability

Availability, as reported by PSCC, is defined as:

$$\text{Availability} = \frac{\text{Scrubber hours operation - hours boiler burning 100\% gas}}{\text{Boiler hours operation - hours boiler burning 100\% gas}}$$

A distinction is also made as to how "scrubber hours operation" is defined for each unit. For the Unit 1 and 3 scrubbers, the scrubber is considered to be operating when all sections of the scrubbers are in service. For the Unit 4 scrubber, the scrubber is considered to be operating if 3 of the 4 sections are in service.

Figure 9 shows cumulative 12-month availabilities for the scrubbers at Cherokee Station based on the above definitions. The data include the time period from when the scrubbers were initially put in operation until April 1977, after which time this recording method was discontinued.

Various trends can be identified from Figure 9. All scrubbers appear to go through an initial start-up/shake-down period when scrubber availabilities are low. As the initial problems were solved, availabilities gradually increased until a maximum point (>90% availability) was reached, typically 30 to 40 months after initial startup. Thereafter, the curves appear to take on more individual pattern reflecting the differences between units. The availability curve for Unit 3 began to sharply decrease after reaching the maximum, while the curve for Unit 4 has constantly remained above 90% availability. Unit 1 scrubber availability was not plotted for any significant period after reaching its maximum point but, because of its similarities to Unit 3 (i.e., no spare scrubber sections, limited weather enclosure, direct reheat, etc.), it would be expected to experience a dropoff in availability similar to that of Unit 3.

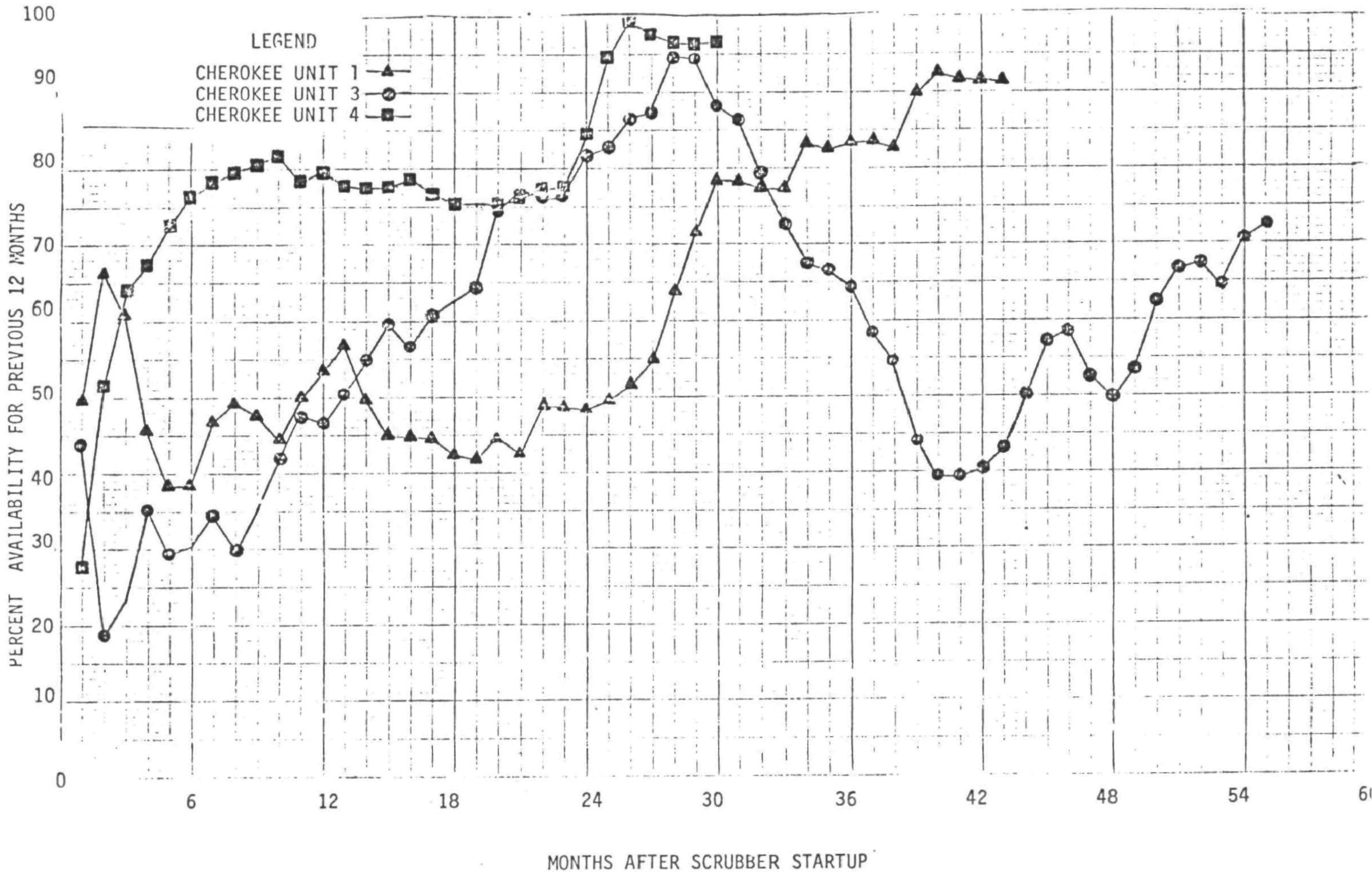

Figure 9: Cumulative Twelve Month Scrubber Availabilities, Cherokee Station, Public Service Company of Colorado

Table 13 shows the average availability for each year of scrubber operation. The overall averages for scrubber availabilities are:

Unit 1	65%
Unit 3	63%
Unit 4	84%

Equipment Upset Data

The upset reports provide information on equipment component malfunctions but the reports are not sufficiently comprehensive to allow a definitive scrubber equipment component evaluation to be made. The data do not show causes of failures nor do they allow differentiation between primary and secondary effects, i.e. whether breakdowns were caused by the equipment component itself or were associated with disturbances from other components. Furthermore, a number of months of data were either not available or too imcomplete to be included in this analysis. Finally, it was impossible to properly distribute downtime to equipment when more than one component required repairs during a given outage. As a result of these factors, only a broad definition of scrubber related problems is possible.

Table 14 shows estimates of relative contributions of various scrubber subsystems to scrubber downtime for each unit. The estimates are expressed as a percentage of the reduction in scrubber availability due to major areas for each 12-month period. The estimates are based on scrubber upset reports prepared by PSCC.

The most illuminating observation from Table 14 is that there are significant differences in problems causing outages between the various units. Major problem areas for the Units 1 and 3 scrubbers are the

Table 13

SUMMARY OF PERCENT SCRUBBER AVAILABILITY†
BY YEAR OF OPERATION
CHEROKEE STATION
PUBLIC SERVICE COMPANY OF COLORADO

Year	Unit 1 %	Unit 3 %	Unit 4 %
1	52	47	80
2	48	81	83
3	82	64	93*
4	90††	49	NA
5	NA	80††	NA
Average**	65	63	84

† *Availability* $= \dfrac{\textit{Scrubber hrs operation - hrs boiler burning 100\% gas}}{\textit{Boiler hrs operation - hrs boiler burning 100\% gas}}$

†† *Based on 7 months data.*

* *Based on 6 months data.*

** *Average is calculated by averaging the availabilities from each year.*

Table 14

MAJOR REPORTED PROBLEM AREAS CAUSING SCRUBBER MALFUNCTIONS[a]
CHEROKEE STATION
PUBLIC SERVICE COMPANY OF COLORADO

	Unit 1	Unit 3	Unit 4
Year 1	Oct. 1973-Sep. 1974 Data not available	Oct. 1972-Sep. 1973 Data not available	Nov. 1974-Oct. 1975 [b] Booster Fans 92% Isolation Dampers 3% Reheater 3% Other 2%
Year 2	Oct. 1974-Sep. 1975 [c] Reheater 51% Scrubber, Internals 21% [d] Booster Fans 21% Recirculating Slurry 3% [e] Other 6%	(Oct. 1973-Sep, 1974) Data not available	Nov. 1975-Oct. 1976 Booster Fans 90% Reheater 1% Other 9%
Year 3	Oct. 1975-Sep. 1976 Recirculating Slurry 58% Scrubber, Internals 33% Reheater 6% Other 3%	(Oct. 1974-Sep. 1975) [c] Reheater 42% Scrubber, Internals 13% Recirculating Pumps 4% Recirculating Slurry 2% Other 39%	Nov. 1976-Oct.1977 [c] Booster Fans 79% Recirculating Slurry 13% Isolation Dampers 3% Recirculating Pumps 2% Reheater 1% Other 2%
Year 4	Oct. 1976-Sep. 1977 [f] Recirculating Pumps 67% Scrubber, Internals 27% Recirculating Slurry 4% Booster Fans 1% Other 1%	(Oct. 1975-Sep. 1976) Reheaters 64% Booster Fans 14% Scrubber, Internals 12% Recirculating Slurry 9% Other 1%	NA
Year 5	NA	(Oct. 1976-Nov. 1977) [f] Recirculating Slurry 65% Reheater 21% Recirculating Pumps 12% Other 2%	NA

a *All data are estimates of scrubber equipment downtime taken from PSCC upset reports expressed as a percent of annual scrubber downtime.*
b *Based on 5 months reported data.*
c *Based on 6 months reported data.*
d *"Scrubber, internals" includes the scrubber grids, scrubber liner mobile balls and recirculating slurry nozzles.*
e *"Recirculating slurry" system includes the slurry drawoff, scrubber slurry hopper and recirculating slurry piping.*
f *Based on 7 months reported data.*

reheaters, scrubber internals, recirculating slurry system and recirculating slurry pumps. The major problem areas for the Unit 4 scrubbers are the scrubber booster fans.

The major problem areas for the Units 1 and 3 scrubbers in apparent order of importances are: reheaters, scrubber internals, recirculating slurry system and recirculating slurry pumps. The reheaters have resulted from corrosion and pluggage of the in-line steam coils. Typical problems with the scrubber internals include inspection, repair, and replacement of scrubber grids, scrubber liner, and mobile balls. Difficulties in the recirculating slurry system include repairing leaky recirculating slurry piping, unplugging the slurry drawoff line and removing slurry buildups in the scrubber hoppers. The recirculating slurry pump problems appear to mainly be due to bearing, packing and motor difficulties.

The major upset problems encountered in the Unit 4 scrubbers are almost exclusively due to scrubber booster fan malfunctions, and lack of other major problems can be attributed to improved design features. The scrubber booster fans are air foil fans which have been highly subject to erosion from fly ash carried over from the ESP's. Unit 4 is operated with one module as a spare, therefore maintenance to scrubber internals, recirculation pumps, piping, etc. can be routinely scheduled. Furthermore as critical scrubber problems occur and require repair, the affected scrubber section can be replaced with the spare section with relatively short-term opacity excursions. Unit 4 scrubbers also have indirect reheaters which are less subject to corrosion and plugging than are direct in-line heaters. Unit 4 scrubbers are totally enclosed, thus preventing significant freezing problems.

EVALUATION OF SCRUBBER PERFORMANCE AND OPERATION

The performance of the TCA scrubber were evaluated using the operating data collected during the study period, and data from previous stack tests, efficiency tests, etc. Prior to this analysis, Meteorological Research, Inc.[4] prepared an analysis of the particulate removal performance of the Cherokee Unit 3 scrubber. Their results and the results of this study are discussed in this section.

Table 15 shows the particulate removal performance data for the scrubbers on each unit based on recent stack tests and published reports. For each unit, a comparison is made between design values and actual values of grain loadings, efficiencies and powerplant load.

The scrubber particulate loadings are important in evaluating compliance with particulate regulations. In reviewing the data, it is noted that, with one exception, the outlet grain loadings show compliance with the process weight regulation requiring particulate emissions to be less than 0.1 lb per MM Btu heat input. The one exception is the average outlet loading of 0.14 g/std m^3 (0.06 gr/SCF) taken from data reported by MRI for November 1974. This loading may have been in excess of 0.1 lb per MM Btu, but could not be determined since the circumstances under which this data was taken could not be evaluated.

Opacity meter data [Table 15] and visible emission observations are also indications of outlet particulate loadings. However, it is significant to note that small particles contribute proportionately more to high opacities than to high particulate loadings. As a result, opacity and outlet particulate loadings are not directly related. The wide variations in opacity data are important because they reflect the wide fluctuations in scrubber operations.

Table 15

ACTUAL AND DESIGN PARTICULATE REMOVAL DATA FOR TCA SCRUBBERS
CHEROKEE STATION
PUBLIC SERVICE COMPANY OF COLORADO[a]

Unit	Unit Load MW	No. Oper. Scrubber Sections	Scrubber Inlet Particulate Loading		Scrubber Outlet Particulate Loading			Particulate Removal Eff.[b]	Visible Emiss. Observ.[c]
			g/std m^3	gr/ft^3	g/std m^3	gr/ft^3	lb/mm Btu	%	% Opacity
Unit 1									
Design	115	3	1.80	0.80	0.046	0.02	-	97.5	-
Actual (PSCC)	94	2[d]	-[g]	-	0.076	0.03	0.069	-	-
Unit 3									
Design	170	3	0.69	0.30	0.046	0.02	-	93	-
Actual (PSCC)	163	2[d]	-	-	0.069	0.04	0.069	-	5-60
Actual (MRI)[e]	160	3	0.87	0.38	0.14	0.06	-	84	-
Actual (MRI)[f]	160	3	1.58	0.69	0.097	0.04	-	94	-
Unit 4									
Design	375	4	1.60	0.70	0.046	0.021	-	97	-
Actual (PSCC)	345	3[d]	-[h]	-	0.047	0.02	0.050	-	5-40

a *Data in this table is taken from references, 1, 2 and 4. Actual data taken by Public Service Co. of Colorado is shown as (PSCC) and actual data taken by Meteorological Rearch, Inc. is shown as (MRI).*

b *Particulate removal efficiencies are not shown for actual PSCC data since inlet and outlet particulate loadings were not taken under similar conditions.*

c *Visible emission observations are from data taken by EPA-NEIC during July-August, 1977 and represent a wide range of operating conditions. These data are included in Appendices A and B.*

d *Sections 1A (Unit 1), 3C (Unit 3) and 4D (Unit 4) were not in service during these tests.*

e *This data is based on tests reported in reference 4 for the dates 11/7/74 - 11/19/74.*

f *This data is based on tests reported in reference 4 for the dates 12/10/74 - 12/12/74.*

g *Actual PSCC data incomplete.*

h *Actual PSCC data not reported because recent tests not available.*

The data in Table 15 show that the actual scrubber outlet loadings for Units 1 and 3 exceed the design values. To investigate the cause and significance of this observation, it is necessary to consider some of the factors which affect the outlet particle loading, i.e., the scrubber inlet particulate loading and the scrubber's particulate removal efficiency. The outlet particulate loading is related to the inlet loading and scrubber efficiency as follows:

Outlet particle loading = Inlet particle loading x (1 - efficiency)

The inlet loading to the scrubber is dependent on a number of factors including: the coal that is being fired, the boiler operation, the mechanical collector/ESP operation and addition of conditioning agent. With such a variety of factors, it is not unexpected that there are reported differences in inlet particulate loadings between units and between the same unit at different time periods. A more significant observation is that actual scrubber inlet particulate loadings can and do significantly exceed design values. Although the scrubbers have some inherent capability for removing excess particulate, it is not known how large an excess can be handled or for how long. In Section V, information reported in PSCC upset reports has shown violations of the 20% opacity standards (as measured by the opacity meters) due to ESP malfunctions. Since these violations occurred when the scrubber was in service, it must be concluded that the scrubber outlet particulate loading can exceed standards even when the scrubber is not in an upset condition. Therefore, it is important that the mechanical collector/ESP efficiency be improved and maintained at optimum conditions. Operation of the ESP's at 40 to 60% efficiency is not acceptable.

Very limited scrubber efficiency data is available for the scrubber installations at Cherokee. From data developed from other mobile bed contactors it is expected that particle collection efficiency will be dependent on gas flow, liquid flows, and state of motion of the mobile contactor beds as indicated by pressure drop.[7] In addition, it is important to recognize that nonuniformities such as gas flow imbalances, liquid flow imbalances, solids pluggage, etc. play an important role in determining the particulate removal efficiency of large-scale scrubber installations. These are reviewed in the following discussion.

The only available efficiency data for the Cherokee Station is presented in the MRI study. In their initial set of tests (average particulate removal efficiency of 84%), they found flow and outlet particle loading imbalances between sections of the Unit 3 scrubber. To correct this, the scrubber was shut down, some of the mobile bed packing was redistributed and a clogged reheater was partially cleaned. Efficiency tests conducted subsequent to this shutdown showed improved efficiency (average efficiencies of 94%). MRI also analyzed the scrubber outlet particulate and found a high concentration of soluble components indicating that liquid entrainment was occurring to a significant degree. MRI concluded that the scrubber performance data they obtained reflected specific scrubber conditons and that general scrubber particulate removal efficiency correlations could not be developed from the data.

The scrubber operating data accumulated during the study also relected a wide range of operating conditions. Table 16 shows gas flow, liquid flow and pressure drop data taken during the study. The data was taken from instrumentation located in the boiler control rooms.

The gas flow data are shown in terms of scrubber booster fan motor amps. These data present little basis for analysis since fan motor amps are also a function of pressure drop and fan/motor efficiencies. It does appear, however, from data taken for Unit 4, that the gas flow is

Table 16

SCRUBBER OPERATING DATA
CHEROKEE STATION
PUBLIC SERVICE COMPANY OF COLORADO

Unit	No. of Observa-tions	Load	Scrubber Booster Fan	Recirculating Slurry Pump			Pressure Drop			
				1	2	3	System Unit	Mobile Beds	Mist Elim.	Reheater
		MW	Amps†	Amps			cm H_2O			
Unit 1	42	84-119	130-150(A) 125-153(B)							
Section A				0-24	NA††	NA	24-50	7-23	2-13	5-28
Section B				21-22	20-28.5	0-24	24-50	10-24	1-7	2-14
Unit 3	4	110-152	190-220(A) 180-220(B)							
Section A				20-24	NA	NA	27-34	15-23	0-1	2-3
Section B				25	22	20-21	27-34	14-18	3-4	NO†††
Section C				NO	NA	NA	27-34	8-10	1-2	1-3
Unit 4	44	253-360								
Section B			200-250	12.5-13	15-16	12-14	NO	10-29	2-3	NO
Section C			220-240	11-13	0-14	12.5-15	23-58	11-38	1-5	1-5
Section D			225-245	11-14	11.5-14	12-14	18-38	10-25	5-7	NO

† *Fans on Unit 1 and 3 scrubbers provide common flow to the scrubbers.*
†† *Not applicable.*
††† *NO = indicating meter not in operation.*

reasonably well distributed between the three scrubbing sectons. No observation can be made for flow distribution between sections in the Unit 1 and Unit 3 scrubbers since these do not have individual fans for each section.

More conclusive data on gas flows are shown in Table 17. These data were taken from recent stack tests performed for the units and are compared against design values. It is noted that in all cases of reduced scrubber section operation the superficial scrubber velocity is 4.8 to 5.8 meters per second (mps) as compared to a design maximum of 40 mps. Furthermore, even under "normal operation" for Units 3 and 4 (4.7 and 4.8 mps superficial velocity, respectively), the design maximum velocity is exceeded. Although this has apparently not affected compliance with the process weight regulation, it can result in improper bed fluidization and high liquid entrainment. Above superficial gas velocities of about 4.0 mps, it has been shown that pressure drops and bed expansion increase to the point where mobile spheres are held up at the top of the retaining grids.[7] Liquid entrainment also increases when gas velocities increase, and can become severe when the velocities are 4 mps and higher.[8]

The distribution of gas flow between scrubber sections on Units 1 and 3 could not be determined from operating data accumulated during this study. However, field measurements made by MRI during 1974 do show the magnitude of typical gas flow variations. Figures 10 and 11 show sets of gas velocity profiles taken before and after the Unit 3 scrubber had been cleaned, balls redistributed, and reheater partially cleaned. Theoretically, the profiles should be reasonably close to one another, but as shown in the curves, the average velocities between sections can vary by as much as 3 to 1. This type of variation indicates that even if the bulk scrubber gas velocity (as calculated in Table 17) is within proper design limits, the velocities within each section may be outside the range required for proper operation of the beds. Overall particulate removal may be reduced and liquid entrainment can be significantly increased.

Table 17

DESIGN VS ACTUAL VALUES OF SCRUBBER SUPERFICIAL VELOCITIES AND LIQUID-TO-GAS RATIOS (L/G)
CHEROKEE STATION
PUBLIC SERVICE COMPANY OF COLORADO†

	Actual Conditions		Scrubber Operation††		Reduced Scrubber Operation*	
	m^3/hr	ft^3/min	Velocity (mps)	L/G ($1/m^3$)	Velocity (mps)	L/G ($1/m^3$)
Unit 1						
Design	730,000	430,000	4.0**	7.7	4.0	7.7
Actual	730,000	430,000	4.0**	7.7**	5.4	4.3
Unit 3						
Design	850,000	500,000	4.0	7.0	4.0	7.0
Actual	1,000,000	590,000	4.7**	5.9**	5.8	3.9
Unit 4						
Design	2,200,000	1,300,000	4.0	7.9	4.0	7.9
Actual	2,100,000	1,200,000	3.7	8.6	4.8**	4.8**

† *Data is representative of scrubber conditions (52°C or 125°F) at full load and is taken from references 1, 2 and 4. Design flowrates are design maximums. Actual flowrates are calculated from representative stack test and precipitator outlet data.*

†† *"Full scrubber operation" assumes all scrubber sections in service.*

* *"Reduced scrubber operation" assumes one section of the scrubber out of service as follows: 1A in unit 1, 3A or 3C in unit 3, any one section in unit 4.*

** *Indicates normal operation for scrubber unit.*

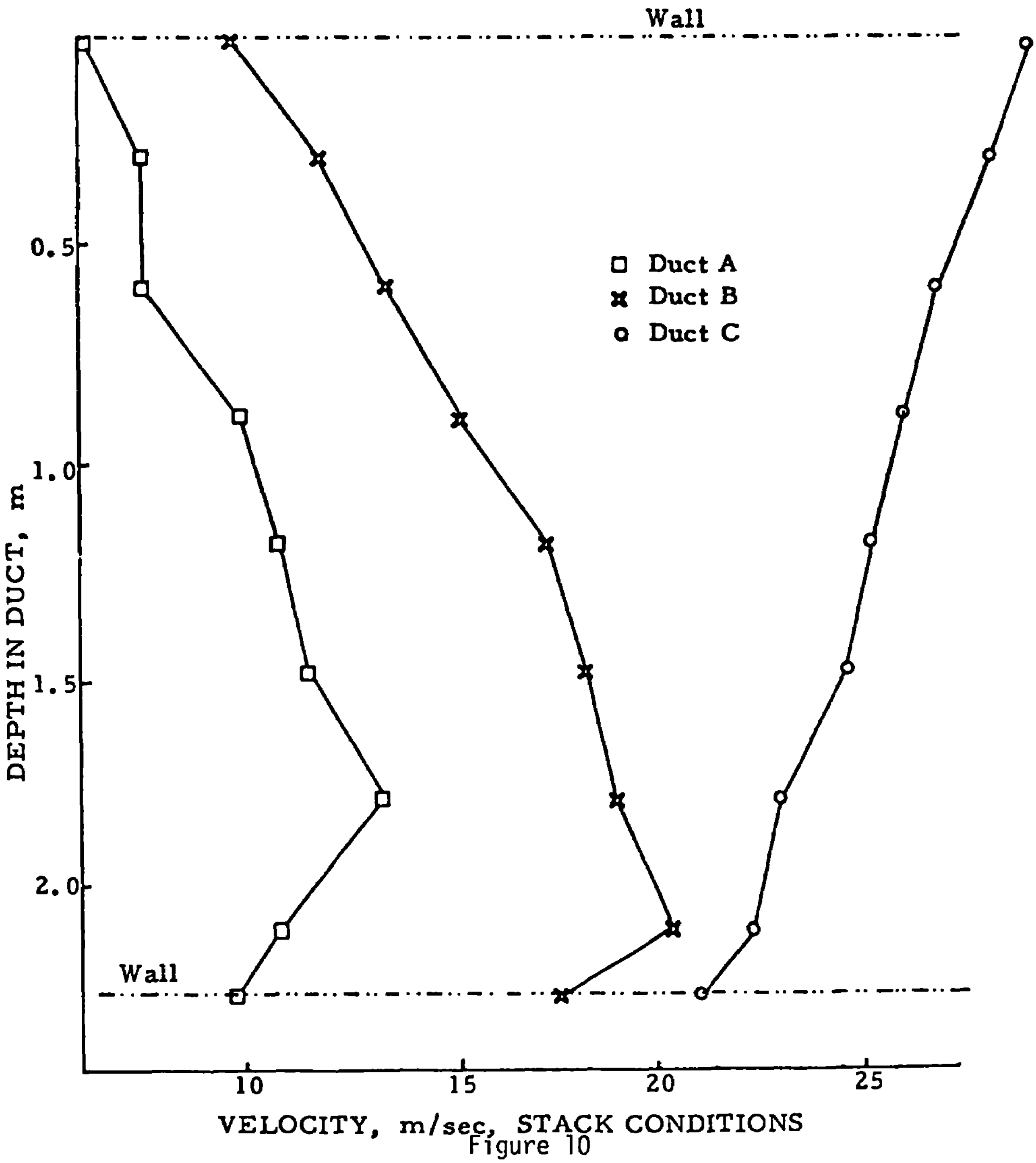

Figure 10
Velocity Profiles for Outlet Ducts Before Cleaning
Cherokee Unit 3 Scrubber (11/18/74)
Cherokee Station
Public Service Company of Colorado[4]

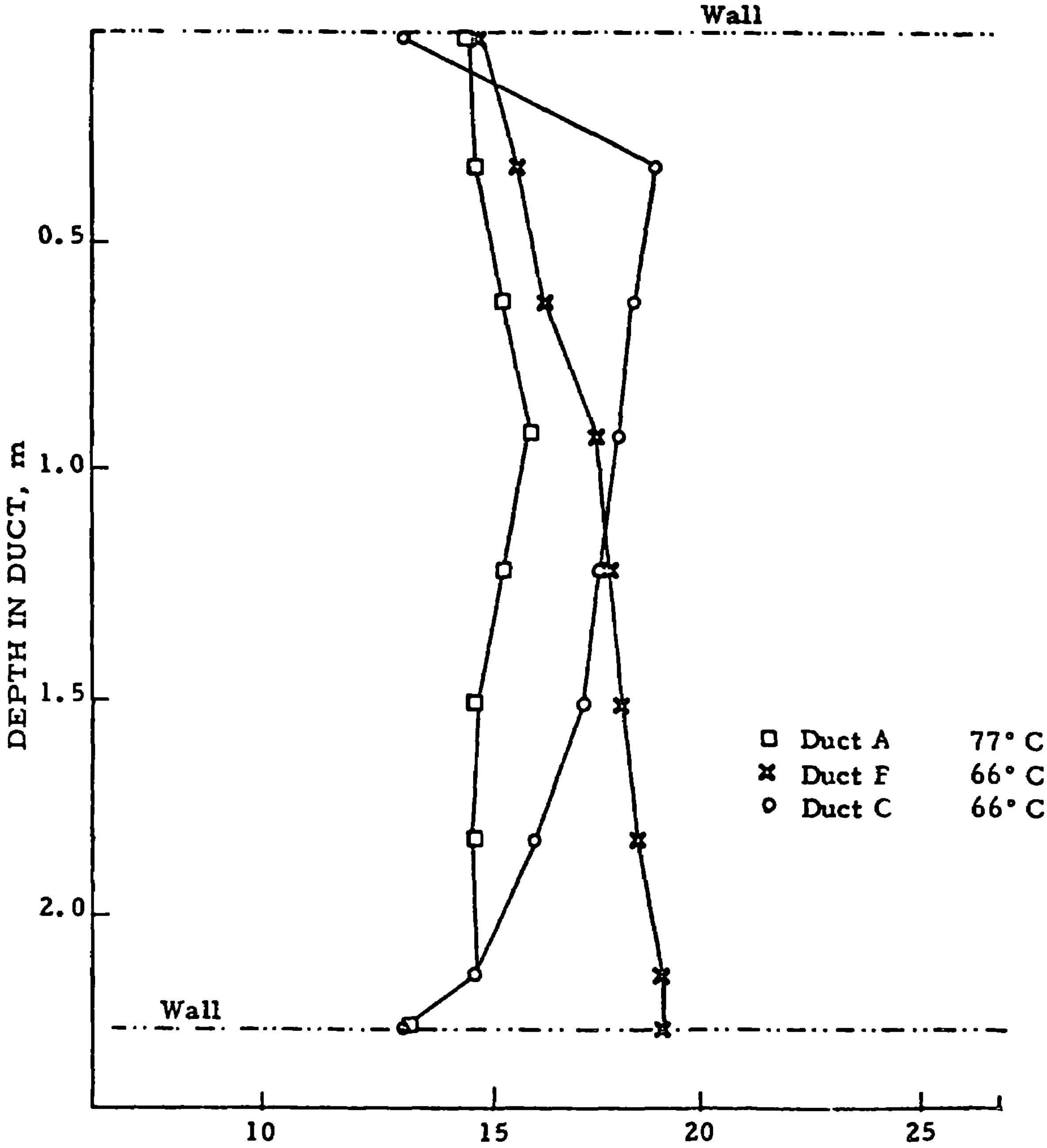

Figure 11. Velocity Profile for Outlet Ducts of Unit 3 Scrubber (12/10/74) After Cleaning
Cherokee Station
Public Service Company of Colorado[4]

Table 13 also shows variations in liquid-to-gas (L/G) ratios under various full load conditions. Once again, there is a significant departure from design L/G values under "normal" scrubber operations (Units 3 and 4 only) and under "reduced" scrubber operations (all Units). In general, decreasing the L/G ratio (with constant gas velocity and pressure drop) is expected to reduce particulate removal; however, no precise quantitative relationships could be developed from available literature to indicate the expected decrease in particulate removal.

More significant observations of liquid flow rate variation are shown in Table 12. For sixteen of the observations (6 days) on Unit 1, the pump in the single-pump scrubber section (Section 1A) was not in service. Obviously, under these conditions, the particulate removal in that section of the scrubber is very much reduced. Furthermore, prolonged exposure of the scrubber internals to these conditions (where scrubber temperatures approach 90°C (200°F) even with some water introduced continuously through the mist eliminator nozzles, may cause the rubber liner to blister and creep and cause deformation of the plastic sphere.

Minor instances of 1 to 2 day's duration were also observed where one of the three pumps in a scrubbing section was out of service. These cases are not as critical since scrubber internals are not severely affected and overall particulate removal may not be significantly reduced depending on ΔP and gas velocity values.

When the current to a given recirculating pump motor is below levels that, by experience, indicate pump or line problems (11 amps on Unit 4 pumps and 20 amps on Units 1 and 3 pumps) an immediate investigation is reportedly made. Typically the problem is one of a plugged suction line and backflushing is initiated. However, as noted in the Unit 3 scrubber inspection, plugging of recirculating spray nozzles may also be occurring and this cannot be detected without an internal scrubber inspection. Besides reducing scrubber liquid flow, plugged nozzles can cause liquid maldistribution and, if extreme, can lead to improper fluidization of the scrubber bed.

The pressure drop (ΔP) across the mobile bed could be expected to be a primary indicator of the particulate removal performance and of the conditions within the bed such as fluidization, gas channeling, etc. Particulate removal performance as a function of ΔP was studied by MRI with a limited amount of data. Table 18 shows the results of that study in which no correlation could be found between particulate removal efficiency and pressure drop. Instead, as noted previously, MRI attributed the variations in particulate removal efficiency to numerous operating factors in existence at the time of their tests.

The pressure drop recorded across the mobile beds should also provide an indication of the conditions within those beds. It was stated by the Company that pressure drops of less than 15 to 20 cm (6 to 8 in) water column (W.C.) at full load are an indication that gas channeling is occurring within the scrubber. At the other extreme, the manufacturer's operating limitations[1] state that the scrubber should not be operated above 30 to 35 cm (12 to 14 in) W.C. due to bed expansion and problems caused by mobile packing held up against the retaining grid. This latter condition can result in flooding within the scrubber. Instances when pressure drops were outside of the lower and upper limits are shown in Table 19.

Interpretation of the pressure drop data in Table 19 is not straight forward. The data indicate, that channeling was occurring in Unit 1 (sections 1A and 1B) and Unit 3 (section 3C), whereas flooding may have been occurring in Unit 4 (section 4A). However, to put the data in proper perspective, it is necessary to compare the Unit 3 pressure drop data with subsequent inspection observations that were made when the scrubber was taken out of service. These inspections indicated that the

Table 18

SCRUBBER COLLECTION EFFICIENCIES - UNIT 3
CHEROKEE STATION
PUBLIC SERVICE COMPANY OF COLORADO

DATE	LOAD	O_2	OUTLET GAS FLOW ACTUAL	SECTION A				SECTION B				SECTION C			
				ΔP SYSTEM	ΔP BED	ΔP MIST ELIMIN.	EFF.	ΔP SYSTEM	ΔP BED	ΔP MIST ELIMIN.	EFF.	ΔP SYSTEM	ΔP BED	ΔP MIST ELIMIN.	EFF.
	mw	Percent	m^3/hr	cmH_2O	cmH_2O	cmH_2O		cmH_2O	cmH_2O	cmH_2O		cmH_2O	cmH_2O	cmH_2O	
11/20	166	3.6	[a]	41	9.9	0.76	ND	45	25	2.5	84.7	46	24	8.3	ND
11/21	164	3.4	[a]	39	9.6	0.76	ND	43	18	1.8	89.9	44	20	5.1	ND
12/10[b]	157	3.4	9.47×10^6	36	15.2	1.7	96.3	41	20.8	2.5	92.6	41	18.5	3.8	86.9
12/11	160	3.0	10.2×10^6	38	14.7	1.5	96.4	42	22.1	3.2	93.2	44	22.4	2.5	96.7
12/12	160	2.6	8.78×10^6	38	14.7	1.8	79.6	44	22.9	2.5	93.1	46	24.1	3.8	92.1

[a] Full velocity traverses were not taken.
[b] The control room data were incomplete. Interviews, data from other days and the log book were used to supplement available information.

Table 19

PRESSURE DROP FOR SCRUBBER MOBILE BED SECTIONS DURING FULL LOAD CONDITIONS CHEROKEE STATION PUBLIC SERVICE COMPANY OF COLORADO

Unit	Load	Total No. of Observations	No. of Observations ΔP bed <15 cm W.C.	No. of Observations ΔP bed >35 cm W.C.
Unit 1	≥115 MW			
Section A		22	18†	0
Section B		22	12	0
Unit 3	≥145 MW			
Section A		3	0	0
Section B		3	0	0
Section C		3	3	0
Unit 4	≥350 MW			
Section B		26	5	0
Section C		26	0	16
Section D		26††	2	1

† *Includes 10 observations when 1A1 recirculation pump was out of service.*
†† *Includes 2 observations when section 4D ΔP bed instrumentation was out of service.*

low pressure drop in section 3C was due to low flow resulting from heavy solids accumulation in both the presaturator and scrubber bed. On the other hand, the inspection revealed that gas flow channeling was existing in other sections (especially section 3A) but was not indicated from pressure drop instrumentation. This may have occurred because the sections were forced to handle higher than design gas flow rates.

It should also be recognized that the type of packing also influences the pressure drop. Studies performed at West Virginia University[1] showed that pressure drop was, in part, dependent on the physical properties of the packing (e.g. shape, weight, size). With the different types of balls being used in the scrubbers and the added problems of ball migration, interpretation of pressure drop measurements is further complicated.

The operating data collected during the scrubber performance evaluation is not conclusive. It is evident that the scrubber sections are typically operated at gas velocities, liquid flowrates and pressure drops outside of design ranges. It is also evident that scrubber instrumentation does not consistently indicate when internal scrubber problems, such as ball migration, gas flow channelling, and solids deposition, are occurring.

EVALUATION OF SCRUBBER SYSTEM RELIABILITY

From the previous discussion, it is apparent that even if 100% of the gas is flowing through the TCA scrubber, the scrubber may not be capable of meeting applicable particulate regulations. Scrubber availability is, therefore, not an adequate measure of scrubber performance. Instead, it is necessary to introduce the term "reliability". Reliability, as used in this report, will be defined as: the percent of time the boiler is on-line that the particulate control systems are operating and meeting applicable particulate regulations.

To adequately review reliability in light of the existing Cherokee Station scrubber operation, it is important to consider the individual equipment components which appear to have the largest impact on scrubber reliability. In their May 1975 study, which appears as an appendix to the MRI evaluation,[4] Stearns-Roger, Inc. identified components presenting major maintenance problems for the Unit 3 scrubber. Those problems and problems which appear to contribute significantly to current scrubber reliability deficiencies are shown in Table 20. As can be seen, most of the problems identified in the earlier study are still present. The major reliability problem components are reviewed individually in the following discussion.

Wear of Mobile Bed Contactors

Prior to this survey, PSCC had extensively tested balls of varying compositions and designs and indicated that the ball wear problem was their major maintenance item. As the balls were exposed to turbulent conditions in the scrubber, they would wear out, break apart, dimple, etc. The fluidization of the bed was disturbed and balls migrated to cause flow channeling in the scrubber and wear problems in other components of the scrubber system. Obviously, the particulate removal ability of the scrubber was then reduced and the scrubber had to be taken out of service to redistribute balls, replace balls, etc.

PSCC has evaluated balls made of a number of different materials including polyethylene, polypropylene and thermoplastic rubber but has now stated that a polyethylene ball of unique construction provides what they consider to be adequate resistance to wear. (A ball providing "adequate" resistance to wear is expected to have a useful life of about one year.) The ball is a hollow green-colored sphere manufactured by Puget Sound Trading Co. The unique feature of the ball is that it has crimps or indentations which tend to give it greater strength. Reportedly, the indentations also cause the ball to acquire a characteristic

Table 20

PROBLEM AREAS IDENTIFIED IN SCRUBBER RELIABILITY EVALUATIONS
CHEROKEE STATION
PUBLIC SERVICE COMPANY OF COLORADO

Major Scrubber Problem Areas Identified in May 1975 Study, Unit 3	Scrubber Reliability Problem Areas of Major Significance Identified in NEIC Study		
	Unit 1	Unit 3	Unit 4
Breakage of mobile bed contactors	Wear of mobile bed contactors	Wear of mobile bed contactors	Wear of mobile bed contactors
Migration of mobile bed contactors	Migration of mobile bed contactors	Migration of mobile bed contactors	Migration of mobile bed contactors
Guillotine dampers	Isolation dampers	Isolation dampers	Isolation dampers
Recirculation pumps	Recirculation pumps	Recirculation pumps	-
Reheater Section	Reheater Section	Reheater Section	Reheater Section
Rubber lined piping	Recirculation piping and nozzle	Recirculation piping and nozzle	Recirculation piping and nozzle
Presaturator buildup	Presaturator buildup	Presaturator buildup	-
Mist eliminators	Mist eliminators	Mist eliminators	Mist eliminators
Stack damper interlock system			
Recirculation system venturi flow meter			
Scrubber booster fan bearings	Scrubber booster fan	Scrubber booster fan	Scrubber booster fan
Weather related problems	Weather related problems	Weather related problems	-
	Outlet ductwork	Outlet ductwork	Outlet ductwork

spin. This, in turn, results in ball wear in one or two spots rather than at a number of points from which a ball can break into pieces.

The green polyethylene ball is still not ideal and PSCC indicates that they continue to search for an improved design. When the green ball does wear it fills with scrubber slurry and falls to the bottom of the stage. Proper turbulent contact is then difficult to maintain within the scrubber if a significant number of the balls are worn.

No matter what ball is used, operating the scrubber with large flow imbalances is still a significant problem. Certain portions of the scrubber are exposed to high ball wear whereas other areas may see minimum or negligible ball wear. A possible solution to this ball wear problem may be to replace the mobile packing with stationary packing. PSCC does not consider this alternative to be feasible, mainly because they feel that Universal Oil Products will no longer stand behind the scrubbers if such a radical change is made.

The use of an open-type packing has been investigated in tests performed by Southern California Edison at the Mohave Generating Station in 1974 and 1975.[9] A polygrid "egg crate" packing was used consisting of plastic grids 3 cm thick with 5 cm square openings, stacked to a depth of 43 cm in each of three stages. The scrubbing liquid was a limestone slurry. The results of the study indicated that high particulate removal i.e. >90%, could be achieved [Figure 12]. Although a limited number of tests were conducted and problems with scaling were not evaluated, the use of open packing appears to be very promising.

Migration of Mobile Bed Contactors

The other major ball problem affecting scrubber operation is ball migration. Balls migrate due to ball wear, ball breakage, and breaks

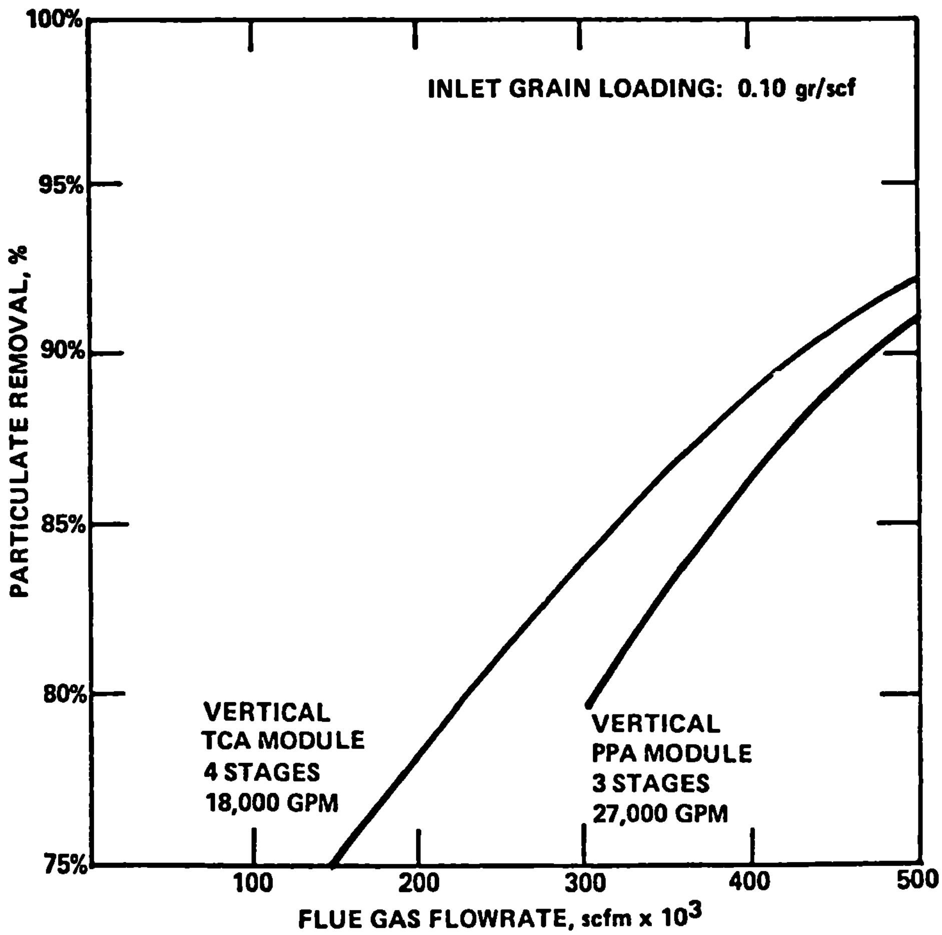

Figure 12. Particulate Removal Tests for a Vertical Scrubber Using Different Types of Packing[9]

in the partitions separating ball compartments. As in the case of the ball wear problem described previously, scrubber particulate removal performance decreases and downtime for repair increases.

PSCC has reduced some of the problems brought about by ball migration by placing screens on the suctions to the recirculation pumps. Previously, balls would circulate through the system, cut pump linings, plug nozzles, etc. The problem of migration within the scrubber still remains, however. The migration problem is not always readily determined from pressure drop data as was noted in previous discussions. Obviously, frequent inspections and replacement of worn grids and balls is an important factor in minimizing ball migration between compartments. Another potential solution is to replace the mobile packing with stationary packing.

Isolation Dampers

On-going isolation damper problems have plagued the TCA scrubbers since these began operation. Inlet dampers accumulate ash deposits and are exposed to varying gas temperatures and conditions. Outlet dampers accumulate sludge deposits from scrubber carryover and are exposed to varying gas temperatures and conditions depending on scrubber mist eliminator and reheater operation. As a result, the gates and lower blades warp; they are difficult to operate and are hampered by gas leaks into drive trains, couplings, etc.

The best available approach to minimizing the isolation damper problem is to improve the damper operating conditions. At the inlet, this would involve reducing particulate loading by optimizing ESP performance as much as possible. At the scrubber outlet, it would be necessary to minimize flow imbalance and liquid entrainment problems and improve the operation of the reheaters. In addition, it may be necessary to routinely exercise isolation dampers similar to what is currently being done for the stack bypass dampers.

Recirculation Pumps

Although a number of major pump problems had been solved during initial scrubber operations, problems with recirculation pump operation still remain. However, in view of the rugged duty to which these pumps are subjected, e.g. fly ash slurry, almost continuous operation, etc., some problems must be expected. It may not be possible to significantly improve the existing slurry pump operation. Major maintenance and repair areas include pump motors, bearings and packing.

The major problem, as noted previously, is where a scrubber section has only one recirculating pump (sections 1A, 3A, and 3C). When the pump is inoperable, either the scrubber section must be taken out of service or it must be operated with no recirculating slurry. The former condition results in reduced scrubber capacity whereas the latter causes severly limited particulate removal performance and possible exposure of scrubber internals to adverse high temperature conditions. Possible solutions to this problem are to install additional pumps on the existing one-pump sections or to pipe all the recirculating slurry pumps for a given unit to a single manifold which would feed all the scrubber sections of that unit.

Reheater Section

There have been numerous problems in the operation of the stack gas reheaters. The direct reheaters on Units 1 and 3 have been subject to pluggage due to carryover from the scrubbers and to corrosion. The reheaters on all three units have been plagued with an inability to provide sufficient reheat of scrubbed gases.

When the direct reheaters on Units 1 and 3 get plugged, the scrubber section is taken out of service for cleaning. The plugging is thought to be caused by water droplets being carried over from the scrubber. When the droplets evaporate, solids which were originally present as dissolved and suspended solids deposit on the in-line coils. Early efforts by PSCC to minimize plugging of reheaters included increasing the number of soot blowers and replacing finned-tube coils with bare-tube coils. Since then PSCC has also attempted to improve mist eliminator performance by installing new mist eliminator designs, but these tests have not yet been evaluated by PSCC. With the gas and liquid flow imbalance problems previously noted, it is questionable whether the new mist eliminator designs will significantly improve the reheater plugging problem. The soundest approach to solving the plugging problem appears to be replacing the direct reheaters with indirect reheaters similar to those now in operation on Unit 4.

Corrosion of the in-line reheater tubes has led to tube failure and resulting scrubber down time for repair. Corrosion is believed to generally occur under the deposits that form on the tubes.[10] Originally the tubes at Cherokee were carbon steel, but after repeated tube failure, PSCC replaced the carbon steel tubes with 316 SS. These have proven to be successful thus far. However, it has been pointed out in other powerplant scrubber applications[10] that 316 SS is highly vulnerable to failure to chloride stress corrosion. A long term solution, as noted above, would be to use indirect reheaters.

The available reheat from the reheater system has been found to be insufficient (less than design) in all three scrubbers. When the reheat is not adequate, condensation occurs in the outlet ductwork and stack, causing corrosion of these components. Also, inadequate reheat results in droplet carryover problems, giving false opacity meter readings.

The cause of inadequate reheat appears to be due to solids buildup on in-line reheater tubes (Units 1 and 3), corrosion of in-line reheater tubes (Units 1 and 3), and presence of liquid entrainment levels (all units). PSCC has reportedly conducted heat balances for the stack gas reheaters. These have shown that much more heat from the steam was used than is necessary for the sensible heat required to provide the stack gas temperatures that are actually measured. Table 21, which shows design and actual observed stack gas exit temperatures, indicates that average stack exit temperatures ranged from 46 to 67°C (115 to 153°F) or about 12 to 40°C (20 to 70°F) less than design values.

Solid buildup on in-line reheater tubes affects reheat by reducing the heat transfer from the tubes to the stack gas while corrosion of in-line reheater tubes not only restricts heat transfer but also can cause leaks resulting in loss of steam. Improvement of these problems was discussed previously. The problem of high lquid entrainment requires improvement in the mist eliminator collection efficiency and/or gas flow distribution in the scrubber.

Recirculation Piping and Nozzles

The recirculating slurry contains fly ash which is composed of very abrasive constituents such as silicon dioxide (SiO_2) and aluminum trioxide (Al_2O_3). As a result, the rubber lining of the pipes is subject to highly erosive conditions, especially where the slurry impinges directly on the liner. This occurs at pipe bends of Y's and locations where the rubber liner is incorrectly applied and surface liner irregularities are formed. When the liner begins to erode, chunks of rubber are broken away and lodge in recirulating slurry nozzles. As the liner continues to erode at a given location, accelerated wear takes place and an increasingly irregular surface is formed. When the liner has been stripped from the pipe, the underlying metal is also exposed to corrosive attack from the low pH slurry.

Table 21

DESIGN AND ACTUAL VALUES† OF STACK GAS TEMPERATURES
CHEROKEE STATION
PUBLIC SERVICE COMPANY OF COLORADO

Parameter	Unit 1		Unit 3		Unit 4	
	°C	°F	°C	°F	°C	°F
Design	93	200	85	185	79	175
Actual (Average)						
Section A	53*	128	46	115	50	NO††
Section B	62	144	65	149	56	132
Section C	NA**	NA	48	118	64	148
Section D	NA	NA	NA	NA	67	153

† *Actual values are those noted in July-August 1977 observations from instrumentation reading.*
†† *NO = Not in operation during July-August observation period.*
* *Unit 1, Section 1A values do not include observations made when the recirculation pump was out of service.*
** *Not applicable.*

Erosion and corrosive attack on the slurry piping will result in reduced scrubber performance and availability. Clogged nozzles will reduce liquid slurry flow rates. Holes in piping will require that scrubber sections be taken down for repair.

The problem of corrosive and erosive attack on piping is impossible to avoid in particulate scrubbers operating on powerplants. Resulting problems can, however, be minimized to some extent by an ongoing inspection system. During shutdowns, nozzles should be inspected for rubber liner pieces. Devices, such as sonic detectors, can be used to measure pipe thicknesses at critical wear points. Nozzle plugging can be minimized to some extent by replacing nozzles with flow diverter cones which essentially have no internal parts to clog.

Presaturator Buildup

Solids accumulate in the presaturator section in the area around presaturator spray nozzles called the wet-dry interface. In this area, the presaturator surfaces are alternatively exposed to the hot, dusty, gas stream and to the cool, wet, presaturator spray. A solid buildup results, and as the size of the buildup increases, parts of the buildup can break loose, fall into the scrubber hopper and plug the recirculation pump inlet screens. In addition, as noted in the Unit 3 inspection, the presaturator buildup can reach the point where gas flow is restricted and the flow balance is altered not only within the scrubber section but also between scrubber sections. Besides affecting screen plugging and flow balance, presaturator buildup may form hard deposits which require extreme methods for removal, such as using a jackhammer to break up the solids. Damage to the underlying presaturator surface then may result.

PSCC has attempted to minimize the presaturator buildup problem by directing the nozzle sprays so that they point 45° into the scrubber rather than being oriented at 90°, i.e., vertical. This modification has apparently helped to some degree but, based upon the Unit 3 equipment inspections, there is still a need for frequent inspection and cleaning to prevent excessive presaturator deposits from developing. This is especially true for Units 1 and 3 where flow distribution problems are more inherent and where spare modules are not available.

Other modifications to further reduce the solids buildup problem might include reducing the inlet particulate loading and providing a means to constantly wet the wet/dry interface area. Decreasing the inlet particulate loading could be achieved by improving the ESP collection efficiency. Wetting the presaturator area might be accomplished by irrigating the bottom surface from a pipe located just upstream of the wet/dry surface.

Mist Eliminators

The mist eliminator installations have presented continuing difficulties in the operation of the Universal Oil Products scrubbers. Problems have arisen in two areas: high pressure drop, and high mist entrainment. The high pressure drop problem was thought to be caused by the initially installed FRP mist eliminators which may have tended to "flutter" when the scrubbers were in service. This problem has reportedly been solved by the substitution of 316 SS mist eliminators.

The problem of high mist entrainment is indicated by the outlet particulate analyses conducted by MRI and by the reheater heat balances conducted by PSCC. Obviously, high carryover not only affects reheater performance but also accounts for decreased scrubber availability due to reheater pluggage from solids carried over with the entrained mist.

Furthermore, mist carryover can cause a high percentage of submicron particulate to be emitted which may not contribute much to the total weight of particulate emissions, but can have a significant adverse impact on the opacity of those emissions.

The problems of high mist carryover can originate from a number of sources. Based upon equipment inspections and discussions held with the Company, mist eliminator blade alignment and mist eliminator plugging are not significant trouble areas. However, sources which may directly or indirectly contribute to high mist carryover are: the heavy mist eliminator inlet loadings, gas flow, liquid entrainment maldistribution, inadequate mist eliminator removal efficiency, and re-entrainment. Unfortunately, very limited droplet loading, mist particle size, and flow distribution measurements have been made for the mist eliminator; however, it must be pointed out that well-developed droplet measuring methods are not presently available. It is apparent, nonetheless, that there are significant gas and liquid flow distribution imbalances to the mist eliminators. This is indicated from velocity measurements, evidence of gas flow channeling within the scrubber, and plugged water nozzles. It is not certain how these imbalances are propagated through the mist eliminator, although the normal ΔP across the mist eliminator (typically 2 to 5 cm W.C.) is probably not sufficient to even out significant flow imbalances.

The Company approach to reducing mist carryover is to improve the removal efficiency of the mist eliminators by using a more efficient design. They have installed new mist eliminator designs in section 3A (Heil Model EB4) and section 3C (Munters Model T271). The Universal Oil Products manufactured chevron unit is a 3-pass mist eliminator with a 90° angle between blades and an offset distance between blades of approximately 4 cm. The Munters Model T271 is a chevron type mist eliminator but is composed of trapeze-shaped separating walls with integral liquid drainage channels. The offset distance between blades is about 5 cm. The Heil Model EB4 is a 4-pass chevron with 4 cm offset between blades. The mist eliminator uses hooks to collect moisture and minimize pressure loss due to turbulence.

Table 22 presents a comparison of the design features of the existing mist eliminators in service. Although the new mist eliminator designs may provide some advantages, it is difficult to reach conclusions from the data presented in the Table. However, there is strong evidence to indicate that more extreme mist eliminator design changes may be required to provide acceptable mist reduction.[11] Potential changes include using a vertical mist eliminator or a two-stage mist eliminator.

The major difficulties which result from the Company mist eliminatcr program are twofold. First, to properly improve mist eliminator design, the conditions under which the mist eliminator is operating must be fully understood. Questions which must be answered include: How significant is the gas flow distribution problem? What mist carryover loadings, drop sizes, and imbalances will the mist eliminator see? These are difficult questions to answer, but without some insight, possible solutions to the mist eliminator problems become very difficult, lengthy trial-and-error endeavors. Second, in evaluating new mist eliminator designs, it is important to minimize the effect of other variables. If the effect of these variables is not minimized, then a design may be discarded because it was exposed to more severe operating conditions, even though it may be superior to the other designs. This could very easily happen at the Cherokee Unit 3 scrubber, where a number of potential problems affecting mist carryover are known and have been observed to occur.

It is not very likely that modifications other than well-developed design modifications will markedly improve the mist carryover problem. Modifying operating variables such as gas velocity and L/G to improve mist carryover are not plausible. For example, gas velocity and L/G

Table 22

COMPARISON OF VARIOUS MIST ELIMINATORS
INSTALLED IN TCA SCRUBBERS
CHEROKEE STATION
PUBLIC SERVICE COMPANY OF COLORADO

Mist Eliminator Type	Gas Velocity Range mps	Pressure Drop Range cm W.C.	Minimum Drop Size Collected μm	Separation Efficiency for Min. Drop Size %	Maximum Liquid Load kg/hr-m^2	Velocity for Reentrain. mps	Reentrain. Drop Size μm
UOP 3-pass stainless steel chevron†	2-4	2-3	10	85-95	5% of gas flow by weight	4	100-500
Munters Euroform Model 271†	2-7	2-7	Unknown	Unknown	24.5	7	Unknown
Heil Heilex Model EB-4†	2-7	0.1-0.5	10-20	85+	Unknown	Unknown	Unknown

† *Data from product literature.*

changes are restricted by the fact that the scrubber must treat all the boiler offgass and must operate at a L/G ratio dictated by particulate removal requirements. Improvements due to revamped maintenance practices are also unlikely. Obviously, the scrubber can be more frequently inspected and overhauled, but it is questionable whether this is a practical procedure for a bas-loaded plant.

Given all these aspects of the mist eliminator problem, it is not expected that the improvements initiated by the Company will have a major impact on upgrading scrubber reliability. Rather, more extreme measures such as reducing upstream gas flow and liquid imbalances, adding an additional mist eliminator stage, or changing the position of the mist eliminator to a horizontal rather than vertical duct may be necessary.

Scrubber Booster Fan

Recurring problems with booster fans have been noted in upset reports throughout most periods of scrubber operation. These upsets vary from fan bearing, alignment, and vibration problems caused by build-up of ash on fan blades to more serious problems of erosive wear of the fan blades caused by the highly abrasive nature of the ash. This latter problem is especially critical for Unit 4 since it utilizes air foil type fans (dictated by volumetric flow rate-pressure drop requirements) as opposed to the radial tip fans used on Units 1 and 3. Air foil fans are extremely sensitive to erosion and fan performance rapidly deteriorates under highly erosive conditions. Obviously, when a fan is taken out of service, part of the gas flow must be bypassed to the stack or to a spare module, if available.

These fan-related problems are difficult to avoid in light of the relatively high dust concentrations involved, even with properly operated fan soot blowers. The most readily apparent solution is then to upgrade the performance of the ESP's, and thereby reduce the concentration of fly ash which the fans must handle. The problem of the fan blade wear on Unit 4 caused by the highly abrasive ash might also be reduced by using harder alloys.

Weather-Related Problems

The freezing of lines during cold weather continues to be a potential problem for the Unit 1 and 3 scrubbers but the magnitude of this problem could not be evaluated from upset data or from observations made during the July-August 1977 observation period. In general, freezing can cause leaks in piping, damage valves and cause portions of the slurry and water streams to become inoperative. The particulate removal performance of the scrubber may then be reduced or sections of the scrubber may need to be taken out of service for repair. The Unit 4 scrubber is enclosed and does not have significant freeze problems. On Units 1 and 3, the Company, reportedly, attempts to drain water and slurry lines when the scrubber is taken out of service for long periods. Difficulties are said to typically result during shutdowns when there is not enough time for proper drainage.

Outlet Ductwork

The ductwork at the outlet of the scrubbers is unlined carbon steel and is highly vulnerable to corrosive attack. When the scrubber reheaters are not in service or are not operating properly, the ductwork is exposed to gas which is at or below its dewpoint with respect to sulfurous and sulfuric acid. The acid collects on the ductwork surfaces and the metal is attacked. The result is corrosion and rusting of the carbon steel with accompanying loss of structural integrity. Holes form in the ductwork, allowing gas to escape; acid condensation then can occur on nearby structural supports, insulation, etc.

Inspection of the Unit 3 scrubber indicated that extensive corrosion has already occurred in the outlet ductwork. Likewise, although outlet ductwork on Unit 1 and 4 scrubbers wasn't inspected, it is expected that with similar reheater problems, these units will also have severely corroded ducting. At this advanced stage, covering the carbon steel with a protective coating may not be feasible. Therefore, remaining options are to immediately repair ductwork failures as they occur and reduce the amount of time that the scrubber is operated when the reheater is defective. Complete replacement of outlet ductwork sections is not advisable until the reheat problem is solved.

VII. OPACITY

EVALUATION OF INSTRUMENTATION

An evaluation of the instrumentation used for measuring smoke density was conducted on July 7 and 20, 1977.

Units No. 1 and 2 exhaust to opposite sides of a single 91 m (300 ft) stack, with a 4.9 m (16 ft) exit diameter. The opacity of Unit No. 1 is measured by a Bailey Dust/density transmitter (bolometer) installed in a 2.1 m (7 ft) wide duct a short distance from the stack. The light source and light detector are on opposite sides of the duct and are joined by a pipe to maintain alignment of the system. Purge air is supplied to both sides of the system to reduce dust accumulation on the lenses. The standard installation, which is indicated to be in place, utilizes a 10 cm (4 in) diameter pipe with a 1.5 m (5 ft) x 8.25 cm (3.25 in) slot across which opacity is measured. The dust path is normal to the plane of the slot. The opacity is registered on a 24-hr circular chart recorder. A clock accumulates the intervals when the opacity exceeds 20%.

Every day the lenses of the transmissometer are cleaned and the recorder charts replaced. All opacity charts are kept at the plant for a one-year period. Unit No. 1 has reheat problems which have reduced the temperature in the duct to about 52°C (125°F). This low temperature reportedly permits ash buildup on the Bailey pipe and reduces the cross-sectional area along the light path. A brush is used to ream the pipe while the unit is in service. During outages the ash buildup is removed by chiseling.

The meter on Unit No. 2 is the same as on Unit No. 1, but is installed across a 2.6 m (8.5 ft) duct. Daily maintenance is the same for each Bailey meter.

Unit No. 3 exhausts to a 91 m (300 ft) tall stack with a 5.9 m (19.5 ft) exit diameter. A Bailey meter, as described above, is installed across a 2.3 m (7.5 ft) duct leading to the stack. A reheat problem exists with Unit No. 3. This has allowed ash buildup similar to that occurring on the piping of the Bailey meter on Unit No. 1.

Unit No. 4 discharges to a 122 m (400 ft) stack with a 6.7 m (22 ft) stack exit diameter. Two Bailey meters are installed on the discharge side of the induced draft (ID) fan. A scrubber downstream of these meters negates use for emission measurements. However, the meters are used for adjusting performance of the unit. A Lear-Siegler RM-4 transmissometer is installed in the duct between the scrubber and the stack. In contrast to the Bailey meters, the RM-4 contains the light source and detector in a single housing on one side of the duct. A pipe is not used to maintain the alignment across the duct. Unlike the older Bailey meters, the RM-4 electronically converts opacity measurements in the duct to read stack exit opacity. The conversion factor is set at the factory prior to installation.

A Leeds and Northrup Speedomax strip chart recorder registers the output of the transmissometer. Charts are replaced when the end of the roll is reached. Plant personnel have found that purge air is effective enough to only require lens cleaning every six months. The filter on the air cleaner must be cleaned every three months.

Operation and maintenance procedures for all meters were found to be acceptable. The location of opacity meters on Units No. 1-3 was also adequate. However, the Lear-Siegler transmissometer is located between two horizontal bends which may create a non-uniform particle distribution.

On July 20, 1977, the Bailey meters on Units No. 1, 2 and 3 were calibrated using a procedure developed at NEIC and standard screens of known opacity (20, 40, 60 and 80%) supplied by the Bailey Meter Company. The Lear-Siegler monitor was not calibrated since that company only supplies an internal standard and NEIC is only now developing a field calibration system for that unit. The procedure permits a check of the linearity and span of the meter while the unit is in operation. A sample calculation is shown in Appendix E.

The test procedure requires that calibrated filters or screens be inserted in the light path to simulate opacity measurable by the transmissometer. The opacity (O) scale is not a linear function but is related to optical density (OD) by the relationship.

$$OD = -\log_{10} (1-O)$$

The optical density is linear and, therefore, is additive while opacity is not. If the duct where the opacity monitor is installed is measuring a background opacity because a unit is in operation, the optical density of screens being inserted is additive to that in the duct. Thus, if a monitor is reading 15% opacity (OD = 0.071) and a 20% opacity (OD = 0.097) screen is inserted, the resulting opacity should read 32% (OD = 0.071 + 0.097 = 0.168) rather than 35% (20% + 15% = 35%).

If the relationship between the meter output and the screen opacity is linear with a 45° slope when plotted in optical density units, then the relationship between meter output and stack opacity is linear [Figure 13]. If, in addition, the meter reads 100% when the light

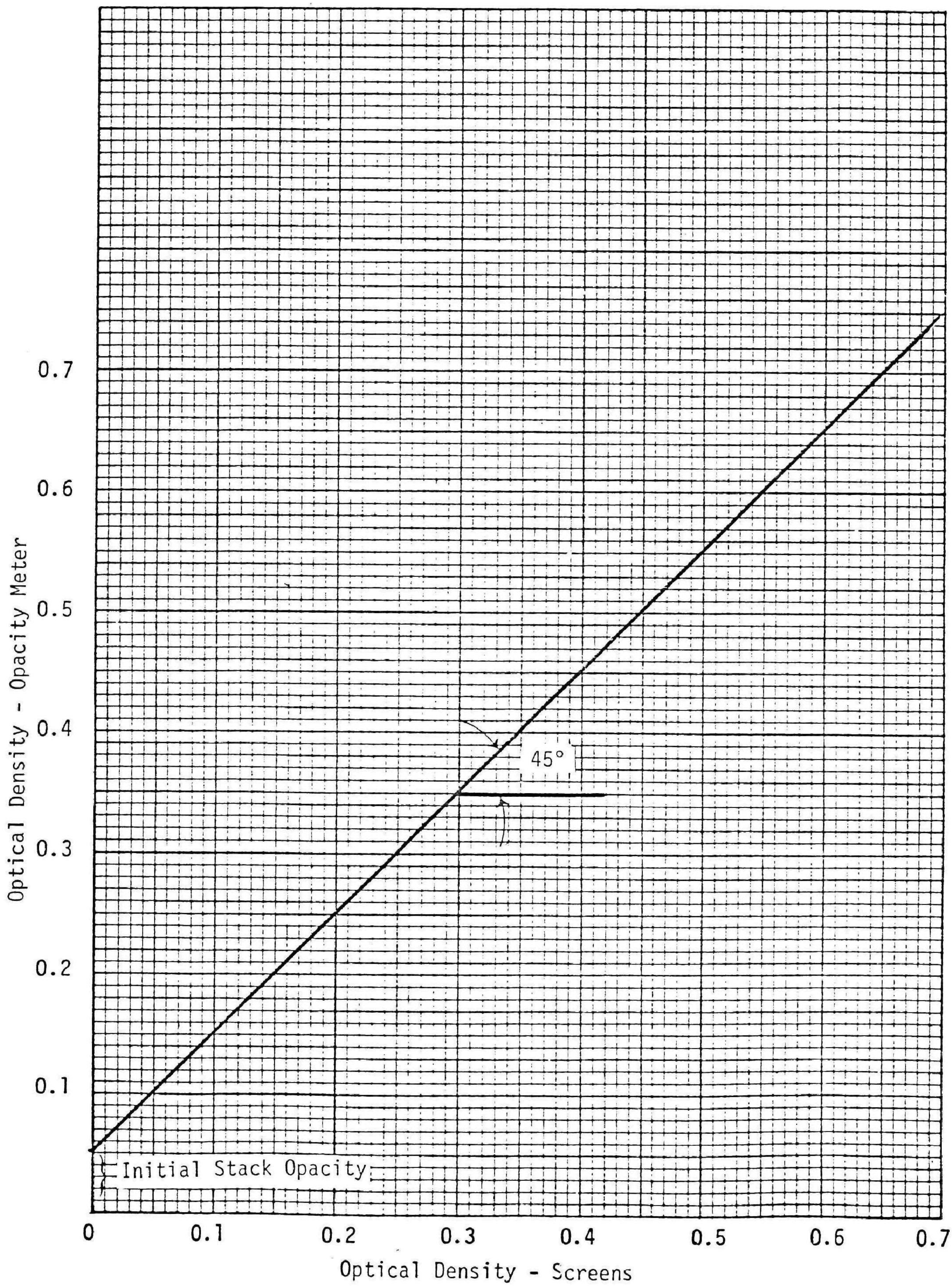

Figure 13. Calibration Curve of Instrument in Calibration Cherokee Station - Public Service Company of Colorado

beam is either completely obscured or extinguished, then the meter can be assumed to be in calibration since a line through the 100% opacity point at 45° slope would also intersect the origin.

When an optical density plot of the meter output vs screen opacity is linear but not at a 45° slope, then the relationship between recorded output and stack opacity is not linear and the meter is out of calibration. In this case the scale is distorted, being elongated if the slope is greater than 45° and shortened when less than 45°. If elongated, the meter will read higher for a given stack opacity, if shortened it will read less. In these cases the meter will still appear to pass through 100% opacity when the light beam is extinguished and, since the zero opacity is not usually measurable during process operations, the transmissometer is thought to be in calibration.

The major problem in calibrating a transmissometer appears to arise from units calibrating near 100% opacity. Figure 14 shows the relationship between opacity, transmittance and optical density. The difference between 0% and 90% opacity is 1 OD unit. The difference between 90% and 99%, or 99% and 99.9% is also 1 OD unit. Thus, calibration procedures causing large changes in optical density result in minor differences in opacity near 100%, but significant variations in the usual range of opacity readings.

While the above calibration procedure is adequate for checking span linearity, it will not determine whether the background opacity reading is a result of smoke in the stack, or is attributable to dust in front of or behind the lenses.

When the smoke density meter on Unit No. 1 was calibrated [Figure 15], the unit was burning 100% natural gas. The recorder was reading -1%, and with the light source extinguished, 99%. The data were shifted

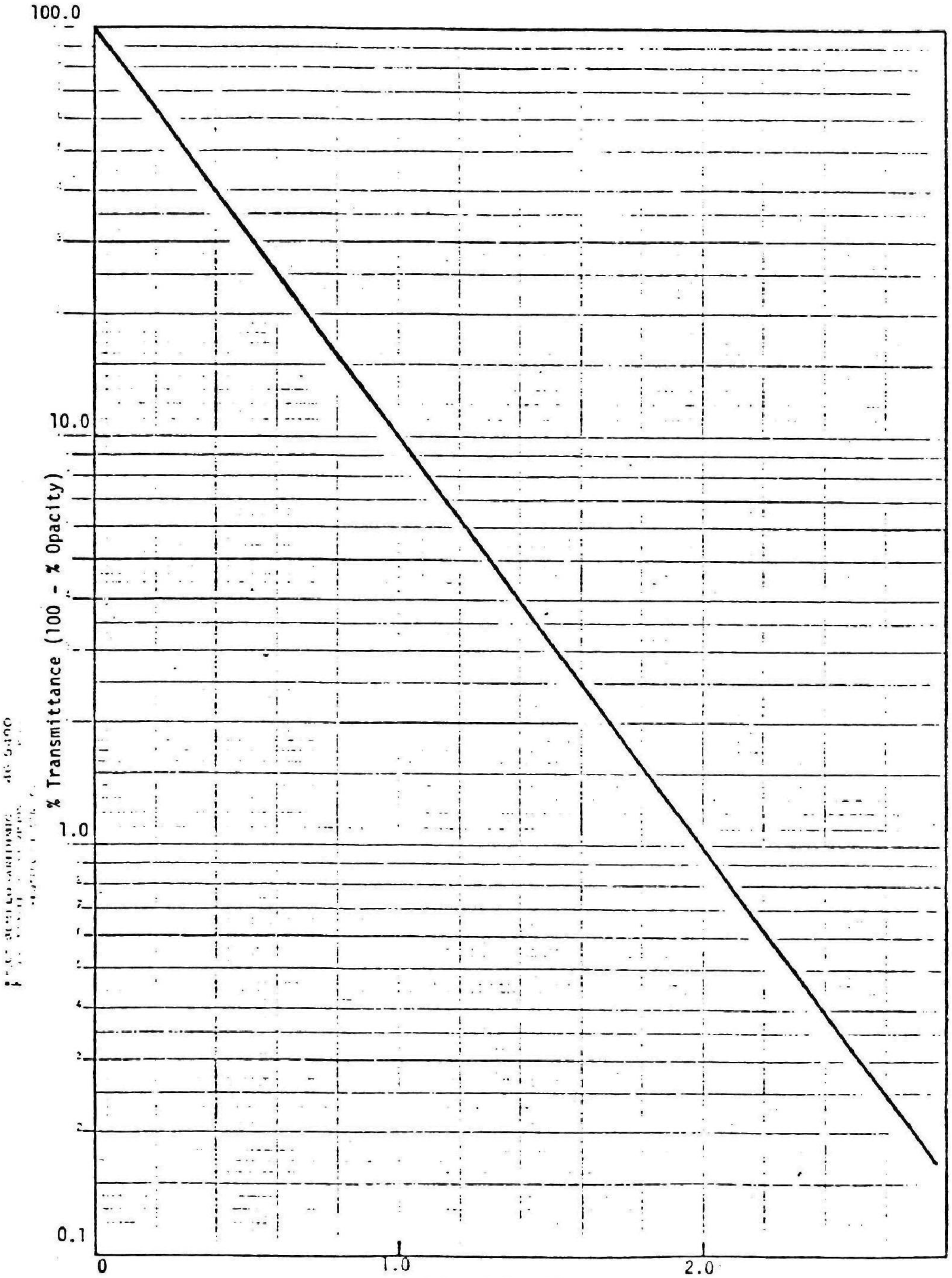

Figure 14. Relationship Between Optical Density, Transmittance and Opacity
Cherokee Station
Public Serice Company of Colorado

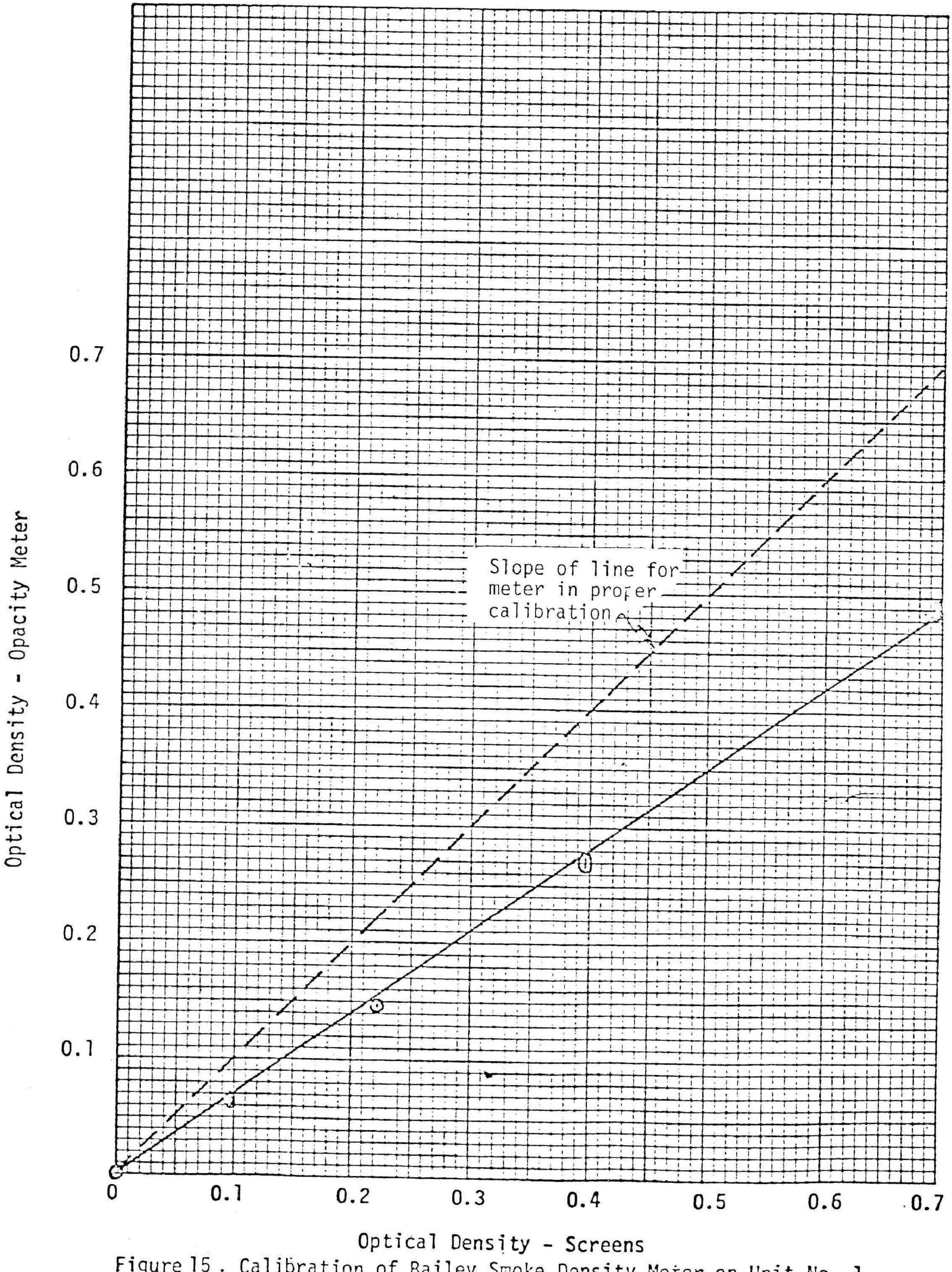

Figure 15 . Calibration of Bailey Smoke Density Meter on Unit No. 1
Cherokee Station - Public Service Company of Colorado

1% upscale before being calculated to account for this offset. Figure 14 indicates that while the linearity is acceptable, the instrument span appears shortened. The shortened span causes reduced output for a given opacity, even though the 0% and 100% points are acceptable. Some of the data points of Figure 14 are indicated as vertical lines where recorder fluctuations (due to opacity variations in the duct) occurred during the calibration procedure.

Unit No. 2 was burning a mixture of 25% natural gas and 75% coal when the smoke density meter was calibrated [Figure 16]. This resulted in a higher background opacity in the duct (6%) as compared to Unit No. 1. When the light source was extinguished, this meter also read 99%. The linearity appears acceptable, however, the span of this unit also is shortened although not to the extent of the meter on Unit No. 1.

If the slope of the line fitting the data is considered an indication of the span, a 45° line (an instrument in proper calibration) would have a value of unity. The opacity monitor on Unit 1 has a slope of 0.70, indicating a span that is 70% of the acceptable value. In a similar fashion,.the monitor on Unit No. 2 had a span of 91% of the desired value.

Unit No. 3 was only burning coal when the opacity monitor was calibrated, thus it was registering a slightly higher opacity (9%) than the other two meters. With the light source extinguished, this meter also read 99%. Again, the linearity appeared acceptable but the span was foreshortened to 86% of the expected value [Figure 17]. In all cases the compression of the span will result in the recorded value being less than the measured value in the duct.

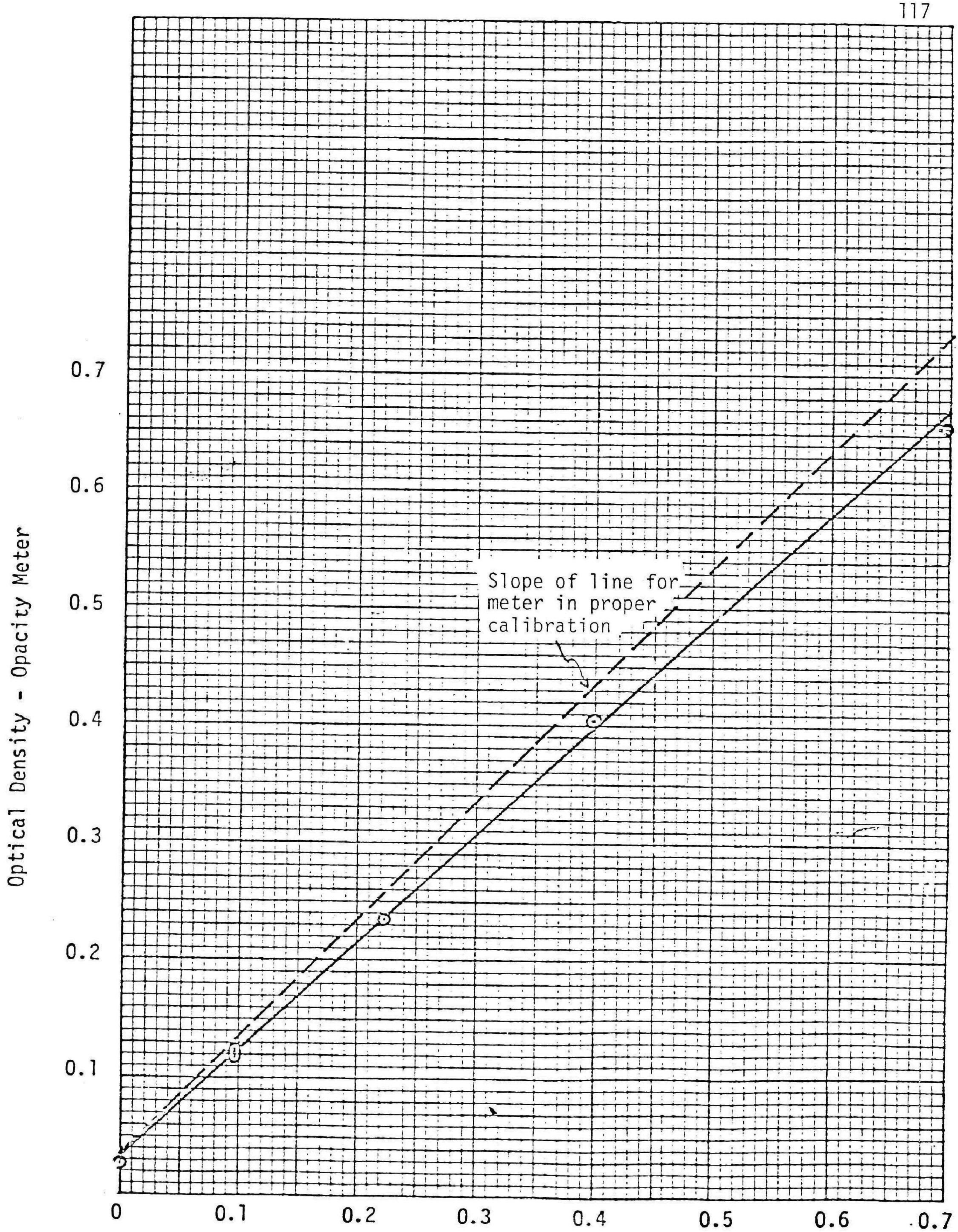

Figure 16. Calibration of Bailey Smoke Density Meter on Unit No. 2
Cherokee Station - Public Service Company of Colorado

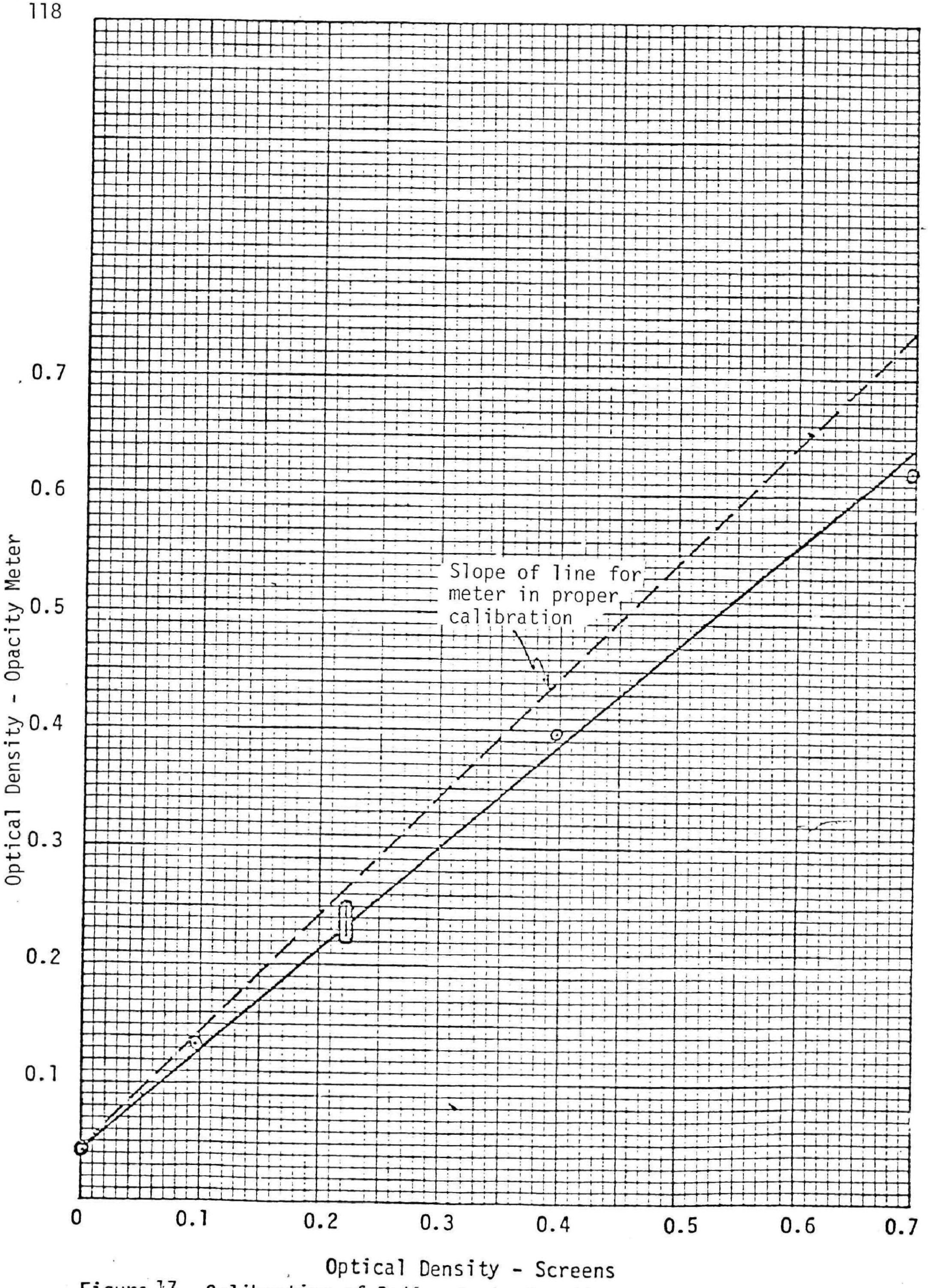

Figure 17. Calibration of Bailey Smoke Density Meter on Unit No. 3.
Cherokee Station - Public Service Company of Colorado

In addition to the lower opacity reading indicated above, it should be noted that the three meters are only reading smoke density across a 1.5 m (5 ft) path length (the length of the slot in the pipe). Below is a comparison of this length with duct and stack exit diameter for each meter.

Meter No.	Slot Length m	ft	Duct Width m	ft	Stack Diameter m	ft
1	1.5	5	2.1	7	4.9	16.0
2	1.5	5	2.6	8.5	4.9	16.0
3	1.5	5	2.3	7.5	4.9	19.5

Since the opacity is a function (logarithmic) of the path length, the meters are only measuring a portion of the opacity when the slot does not extend across the duct. Also, since the ducts are all narrower than the stack exit diameters, the opacity measured at the stack exit would be greater than measured across the duct (all else being equal). The following relationship relates opacities to varying path lengths:

$$\frac{\log_{10} (1-O_1)}{d_1} = \frac{\log_{10} (1-O_2)}{d_2}$$

where O_1 and O_2 are opacities measured across distances d_1 and d_2. For example, if the meter on Unit No. 3 was reading 10% opacity (across the 1.5 m slot), a meter across the duct (2.3 m) would be expected to read 15%, while 34% opacity would be expected at the stack exit (5.9). These differences are significant and also indicate a case where the meter would be reading below 20%, therefore not requiring a report to State and Federal agencies, while the opacity at the stack would be above the value that requires notification. As indicated earlier, the

Lear-Siegler transmissometer corrects for this difference and reports exit opacity.

In the case of Units No. 1 and 2 which exhaust to the same stack, the observed stack opacity would be a function of the opacities in each duct, but in all cases would be greater than the opacity from a single source. The relationship is given by the equation:

$$\frac{\log(1-O_1) + \log(1-O_2)}{d_1 + d_2} = \frac{\log(1-O_s)}{d_s}$$

where O_1, O_2 and O_s are the opacities recorded on Units 1 and 2, and the opacity of the stack and d_1, d_2 and d_s are the meter path lengths 1.5 m and the stack exit diameter 4.9 m, respectively.

Using the above equation, it is possible to determine the relationship between the two opacity meters that will produce a 20% opacity at the stack as follows:

Opacity Either Unit %	Opacity Other Unit %	Exit Stack Opacity %
0	13	20
2	11	20
4	9	20
6	7	20
8	5	20
10	3	20
12	1	20

The table shows that when either meter is reporting over 13% opacity, the stack exit opacity will be $\geq$ 20% and that even with opacities as low as 7% on each meter this condition can occur.

Even with proper operation and maintenance, the three meters examined were out of calibration in that the span was foreshortened on all three. However, when this problem is corrected, the meters will still not be making the measurement that is desired; i.e., the opacity of the plume at the stack exit. Thus, when the Company reports the incidence of opacity greater than 20%, it will be occuring across the 1.5 m (5 ft) slot and not at the stack exit. On the other hand, as the examples showed, 20% opacity may occur at the stack exit and go unreported because the meter is reading less across the slotted pipe.

The deficiencies in the plant monitoring system can be corrected by the following:

1. The three Bailey units should be calibrated using the 40% opacity plate or a filter in that range. This should be done by adding the optical density of the duct opacity to that of the plate or filter to determine a total optical density. When this total is converted to opacity, the value should be set on the meter. Because the meters are presently out of calibration, this may initially require several iterations since the duct opacity will be in error.

2. The reporting requirements for Units 1 and 2 should be modified to account for the relationship shown above. This may be done either by installation of electronic circuitry designed to output the relationships between the two instruments to produce a recording of combined stack exit opacity or by use of the above table computing this relationship.

3. The reporting requirements for Unit 3 should be modified to account for the relationship between opacity across the 1.5 m (5 ft) slot length and the 5.9 m (19.5 ft) stack exit diameter. From the relationship between opacity and path length, 6% opacity at the bolometer will correspond to 20% at the stack exit (all else being equal).

VISIBLE EMISSION OBSERVATIONS

During the study period, visible emission observations (VEO) were randomly made on the three boiler stacks at Cherokee Station. The VEO's were made by eleven different NEIC observers using EPA Method 9. A summary of the observations is given in Table 23. Appendix B contains a listing of the VEO's for the individual stacks at Cherokee. During the study period, 92 VEO's were made and the average opacity exceeded 20% during 51 of those observations [Table 23]. Because the opacity regulations in the State Implementation Plan (SIP) has no time limitation, the individual readings were also summarized for the set of 51 observations. Of 1,374 individual readings, 949 exceeded 20% but were less than 40% opacity.

During the July and August VEO's, an NEIC observer monitored the plant operation and recorded unit load, fuel type, opacity meter readings and control equipment data. This data was recorded before and after each VEO [Appendix A]. Only the process data was recorded during the October VEO's and were normally recorded after the observations were made. It was not possible to correlate the VEO readings with the Bailey opacity meter readings. The readings did confirm the calibration tests results that indicated the stack opacities would be greater than the Bailey Meter readings, due to path length differences. The average stack opacities read by the NEIC observers were greater than Bailey meter readings. Because the Bailey meters were found to be out of calibration, the VEO's were not compared to calculated stack opacities. It is recommended that once the deficiencies in the opacity monitoring system are corrected, that actual VEO's be compared to the calculated stack opacities to ensure that the meters are accurately recording exit stack opacities.

Table 23

SUMMARY OF VISIBLE EMISSION OBSERVATIONS
CHEROKEE STATION
PUBLIC SERVICE COMPANY OF COLORADO

Stack	No. of 6 min Observations	No. of Times Average Opacity >20%	No. of Readings Total	No. of Readings >20% <40%	No. of Readings >40%
	July 27-August 28, 1977				
Unit 1 & 2	34	23[a]	552	417	4
Unit 3	10	8[b]	192	113	57
Unit 4	27	7	170	110	0
	October 4-18, 1977				
	No. of 9 min Observations				
Unit 1 & 2	7	5[c]	184	72	12
Unit 3	7	5[d]	168	74	90
Unit 4	7	3[e]	108	63	23
TOTALS	92	51	1,374	949	186

a *The recirculation pump for section A of the scrubber was out of service during 13 of these periods.*
b *Unit 3 scrubber was off-line during entire period. Fuel was 50% coal and 50% gas. Unit 3 down for scheduled outage on 8/20/77.*
c *Unit 1 reheater plugged. Scrubber being bypassed three of these periods.*
d *Recirculation pump out of service one time and booster fan out with 50% bypass during other four observations.*
e *Unit startup during one observation.*

VIII. PARTICULATE CONTROL SYSTEM RELIABILITY IMPROVEMENT

Before any discussion of alternatives to improve system reliability is presented, there are a number of related topics that should be reviewed. Some consideration must be given to the ultimate reliability goal to be attained. Thought must be given to how various options for improving reliability are to be evaluated. It must also be recognized that economics and redundancy will have a large impact on reliability considerations.

A determination of required system reliability is of primary importance. There are a number of ways of expressing system reliability but normally it is done on the basis of percent boiler on-line time. An "acceptable" percent reliability will vary and depend on, among other things, the specific application, and revelant SIP regulations as interpreted by the administering agencies. Ninety percent reliability is considered to be achievable for powerplant flue gas desulfurization processes and is also acknowledged to be within the limits of particulate removal technology by most particulate control equipment manufacturers. The State of Indiana requires 95% reliability for meeting their particulate regulations.

A method is also needed to gauge how various modifications will affect reliability. If the necessary reliability component data is available, it is possible that reliability analysis techniques pioneered in the nuclear industry could be applied to particulate control systems. For example, when reasonable estimates of mean time to failure and mean repair times of critical equipment can be made, then a fault tree analysis can be conducted and quantitative comparisons can be obtained. Otherwise, reliability analysis must be left to qualitative engineering judgments which are often subject to extensive debate and disagreement.

Economics will be an important part of comparing control plan alternatives. Any system can be upgraded to provide 99.9%+ reliability. The cost of that system, however, may be prohibitive. Although economics were not evaluated in this study, such effects must be considered in any further analyses.

Redundancy will be a key factor in achieving consistent operation of any particulate control system. Equipment used in near continuous service and exposed to dusty environments, variable temperatures and corrosive conditions will eventually break down. Therefore, to achieve reliable operation under such circumstances, it is necessary to provide spares for critical equipment components. The problem is in determining which are the critical components. Some of the areas of improvement are discussed below.

SCRUBBER IMPROVEMENTS

There are numerous areas for improvement suggested from the scrubber evaluation. In this section, only those changes which are considered to have a significant impact on scrubber reliability are presented. These include: adding spare scrubber capacity, replacing the direct reheat systems with indirect reheat, adding spare recirculating pumps, providing for more frequent inspection and cleaning of those scrubbers that don't have spares, improving the mist eliminator design, improving the mobile packing design, and providing an enclosure for all scrubber sections.

The addition of spare scrubber modules would have a very significant effect on reliability. Provision for spare modules would allow for a scheduled maintenance program in which modules would be routinely taken offline for cleaning and repair. A spare module would also allow for switching modules on- and offline when emergency repairs were required.

On those units with direct reheaters, improvement in scrubber availability would be realized if the direct reheaters were replaced with indirect reheaters. The in-line tubes are subject to plugging and corrosion which is highly dependent on upstream scrubber and mist eliminator conditions. The ability of indirect reheaters to stay in service is much less dependent on such conditions. As an added advantage, indirect reheat air fans can be used to provide fresh air to scrubber sections during maintenance, reducing the need for tight isolation damper shut offs.

Adding spare recirculation pumps is considered very important in improving operation of single-pump scrubber sections. When a recirculating pump is out of service in a single-pump section, the section must be taken off line or operated under very reduced capability. Adding spare recirculation pumps to a scrubbing section which has three operating pumps is less critical.

Increased frequency of inspection and repair must be considered as a potential alternative for improving reliability on Units 1 and 3. PSCC's current maintenance practices and thoroughness in performing maintenance does not appear to be improper. The problem occurs when scrubber instrumentation does not always indicate when scrubber internal problems are occurring. Detection of such problems then requires frequent visual inspections. Unfortunately, the practicality of frequent visual inspections on a base-loaded plant is questionable. Furthermore, the required frequency at which inspections must be made is affected by the quality of the coal fired, the operation of the plant, the operation of the ESP's, etc. An optimal inspection frequency will be different under different conditions.

PSCC is currently attempting to improve the operation of the scrubber system by improving the mist eliminator design. The success of this effort will depend on how scrubber operations affect new design considerations, and how the mist eliminator tests are being conducted. Any program of this type must be considered a research effort and will require time for adequate tests to be run and evaluated. It is probable that the Company will have to resort to major mist eliminator modifications, such as installing two horizontal mist eliminator stages or a single vertical mist eliminator stage, to markedly reduce mist entrainment.

The improvement of the scrubber operation is very significantly affected by the type of packing used in the scrubbers, and PSCC has expended considerable effort in this direction. They have not tested stationary packings; however, and in view of success of stationary packings observed in other related applications, this appears to be an area which should be thoroughly investigated. As in the case of improving mist eliminator design, a research and development effort is required and additional time will be needed for proper evaluation.

Enclosing the scrubbers on Units 1 and 3 would reduce down time due to freezing lines. This has proven effective on the Unit 4 scrubbers.

ESP IMPROVEMENTS

The evaluation of the precipitators was hampered by not knowning the flow of gas conditioning agent to the boiler off-gases. The first area of improvement should be to add flow monitoring devices to monitor the SO_3 flow to each of the units (including Unit 3), then an evaluation program must be undertaken to determine the effectiveness of the gas conditioning on ESP efficiency. Once this is done, the operation of the ESP may be inproved to the point of meeting design efficiencies. Major modifications would need to be undertaken to significantly improve the collection efficiency of the ESP's and thus reduce the particulate loadings to the scrubbers and to the stack in the case of Unit 2. These would include adding more electrical sections, increasing collection plate area, and upgrading the automatic control systems. Adding more electrical sections would increase the power input to the ESP's and provide for higher corona power and current densities. This would also provide for a more efficient and reliable precipitator since a smaller portion of the precipitator would have to be taken out of service when broken wires are changed. Enlarging the precipitators by increasing the plate area would probably be the most expensive way of increasing the efficiencies of the precipitators, since this would essentially be the same as adding a new precipitator to the existing system. The existing automatic controls are of the saturable core reactor type and are typically slow in responding to voltage changes. This is especially critical if excessive sparking occurs and the controls do not respond fast enough to prevent corona wires from burning out. This was not observed during the study but may be a problem if higher power inputs are wanted.

The previously discussed improvements were based on evaluations made on the existing particulate control equipment. Other alternatives not evaluated in this report, include replacing the existing equipment with high efficiency (+99%) precipitators or replacing the scrubbers with baghouses. These options should also be considered when evaluating a program for improving reliability.

REFERENCES

1. August 5, 1977. *Letter*: from Robert L. Pearson - Public Service Company of Colorado, Denver to Irwin L. Dickstein - Environmental Protection Agency, Region VIII, Denver.

2. August 8, 1977. *Letter*: from George P. Green - Public Service Company of Colorado, Denver to Irwin L. Dickstein - Environmental Protection Agency, Region VIII, Denver.

3. White, H. J. 1977. Electrostatic Precipitation of Fly Ash. *Journal of the Air Pollution Control Association* 27:3, p 206-217.

4. Meteorology Research, Inc., Nov. 1975. *Evaluation of Particulate Scrubber on a Coal-Fired Utility Boiler*. Environmental Protection Agency: EPA 600/2-75-074, 81 p.

5. Calvert, S. et al., Oct. 1974. *Eine Particle Scrubber Performance*, Environmental Protection Agency: EPA 650/2-74-093, 258 p.

6. Statnick, R. M. and Drehmel, D.C. June 1974. *Fine Particle Control Using Sulfur Oxide Scrubbers*. 67th Meeting of the Air Pollution Control Assoc., Denver, Colorado, Paper No. 74-231.

7. Uchida, S. et al. Aug. 1977. *Mechanics of A Turbulent Contact Absorber*. The Second Pacific Chemical Engineering Congress, AICHE. New York, p 1251-1267.

8. Calvert, S. et al. Aug. 1977. Liquid Entrainment From a Mobile Bed Scrubber, *Journal of the Air Pollution Control Association*, 27:8, p 768-770.

9. Johnson, J. M. et al. Oct. 1976. *Scrubber Experience at Mohave*. Conference on Particulate Collection Problems in Converting to Low Sulfur Coals. Environmental Protection Agency: EPA 600/7-76-016, p 208-224.

10. Choi, P.S., et al. Feb. 1977. *Stack Gas Reheat for Wet Flue Gas Desulfurization Systems*. Electric Power Research Institute: EPRI FP-361. Palo Alto, California 73 p.

11. Battelle Columbus Laboratories, Dec. 1976. *Guidelines for the Design of Mist Eliminators for Lime/Limestone Scrubbing Systems*. Electric Power Research Institute, EPRI FP-327. Palo Alto, California, 102 p.

APPENDIX A

PROCESS DATA SHEETS
CHEROKEE STATION
PUBLIC SERVICE COMPANY OF COLORADO
July - August, 1977

CHEROKEE STATION UNIT 1 DATA SHEET

Date:	7/27/77	7/27/77	7/29/77	7/29/77	7/30/77	7/30/77	8/1/77	8/1/77
Time:	1325	1545	0915	1048	1823*	1934	1716	1818
Plant								
Mw. Gross	116	106	115	116	116	102	118	117
XS O_2 (%)	2.4	2.5	3.6	3.6	1.6	2.8	3.2	4.5
Steam Flow (lbs/hr)	9.4×10^5	8.4×10^5	9.3×10^5	9.4×10^5	9.5×10^5	8.2×10^5	9.5×10^5	9.0×10^5
Steam Pressure (psig)	1430	1420	1420	1420	1420	1410	1420	1410
Steam Temperature (°F)	970	950	980	980	970	940	1002	1000
Opacity, ~~Bypass~~ (%)	0	0	0	0	4	5	6	7
~~Opacity, Scrubber (%)~~								
Fuel	Gas	Gas	Gas	Gas	coal	coal	coal	coal
ESP								
Section A1-A2; AC Voltage (v)	180	180	180	180	180	180	180	180
AC Current (a)	50	55	50	50	60	75	35	90
DC Voltage (Kv)	33	33	32	33	33	33	38	34
DC Current (ma)	~~0~~ 180	180	160	160	170	170	40	40
Spark Rate (spm)	0	0	0	0	>2500	460	350	300
Section B1-B2; AC Voltage (v)	160	160	155	155	160	160	165	165
AC Current (a)	50	55	55	55	60	60	35	35
DC Voltage (Kv)	—	Out	Out	Out	Out	Out	Out	Out
DC Current (ma)	~~0~~ 220	220	210	210	220	230	~~[illegible]~~ 130	110
Spark Rate (spm)	0	0	0	0	>2500	>2500	330	240
Scrubber								
Fans; Fan Inlet Pressure (in. H_2O)	Scbr Not in	Scbr Not in	Scbr Not in	Scbr Not in	-.5	-.5	-.5	-.5
Fan A Outlet Pressure (in. H_2O)	Operation	Operation	Operation	Operation	18.5	16	19.5	19
Fan B Outlet Pressure (in. H_2O)					18.5	16	19.5	19
Fan A Amps					150	140	150	150
Fan B Amps					150	135	155	155
Stack Damp A, Pos. (% Opn)					0	0	0	0
Pumps; Recirc. Pump A1 (amps)					23	23	23	22.5
Recirc. Pump B1 (amps)					22	22	22	21.5
Recirc. Pump B2 (amps)					23	23	23	23
Recirc. Pump B3 (amps)					23	23	23.5	23.5
Reheater; Steam Flow (M lbs)					Out	Out	Out	Out
Steam Pressure (psig)								
Section A; Presat Water Flow (gpm)					54	65	64	64
Outlet Gas Temp. (°F)					142	140	140	190
Bed Diff. (in. H_2O)					9.0	8.0	8.0	8.6
Demister Diff. (in. H_2O)					4±.5	3±.5	5	4.25
RH Diff. (in. H_2O)					3.0?	3.0?	3.5	3.5
Gas Outlet Flow (in. H_2O)					3.0	2.5	2.5	2.4
Section B; Presat Water Flow (gpm)					210	220	215	218
Outlet Gas Temp. (°F)					150	150	150	150
Bed Diff. (in. H_2O)					9±.5	8	9.5	9.5
Demister Diff. (in. H_2O)					2±.5	1±.5	2±.5	2±.5
RH Diff. (in. H_2O)					3.0?	2.5?	3.0	3.0
Gas Outlet Flow (in. H_2O)					0.2	0	0.6	0
Nat'l Gas Flow (scfh)	1.4×10^6	1.5×10^6	1.3×10^6	1.4×10^6				

Comments

~~Spark rate meters not in operation~~

~~DC voltmeter not operating properly~~

* exercised the stack damper

demister wash on

CHEROKEE STATION UNIT 1 DATA SHEET

Date:	8/3/77	8/3/77	8/4/77	8/4/77	8/4/77	8/[illegible]
Time:	1650	1915	1000	1150	~~0~~1416	1[illegible]
Plant			BASE LOAD			
Mw, Gross	112	109	114	113	113	11
XS O_2 %	2.8	2.8	2.8	3.0	1.6	2
Steam Flow (lbs/hr) $\times 10^5$	8.9	7.6	9.2	9.2	9.4	9.2
Steam Pressure (psig)	1420	1420	1420	1420	1420	1[illegible]
Steam Temperature (°F)	1020	1000	1000	990	990	[illegible]
Opacity, ~~Bypass~~ (%)	10	15	10	10	15	1
~~Opacity, Scrubber (%)~~ FUEL	100% COAL	100% COAL	100% COAL	100% COAL	100% COAL	[illegible]
NAT. GAS FLOW (SCFH)	0	0	0	0	0	0
ESP						
Section A1-A2; AC Voltage (v)	160	190±10	190±10	200±10	190±10	[illegible]
AC Current (a)	50±10	50±10	50±20	50±20	45±20	45
DC Voltage (Kv)	35	37±2	38±2	38±2	37±2	37
DC Current (ma)	110±10	140±20	140±20	140±20	100	10[illegible]
Spark Rate (spm)	450±20	~~300~~ 450 ±20	400±40	380±20	380±10	38[illegible]
Section B1-B2; AC Voltage (v)	160	170	165	175	175	18[illegible]
AC Current (a)	35±10	35±10	40±10	35±10	30±5	25±[illegible]
DC Voltage (Kv)	~~2~~	~~8~~	~~2~~	~~2~~	Out	[illegible]
DC Current (ma)	120~~100~~	100±20	100±20	100±20	100 ~~65~~ ±10	1[illegible]
Spark Rate (spm)	370±50	~~200~~ 250 ±50	290±40	290±30	300±5	140[illegible]
Scrubber						
Fans; Fan Inlet Pressure (in. H_2O)	-0.3	-0.25	-0.25	-0.25	-0.3	-
Fan A Outlet Pressure (in. H_2O)	16.5	9.5	15	14	16	1[illegible]
Fan B Outlet Pressure (in. H_2O)	16.5	9.5	15	14	16	15.5
Fan A Amps	145	130	145	145	150	1[illegible]
Fan B Amps	150	125	145	145	150	15
Stack Damp A, Pos. (% Opn)	0	0	0	0	0	0
Pumps; Recirc. Pump A1 (amps)	23	24	23	23	23	[illegible]
Recirc. Pump B1 (amps)	21	21	21	21	22	[illegible]
Recirc. Pump B2 (amps)	23	23	23	23	23.5	2
Recirc. Pump B3 (amps)	24	24	24	24	23.5	23.5
Reheater; Steam Flow (M lbs)	OUT	OUT	OUT	OUT	Out	[illegible]
Steam Pressure (psig)	-	-	-	-	-	
Section A; Presat Water Flow (gpm)	64~~X~~	56	64	64	64	64
Outlet Gas Temp. (°F)	140	150	175	175	120	1
Bed Diff. (in. H_2O)	5	4	5.6	5.0	5.2	[illegible]
Demister Diff. (in. H_2O)	4.5	3	3.9	3.8	4.8	4.[illegible]
RH Diff. (in. H_2O)	3.5	2	3	3	3.8	3.7
Gas Outlet Flow (in. H_2O)	2.2	1	1.8	1.6	1.8	1[illegible]
Section B; Presat Water Flow (gpm)	220	220	220	220	220	2[illegible]
Outlet Gas Temp. (°F)	150	155	155	155	160	155
Bed Diff. (in. H_2O)	7.5	4.6	6±.2	6±.2	7±.4	7
Demister Diff. (in. H_2O)	1.5±.5	1.0±.3	1.5±.3	1.5±.2	2±.5	1.[illegible]
RH Diff. (in. H_2O)	3	2	3	3	3	
Gas Outlet Flow (in. H_2O)	0.4	0.2	0.5	0.4	0.3	0.[illegible]

Comments 8/3/77 TABLE MOUNTAIN CONTROL IS REGULATING UNITS 1 & 2 DISPATCH CONTROL CENTER FOR AREA.

OBSERVER - R. IDA

CHEROKEE STATION UNIT 1 DATA SHEET

Date:	8/8/77	8/8/77	8/9/77	8/9/77
Time:	0934	1036	1351	1454
Plant				
Mw. Gross	117	118	117	117
XS O_2	2.5	1.8	2.3	2.3
Steam Flow (lbs/hr) x 10^5	9.3	9.4	9.4	9.4
Steam Pressure (psig)	1420	1420	1420	1420
Steam Temperature (°F)	1015	1010	1015	1015
Opacity, ~~Bypass~~ (%)	7	7	9	8
~~Opacity, Scrubber (%)~~ Fuel	coal	Coal	Coal	Coal
Nat'l Gas Flow (SCFH)	—	—	—	—
ESP				
Section A1-A2; AC Voltage (v)	180	175	185	170
AC Current (a)	40±15	40±15	40±10	40±10
DC Voltage (Kv)	37±2	37±2	37±2	35
DC Current (ma)	80	90	80	80
Spark Rate (spm)	430±30	410	400±20	440±30
Section B1-B2; AC Voltage (v)	155	155	160	155
AC Current (a)	35±10	35±10	35±10	35±10
DC Voltage (Kv)	out	out	out	out
DC Current (ma)	90	100	90	100
Spark Rate (spm)	200±20	190±40	240±10	220±20
Scrubber				
Fans; Fan Inlet Pressure (in. H_2O)	-.7	-.7	-.7	-.7
Fan A Outlet Pressure (in. H_2O)	15.5	15.5	14.5	14.5
Fan B Outlet Pressure (in. H_2O)	15.5	15.5	14.5	14.5
Fan A Amps	150	150	145	145
Fan B Amps	155	155	150	150
Stack Damp A, Pos. (% Opn)	0	0	0	0
Pumps; Recirc. Pump A1 (amps)	23	22.5	23	23
Recirc. Pump B1 (amps)	21.5	21	21.5	21.5
Recirc. Pump B2 (amps)	28.5	28	28.5	28.5
Recirc. Pump B3 (amps)	0	0	0	0
Reheater; Steam Flow (M lbs)	out	out	out	out
Steam Pressure (psig)	—	—	—	—
Section A; Presat Water Flow (gpm)	67	68	68	68
Outlet Gas Temp. (°F)	118	118	115	115
Bed Diff. (in. H_2O)	5.0	5.0	4.0	4.2
Demister Diff. (in. H_2O)	3.8±.2	3.8±.3	4.8	4.3
RH Diff. (in. H_2O)	3.8	3.8	3.5	3.8
Gas Outlet Flow (in. H_2O)	0.6	0.4	3.0	3.8
Section B; Presat Water Flow (gpm)	225	225	225	225
Outlet Gas Temp. (°F)	155	155	120	120
Bed Diff. (in. H_2O)	6	6	6	6
Demister Diff. (in. H_2O)	1.8±.3	1.5±.3	1.5±.3	1.5±.3
RH Diff. (in. H_2O)	3.2	3.3	3.2	3.2
Gas Outlet Flow (in. H_2O)	0.6	0.4	0	0.3

Comments

#1, 300 ft
#4 400 ft

A-4

CHEROKEE STATION UNIT 1 DATA SHEET

Date:	8/6/77	8/6/77	8/10/77	8/10/77
Time:	1310	1445	2130	2330
Plant				
Mw, Gross	102	96	86	84
XS O_2 %	3.5	~~4~~ 4.0	4.4	5
Steam Flow (lbs/hr) $\times 10^3$	800	770	660	640
Steam Pressure (psig)	1420	1400	1420	1420
Steam Temperature (°F)	990	980	950	970
Opacity, ~~Bypass (%)~~	11	9	10	10
~~Opacity, Scrubber (%)~~ FUEL	100% COAL	100% COAL	100% COAL	100% Col
ESP				
Section A1-A2; AC Voltage (v)	200	180 ± 10	~~[illegible]~~ 200 ± 10	200 ± 10
AC Current (a)	25	30 ± 20	30 ± 20	35 ± 20
DC Voltage (Kv)	~~400~~ 40	37	40 ± 3	40 ± 3
DC Current (ma)	100	120 ± 20	120 ± 20	120 ± 30
Spark Rate (spm)	150 ± 50	450 ± 50	300 ± 20	250 ± 50
Section B1-B2; AC Voltage (v)	170	170	170 ± 10	170 ± 10
AC Current (a)	25	25 ± 10	30 ± 20	30 ± 10
DC Voltage (Kv)	~~2~~ OUT	~~2~~	~~2~~	~~2~~
DC Current (ma)	60	60 ± 20	100 ± 20	100 ± 20
Spark Rate (spm)	60 ± 10	150 ± 20	400 ± 20	310 ± 20
Scrubber				
Fans; Fan Inlet Pressure (in. H_2O)	-0.5	~~[illegible]~~ -0.25	-0.6	-0.65
Fan A Outlet Pressure (in. H_2O)	10.5	12.5	10.5	10
Fan B Outlet Pressure (in. H_2O)	10.5	12.5	10.5	10
Fan A Amps	135	140	135	130
Fan B Amps	130	140	130	130
Stack Damp A, Pos. (% Opn)	0	0	0	0
Pumps; Recirc. Pump A1 (amps)	23	23	23	23
Recirc. Pump B1 (amps)	22	22	21	21
Recirc. Pump B2 (amps)	23	23	21	21
Recirc. Pump B3 (amps)	24	24	25	25
Reheater; Steam Flow (M lbs)	OUT	OUT	OUT	OUT
Steam Pressure (psig)	–	–	–	–
Section A; Presat Water Flow (gpm)	68	67	68	68
Outlet Gas Temp. (°F)	120	125	125	125
Bed Diff. (in. H_2O)	4.0	4.0	3.8	3.7
Demister Diff. (in. H_2O)	3.0	3.4	2.8	2.8
RH Diff. (in. H_2O)	2.5	3.0	2.5	2.5
Gas Outlet ~~Flow~~ PR (in. H_2O)	6.0	3.5	OUT	OUT
Section B; Presat Water Flow (gpm)	22.5	23.5	26	23
Outlet Gas Temp. (°F)	160	155	115	115
Bed Diff. (in. H_2O)	5 ± .2	5.8 ± .2	4.5 ± .2	4.6 ± .2
Demister Diff. (in. H_2O)	1 ± .2	1.5 ± .2	1.0 ± .4	0.4 ± .1
RH Diff. (in. H_2O)	2	2.5	2	2
Gas Outlet ~~Flow~~ PR (in. H_2O)	0.2	0.5	0	0

Comments 8/6/77 – Units 1 & 2 are being regulated not base load.

8/10/77 SAME AS ABOVE

CHEROKEE STATION UNIT 1 DATA SHEET

Date:	8/12/77	8/12/77	8/13/77	8/13/77
Time:	1330	1500	0920	1055
Plant				
Mw, Gross	116	116	108	115
XS O_2	5%	3%	3%	2.5
Steam Flow (lbs/hr) x10	940 ~~1330~~	940	830	910
Steam Pressure (psig)	1420	1420	1420	1420
Steam Temperature (°F)	1000	1000	950	1000
Opacity, ~~Bypass (%)~~	9	9	8	10
~~Opacity, Scrubber (%)~~ FUEL	75% COAL	75% COAL	100% COAL	100% COAL
NAT. GAS SCFH x10^3	280	280	—	—
ESP				
Section A1-A2; AC Voltage (v)	200±10	190±10	190±10	190±10
AC Current (a)	25±10	30±10	25±10	30±20
DC Voltage (Kv)	42±2	40±4	40±2	40±4
DC Current (ma)	80±20	80±20	70±10	80±20
Spark Rate (spm)	220±30	200±20	200±50	200±40
Section B1-B2; AC Voltage (v)	170±10	170±10	170±5	170±5
AC Current (a)	30±10	30±10	30±10	30±10
DC Voltage (Kv)	~~2~~ OUT	~~2~~	~~2~~	~~2~~
DC Current (ma)	70±10	60±20	70±10	60±20
Spark Rate (spm)	150±20	150±20	150±20	200±50
Scrubber				
Fans; Fan Inlet Pressure (in. H_2O)	-0.55	-0.6	-0.3	-0.6
Fan A Outlet Pressure (in. H_2O)	17	16.5	14.0	15.5
Fan B Outlet Pressure (in. H_2O)	17	16.5	14.0	15.5
Fan A Amps	150	150	140	150
Fan B Amps	150	150	135	150
Stack Damp A, Pos. (% Opn)	0	0	0	0
Pumps; Recirc. Pump A1 (amps)	23	23	22	23
Recirc. Pump B1 (amps)	21	21	21	21
Recirc. Pump B2 (amps)	21	21	21	21
Recirc. Pump B3 (amps)	25	25	25	25
Reheater; Steam Flow (M lbs)	OUT	OUT	OUT	OUT
Steam Pressure (psig)	—	—	—	—
Section A; Presat Water Flow (gpm)	57	68	68	68
Outlet Gas Temp. (°F)	115	120	110	115
Bed Diff. (in. H_2O)	4.8	4.8	4.2	4.4
Demister Diff. (in. H_2O)	4.4	4.4	3.8	4.6
RH Diff. (in. H_2O)	4.5	4.5	3.5	4.4
Gas Outlet ~~Flow~~ PL (in. H_2O)	7.6	8.2	0	1.5
Section B; Presat Water Flow (gpm)	24	23	23	23
Outlet Gas Temp. (°F)	125	125	120	120
Bed Diff. (in. H_2O)	6	6±.5	5±.2	6±.5
Demister Diff. (in. H_2O)	1.5±1.0	1.6±.5	1.3±.4	1.5±.3
RH Diff. (in. H_2O)	4	4	3.5	4
Gas Outlet Flow (in. H_2O)	1.0	0.4	0.5	0.8

Comments

CHEROKEE STATION UNIT 1 DATA SHEET

Date:	8/15/77	8/15/77	8/22/77	8/22/77
Time:	0935	1110	0920	1100
Plant				
Mw, Gross	116	116	119	116
XS O_2	2.5%	4%	5.5%	BEING CALIBRATED
Steam Flow (lbs/hr) $\times 10^3$	940	940	945	945
Steam Pressure (psig)	1420	1420	1430	1420
Steam Temperature (°F)	1000	1000	1010	1000
Opacity, ~~Bypass (%)~~	15%	15%	23%	20%
~~Opacity, Scrubber (%)~~ FUEL	100% COAL	100% COAL	100% COAL	100% COAL
NAT GAS SCFH	—	—	—	
ESP				
Section A1-A2; AC Voltage (v)	180±10	170±20	180±20	180±20
AC Current (a)	35±10	35±10	30±30	35±10
DC Voltage (Kv)	38±2	38±3	26±4	35±2
DC Current (ma)	80±20	80±20	150±50	130±20
Spark Rate (spm)	290±30	300±30	250±50	230±40
Section B1-B2; AC Voltage (v)	160	170±10	160	160
AC Current (a)	35±10	35±10	5	10±5
DC Voltage (Kv)	2	2	2	2
DC Current (ma)	70±10	70±10	30	30
Spark Rate (spm)	200±40	200±40	0	0
Scrubber				
Fans; Fan Inlet Pressure (in. H_2O)	-0.3	-0.3	-0.3	-0.3
Fan A Outlet Pressure (in. H_2O)	16.5	17	16	12
Fan B Outlet Pressure (in. H_2O)	16.5	17	16	15
Fan A Amps	150	150	150	145
Fan B Amps	150	150	150	145
Stack Damp A, Pos. (% Opn)	0	0	0	0
Pumps; Recirc. Pump A1 (amps)	23	23	OFF*	OFF
Recirc. Pump B1 (amps)	21	22	21	21
Recirc. Pump B2 (amps)	21	21	21	20
Recirc. Pump B3 (amps)	25	25	25	25
Reheater; Steam Flow (M lbs)	OUT	OUT	OUT	
Steam Pressure (psig)	—	—		
Section A; Presat Water Flow (gpm)	68	68	67	67
Outlet Gas Temp. (°F)	120	120	(210)	220
Bed Diff. (in. H_2O)	4.6	4.8	2.8	2.8
Demister Diff. (in. H_2O)	4.3	4.5	0.8	0.8
RH Diff. (in. H_2O)	5.5	5.5	9.5	8.5
Gas Outlet Flow (in. H_2O)	2.0	0.4	10	10
Section B; Presat Water Flow (gpm)	23	23	22.5	23
Outlet Gas Temp. (°F)	120	120	150	150
Bed Diff. (in. H_2O)	5.5±.5	5.5±.5	5±.5	4.5±0.5
Demister Diff. (in. H_2O)	2.0±.5	2.0±.5	2.0±.5	1.5±0.5
RH Diff. (in. H_2O)	5.5	5.5	5	4.5
Gas Outlet Flow (in. H_2O)	0.5	0	0.4	0.5

Comments * MOTOR ON RECIRC PUMP A1 BURNED OUT. WILL TRY AND REPLACE AND KEEP ON-LINE UNLESS TEMP GETS TOO HIGH (OUTLET TEMP).

CHEROKEE STATION UNIT 1 DATA SHEET

Date:	8/23/77	8/23/77	8/24/77	8/24/77	8/24/77	8/24/77
Time:	0925	1030	0850	1115	1250	1425
Plant FUEL	100% COAL	100% COAL	100% COAL	100%	100% COAL	100% COAL
Mw, Gross	110	116	108	116	116	116
XS O_2	3.5%	OUT	3.5%	3.5%	3.0%	3%
Steam Flow (lbs/hr) $\times 10^3$	830	940	850	940	945	950
Steam Pressure (psig)	1430	1420	1420	1420	1420	1420
Steam Temperature (°F)	1010	1000	1000	990	990	1000
Opacity, ~~Bypass (%)~~	17%	17%	17%	22%	20%	22%
~~Opacity, Scrubber (%)~~ NAT GAS FLOW (SCFH)	—	—	—	—	—	—
ESP						
Section A1-A2; AC Voltage (v)	180±10	180±10	180±10	180	180	180
AC Current (a)	40±10	40±10	40±20	50±10	45±10	45±10
DC Voltage (Kv)	38±2	36±2	37±2	35±2	36±2	36±2
DC Current (ma)	110±20 ~~300±10~~	100±20	140±20	130±20	140±20	130±20
Spark Rate (spm)	380±40	450±50	450±50	450±50	450±50	450±50
Section B1-B2; AC Voltage (v)	160	160±10	160	160±10	160±10	160
AC Current (a)	5	5	20±5	25±5	20±5	20±5
DC Voltage (Kv) **	~~2~~ OUT	OUT ~~2~~	OUT	OUT	OUT	OUT
DC Current (ma)	20	20	50±10	50±10	50±10	50±10
Spark Rate (spm)	120±50	120±50	340±50	250±50	270±30	280±40
Scrubber						
Fans; Fan Inlet Pressure (in. H_2O)	-0.3	-0.3	-0.25	-0.25	-0.25	-0.25
Fan A Outlet Pressure (in. H_2O)	14	14.5	13.5	15.5	15	15
Fan B Outlet Pressure (in. H_2O)	14	14.5	13.5	15.5	15	15
Fan A Amps	145	145	140	150	150	145
Fan B Amps	145	145	140	150	150	145
Stack Damp A, Pos. (% Opn)	0	0	0	0	0	0
Pumps; Recirc. Pump A1 (amps) ~~OUT~~	* OFF ~~OUT~~	OFF ~~OUT~~	OFF ~~OUT~~	OFF ~~OUT~~	OFF ~~OUT~~	OFF
Recirc. Pump B1 (amps)	22	22	21	22	22	22
Recirc. Pump B2 (amps)	21	21	21	21	21	21
Recirc. Pump B3 (amps)	25	25	25	25	25	24
Reheater; Steam Flow (M lbs)	OUT	OUT	OUT	OUT	OUT	OUT
Steam Pressure (psig)	—	—	—	—	—	—
Section A; Presat Water Flow (gpm)	58	58	59	59	58	58
Outlet Gas Temp. (°F)	135	160	150	160	160	195
Bed Diff. (in. H_2O)	3.0	3.0	3.2	3.2	3.2	3.2
Demister Diff. (in. H_2O)	0.75	0.8	0.7	0.9	0.9	0.9
RH Diff. (in. H_2O)	7.5	8.0	7.5	8.5	8.0	8.0
Gas Outlet ~~Flow~~ PR (in. H_2O)	2.5	2.4	3.0	3.8	3.0	6.0
Section B; Presat Water Flow (gpm)	23	23	22	22	22	22.5
Outlet Gas Temp. (°F)	150	150	150	150	150	150
Bed Diff. (in. H_2O)	4.5±.3	4.5±.3	4.5	4.5±.3	5.0	5.0±.5
Demister Diff. (in. H_2O)	1.0±.3	1.4±.3	1.4±.2	1.5±.3	1.5±.3	1.5±.3
RH Diff. (in. H_2O)	4.0	4.5	4.5	5.0	4.7	4.7
Gas Outlet ~~Flow~~ PR (in. H_2O)	0.4	0.3	0.2	0	.25	0

Comments * KEEPING GAS TEMP DOWN BY KEEPING DEMISTER WASH WATER ON.
** SIGN ON METER INDICATING OUT OF SERVICE

CHEROKEE STATION UNIT 1 DATA SHEET

Date:	8/25/77	8/25/77
Time:	0620	0830
Plant		
Mw, Gross	108	114
XS O_2	3%	4%
Steam Flow (lbs/hr) X10[3]	820	930
Steam Pressure (psig)	1420	1420
Steam Temperature (°F)	990	1000
Opacity, ~~Bypass (%)~~	17%	19%
~~Opacity, Scrubber (%)~~ FUEL	100% COAL	100% COAL
NAT. GAS FLOW SCFH	—	
ESP		
Section A1-A2; AC Voltage (v)	180±20	170±10
AC Current (a)	40±20	40±10
DC Voltage (Kv)	35±5	33±5
DC Current (ma)	140±40	140±20
Spark Rate (spm)	350±50	450±50
Section B1-B2; AC Voltage (v)	170±10	170
AC Current (a)	10	10
DC Voltage (Kv)	OUT	OUT
DC Current (ma)	20	50
Spark Rate (spm)	50±50	100-400
Scrubber		
Fans; Fan Inlet Pressure (in. H_2O)	-0.5	-0.6
Fan A Outlet Pressure (in. H_2O)	14	15
Fan B Outlet Pressure (in. H_2O)	14	15
Fan A Amps	145	150
Fan B Amps	145	150
Stack Damp A, Pos. (% Opn)	0	0
Pumps; Recirc. Pump A1 (amps)	OFF	OFF
Recirc. Pump B1 (amps)	21	21
Recirc. Pump B2 (amps)	21	21
Recirc. Pump B3 (amps)	25	21
Reheater; Steam Flow (M lbs)	—	—
Steam Pressure (psig)	—	—
Section A; Presat Water Flow (gpm)	55	55
Outlet Gas Temp. (°F)	115	115
Bed Diff. (in. H_2O)	3.4	3.4
Demister Diff. (in. H_2O)	0.4	1.0
RH Diff. (in. H_2O)	7.7	8.0
Gas Outlet ~~Flow~~ PR (in. H_2O)	—	—
Section B; Presat Water Flow (gpm)	21.5	21
Outlet Gas Temp. (°F)	150	150
Bed Diff. (in. H_2O)	5.0	4.8
Demister Diff. (in. H_2O)	1±.3	1.3±.4
RH Diff. (in. H_2O)	4.5	5.0
Gas Outlet ~~Flow~~ PR (in. H_2O)	0	0.6

Comments

CHEROKEE STATION UNIT 1 DATA SHEET

Date:	8/19	8/19	8/23	8/23	8.26	8/26	8/28	8/28
Time:	1012	1112	1724*	1828*	1409*	1500*	0923	1035
Plant								
Mw. Gross	88	100	117	116	118	117	103	108
XS O_2	Out	Out	~~Out~~ 2.4	1.6	[illegible]	2.6	4.6	3.6
Steam Flow (lbs/hr) x 10^3	850	910	950	950	[illegible]	950	760	840
Steam Pressure (psig)	1380	1400	1420	1420	[illegible]	[illegible]	1440	1420
Steam Temperature (°F)	970	990	1000	990	[illegible]	980	980	970
Opacity, ~~Bypass (%)~~	11	10	20	18	12	20	22	27
~~Opacity, Scrubber (%)~~ Fuel	coal	coal	coal	coal	coal	coal	coal	coal
ESP								
Section A1-A2; AC Voltage (v)	200	200	165	170	[illegible]	165	175	175
AC Current (a)	40±10	40±15	45±5	45±10	[illegible]	[illegible]±10	40±10	40±5
DC Voltage (Kv)	40	40	34	36	[illegible]	32±3	32±3	35±2
DC Current (ma)	90	80	80	80	90	80	60	60
Spark Rate (spm)	220±20	270±20	>500	>500	[illegible]	[illegible]±30	400±20	420±30
Section B1-B2; AC Voltage (v)	180	175	160	166	[illegible]	[illegible]	165	165
AC Current (a)	35±10	35±10	<25	<25	[illegible]	[illegible]	25	25
DC Voltage (Kv)	Out	Out	Out	Out	[illegible]	[illegible]	Out	Out
DC Current (ma)	120	120	~~20±20~~ 40	50	[illegible]	20	60	60
Spark Rate (spm)	360	430	210±20	150±50	0	[illegible]	380±30	380±20
Scrubber								
Fans; Fan Inlet Pressure (in. H_2O)	-.3	-.4	-.4	-.5	-.7	-.7	-.6	-.7
Fan A Outlet Pressure (in. H_2O)	13	15	15.5	15.0	17.0	17.0	13.0	15.0
Fan B Outlet Pressure (in. H_2O)	13	15	15.5	15.0	[illegible]	[illegible]	13.0	15.0
Fan A Amps	135	145	145	150	145	[illegible]	135	145
Fan B Amps	135	145	150	150	155	[illegible]	135	145
Stack Damp A, Pos. (% Opn)	0	0	0	0	0	0	0	0
Pumps; Recirc. Pump A1 (amps)	23	22	0	0	0	0	0	0
Recirc. Pump B1 (amps)	21	21	21.5	21	21.5	[illegible]	21	21
Recirc. Pump B2 (amps)	21	21	21	21	21	[illegible]	21	21
Recirc. Pump B3 (amps)	25	25	25	25	21	[illegible]	20.5	21
Reheater; Steam Flow (M lbs)	Out	Out	Out	Out	[illegible]	[illegible]	Out	Out
Steam Pressure (psig)	—	—	—	—	—	—	—	—
Section A; Presat Water Flow (gpm)	68	65	55	52	57	[illegible]	57	57
Outlet Gas Temp. (°F)	110	125	175	170	165	170	185	185
Bed Diff. (in. H_2O)	3.9	[illegible]	3.0	3.0	2.7	2.7	4.4	4.8
Demister Diff. (in. H_2O)	2.2	4.0	0.9	0.9	[illegible]	[illegible]	0.6	0.6
PH Diff. (in. H_2O)	4.0	5.0	8.5	8.5	[illegible]	[illegible]	6.5	7.6
Gas Outlet Flow (in. H_2O)	2.7	2.0	0.4	0	3.0	[illegible]	0	2
Section B; Presat Water Flow (gpm)	225	195	218	225	215	215	220	220
Outlet Gas Temp. (°F)	150	145	150	150	150	150	145	145
Bed Diff. (in. H_2O)	4.6	4.5	5.0	5.0	6.2	[illegible]	4.4	5.2
Demister Diff. (in. H_2O)	1.0	1.3±.2	1.5±.5	1.5±.3	1.0±[illegible]	1.0	0.8	1.0
RH Diff. (in. H_2O)	3.8	4.8	4.8	4.9	5.5	5.5	4.5	5.0
Gas Outlet Flow (in. H_2O)	0	0	0	0	0	0	0	0.2

Comments

* Demister wash water is on

CHEROKEE STATION UNIT 2 DATA SHEET

Date:	7/27/77	7/27/77	7/29/77	7/29/77	7/30/77	7/30/77	8/1/77	8/1/77
Time:	1335	1548	0918	1046	1826*	1943	1723	1824
Plant								
Mw. Gross	113	106	110	111	94	88	114	94
XS O_2 (%)	4.3	3.5	4.0	3.8	5.6	3.5	4.8	5.2
Steam Flow (lbs/hr)	9.3×10^5	8.5×10^5	8.8×10^5	8.9×10^5	7.5×10^5	6.9×10^5	9.3×10^5	7.2×10^5
Steam Pressure (psig)	1440	1440	1440	1440	1400	1420	1420	1420
Steam Temperature (°F)	990	970	990	980	980	990	990	980
Opacity, Bypass (%)	13	15	14	20	15	12	12	12
Fuel	75C/25G	75C/25G	75C/25G	75C/25G	75C/25G	75C/25G	75C/25G	75C/25G
ESP								
Section A1-A2; AC Voltage (v)	200+	200+	180	175	325	325	170	175
AC Current (a)	~~20~~	~~20~~	20	15	58	58	18	19
DC Voltage (Kv)	24	25	23	23	36/37	36/37	22/25	24/26
DC Current (ma)	50	40	40	35	195/200	195/200	35/35	35/35
Spark Rate (spm)		0/150	12/18	7200/20	0/5	0/5	7200/98	7200/100
Section A3-A4: AC Voltage (v)	~~250~~ 290+	200	~~200~~ 240	300	285	310	350	230
AC Current (a)	~~45~~ 58	42	~~24~~ 58	61	61	60	50	45
DC Voltage (Kv)	~~33~~ 44	~~24~~ 48	~~27~~ 42	42	42/41	45/44	40/38	37/36
DC Current (ma)	~~0~~ 300	~~90~~ 300	280	300	310	300	200	180
Spark Rate (spm)	—	0/0	0	0	0	0	0	0
Section B1-B2; AC Voltage (v)	250++	290	210	175	Tripped	Tripped	260	270
AC Current (a)	15	39	24	20	out	out	10	10
DC Voltage (Kv)	33	~~0~~ 22	24	27			37/35	38/35
DC Current (ma)	40	130	60	50			40/35	50/45
Spark Rate (spm)	—	0/0	0/0	0/0			0/0	0/0
Section B3-B4: AC Voltage (v)	290	290	280	290	290	310	~~300~~ 230	230
AC Current (a)	93	58	93	93	92	93	~~86~~ 65	65
DC Voltage (Kv)	38	~~42~~ 38	37	38	37/39	40/40	33/33	31/31
DC Current (ma)	~~0~~ 550	~~0~~ 550	550	530	540	550	[illegible]	370
Spark rate (spm)	—	0	0	0	0	0	[illegible]	0
Section C1-C2: AC Voltage (v)	290	290	290	285	320	305	320	315
AC Current (a)	40	93	40	34	56	56	36	34
DC Voltage (Kv)	0	38	out	out	out	out	out	out
DC Current (ma)	140	0	130	110	200/195	200/195	100/92	135/130
Spark rate (spm)	—	0	0/0	0/0	0/0	0/0	0/0	0/0
Section C3-C4: AC Voltage (v)	255	250	245	250	255	260	240	295
AC Current (a)	93	92	91	92	92	92	83	93
DC Voltage (Kv)	~~0~~ 38	38	36	37	38/38	39.5/39.5	41/41	44/44
DC Current (ma)	550	~~0~~ 520	520	530	520	530	500	530
Spark Rate (spm)	10	10	10	10	10	10	10	10
~~Section D1-D2; AC Voltage (v)~~								
~~AC Current (a)~~								
~~DC Voltage (Kv)~~								
~~DC Current (ma)~~								
Spark Rate (spm)								
~~Section D3-D4; AC Voltage (v)~~								
~~AC Current (a)~~								
~~DC Voltage (Kv)~~								
~~DC Current (ma)~~								
Spark Rate (spm)								
Gas Rate (scfm)	2.6×10^5	2.6×10^5	2.2×10^5	2.3×10^5	2.0×10^5	2.0×10^5	2.6×10^5	2.2×10^5

Comments

\+ ±50 v fluctuations

++ -100 v "

* ESP trouble tt alarm, excessed stack damper

A-12

CHEROKEE STATION UNIT 2 DATA SHEET

Date:	8/3	8/3*	8/4	8/4	8/4
Time:	1705	1930	BASE LOAD		1427
Plant Fuel	25% GAS 75% COAL	75% COAL	75% COAL	75% COAL	75% COAL
Mw. Gross	109	62	110	112	111
XS O_2	3.5	5	4	3.5	3.8
Steam Flow (lbs/hr) $\times 10^3$	870	470	895	900	880
Steam Pressure (psig)	1440	1420	1420	1440	1440
Steam Temperature (°F)	1000	1000	1000	1000	990
Opacity, Bypass (%)	16	12	11	10	12
NAT. GAS SCFH $\times 10^5$	2.6	0.75	1.8	1.7	1.7
ESP					
Section A1-A2; AC Voltage (v)	150-400	350	340 ± 50	340	280 ± 70
AC Current (a)	?	58	28 ± 4	32	26
DC Voltage (Kv)	24-40/30-40	40/40	42/42 (DEFLECTING)	42/42	35/35
DC Current (ma)	60/60 ± 20	190/190	90/90	90/90	60/60
Spark Rate (spm)	90/10	10/8	30/10	38/8	10/25
Section [B1-B2]: AC Voltage (v)	310	320	340	340	340
AC Current (a)	?	47	47	42	32
DC Voltage (Kv)	40/36	38/34	39/36	40/36	40/36
DC Current (ma)	85/65	160/140	150/130	130/110	80/70
Spark Rate (spm)	0/0	0/0	0/0	0/0	0/0
Section [C1-C2]: AC Voltage (v)	310	310	330	350	330
AC Current (a)	35	50	56	58	50
DC Voltage (Kv)	OUT	OUT	OUT	OUT	OUT
DC Current (ma)	120/120	190/180	170/160	210/210	140/135
Spark Rate (spm)	0/0	0/0	0/0	0/0	0/0
Section [A3-A4]: AC Voltage (v)	240 ± 10	260	250 ± 20	270 ± 10	250
AC Current (a)	50	60	55 ± 5	55 ± 5	50
DC Voltage (Kv)	39/38	39/38	39/38	42/40	39/38
DC Current (ma)	200	300	220	250	170
Spark rate (spm)	0	0	0	0	0
Section [B3-B4]: AC Voltage (v)	250 ± 30	290	250 ± 30	230 ± 30	230 ± 30
AC Current (a)	70 ± 10	92	70 ± 10	75 ± 10	70 ± 10
DC Voltage (Kv)	30	38/39	31/31	31/31	32/32
DC Current (ma)	300 ± 20	550	350	330	330
Spark rate (spm)	0	0	0	0	0
Section C3-C4: AC Voltage (v)	280	265	270*	270*	270 ± 10
AC Current (a)	94	93	93	93	92
DC Voltage (Kv)	42/42	39/39	40/40	41/41	42/42
DC Current (ma)	550	540	540	540	540
Spark Rate (spm)	10	10	10	0	10
Section D1-D2; AC Voltage (v)					
AC Current (a)					
DC Voltage (Kv)					
DC Current (ma)					
Spark Rate (spm)					
Section D3-D4; AC Voltage (v)					
AC Current (a)					
DC Voltage (Kv)					
DC Current (ma)					
Spark Rate (spm)					

Comments * ESP METERING VERY STEADY, OBSERVER → R. IDA

CHEROKEE STATION UNIT 2 DATA SHEET

Date:	8/8/77	8/8/77	8/9/77	8/9/77
Time:	1000	1041	1356	1502
Plant				
Fuel	750/250	750/250	750/250	750/250
Mw, Gross	107	109	109	108
XS O_2	3.5	3.2	3.4	
Steam Flow (lbs/hr) x 10^3	850	860	815	860
Steam Pressure (psig)	1440	1440	1440	1440
Steam Temperature (°F)	1040	1000	990	985
Opacity, Bypass (%)	12	13	13	7
Nat'l Gas (SCFM) x 10^5	2.0	2.0	1.8	1.7
ESP				
Section A1-A2; AC Voltage (v)	280±30	335±40	280±40	280±50
AC Current (a)	28±4	35±4	35±5	32±5
DC Voltage (Kv)	38/38	35/35	38/38	35/35
DC Current (ma)	70/60	60/60	110/110	90/90
Spark Rate (spm)	35/10	40/5	35/1.0	35/5
Section ~~A3-A4~~ B1-B2: AC Voltage (v)	300	270	300	285
AC Current (a)	30	26	38	34
DC Voltage (Kv)	37/33	39/34	37/35	38/33
DC Current (ma)	105/95	80/70	120/110	130/110
Spark Rate (spm)	0/0	0/0	0/0	0/0
Section ~~B1-B2~~ C1-C2: AC Voltage (v)	335	330	340	320
AC Current (a)	57	53	57	57
DC Voltage (Kv)	Out	Out	Out	Out
DC Current (ma)	205/200	195/190	205/200	205/195
Spark Rate (spm)	0/0	0/0	0/0	0/0
Section ~~B3-B4~~ A3-A4: AC Voltage (v)	220	200	220	310
AC Current (a)	50	48	50	50
DC Voltage (Kv)	35/34	34/33	34/33	35/34
DC Current (ma)	170	150	170	180
Spark rate (spm)	0	0	0	0
Section ~~C1-C2~~ B3-B4: AC Voltage (v)	230±15	220±10	210±20	225±10
AC Current (a)	70±10	75±5	70±5	70±10
DC Voltage (Kv)	32/32	31/31	30/30	31/31
DC Current (ma)	350	350±50	400	340
Spark rate (spm)	0	0	0	0
Section C3-C4: AC Voltage (v)	210±20	210±20	200±10	210
AC Current (a)	75±5	75±5	70±5	70
DC Voltage (Kv)	33/33	33/30	33/33	33/33
DC Current (ma)	360	340±40	350±20	370
Spark Rate (spm)	10	10	10	10
~~Section D1-D2~~: ~~AC Voltage (v)~~				
~~AC Current (a)~~				
~~DC Voltage (Kv)~~				
~~DC Current (ma)~~				
~~Spark Rate (spm)~~				
~~Section D3-D4~~: ~~AC Voltage (v)~~				
~~AC Current (a)~~				
~~DC Voltage (Kv)~~				
~~DC Current (ma)~~				
~~Spark Rate (spm)~~				

Comments

CHEROKEE STATION UNIT 2 DATA SHEET

Date:	8/6/77	8/6/77	8/10/77	8/10/77
Time:	1315	1445	2145	2330
Plant ~~Fuel~~ 3 (MILLS)	85% COAL	85% COAL	85% COAL	85% COAL
Mw. Gross	60	91	70	72
XS O_2 %	6.5	3.4	5.0	5.8
Steam Flow (lbs/hr) $\times 10^3$	450	700	580 (GOING DOWN)	540
Steam Pressure (psig)	1420	1440	1420	1420
Steam Temperature (°F)	1000	990	950	940
Opacity, Bypass (%)	0	0	10	10
N.G. FLOW SCFH $\times 10^3$	140	160	160	160
ESP				
Section A1-A2; AC Voltage (v)	* 360	340 D	335*	330*
AC Current (a)	60	34 D	60	60
DC Voltage (Kv)	41/41	42/43	36/37	36/37
DC Current (ma)	210/210	120/120	200/210	200/210
Spark Rate (spm)	0/5	25/20	3/5	2/5
Section ~~A3-A4~~ B1-B2; AC Voltage (v)	* 300	330	280*	280*
AC Current (a)	47	48	47	47
DC Voltage (Kv)	36/32	40/36	32/26	32/26
DC Current (ma)	160/135	160/140	160/135	160/135
Spark Rate (spm)	0/0	0/0	0/0	0/0
Section ~~B1-B2~~ C1-C2; AC Voltage (v)	* 310	330	280	280
AC Current (a)	57	57	56	57
DC Voltage (Kv)	OUT	OUT	OUT	OUT
DC Current (ma)	200/200	210/200	200/145	200/195
Spark Rate (spm)	0/0	0/0	0/0	0/0
Section ~~B3-B4~~ A3-A4; AC Voltage (v)	280	270±20	250 ~~[illegible]~~ ±20	250±20
AC Current (a)	60	55±5	~~[illegible]~~ 53	55±5
DC Voltage (Kv)	41	40	40/39	35/36
DC Current (ma)	300	270	300	300
Spark rate (spm)	0	0	0	0
Section ~~C1-C2~~ B3-B4; AC Voltage (v)	280	300±10	210±30	230±20
AC Current (a)	92	90±10	70±10	80±20
DC Voltage (Kv)	36	39 ~~35~~	28/28	36/36
DC Current (ma)	540	500±50	300±50	450±50
Spark rate (spm)	0	0	0	0
Section ~~C3-C4~~ C3-C4; AC Voltage (v)	250	260	260*	260*
AC Current (a)	93	92	92	92
DC Voltage (Kv)	37	38	38/38	38/38
DC Current (ma)	530	530	540	540
Spark Rate (spm)	10	10	10	10
~~Section D1-D2; AC Voltage (v)~~				
~~AC Current (a)~~				
~~DC Voltage (Kv)~~				
~~DC Current (ma)~~				
~~Spark Rate (spm)~~				
~~Section D3-D4; AC Voltage (v)~~				
~~AC Current (a)~~				
~~DC Voltage (Kv)~~				
~~DC Current (ma)~~				
~~Spark Rate (spm)~~				

Comments * ALL READINGS STEADY
D = DEFLECTING

CHEROKEE STATION UNIT 2 DATA SHEET

Date:	8/12/77	8/12/77	8/13/77	8/13/77	
Time:	1340	1510	0935	1100	
Plant FUEL	75% COAL	75% COAL	75% COAL	75% COAL	
Mw. Gross	103	102	92	106	
XS O_2	4%	5%	4%	12	
Steam Flow (lbs/hr) x10³	810	810	720	850	
Steam Pressure (psig)	1420	1420	1410	1420	
Steam Temperature (°F)	1000	1000	1000	1010	
Opacity, ~~Bypass (%)~~ (5%)	~~75/80%~~	~~20%~~ *	5%	4%	
NAT. GAS FLOW SCFH	220	220	220	220	
ESP					
Section A1-A2; AC Voltage (v)	340	340	250 ± 100	180 ± 30	
AC Current (a)	56	54	20 ± 7	25 ± 5	
DC Voltage (Kv)	39/39	39/38	26 ± 6/30 ± 10	24 ± 4/25 ± 4	
DC Current (ma)	190/190	160/160	50 ± 30/50 ± 30	35 ± 10/35 ± 10	
Spark Rate (spm)	5/5	12/10	** 150/15	200/50	
Section ~~A3-A4~~ B1-B2: AC Voltage (v)	320	320	310	290 deflecting (all meters in section)	
AC Current (a)	60	55	40	15	
DC Voltage (Kv)	37/32	37/32	37/32	38/34	
DC Current (ma)	210/180	210/170	140/110	50/45	
Spark Rate (spm)	0/0	0/0	0/0	0/0	
Section ~~B1-B2~~ C1-C2: AC Voltage (v)	300	300	320	350	
AC Current (a)	56	56	58	55	
TOP/BOTTOM DC Voltage (Kv)	OUT	OUT	OUT	OUT	
C1/C2 DC Current (ma)	200/190	200/190	210/200	180/180	
Spark Rate (spm)	0/0	0/0	0/0	0/0	
Section ~~B3-B4~~ A3-A4: AC Voltage (v)	190 ± 10	190 ± 10	190 ± 10	180 ± 10	
AC Current (a)	50 ± 5	50 ± 5	50 ± 5	45 ± 5	
DC Voltage (Kv)	31/30	29/28	31/31	29/29	
DC Current (ma)	180 ± 20	180 ± 20	150	180 ± 20	
Spark rate (spm)	0	0	0	0	
Section ~~C1-C2~~ B3-B4: AC Voltage (v)	200 ± 20	210 ± 20	220 ± 10	200 ± 20	
AC Current (a)	70 ± 10	75 ± 10	70 ± 10	80 ± 10	
DC Voltage (Kv)	28/29	27/27	30/30	25/25	
DC Current (ma)	370 ± 20	400	350 ± 40	450 ± 50	
Spark rate (spm)	0	0	0	0	
Section C3-C4; AC Voltage (v)	200 ± 20	200 ± 10	200 ± 20	200 ± 10	
AC Current (a)	75 ± 10	75 ± 10	70 ± 10	80 ± 10	
DC Voltage (Kv)	31/31	31/30	33/33	30/30	
DC Current (ma)	280 ± 20	400 ± 20	350 ± 50	440 ± 40	
Spark Rate (spm)	10	10	10		
~~Section D1-D2; AC Voltage (v)~~					
~~AC Current (a)~~					
~~DC Voltage (Kv)~~					
~~DC Current (ma)~~					
~~Spark Rate (spm)~~					
~~Section D3-D4; AC Voltage (v)~~					
~~AC Current (a)~~					
~~DC Voltage (Kv)~~					
~~DC Current (ma)~~					
~~Spark Rate (spm)~~					

Comments * NO READING, CALIBRATING CHART
** SPARK RATE UP FROM PREVIOUS

CHEROKEE STATION UNIT 2 DATA SHEET

Date:	8/15/77	8/15/77	8/22/77	8/22/77
Time:	0940	1115	0930	1100
Plant FUEL	75% COAL	75% COAL	75% COAL	75% COAL
Mw. Gross	110	115	115	113
XS O_2	3%	4%	4%	3.5%
Steam Flow (lbs/hr) $\times 10^3$	870	920	930	930
Steam Pressure (psig)	1420	1420	1420	1420
Steam Temperature (°F)	1000	1000	1010	990
Opacity, Bypass (%)	13%	12%	18%	20%
NAT GAS FLOW SCFH $\times 10^3$	270	290	320	320
ESP				
Section A1-A2; AC Voltage (v)	300	300	325	340
AC Current (a)	58	58	57	58
DC Voltage (Kv)	34/34	34/34	36/37	39/39
DC Current (ma)	195/200	190/200	190/190	200/200
Spark Rate (spm)	0/5	0/5	0/5	0/5
Section ~~A3-A4~~ B1-B2; AC Voltage (v)	250	250	260	250
AC Current (a)	58	52	50	50
DC Voltage (Kv)	28/24	30/25	30/24	30/26
DC Current (ma)	160/140	170/160	165/140	160/140
Spark Rate (spm)	0/0	0/0	0/0	0/0
Section ~~B1-B2~~ C1-C2; AC Voltage (v)	240	240	240	240
AC Current (a)	56	56	56	56
DC Voltage (Kv)	OUT	OUT	OUT	OUT
DC Current (ma)	195/190	195/190	195/190	195/190
Spark Rate (spm)	0/0	0/0	0/0	0/0
Section ~~B3-B4~~ A3-A4; AC Voltage (v)	230	225	320	325
AC Current (a)	57	59	58	59
DC Voltage (Kv)	34/34	35/34	45/45	48/46
DC Current (ma)	300	300	300	300
Spark rate (spm)	0	0	0	0
Section ~~C1-C2~~ B3-B4; AC Voltage (v)	250	250	270	290
AC Current (a)	91	91	91	91
DC Voltage (Kv)	32/33	33/33	35/36	36/36
DC Current (ma)	540	540	530	520
Spark rate (spm)	0	0	0	0
Section C3-C4; AC Voltage (v)	230	230	220	220
AC Current (a)	92	92	91	91
DC Voltage (Kv)	34/34	34/34	32/32	32/32
DC Current (ma)	520	520	520	520
Spark Rate (spm)	10	10	10	10
Section D1-D2; AC Voltage (v)				
AC Current (a)				
DC Voltage (Kv)				
DC Current (ma)				
Spark Rate (spm)				
Section D3-D4; AC Voltage (v)				
AC Current (a)				
DC Voltage (Kv)				
DC Current (ma)				
Spark Rate (spm)				

Comments 8/15/77 ESP READINGS - STEADY

CHEROKEE STATION UNIT 2 DATA SHEET

Date:	8/23/77	8/23/77	8/24/77	8/24/77	8/24/77	8/24/77
Time:	0930	1035	0855	1115	1255	1450
Plant FUEL	75% COAL	75%	75% COAL	75% COAL	75% COAL	75% COAL
Mw. Gross	104	113	82	115	115	115
XS O_2	5.5%	5.5%	4.5%	4.0	4%	3.5%
Steam Flow (lbs/hr) x10³	840	850	650	940	940	940
Steam Pressure (psig)	1420	1420	1420	1420	1420	1420
Steam Temperature (°F)	990	1000	990	1000	1000	1000
Opacity, Bypass (%)	13%	15%	15%	15%	15%	15%
NAT GAS FLOW (SCFH) x10³	290	300	110	~~30~~ 310	310	310
ESP						
Section A1-A2; AC Voltage (v)	340	360	350	340	340	350
AC Current (a)	56	58	56	58	57	58
DC Voltage (Kv)	39/39	41/41	36/37	39/39	40/40	40/40
DC Current (ma)	190/200	200/200	180/190	200/200	200/200	200/200
Spark Rate (spm)	0/5	0/5	0/5	0/5	0/5	0/5
Section ~~A3-A4~~ B1-B2; AC Voltage (v)	290	290	280	290	300	300
AC Current (a)	58	56	58	58	58	58
DC Voltage (Kv)	34/28	34/28	33/28	34/30	34/30	35/30
DC Current (ma)	200/175	190/160	200/170	200/170	190/160	200/170
Spark Rate (spm)	0/0	0/0	0/0	0/0	0/0	0/0
Section ~~B1-B2~~ C1-C2; AC Voltage (v)	240	250	240	240	250	250
AC Current (a)	56	56	56	56	56	55
DC Voltage (Kv)	OUT	OUT	OUT	OUT	OUT	OUT
DC Current (ma)	200/190	200/190	190/190	190/190	190/190	190/185
Spark Rate (spm)	0/0	0/0	0/0	0/0	0/0	0/0
Section ~~B3-B4~~ A3-A4; AC Voltage (v)	320	220±40	290	270±20	250±20	250±20
AC Current (a)	57	50±5	58	55±5	50±5	50±5
DC Voltage (Kv)	45/43	~~34~~/34	42/40	38/37	38/37	38/37
DC Current (ma)	250±20	150±10	300	230	200	200
Spark rate (spm)	0	0	0	0	0	0
Section ~~C1-C2~~ B3-B4; AC Voltage (v)	295	230±40	290	250±40	230±50	220±50
AC Current (a)	92	70±20	91	80±20	70±10	70±10
DC Voltage (Kv)	38/38	32/32	38/38	32/33	30/30	30/30
DC Current (ma)	540	250±50	540	400±50	310±30	300±20
Spark rate (spm)	0	0	0	0	0	0
Section C3-C4; AC Voltage (v)	230	250	230	240	250	250
AC Current (a)	91	92	91	91	92	92
DC Voltage (Kv)	34/34	37/37	34/35	35/35	36/36	37/37
DC Current (ma)	520	530	510	520	520	530
Spark Rate (spm)	10	10	10	10	10	10
~~Section D1-D2; AC Voltage (v)~~						
~~AC Current (a)~~						
~~DC Voltage (Kv)~~						
~~DC Current (ma)~~						
~~Spark Rate (spm)~~						
~~Section D3-D4; AC Voltage (v)~~						
~~AC Current (a)~~						
~~DC Voltage (Kv)~~						
~~DC Current (ma)~~						
~~Spark Rate (spm)~~						

Comments

CHEROKEE STATION UNIT 2 DATA SHEET

Date:	8/25/77	~~8/25/77~~	8/25/77							
Time:	0630		0830							
Plant FUEL	75% COAL		75% COAL							
Mw. Gross	98		112							
XS O_2	4.5		4.5							
Steam Flow (lbs/hr)	890		940							
Steam Pressure (psig)	1420		1420							
Steam Temperature (°F)	980		1000							
Opacity, Bypass (%)	13%		20%							
NAT GAS FLOW (SCFH)	240		300							
ESP										
Section A1-A2; AC Voltage (v) *	370		* 360							
AC Current (a) *	57		* 54							
DC Voltage (Kv)	40/40		* 40/40							
DC Current (ma)	200/210		* 180/180							
Spark Rate (spm)	3/5		4/5							
Section A3-A4; AC Voltage (v)	300		300							
AC Current (a)	60		58							
DC Voltage (Kv)	34/29		34/29							
DC Current (ma)	210/180		190/160							
Spark Rate (spm)	0/0		0/0							
Section B1-B2; AC Voltage (v)	240		250							
AC Current (a)	56		56							
DC Voltage (Kv)	OUT		OUT							
DC Current (ma)	200/190		200/190							
Spark Rate (spm)	0/0		0/0							
Section B3-B4; AC Voltage (v)	320		270 ± 30							
AC Current (a)	59		52 ± 3							
DC Voltage (Kv)	46/44		42/41							
DC Current (ma)	300		220 ± 20							
Spark rate (spm)	0		0							
Section C1-C2; AC Voltage (v)	300		250 ± 50							
AC Current (a)	94		75 ± 20							
DC Voltage (Kv)	40/40		36/36							
DC Current (ma)	550		400 ± 50							
Spark rate (spm)	0		0							
Section C3-C4; AC Voltage (v)	235		240							
AC Current (a)	92		92							
DC Voltage (Kv)	35/35		36/36							
DC Current (ma)	540		520							
Spark Rate (spm)	10		10							
~~Section D1-D2; AC Voltage (v)~~										
~~AC Current (a)~~										
~~DC Voltage (Kv)~~										
~~DC Current (ma)~~										
~~Spark Rate (spm)~~										
~~Section D3-D4; AC Voltage (v)~~										
~~AC Current (a)~~										
~~DC Voltage (Kv)~~										
~~DC Current (ma)~~										
~~Spark Rate (spm)~~										

Comments * DEFLECTING

CHEROKEE STATION UNIT 2 DATA SHEET

Date:	8/19/77	[illegible]	8/23/77	8/23/77	[illegible]	8/26	8/28	8/28		
Time:	1020	[illegible]	1239*	1834	1414	1506	0930	1639		
Plant										
Fuel	750/250	750/250	750/250	750/256	[illegible]	[illegible]	750/250	750/250		
Mw. Gross	113	[illegible]	113	113	116	116	74	93		
XS O_2	2.0	2.6	2.9	3.3	[illegible]	1.7	8.4	3.8		
Steam Flow (lbs/hr) $\times 10^3$	950	[illegible]	930	930	[illegible]	[illegible]	550	720		
Steam Pressure (psig)	1420	1420	1420	1420	[illegible]	[illegible]	1420	1420		
Steam Temperature (°F)	1000	1000	1000	1000	1000	1000	980	990		
Opacity, ~~Bypass~~ (%)	10	[illegible]	15	13	[illegible]	15	12.5	12		
[illegible] SCFH $\times 10^5$	3.0	3.0	3.0	3.0	[illegible]	3.0	1.6	2.3		
ESP										
Section A1-A2; AC Voltage (v)	300	310	370	375	415	415	250±50	290		
AC Current (a)	48	[illegible]	58	58	[illegible]	[illegible]	22	34		
DC Voltage (Kv)	35/36	[illegible]	43/42	43/43	[illegible]	45/44	33/33	35/35		
DC Current (ma)	160/160	[illegible]	195/195	210/210	[illegible]	[illegible]	70/70	110/110		
Spark Rate (spm)	0/5	0/5	3/5	3/5	[illegible]	2/5	0/5	0/5		
Section ~~A3-A4~~ B1-B2; AC Voltage (v)	230	[illegible]	300	300	[illegible]	320	280	270		
AC Current (a)	43	[illegible]	58	59	[illegible]	[illegible]	52	42		
DC Voltage (Kv)	29/22	[illegible]	35/30	35/30	[illegible]	28/22	33/27	32/25		
DC Current (ma)	150/130	[illegible]	200/170	205/175	[illegible]	[illegible]	180/150	135/120		
Spark Rate (spm)	0/0	0/0	0/0	0/0	[illegible]	0/0	0/0	0/0		
Section ~~B1-B2~~ C1-C2; AC Voltage (v)	240	240	250	250	[illegible]	260	200	260		
AC Current (a)	56	[illegible]	55	56	[illegible]	[illegible]	57	57		
DC Voltage (Kv)	Out	Out	Out	Out	[illegible]	[illegible]	Out	Out		
DC Current (ma)	175/190	[illegible]	190/180	195/190	[illegible]	[illegible]	200/195	200/195		
Spark Rate (spm)	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0		
Section ~~B3-B4~~ A3-A4; AC Voltage (v)	265	[illegible]	220±20	220±20	[illegible]	[illegible]	276	280		
AC Current (a)	58	[illegible]	48	48	50	[illegible]	56	56		
DC Voltage (Kv)	40/38	41/39	33/33	35/34	[illegible]	[illegible]	41/39	41/40		
DC Current (ma)	300	[illegible]	160	160	[illegible]	[illegible]	310	310		
Spark rate (spm)	0	0	0	0	0	0	0	0		
Section ~~C1-C2~~ B3-B4; AC Voltage (v)	250	[illegible]	230±20	230±30	[illegible]	[illegible]	285	290		
AC Current (a)	91	[illegible]	70±10	70±10	[illegible]	[illegible]	93	93		
DC Voltage (Kv)	33/33	[illegible]	32/32	30/29	[illegible]	[illegible]	38/38	38/38		
DC Current (ma)	520	[illegible]	280	300±20	[illegible]	[illegible]	550	550		
Spark rate (spm)	0	0	0	0		0	0	0		
Section ~~C3-C4~~ C3-C4; AC Voltage (v)	215	215	260	260	[illegible]	[illegible]	235	235		
AC Current (a)	92	[illegible]	93	93	[illegible]	[illegible]	92	93		
DC Voltage (Kv)	32/31	[illegible]	38/38	38/38	[illegible]	[illegible]	35/35	35/35		
DC Current (ma)	520	[illegible]	530	530	[illegible]	530	530	530		
Spark Rate (spm)	10	10	10	10	[illegible]	10	10	10		
~~Section D1-D2. AC Voltage (v)~~										
~~AC Current (a)~~										
~~DC Voltage (Kv)~~										
~~DC Current (ma)~~										
~~Spark Rate (spm)~~										
~~Section D3-D4; AC Voltage (v)~~										
~~AC Current (a)~~										
~~DC Voltage (Kv)~~										
~~DC Current (ma)~~										
~~Spark Rate (spm)~~										

Comments

* Soot Blowing in progress; to be completed in ~30 min.

CHEROKEE STATION UNIT 3 DATA SHEET

Date:	7/21/77	7/22/77	7/29/77	7/29/77	7/30/77	7/30/77	8/1/77	8/1/77
Time:	1355	1533	0935	1057	1849	1951	1836	1835
Plant								
Mw, Gross	152	110	145	145	132	132	136	136
XS O_2	2.8	3.6	3.6	4.0	2.6	2.5	2.3	2.4
Steam Flow (lbs/hr)	1170×10^3	830×10^3	1150×10^3	1.15×10^6	1.01×10^6	1.04×10^6	1.06×10^6	1.04×10^6
Steam Pressure (psig)	1800	1800	1800	1800	1800	1800	~~1800~~ 1950	~~1800~~ 1900
Steam Temperature (°F)	1000	930	1050	1050	1060	1100	1000	1000
Opacity, ~~Bypass~~ (%)	19	18	13	15	2	2	0	0
~~Opacity, Scrubber (%)~~								
~~Steam~~ Gas Flow, ~~(lbs/hr)~~ SCFH					1.54×10^6	1.52×10^6	1.7×10^6	1.7×10^6
ESP								
Section ~~A1-A2~~ B1-B2; AC Voltage (v)	170	170	170	170	165	165	170	170
AC Current (a)	105	105	107	107	106	106	107	107
DC Voltage (Kv)	40	40	40	41	40	40	41	40
DC Current (ma)	600	600	600	600	590	590	600	600
Spark Rate (spm)	0	0	0	0	0	0	0	0
Section ~~B1-B2~~ A1-A2; AC Voltage (v)	50	50	50	<50	50	50	<50	50
AC Current (a)	90	90	90	93	92	92	95	95
DC Voltage (Kv)	8	8	8	8	8	8	8	8
DC Current (ma)	510	510	510	510	510	520	530	530
Spark Rate (spm)	0	0	0	0	0	0	0	0
Scrubber								
Fans; Fan A Inlet Pressure (in. H_2O)	-.6	0	0	0	Scrubber Not in Service*	SCRR Not in Service*	Scbr Not in service*	Scbr Not in service
Fan B Inlet Pressure (in. H_2O)	-.7	-.8	-1.5	-.6				
Fan A Outlet Pressure (in. H_2O)	~~-.6~~ 13	10.5	13.5	13.5				
Fan B Outlet Pressure (in. H_2O)	~~-.7~~ 13	10.5	13.5	13.5				
Fan A Amps	230	190	215	220				
Fan B Amps	210	185	215	220				
Stack Damper A, Pos. (% Opn)	0	0	0	0				
Stack Damper B, Pos. (% Opn)	0	0	0	0				
Pumps; Recirc. Pump A1 (Amps)	20	23	23	24				
Recirc. Pump B1 (Amps)	25	25	25	25				
Recirc. Pump B2 (Amps)	22	22	22	23				
Recirc. Pump B3 (Amps)	20	20	21	20				
Recirc. Pump C1 (Amps)	Down	Down	Down	Down				
Reheater; Steam Flow (M lbs/hr)	Out	Out	Out	Out				
Steam Temp. (°F)	— +	+	+	+				
Steam Pressure (psig)	— +	+	+	+				
Section A; Presat. Water Flow (gpm)	72	72	73	67				
Outlet Gas Temp. (°F)	120	105	125	110				
Bed Diff. (in. H2O)	6	6.5	8.3	8.9				
Demister Diff. (in. H2O)	.4	0	0	0				
RH Diff. (in. H2O)	1.0	0.7	0.7	0.7				
Gas Outlet Flow (in. H2O)	Out	Out	Out	Out				
Section B; Presat. Water Flow (gpm)	210	210	210	194				
Outlet Gas Temp. (°F)	120	130	115	115				
Bed Diff. (in. H_2O)	6.4	5.4	6.4	7.0				
Demister Diff. (in. H_2O)	1.2	1.1	1.6	1.5				
RH Diff. (in. H_2O)	RH Out	RH Out	RH Out	1.5				
Gas Outlet Flow (in. H_2O)	Out	Out	Out	Out				
Section C; Presat. Water Flow (gpm)	70	70	72	65				
Outlet Gas Temp (°F)	130	120	110	110				
Bed Diff. (in. H2O)	4	3.4	3.4	3.2				
Demister Diff. (in. H2O)	0.6	0.4	0.8	0.8				
RH Diff. (in. H2O)	0(?)	1.2	0.5	0.8				
~~RH Diff. (in. H2O)~~								
Gas Outlet Flow (in. H2O)	Out	Out	Out	Out				

Comments

+ No steam flow

* Instructions were if Unit 1 on coal put unit 3 on gas

Heil Meurers
Plugging of ... w/ SO_3
... / operations

CHEROKEE STATION UNIT 3 DATA SHEET

Date:	8/3	8/3	8/4	8/4	8/5	8/
Time:	1730	1950	1045	1215	1457	15
Plant			BASE LOAD			
Mw, Gross (CHART)	58	135	135	132	131	13
XS O_2		1.5	1.2	1.2	2.2	1.
Steam Flow (lbs/hr) ~~x10~~ x10^3	500	1075	1050	1030	1030	10
Steam Pressure (psig)	1700	1800	1800	1800	1800	1800
Steam Temperature (°F)	930	950	975	1000	1000	1010
Opacity, ~~Bypass (%)~~	36%	35%	0	0	0	[illegible]
~~Opacity, Scrubber (%)~~ FUEL	NG	NG	NG	NG	NG	N
NATURAL GAS FLOW (SCFH) x10^3	800	1650	1550	1620	1600	16
ESP						
Section A1-A2; AC Voltage (v)	50	50	50	50	50	5
AC Current (a)	100	90	95	95	95	9
DC Voltage (Kv)	8	8	8	8	8	8
DC Current (ma)	520	510	520	520	520	530
Spark Rate (spm)	0	0	0	0	0	C
Section B1-B2; AC Voltage (v)	170	170	170	170	170	1
AC Current (a)	110	110	110	112	107	108
DC Voltage (Kv)	41	40	40	40	41	4
DC Current (ma)	600	600	600	600	600	6
Spark Rate (spm)	0	0	0	0	0	[illegible]
Scrubber	NOT IN SERVICE	NOT IN SERVICE	NOT IN SERVICE	NOT IN SERVICE	NOT IN SERVICE	NOT [illegible] SER
Fans; Fan A Inlet Pressure (in. H_2O)						
Fan B Inlet Pressure (in. H_2O)						
Fan A Outlet Pressure (in. H_2O)						
Fan B Outlet Pressure (in. H_2O)						
Fan A Amps						
Fan B Amps						
Stack Damper A, Pos. (% Opn)						
Stack Damper B, Pos. (% Opn)						
Pumps: Recirc. Pump A1 (Amps)						
Recirc. Pump B1 (Amps)						
Recirc. Pump B2 (Amps)						
Recirc. Pump B3 (Amps)						
Recirc. Pump C1 (Amps)						
Reheater; Steam Flow (M lbs/hr)						
Steam Temp. (°F)						
Steam Pressure (psig)						
Section A; Presat. Water Flow (gpm)						
Outlet Gas Temp. (°F)						
Bed Diff. (in. H_2O)						
Demister Diff. (in. H_2O)						
RH Diff. (in. H_2O)						
~~Gas Outlet Flow (in. H_2O)~~						
Section B; Presat. Water Flow (gpm)						
Outlet Gas Temp. (°F)						
Bed Diff. (in. H_2O)						
Demister Diff. (in. H_2O)						
RH Diff. (in. H_2O)						
~~Gas Outlet Flow (in. H_2O)~~						
Section C; Presat. Water Flow (gpm)						
Outlet Gas Temp (°F)						
Bed Diff. (in. H_2O)						
Demister Diff. (in. H_2O)						
RH Diff. (in. H_2O)						
RH Diff. (in. H_2O)						
~~Gas Outlet Flow (in. H_2O)~~						

Comments 8/3/77 - 1730 OPERATING ON 1 BFW PUMP. — 2000 - 2 BFW PUMPS OPERATING

OBSERVER R. IDA

CHEROKEE STATION UNIT 3 DATA SHEET

Date:	8/8/77	8/8/77	8/9/77	8/9/77
Time:	1014	1051	1411	1512
Plant				
Mw, Gross	137	135	137	135
XS O_2	1.7	1.9	2.3	2.2
Steam Flow (lbs/hr) $\times 10^3$	1050	1050	1050	1050
Steam Pressure (psig)	1800	1800	1800	1800
Steam Temperature (°F)	1000	1000	975	975
Opacity, Bypass (%)	0	0	5	5
~~Opacity, Scrubber (%)~~ Fuel	Gas	Gas	750/250	750/250
~~Natural Gas Flow (SCFH)~~ $\times 10^3$	166	160	1,15	1,18
ESP				
Section A1-A2; AC Voltage (v)	190	190	220	220
AC Current (a)	68	68	65	65
DC Voltage (Kv)	35	35	39	38
DC Current (ma)	310	310	280	280
Spark Rate (spm)	0	0	0	0
Section B1-B2; AC Voltage (v)	170	170	170	170
AC Current (a)	110	110	110	110
DC Voltage (Kv)	41	41	41	42
DC Current (ma)	630	630	620	630
Spark Rate (spm)	0	0	0	0
Scrubber				
Fans; Fan A Inlet Pressure (in. H_2O)	Not In	Not In	Not In	Not In
Fan B Inlet Pressure (in. H_2O)	Service	Service	Service	Service
Fan A Outlet Pressure (in. H_2O)				
Fan B Outlet Pressure (in. H_2O)				
Fan A Amps				
Fan B Amps				
Stack Damper A, Pos. (% Opn)				
Stack Damper B, Pos. (% Opn)				
Pumps; Recirc. Pump A1 (Amps)				
Recirc. Pump B1 (Amps)				
Recirc. Pump B2 (Amps)				
Recirc. Pump B3 (Amps)				
Recirc. Pump C1 (Amps)				
Reheater; Steam Flow (M lbs/hr)				
Steam Temp. (°F)				
Steam Pressure (psig)				
Section A; Presat. Water Flow (gpm)				
Outlet Gas Temp. (°F)				
Bed Diff. (in. H_2O)				
Demister Diff. (in. H_2O)				
RH Diff. (in. H_2O)				
Gas Outlet Flow (in. H_2O)				
Section B; Presat. Water Flow (gpm)				
Outlet Gas Temp. (°F)				
Bed Diff. (in. H_2O)				
Demister Diff. (in. H_2O)				
RH Diff. (in. H_2O)				
Gas Outlet Flow (in. H_2O)				
Section C; Presat. Water Flow (gpm)				
Outlet Gas Temp (°F)				
Bed Diff. (in. H_2O)				
Demister Diff. (in. H_2O)				
RH Diff. (in. H_2O)				
RH Diff. (in. H_2O)				
Gas Outlet Flow (in. H_2O)				

Comments * Had to put on some coal so that unit could be more easily contro

CHEROKEE STATION UNIT 3 DATA SHEET

Date:	8/6/77	5/6/77	8/10/77	8/10/77
Time:	1335	1450	2205	2345
Plant				
Mw, Gross	DOWN	DOWN	138	96
XS O_2			2.5	4.5
Steam Flow (lbs/hr) $\times 10^3$			1050	710
Steam Pressure (psig)			1800	1800
Steam Temperature (°F)			1000	1000
Opacity, ~~Bypass (%)~~	8		16	14
~~Opacity, Scrubber (%)~~ FUEL			50% coal	50% coal
NAT. GAS FLOW SCFH $\times 10^3$			720	540
ESP				
Section A1-A2; AC Voltage (v)			240	235
AC Current (a)			132.5	~~125~~/130
DC Voltage (Kv)			40	40
DC Current (ma)			700	720
Spark Rate (spm)			0	5
Section B1-B2; AC Voltage (v)			220	220
AC Current (a)			128	127
DC Voltage (Kv)			46	46
DC Current (ma)			700	700
Spark Rate (spm)			0	0
Scrubber			DOWN	DOWN
Fans; Fan A Inlet Pressure (in. H_2O)				
Fan B Inlet Pressure (in. H_2O)				
Fan A Outlet Pressure (in. H_2O)				
Fan B Outlet Pressure (in. H_2O)				
Fan A Amps				
Fan B Amps				
Stack Damper A, Pos. (% Opn)				
Stack Damper B, Pos. (% Opn)				
Pumps; Recirc. Pump A1 (Amps)				
Recirc. Pump B1 (Amps)				
Recirc. Pump B2 (Amps)				
Recirc. Pump B3 (Amps)				
Recirc. Pump C1 (Amps)				
Reheater; Steam Flow (M lbs/hr)				
Steam Temp. (°F)				
Steam Pressure (psig)				
Section A; Presat. Water Flow (gpm)				
Outlet Gas Temp. (°F)				
Bed Diff. (in. H_2O)				
Demister Diff. (in. H_2O)				
RH Diff. (in. H_2O)				
Gas Outlet Flow (in. H_2O)				
Section B; Presat. Water Flow (gpm)				
Outlet Gas Temp. (°F)				
Bed Diff. (in. H_2O)				
Demister Diff. (in. H_2O)				
RH Diff. (in. H_2O)				
Gas Outlet Flow (in. H_2O)				
Section C; Presat. Water Flow (gpm)				
Outlet Gas Temp (°F)				
Bed Diff. (in. H_2O)				
Demister Diff. (in. H_2O)				
RH Diff. (in. H_2O)				
RH Diff. (in. H_2O)				
Gas Outlet Flow (in. H_2O)				

Comments

CHEROKEE STATION UNIT 3 DATA SHEET

Date:	8/12/77	8/12/77	8/13/77	8/13/77
Time:	1355	1520	0950	1115
Plant				
Mw, Gross	130	130	128	131
XS O_2	3.2%	3.0%	2%	2.5%
Steam Flow (lbs/hr)	1000	1000	1000	1040
Steam Pressure (psig)	1775	1775	1750	1750
Steam Temperature (°F)	1050 ~~[illegible]~~	1050	975	980
Opacity, ~~Bypass (%)~~	24	23	18%	20
~~Opacity, Scrubber~~ (%) FUEL	≈ 50% COAL	≈ 50% COAL	≈ 50% COAL	≈ 50% COAL
NAT GAS SCFH $\times 10^3$	730	740	780	740
ESP				
Section A1-A2; AC Voltage (v)	240	230	230±10	240±10
AC Current (a)	125	125	~~135~~ 125	125
DC Voltage (Kv)	39	38	~~[illegible]~~ 36	38
DC Current (ma)	680	700	~~240~~ 720±20	700±20
Spark Rate (spm)	0	10	150±100 ~~[illegible]~~	60±20
Section B1-B2; AC Voltage (v)	230	230	230	230
AC Current (a)	130	135	135	135
DC Voltage (Kv)	51	52	50	50
DC Current (ma)	730	740	740	740
Spark Rate (spm)	0	0	0	0
Scrubber	OUT	OUT	OUT	OUT
Fans; Fan A Inlet Pressure (in. H_2O)				
Fan B Inlet Pressure (in. H_2O)				
Fan A Outlet Pressure (in. H_2O)				
Fan B Outlet Pressure (in. H_2O)				
Fan A Amps				
Fan B Amps				
Stack Damper A, Pos. (% Opn)				
Stack Damper B, Pos. (% Opn)				
Pumps; Recirc. Pump A1 (Amps)				
Recirc. Pump B1 (Amps)				
Recirc. Pump B2 (Amps)				
Recirc. Pump B3 (Amps)				
Recirc. Pump C1 (Amps)				
Reheater; Steam Flow (M lbs/hr)				
Steam Temp. (°F)				
Steam Pressure (psig)				
Section A; Presat. Water Flow (gpm)				
Outlet Gas Temp. (°F)				
Bed Diff. (in. H_2O)				
Demister Diff. (in. H_2O)				
RH Diff. (in. H_2O)				
Gas Outlet Flow (in. H_2O)				
Section B; Presat. Water Flow (gpm)				
Outlet Gas Temp. (°F)				
Bed Diff. (in. H_2O)				
Demister Diff. (in. H_2O)				
RH Diff. (in. H_2O)				
Gas Outlet Flow (in. H_2O)				
Section C; Presat. Water Flow (gpm)				
Outlet Gas Temp (°F)				
Bed Diff. (in. H_2O)				
Demister Diff. (in. H_2O)				
RH Diff. (in. H_2O)				
RH Diff. (in. H_2O)				
Gas Outlet Flow (in. H_2O)				

Comments

CHEROKEE STATION UNIT 3 DATA SHEET

Date:	8/15/77	8/15/77	8/22/77	8/22/77
Time:	0950	1120	0950	1115
Plant				
Mw, Gross	132	133	OUT	OUT
XS O_2	3%	3%		
Steam Flow (lbs/hr) $\times 10^3$	1050	1050		
Steam Pressure (psig)	1780	1780		
Steam Temperature (°F)	990	990		
Opacity, ~~Bypass (%)~~	22%	22%		
~~Opacity, Scrubber (%)~~ FUEL	50% COAL	50% COAL		
NAT GAS SCFH $\times 10^3$	750	750		
ESP				
Section A1-A2; AC Voltage (v)	230±10	230±10		
AC Current (a)	125±10	125±10		
DC Voltage (Kv)	36	36		
DC Current (ma)	700	720±20		
Spark Rate (spm)	180±20	350±50		
Section B1-B2; AC Voltage (v)	230	230		
AC Current (a)	130	135		
DC Voltage (Kv)	50 ~~500~~	52		
DC Current (ma)	730	740		
Spark Rate (spm)	0	0		
Scrubber	OUT	OUT		
Fans; Fan A Inlet Pressure (in. H_2O)				
Fan B Inlet Pressure (in. H_2O)				
Fan A Outlet Pressure (in. H_2O)				
Fan B Outlet Pressure (in. H_2O)				
Fan A Amps				
Fan B Amps				
Stack Damper A, Pos. (% Opn)				
Stack Damper B, Pos. (% Opn)				
Pumps; Recirc. Pump A1 (Amps)				
Recirc. Pump B1 (Amps)				
Recirc. Pump B2 (Amps)				
Recirc. Pump B3 (Amps)				
Recirc. Pump C1 (Amps)				
Reheater; Steam Flow (M lbs/hr)				
Steam Temp. (°F)				
Steam Pressure (psig)				
Section A; Presat. Water Flow (gpm)				
Outlet Gas Temp. (°F)				
Bed Diff. (in. H_2O)				
Demister Diff. (in. H_2O)				
RH Diff. (in. H_2O)				
Gas Outlet Flow (in. H_2O)				
Section B; Presat. Water Flow (gpm)				
Outlet Gas Temp. (°F)				
Bed Diff. (in. H_2O)				
Demister Diff. (in. H_2O)				
RH Diff. (in. H_2O)				
Gas Outlet Flow (in. H_2O)				
Section C; Presat. Water Flow (gpm)				
Outlet Gas Temp (°F)				
Bed Diff. (in. H_2O)				
Demister Diff. (in. H_2O)				
RH Diff. (in. H_2O)				
RH Diff. (in. H_2O)				
Gas Outlet Flow (in. H_2O)				

Comments

CHEROKEE STATION UNIT 3 DATA SHEET

Date:	8/23/77	8/23/77		8/24/77	8/24/77		8/24/77			
Time:	0945	1045		0910	1255		1500			
Plant										
Mw, Gross	OUT	OUT		OUT	OUT		OUT			
XS O_2										
Steam Flow (lbs/hr)										
Steam Pressure (psig)										
Steam Temperature (°F)										
Opacity, Bypass (%)										
Opacity, Scrubber (%)										
ESP										
Section A1-A2; AC Voltage (v)										
AC Current (a)										
DC Voltage (Kv)										
DC Current (ma)										
Spark Rate (spm)										
Section B1-B2; AC Voltage (v)										
AC Current (a)										
DC Voltage (Kv)										
DC Current (ma)										
Spark Rate (spm)										
Scrubber										
Fans; Fan A Inlet Pressure (in. H_2O)										
Fan B Inlet Pressure (in. H_2O)										
Fan A Outlet Pressure (in. H_2O)										
Fan B Outlet Pressure (in. H_2O)										
Fan A Amps										
Fan B Amps										
Stack Damper A, Pos. (% Opn)										
Stack Damper B, Pos. (% Opn)										
Pumps; Recirc. Pump A1 (Amps)										
Recirc. Pump B1 (Amps)										
Recirc. Pump B2 (Amps)										
Recirc. Pump B3 (Amps)										
Recirc. Pump C1 (Amps)										
Reheater; Steam Flow (M lbs/hr)										
Steam Temp. (°F)										
Steam Pressure (psig)										
Section A; Presat. Water Flow (gpm)										
Outlet Gas Temp. (°F)										
Bed Diff. (in. H_2O)										
Demister Diff. (in. H_2O)										
RH Diff. (in. H_2O)										
Gas Outlet Flow (in. H_2O)										
Section B; Presat. Water Flow (gpm)										
Outlet Gas Temp. (°F)										
Bed Diff. (in. H_2O)										
Demister Diff. (in. H_2O)										
RH Diff. (in. H_2O)										
Gas Outlet Flow (in. H_2O)										
Section C; Presat. Water Flow (gpm)										
Outlet Gas Temp (°F)										
Bed Diff. (in. H_2O)										
Demister Diff. (in. H_2O)										
RH Diff. (in. H_2O)										
RH Diff. (in. H_2O)										
Gas Outlet Flow (in. H_2O)										

Comments

CHEROKEE STATION UNIT 3 DATA SHEET

Date:	8/25/77		8/25/77							
Time:	0640		0845							
Plant										
Mw, Gross	OUT		OUT							
XS O_2										
Steam Flow (lbs/hr)										
Steam Pressure (psig)										
Steam Temperature (°F)										
Opacity, Bypass (%)										
Opacity, Scrubber (%)										
ESP										
Section A1-A2; AC Voltage (v)										
AC Current (a)										
DC Voltage (Kv)										
DC Current (ma)										
Spark Rate (spm)										
Section B1-B2; AC Voltage (v)										
AC Current (a)										
DC Voltage (Kv)										
DC Current (ma)										
Spark Rate (spm)										
Scrubber										
Fans; Fan A Inlet Pressure (in. H_2O)										
Fan B Inlet Pressure (in. H_2O)										
Fan A Outlet Pressure (in. H_2O)										
Fan B Outlet Pressure (in. H_2O)										
Fan A Amps										
Fan B Amps										
Stack Damper A, Pos. (% Opn)										
Stack Damper B, Pos. (% Opn)										
Pumps; Recirc. Pump A1 (Amps)										
Recirc. Pump B1 (Amps)										
Recirc. Pump B2 (Amps)										
Recirc. Pump B3 (Amps)										
Recirc. Pump C1 (Amps)										
Reheater; Steam Flow (M lbs/hr)										
Steam Temp. (°F)										
Steam Pressure (psig)										
Section A; Presat. Water Flow (gpm)										
Outlet Gas Temp. (°F)										
Bed Diff. (in. H_2O)										
Demister Diff. (in. H_2O)										
RH Diff. (in. H_2O)										
Gas Outlet Flow (in. H_2O)										
Section B; Presat. Water Flow (gpm)										
Outlet Gas Temp. (°F)										
Bed Diff. (in. H_2O)										
Demister Diff. (in. H_2O)										
RH Diff. (in. H_2O)										
Gas Outlet Flow (in. H_2O)										
Section C; Presat. Water Flow (gpm)										
Outlet Gas Temp (°F)										
Bed Diff. (in. H_2O)										
Demister Diff. (in. H_2O)										
RH Diff. (in. H_2O)										
RH Diff. (in. H_2O)										
Gas Outlet Flow (in. H_2O)										

Comments

CHEROKEE STATION UNIT 3 DATA SHEET

Date:	8/19/77	8/19/77								
Time:	1030	1123								
Plant										
Fuel	500/500	500/500								
Mw, Gross	140	141								
XS O_2	2.1	3.9								
Steam Flow (lbs/hr) x10^3	1030	1050								
Steam Pressure (psig)	1800	1800								
Steam Temperature (°F)	990	980								
Opacity, Bypass (%)	15	16								
~~Opacity, Scrubber (%)~~ Vent Gas	7.4	7.5								
ESP										
Section A1-A2; AC Voltage (v)	240	230								
AC Current (a)	130	115								
DC Voltage (Kv)	37	37								
DC Current (ma)	610	620								
Spark Rate (spm)	50	180								
Section B1-B2; AC Voltage (v)	230	230								
AC Current (a)	132	132								
DC Voltage (Kv)	50	50								
DC Current (ma)	740	730								
Spark Rate (spm)	0	0								
Scrubber	Out of	Out of								
Fans; Fan A Inlet Pressure (in. H_2O)	Service	Service								
Fan B Inlet Pressure (in. H_2O)	↓	↓								
Fan A Outlet Pressure (in. H_2O)										
Fan B Outlet Pressure (in. H_2O)										
Fan A Amps										
Fan B Amps										
Stack Damper A, Pos. (% Opn)										
Stack Damper B, Pos. (% Opn)										
Pumps; Recirc. Pump A1 (Amps)										
Recirc. Pump B1 (Amps)										
Recirc. Pump B2 (Amps)										
Recirc. Pump B3 (Amps)										
Recirc. Pump C1 (Amps)										
Reheater; Steam Flow (M lbs/hr)										
Steam Temp. (°F)										
Steam Pressure (psig)										
Section A; Presat. Water Flow (gpm)										
Outlet Gas Temp. (°F)										
Bed Diff. (in. H_2O)										
Demister Diff. (in. H_2O)										
RH Diff. (in. H_2O)										
Gas Outlet Flow (in. H_2O)										
Section B; Presat. Water Flow (gpm)										
Outlet Gas Temp. (°F)										
Bed Diff. (in. H_2O)										
Demister Diff. (in. H_2O)										
RH Diff. (in. H_2O)										
Gas Outlet Flow (in. H_2O)										
Section C; Presat. Water Flow (gpm)										
Outlet Gas Temp (°F)										
Bed Diff. (in. H_2O)										
Demister Diff. (in. H_2O)										
RH Diff. (in. H_2O)										
RH Diff. (in. H_2O)										
Gas Outlet Flow (in. H_2O)	↓	↓								

Comments

CHEROKEE STATION UNIT 4 DATA SHEET

Date:	7/21/77	7/27/77	7/28/77	7/29/77	7/30/77	7/30/77	8/1/77	8/1/77
Time:	1406	1515	0945	1104	1855	1956	1740	1828
Plant								
MW, Gross	357	355	360	355	345	341	306	322
XS O_2	4.0	3.8	4.2	4.3	3.6	3.7	4.0	4.0
Steam Flow (lbs/hr)	2.5×10^6	2.4×10^6	2.4×10^6	2.3×10^6	2.3×10^6	2.1×10^6	2.0×10^6	2.1×10^6
Steam Pressure (psig)	2400	2350	2350	2350	2350	2300	1950	2050
Steam Temperature (°F)	980	960	980	980	975	975	1000	990
Opacity, Bypass (%)	~~14~~ 9/20	10/25	15/15	20/16	35/10	27/20	27/20	50/20
Opacity, Scrubber (%)	~~4/20~~ 19	~~40~~ 24	14	17	21	22	26	29
ESP								
Section A1; AC Voltage (v)	270	270	280	UNIT	260	~~220~~ 270	230	230
AC Current (a)	140	140	140	TRIP	130	~~80~~ 120	130	125
DC Voltage (Kv)	Out	Out	Out	DISCON	Out	Out	Out	Out
DC Current (ma)	720	680	700	DATA	690	640	680	660
Spark Rate (spm)	15	25	35		87	85	83	87
Section A2; AC Voltage (v)	Same	Same	Same		Same	Same	Same	Same
AC Current (a)								
DC Voltage (Kv)								
DC Current (ma)								
Spark Rate (spm)								
Section A3; AC Voltage (v)	250	250	250		220	225	200	200
AC Current (a)	110	110	120		80	85	85	80
DC Voltage (Kv)	~~510~~ Out	Out	Out		Out	Out	Out	Out
DC Current (ma)	510	520	600		420	410	400	390
Spark Rate (spm)	Out	Out	Out		Out	Out	Out	Out
Section A4; AC Voltage (v)	Same	Same	Same		Same	Same	Same	Same
AC Current (a)								
DC Voltage (Kv)								
DC Current (ma)								
Spark Rate (spm)								
Section B1; AC Voltage (v)	300	310	320		300	300	290	280
AC Current (a)	150	150	145		145	150	150	130
DC Voltage (Kv)	Out	Out	Out		Out	Out	Out	Out
DC Current (ma)	800	800	740		740	760	710	640
Spark Rate (spm)	>200	>200	185		>200	>200	185	185
Section B2; AC Voltage (v)	Same	Same	Same		Same	Same	Same	Same
AC Current (a)								
DC Voltage (Kv)								
DC Current (ma)								
Spark Rate (spm)								
Section B3; AC Voltage (v)	250	250	250		230	240	230	220
AC Current (a)	100	100	100		85	85	80	75
DC Voltage (Kv)	31	30	30		30	31	30	30
DC Current (ma)	480	500	480		370	380	350	320
Spark Rate (spm)	30	20	55		45	45	60	50
Section B4; AC Voltage (v)	Same	Same	Same		Same	Same	Same	Same
AC Current (a)								
DC Voltage (Kv)								
DC Current (ma)								
Spark Rate (spm)								

CHEROKEE STATION UNIT 4 DATA SHEET
(continued)

Scrubber								
Fans; ID Discharge Pressure (in. H_2O)		-.3	-.5	-.4	-.5	-.4	-.6	-.3
Fan B Outlet Pressure (in. H_2O)	OUT	Out	OUT	Out	Out	Out	~~Out~~	Out
Fan C Outlet Pressure (in. H_2O)	13.5	13.5	15.5	15.5	16	13	9	13.5
Fan D Outlet Pressure (in. H_2O)	13.5	13.5	11	11	15	11.5	8	11
Fan B Amps	220	230	230	235	205	210	230	210
Fan C Amps	220	230	230	230	220	220	225	225
Fan D Amps	240	240	230	230	230	230	245	235
Stack Damper A, Pos. (% Opn)	0	0	0	0	0	0	0	0
Stack Damper B, Pos. (% Opn)	0	0	0	0	0	0	0	0
Pumps; Recirc. Pump B1 (amps)	13	12.5	12	12	12	12.5	12.5	12.5
Recirc. Pump B2 (amps)	15	15.5	15	15	15	15.5	16	16
Recirc. Pump B3 (amps)	14	13.5	14	14	14	14	14	13.5
Recirc. Pump C1 (amps)	13	12	13	12	11	11	11	11
Recirc. Pump C2 (amps)	12	12	12	12	11	11	11	11
Recirc. Pump C3 (amps)	13	13	13	13	13	13.5	13.5	13.5
Recirc. Pump D1 (amps)	14	14	13	12	11	11	11.5	11.5
Recirc. Pump D2 (amps)	14	14	14	14	14	13.5	11.5	12
Recirc. Pump D3 (amps)	14	14	14	14	14	14	12	12
Reheater; Steam Flow (M lbs/hr)	55	55	55	55	45	45	45	45
Steam Temp. (°F)								
Steam Pressure (psig)	1500	1500	1650	1670	1480	1480	1480	1480
Section B; Presat. Water Flow (gpm)	185	185	185	185	185	185	185	185
Outlet Gas Temp. (°F)	145	145	135	135	140	140	140	140
Bed Diff. (in. H_2O)	7.2	5.4	4.2	6.7	5.4	3.8	5.0	5.0
Demister Diff. (in. H_2O)	.85	0.85	0.9	0.9	0.8	0.8	0.7	0.7
RH Diff. (in. H_2O)	0	0	~~9.7~~ 0	0	0	0	0	0
~~Gas Outlet Flow (in. H_2O)~~ RH Steam Press (psig)	~~0~~ 300	210	370	390	300	300	410	410
Section C; Presat Water Flow (gpm)	180	183	180	180	175	175	180	175
Outlet Gas Temp. (°F)	155	155	150	155	150	150	140	150
Bed Diff. (in. H_2O)	14.6	14.6	10.6	10.8	8.2	8.0	5.6	8.5
Demister Diff. (in. H_2O)	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
RH Diff. (in. H_2O)	0.4	~~5.2~~ 0.8	0.3	0.2	0.7	0.9	0.4	0.8
~~Gas Outlet Flow (in. H_2O)~~ RH Steam Press (psig)	450 ~~[illegible]~~	450	450	450	320	320	340	330
Section D; Presat. Water Flow (gpm)	186	186	185	185	185	185	185	185
Outlet Gas Temp. (°F)	160	160	150	160	150	150	160	140
Bed Diff. (in. H_2O)	9.2	9.2	6.3	7.2	6.5	7.0	4.2	6.0
Demister Diff. (in. H_2O)	2.6	2.5	1.9	[illegible]	2.2	2.4	2.0	2.1
RH Diff. (in. H_2O)	0	0	0	Trip	0	0	0	0
~~Gas Outlet Flow (in. H_2O)~~ RH Steam Press (psig)	400	470	420	↓	250	250	200	200

Comments

steam is off of drum

CHEROKEE STATION UNIT 4 DATA SHEET

Date:	8/3	8/3	8/4	8/4	8/4	8/4
Time:	1740	2000	1050	1220	1502	1543
Plant			BASE LOAD	BASE LOAD		
Mw, Gross (CHARTS)	335	345	355	355	355	355
XS O_2	3.6	3.5	4.5	3.8	3.8	4.2
Steam Flow (lbs/hr) x10^3	2200	2300	2400	2400	2350	2400
Steam Pressure (psig) x100	23	23.5	23	23.5	23.5	23.0
Steam Temperature (°F)	990	970	985	990	970	970
Opacity, Bypass (%) 4N/4S	26/10	27/20	35/13	35/12	30/10	30/8
Opacity, Scrubber (%)	26	34	29	24	22	22
COAL FLOW (T/HR)	—	140	100% COAL 150	145		
ESP						
Section A1; AC Voltage (v)	250±20	250±20	250±20	250±20	240±20	220±20
AC Current (a)	100±20	100±40	120±20	120±20	110±20	75±20
DC Voltage (Kv)	OUT	OUT	OUT	OUT	Out	out
DC Current (ma)	550±50	550±50	700±50	650±50	510±40	480±20
Spark Rate (spm)	90	90	80	85	80	90
Section A2; AC Voltage (v)	SAME	SAME	SAME	SAME	Same	Same
AC Current (a)						
DC Voltage (Kv)						
DC Current (ma)						
Spark Rate (spm)						
Section A3; AC Voltage (v)	200±30	200±40	200±40	220±40	210±20	200±25
AC Current (a)	75±5	75±5	80±5	80±10	80±5	75±5
DC Voltage (Kv)	OUT	OUT	OUT	OUT	Out	Out
DC Current (ma)	360±30	380±20	380±20	400±20	400±20	380±20
Spark Rate (spm)	OUT	OUT	OUT	OUT	Out	Out
Section A4; AC Voltage (v)	SAME	SAME	SAME	SAME	Same	Same
AC Current (a)						
DC Voltage (Kv)						
DC Current (ma)						
Spark Rate (spm)						
Section B1; AC Voltage (v)	270	280±10	280±10	280±20	270±10	270±10
AC Current (a)	125	130±5	130±5	130±10	125±10	120±5
DC Voltage (Kv)	OUT	OUT	OUT	OUT	Out	Out
DC Current (ma)	600	600±20	600±20	620±20	570±20	540±20
Spark Rate (spm)	185	185	185	185	185	185
Section B2; AC Voltage (v)	SAME	SAME	SAME	SAME	Same	Same
AC Current (a)						
DC Voltage (Kv)						
DC Current (ma)						
Spark Rate (spm)						
Section B3; AC Voltage (v)	230±20	230±20	230±20	230±20	225±25	225±25
AC Current (a)	70±5	70±5	70±10	75±10	70	75
DC Voltage (Kv)	31	30	30	31	30	31
DC Current (ma)	300	300±10	300±10	320±20	300	300
Spark Rate (spm)	60	55	45	45	45	70
Section B4; AC Voltage (v)	SAME	SAME	SAME	SAME	Same	Same
AC Current (a)						
DC Voltage (Kv)						
DC Current (ma)						
Spark Rate (spm)						

OBSERVER – R. IDA

A-34

CHEROKEE STATION UNIT 4 DATA SHEET
(continued)

	8/3	8/3	8/4 1400	8/4 1225	8/5	8/5
Scrubber						
Fans; ID Discharge Pressure (in. H_2O)	-0.75	-0.8	-0.5	-0.5	-.5	-.5
Fan B Outlet Pressure (in. H_2O)	OUT	OUT	OUT	OUT	OUT	OUT
Fan C Outlet Pressure (in. H_2O)	11	11	14	15	15	15
Fan D Outlet Pressure (in. H_2O)	10	10	12	12	12.5	12
Fan B Amps x 10	20	21	21	21	22	22
Fan C Amps x 10	22	22	23	23	24	23
Fan D Amps x 10	23	23	24	24	23	23.5
Stack Damper A, Pos. (% Opn)	0	0	0	0	0	0
Stack Damper B, Pos. (% Opn)	0	0	0	0	0	0
Pumps; Recirc. Pump B1 (amps)	13	13	13	13	13	13
Recirc. Pump B2 (amps)	16	16	16	16	16	16
Recirc. Pump B3 (amps)	14	14	13	13	12.5	12.5
Recirc. Pump C1 (amps)	11	11	11	12	11.5	11.5
Recirc. Pump C2 (amps)	12	12	11	12	11.5	11.5
Recirc. Pump C3 (amps)	14	13	14	14	13.5	13.5
Recirc. Pump D1 (amps)	12	12	12	13	13	13
Recirc. Pump D2 (amps)	12	12	13	13	13	13
Recirc. Pump D3 (amps)	12	12	12	12	14	14
Reheater; Steam Flow (M lbs/hr)	45	45	55	55	55	55
Steam Temp. (°F)	—	—	—	—	—	—
Steam Pressure (psig) BLUE x10^2	15	15	15	15	15	15
Section B; Presat. Water Flow (gpm)	185	190	185	185	185	185
Outlet Gas Temp. (°F)	145	140	140	140	140	140
Bed Diff. (in. H_2O)	5	0	6.5	7.6	8.0	7.6
Demister Diff. (in. H_2O)	0.8	0.9	0.9	0.9	0.9	0.9
RH Diff. (in. H_2O)	0	0	0 ~~3.9~~	0	0	0
~~Gas Outlet Flow (in. H_2O)~~ REHEAT STM PRESS PSIG	400	380	390	380	380	380
Section C; Presat Water Flow (gpm)	155	155	180	180	175	185
Outlet Gas Temp. (°F)	150	150	130	150	150	155
Bed Diff. (in. H_2O)	14.8	14.8	14.8	14.8	14.6	14.7
Demister Diff. (in. H_2O)	0.3	0.3	0.4	0.4	0.3	0.3
RH Diff. (in. H_2O)	0.8 ~~3.5~~	1.9	0.5	0.4	0.3	0.5
~~Gas Outlet Flow (in. H_2O)~~ REHEAT STM PRESS PSIG	350	350	390	380	380	380
Section D; Presat. Water Flow (gpm)	190	190	180	185	185	185
Outlet Gas Temp. (°F)	155	160	155	150	155	155
Bed Diff. (in. H_2O)	5.4	5.4	6.8	7.2	7.6	7.6
Demister Diff. (in. H_2O)	2.2	2.4	2.0	2.1	2.3	2.6
RH Diff. (in. H_2O)	0	0	0	0	0	0
~~Gas Outlet Flow (in. H_2O)~~ REHEAT STM PRESS PSIG	200	200	350	350	350	350

Comments OBSERVER - R. IDA

CHEROKEE STATION UNIT 4 DATA SHEET

Date:	8/8/77	8/8/77	8/9/77	8/9/77						
Time:	1018	1054	1415	1517						
Plant										
Mw, Gross	350	357	357	354						
XS O_2	4.3	4.3	4.3	4.6						
Steam Flow (lbs/hr) x10^3	2350	2300	2350	2350						
Steam Pressure (psig)	2300	2350	2350	2350						
Steam Temperature (°F)	965	970	970	970						
Opacity, Bypass (%)	24/7	22/7	26/8	18/6						
Opacity, Scrubber (%)	22	23	20	18						
ESP										
Section A1; AC Voltage (v)	240±30	250±20	250±20	250±20						
AC Current (a)	115±20	100±25	110±20	120±10						
DC Voltage (Kv)	Out	Out	out	Out						
DC Current (ma)	500±100	610±10	500±90	450±50						
Spark Rate (spm)	85	85	90	90						
Section A2; AC Voltage (v)	same ~~200±10~~	Same	Same	same						
AC Current (a)	~~65±10~~									
DC Voltage (Kv)	~~Out~~									
DC Current (ma)	~~340~~									
Spark Rate (spm)	~~Out~~									
Section A3; AC Voltage (v)	200±10	200±20	190±10	190±20						
AC Current (a)	65±10	65±10	65±10	65±5						
DC Voltage (Kv)	Out	out	out	out						
DC Current (ma)	340	220±20	310±10	300±10						
Spark Rate (spm)	Out	Out	Out	Out						
Section A4; AC Voltage (v)	Same	Same	Same	Same						
AC Current (a)										
DC Voltage (Kv)										
DC Current (ma)										
Spark Rate (spm)										
Section B1; AC Voltage (v)	290	290	280	280±10						
AC Current (a)	135	135±10	130±15	130±10						
DC Voltage (Kv)	Out	Out	Out	Out						
DC Current (ma)	680	660	600±10	630±10						
Spark Rate (spm)	185	185	185	185						
Section B2; AC Voltage (v)	same	same	Same	same						
AC Current (a)										
DC Voltage (Kv)										
DC Current (ma)										
Spark Rate (spm)										
Section B3; AC Voltage (v)	215±10	210±10	220±20	210±20						
AC Current (a)	60	60	55±5	55±5						
DC Voltage (Kv)	31	31	33	33						
DC Current (ma)	240	240	220±10	240±10						
Spark Rate (spm)	45	45	55	550						
Section B4; AC Voltage (v)	same	Same	Same	Same						
AC Current (a)										
DC Voltage (Kv)										
DC Current (ma)										
Spark Rate (spm)										

CHEROKEE STATION UNIT 4 DATA SHEET (continued)

Scrubber										
Fans: ID Discharge Pressure (in. H_2O)	-4.5	-.5	-.6	-.5						
Fan B Outlet Pressure (in. H_2O)	0.5	0.4	0.5	0.4						
Fan C Outlet Pressure (in. H_2O)	13.5	13.0	16.5	16						
Fan D Outlet Pressure (in. H_2O)	12.5	11.5	12.0	11.5						
Fan B Amps	250	240	245	240						
Fan C Amps	225	220	225	225						
Fan D Amps	240	230	235	235						
Stack Damper A, Pos. (% Opn)	0	0	0	0						
Stack Damper B, Pos. (% Opn)	0	0	0	0						
Pumps: Recirc. Pump B1 (amps)	12.5	12.5	12.5	12.5						
Recirc. Pump B2 (amps)	16	16	16	16						
Recirc. Pump B3 (amps)	12.5	12.5	12.5	12.5						
Recirc. Pump C1 (amps)	13.5	12.5	13	13						
Recirc. Pump C2 (amps)	0	0	13	13						
Recirc. Pump C3 (amps)	13.5	12.5	13	13						
Recirc. Pump D1 (amps)	13.5	13.5	13.5	13.5						
Recirc. Pump D2 (amps)	13.5	13	12.5	13						
Recirc. Pump D3 (amps)	14	14	13.0	13.5						
Reheater: Steam Flow (M lbs/hr)	60	60	50	50						
Steam Temp. (°F)	—	—	—	—						
Steam Pressure (psig)	1480	1480	1480	1480						
Section B: Presat. Water Flow (gpm)	185	185	185	185						
Outlet Gas Temp. (°F)	135	125	123	125						
Bed Diff. (in. H_2O)	0	0.7	16.3	16.0						
Demister Diff. (in. H_2O)	0.9	0.9	0.9	0.9						
RH Diff. (in. H_2O)	0	0	0	0						
~~Steam~~ ~~Gas Outlet Flow (in. H_2O)~~ Steam press (psig)	320	320	270	270						
Section C: Presat Water Flow (gpm)	175	175	175	175						
Outlet Gas Temp. (°F)	155	155	150	150						
Bed Diff. (in. H_2O)	14.0	14.0	11.0	11.0						
Demister Diff. (in. H_2O)	0.3	0.3	0.15	0.25						
RH Diff. (in. H_2O)	0.4	0.4	0.2	0.1						
~~Gas Outlet Flow (in. H_2O)~~ Steam press (psig)	500	470	460	470						
Section D: Presat. Water Flow (gpm)	185	185	185	185						
Outlet Gas Temp. (°F)	155	160	155	160						
Bed Diff. (in. H_2O)	7.4	6.8	7.3	7.3						
Demister Diff. (in. H_2O)	2.4	2.1	2.2	2.2						
RH Diff. (in. H_2O)	0	0	0	0						
~~Gas Outlet Flow (in. H_2O)~~ Steam press (psig)	460	430	460	460						

Comments

CHEROKEE STATION UNIT 4 DATA SHEET

Date:	8/6/77	8/6/77	8/10/77	8/10/77
Time:	1335	1500	2215	2350
Plant				
Mw, Gross	345	350	295	295
XS O_2	4.5	4.4	3.7	4.0
Steam Flow (lbs/hr) $\times 10^3$	2300	2300	1800	1850
Steam Pressure (psig)	2300 ~~[illegible]~~	2300	2350	2350
Steam Temperature (°F)	990	980	1000	1000
Opacity, ~~Bypass~~ (%) 4N/4S	30/6	25/15	20/12	12/8
Opacity, ~~Scrubber (%)~~	22	23	20	17
COAL FLOW (T/HR)	–	–	120	120
ESP				
Section A1; AC Voltage (v)	270±30	270±30	270±30	270±30
AC Current (a)	130±10	135±10	140±10	140±20
DC Voltage (Kv)	OUT	OUT	OUT	OUT
DC Current (ma)	650±50	650±50	700±50	700±50
Spark Rate (spm)	85	85	60	65
Section A2; AC Voltage (v)	SAME	SAME	SAME	SAME
AC Current (a)				
DC Voltage (Kv)				
DC Current (ma)				
Spark Rate (spm)				
Section A3; AC Voltage (v)	240±30	240±30	220±20	220±20
AC Current (a)	100±20	90±20	75±10	80±10
DC Voltage (Kv)	OUT	OUT	OUT	OUT
DC Current (ma)	500±30	500±20	350±40	400±50
Spark Rate (spm)	OUT	OUT	OUT	OUT
Section A4; AC Voltage (v)	SAME	SAME	SAME	SAME
AC Current (a)				
DC Voltage (Kv)				
DC Current (ma)				
Spark Rate (spm)				
Section B1; AC Voltage (v)	300±10	320±20	320±20	320±20
AC Current (a)	150±10	150±20	150±20	150±20
DC Voltage (Kv)	OUT	OUT	OUT	OUT
DC Current (ma)	800±20	800±50	750±30	750±40
Spark Rate (spm)	185	185	185	185
Section B2; AC Voltage (v)	SAME	SAME	SAME	SAME
AC Current (a)				
DC Voltage (Kv)				
DC Current (ma)				
Spark Rate (spm)				
Section B3; AC Voltage (v)	250±30	250±40	250±40	250±40
AC Current (a)	80±20	80±20	70±10	70±10
DC Voltage (Kv)	30±1	30±1	34±2	38±2
DC Current (ma)	400±40	400±40	300±20	300±20
Spark Rate (spm)	40	45	35	35
Section B4; AC Voltage (v)	SAME	SAME	SAME	SAME
AC Current (a)				
DC Voltage (Kv)				
DC Current (ma)				
Spark Rate (spm)				

CHEROKEE STATION UNIT 4 DATA SHEET
(continued)

Scrubber	8/6/77	8/6/77		8/10/77	8/10/77
Fans; ID Discharge Pressure (in. H_2O)	-0.5	-0.5	-0.5	~~[illegible]~~	-0.5
Fan B Outlet Pressure (in. H_2O)	OUT	OUT		OUT	OUT
Fan C Outlet Pressure (in. H_2O)	13	12.5		11	11 ~~[illegible]~~
Fan D Outlet Pressure (in. H_2O)	12	12		9	9 ~~[illegible]~~
Fan B Amps x10	24	24		23	23
Fan C Amps x10	22	22		22	22
Fan D Amps x10	23	23		24	24
Stack Damper A, Pos. (% Opn)	0	0		0	0
Stack Damper B, Pos. (% Opn)	0	0		0	0
Pumps: Recirc. Pump B1 (amps)	13	13		13	13
Recirc. Pump B2 (amps)	16	16		16	16
Recirc. Pump B3 (amps)	13	13		13	13
Recirc. Pump C1 (amps)	12	12		13	13
Recirc. Pump C2 (amps)	11	11		12	12
Recirc. Pump C3 (amps)	13	13		13	13
Recirc. Pump D1 (amps)	13	13		13	13
Recirc. Pump D2 (amps)	13	13		13	13
Recirc. Pump D3 (amps)	13	13		13	13
Reheater: Steam Flow (M lbs/hr)	55	55		50	50
Steam Temp. (°F)	–	–		–	–
Steam Pressure (psig) x10²	15	15		12	12.5
Section B: Presat. Water Flow (gpm)	185	185		190	190
Outlet Gas Temp. (°F)	145	145		130	130
Bed Diff. (in. H_2O)	11	11		6.8	6.8
Demister Diff. (in. H_2O)	0.9	0.9		0.9	0.8
RH Diff. (in. H_2O)	OUT	OUT		OUT	OUT
~~Gas Outlet Flow (in. H2O)~~ RH STM PR (PSIG x 100)	4.5	4.5		1.4	1.4
Section C: Presat Water Flow (gpm)	175	175		175	175
Outlet Gas Temp. (°F)	155	155		150	150
Bed Diff. (in. H_2O)	14.8	14.8		7.8	8.0
Demister Diff. (in. H_2O)	0.3	0.3		0.2	0.2
RH Diff. (in. H_2O)	0.2	0.1		1.9	1.9
~~Gas Outlet Flow (in. H2O)~~ RH STM PR PSIG x 100	400	4.0		4.6	4.6
Section D: Presat. Water Flow (gpm)	185	190		190	190
Outlet Gas Temp. (°F)	160	160		160	160
Bed Diff. (in. H_2O)	6.8	6.4		5.6	5.6
Demister Diff. (in. H_2O)	2.0	2.1		1.8	1.8
RH Diff. (in. H_2O)	OUT	OUT		OUT	OUT
~~Gas Outlet Flow (in. H2O)~~ RH STM PR (PSIG x 100)	4.0	4.0		2.4	2.4

Comments

CHEROKEE STATION UNIT 4 DATA SHEET

Date:		8/12/77	8/12/77	8/13/77	8/13/77
Time:		1400	1530	0950	1120
Plant					
Mw, Gross		350	350	DOWN	DOWN
XS O_2		6.9	7.0	FOR	
Steam Flow (lbs/hr) $\times 10^3$		2350	2350	STEAM	
Steam Pressure (psig)		2350	2350	LEAK	
Steam Temperature (°F)		990	980		
Opacity, Bypass (%) Lear Siegler		34	34	IN	
Opacity, Scrubber (%) 4N/4S		22/15	22/17	BOILER	
COAL FLOW T/HR		140	145		
ESP					
Section A1;	AC Voltage (v)	250±30	250±30		
	AC Current (a)	125±20	115±20		
	DC Voltage (Kv)	OUT	OUT		
	DC Current (ma)	600±50	550±50		
	Spark Rate (spm)	90	90		
Section A2;	AC Voltage (v)	SAME	SAME		
	AC Current (a)				
	DC Voltage (Kv)				
	DC Current (ma)				
	Spark Rate (spm)				
Section A3;	AC Voltage (v)	200±40	200±40		
	AC Current (a)	70±10	70±20		
	DC Voltage (Kv)	OUT	OUT		
	DC Current (ma)	300±40	300±40		
	Spark Rate (spm)	OUT	OUT		
Section A4;	AC Voltage (v)	SAME	SAME		
	AC Current (a)				
	DC Voltage (Kv)				
	DC Current (ma)				
	Spark Rate (spm)				
Section B1;	AC Voltage (v)	280±20	280±20		
	AC Current (a)	130±20	125±30		
	DC Voltage (Kv)	OUT	OUT		
	DC Current (ma)	660±20	640±40		
	Spark Rate (spm)	7200	7200		
Section B2;	AC Voltage (v)	SAME	SAME		
	AC Current (a)				
	DC Voltage (Kv)				
	DC Current (ma)				
	Spark Rate (spm)				
Section B3;	AC Voltage (v)	220±40	220±30		
	AC Current (a)	60±5	60±5		
	DC Voltage (Kv)	35	34±2		
	DC Current (ma)	250±20	230±20		
	Spark Rate (spm)	50	65		
Section B4;	AC Voltage (v)	SAME	SAME		
	AC Current (a)				
	DC Voltage (Kv)				
	DC Current (ma)				
	Spark Rate (spm)				

8/12/77. REHEAT STEAM OFF DUE TO BOILER LEAK
TRYING TO CONSERVE STM.

CHEROKEE STATION UNIT 4 DATA SHEET
(continued)

	8/12/77	8/12/77	8/13/77	8/13/77
Scrubber				
Fans: ID Discharge Pressure (in. H_2O)	-0.5	-0.5		
Fan B Outlet Pressure (in. H_2O)	OUT	OUT	DOWN	DOWN
Fan C Outlet Pressure (in. H_2O)	16	16.5		
Fan D Outlet Pressure (in. H_2O)	12.5	12.3		
Fan B Amps	23	22		
Fan C Amps	22	22		
Fan D Amps	24	24		
Stack Damper A, Pos. (% Opn)	0	0		
Stack Damper B, Pos. (% Opn)	0	0		
Pumps: Recirc. Pump B_1 (amps)	13	13		
Recirc. Pump B_2 (amps)	16	16		
Recirc. Pump B_3 (amps)	12	12		
Recirc. Pump C_1 (amps)	13	13		
Recirc. Pump C_2 (amps)	11	11		
Recirc. Pump C_3 (amps)	13	13		
Recirc. Pump D_1 (amps)	13	13		
Recirc. Pump D_2 (amps)	13	13		
Recirc. Pump D_3 (amps)	12	12		
Reheater: Steam Flow (M lbs/hr)	0	0		
Steam Temp. (°F)	—	—		
Steam Pressure (psig)	—	—		
Section B: Presat. Water Flow (gpm)	180	185		
Outlet Gas Temp. (°F)	120	120		
Bed Diff. (in. H_2O)	10	10.4		
Demister Diff. (in. H_2O)	~~90~~ 0.9	0.9		
RH Diff. (in. H_2O)	—	—		
Gas Outlet Flow (in. H_2O)	—	—		
RH STM PR psig	—			
Section C: Presat Water Flow (gpm)	175	175		
Outlet Gas Temp. (°F)	120	120		
Bed Diff. (in. H_2O)	11	11.4		
Demister Diff. (in. H_2O)	0.2	0.2		
RH Diff. (in. H_2O)	—	—		
~~Gas Outlet Flow (in. H_2O)~~ ~~RH STM PR (PSIG)~~	—	—		
Section D: Presat. Water Flow (gpm)	190	190		
Outlet Gas Temp. (°F)	125	125		
Bed Diff. (in. H_2O)	7.4	7.2		
Demister Diff. (in. H_2O)	2.2	2.3		
RH Diff. (in. H_2O)	—	—		
~~Gas Outlet Flow (in. H_2O)~~ RH STM PR (PSIG)	—	—		

Comments

CHEROKEE STATION UNIT 4 DATA SHEET

Date:	8/15/77	8/15/77	8/22/77	8/22/77
Time:	1005	1130	0950	1115
Plant				
Mw, Gross	270	270	365	350
XS O_2	4.2%	4.6%	4%	3.8%
Steam Flow (lbs/hr) x10^3	1650	1650	2250	2300
Steam Pressure (psig)	2350	2350	2400	2350
Steam Temperature (°F)	1000	1000	1000	1000
Opacity, Bypass (%) COAL SIEGLER	20	24	31	30
Opacity, Scrubber (%) 4N/4S	15/5	18/8	42/26	35/17
COAL FLOW T/HR	110	110	150	145
ESP				
Section A1; AC Voltage (v)	260±10	260±20	210±10	210±10
AC Current (a)	70±20	70±20	70±20	70±20
DC Voltage (Kv)	OUT	OUT	OUT	OUT
DC Current (ma)	400	400	420±20	400±20
Spark Rate (spm)	165	165	>200	>200
Section A2; AC Voltage (v)	SAME	SAME	SAME	SAME
AC Current (a)				
DC Voltage (Kv)				
DC Current (ma)				
Spark Rate (spm)				
Section A3; AC Voltage (v)	220±20	230±20	220±10	200±20
AC Current (a)	90±10	80±10	100±10	80±10
DC Voltage (Kv)	OUT	OUT	OUT	OUT
DC Current (ma)	450±20	450±20	520±20	400±20
Spark Rate (spm)	OUT	OUT	OUT	OUT
Section A4; AC Voltage (v)	SAME	SAME	SAME	SAME
AC Current (a)				
DC Voltage (Kv)				
DC Current (ma)				
Spark Rate (spm)				
Section B1; AC Voltage (v)	320	310	270±20	270±20
AC Current (a)	120±5	120±5	130±20	150±30
DC Voltage (Kv)	OUT	OUT	OUT	OUT
DC Current (ma)	580±20	580±20	580±20	580±20
Spark Rate (spm)	15	20±10	185	185
Section B2; AC Voltage (v)	SAME	SAME	SAME	SAME
AC Current (a)				
DC Voltage (Kv)				
DC Current (ma)				
Spark Rate (spm)				
Section B3; AC Voltage (v)	260±20	260±40	250	250
AC Current (a)	110±20	100±20	110	140
DC Voltage (Kv)	31	31±2	34	33±2
DC Current (ma)	460±20	460±40	520	620±20
Spark Rate (spm)	45	45	105	105
Section B4; AC Voltage (v)	SAME	SAME	SAME	SAME
AC Current (a)				
DC Voltage (Kv)				
DC Current (ma)				
Spark Rate (spm)				

CHEROKEE STATION UNIT 4 DATA SHEET
(continued)

Scrubber	8/15/77	8/15/77	8/22/77	1115 8/22/77		
Fans: ID Discharge Pressure (in. H_2O)	-0.2	-0.5	-0.4 ~~[illegible]~~	-0.4		
Fan B Outlet Pressure (in. H_2O)	OUT	OUT	OUT	OUT		
Fan C Outlet Pressure (in. H_2O)	10.5	10.5	11.5	12		
Fan D Outlet Pressure (in. H_2O)	7.0	7.5	12	12		
Fan B Amps x10	22	22	20	21		
Fan C Amps x10	22	22	22	22		
Fan D Amps x10	23	23	24	24		
Stack Damper A, Pos. (% Opn)	0	0	0	0		
Stack Damper B, Pos. (% Opn)	0	0	0	0		
Pumps: Recirc. Pump B_1 (amps)	13	13	13	13		
Recirc. Pump B_2 (amps)	16	16	16	16		
Recirc. Pump B_3 (amps)	13	13	13	13		
Recirc. Pump C_1 (amps)	13	13	12	12		
Recirc. Pump C_2 (amps)	14	14	13	13		
Recirc. Pump C_3 (amps)	14	14	14	14		
Recirc. Pump D_1 (amps)	13	13	13	13		
Recirc. Pump D_2 (amps)	13	13	13	13		
Recirc. Pump D_3 (amps)	12	12	13	13		
Reheater: Steam Flow (M lbs/hr)	40	40	45	45		
Steam Temp. (°F)	-	-	-	-		
Steam Pressure (psig)	600	600	1000	1000		
Section B; Presat. Water Flow (gpm)	185	185	190	185		
Outlet Gas Temp. (°F)	125	120	140	125		
Bed Diff. (in. H_2O)	3.8	3.8	8	8.0		
Demister Diff. (in. H_2O)	0.7	0.7	0.9	0.9		
RH Diff. (in. H_2O)	0.4	0.4	0	0		
~~Gas Outlet Flow (in. H_2O)~~ RH STM PR (psig)	250	300	300	310		
Section C; Presat Water Flow (gpm)	175	175	175	175		
Outlet Gas Temp. (°F)	160	160	155	155		
Bed Diff. (in. H_2O)	7.2	7.2	8.0	10.4		
Demister Diff. (in. H_2O)	0.2	0.2	0.2	0.3		
RH Diff. (in. H_2O)	OUT	OUT	0.4 ~~OUT~~	0.4		
~~Gas Outlet Flow (in. H_2O)~~ RH STM PR (PSIG)	310	320	380	380		
Section D; Presat. Water Flow (gpm)	185	185	190	190		
Outlet Gas Temp. (°F)	160	160	150	150		
Bed Diff. (in. H_2O)	4.0	4.0	11.8	9.8		
Demister Diff. (in. H_2O)	1.1	1.3	2.0	2.0		
RH Diff. (in. H_2O)	OUT	OUT	OUT	OUT		
~~Gas Outlet Flow (in. H_2O)~~ RH STM PR (PSIG)	100	100	100	100		

Comments

CHEROKEE STATION UNIT 4 DATA SHEET

Date:	8/23/77	8/23/77	8/24/77	8/24/77	8/24/77	8/24/77
Time:	0945	1045	0910	1130	1305	1500
Plant FUEL	100% COAL	100% COAL	100% COAL	100%	100% COAL	100% COAL
Mw, Gross	365	360	365	360	355	355
XS O_2	3.8	3.8	4%	4%	3.8%	3.8%
Steam Flow (lbs/hr) $\times 10^3$	2400	2400	2450	2400	2400	2400
Steam Pressure (psig)	2350	2350	2250	2350	2350	2350
Steam Temperature (°F)	990	970	470	990	990	990
Opacity, Bypass (%) LEAR SIEGLER	30%	* 50%	28%	35%	24%	30%
Opacity, Scrubber (%) 4N/4S	31/18%	35/16	24/16	30/25	25/18	40/30
COAL FLOW T/HR	150	150	150	150	145 ~~150~~	145
ESP						
Section A1; AC Voltage (v)	220±10	220	230	230	230	220
AC Current (a)	75±5	75	60	70±5	65	75
DC Voltage (Kv)	OUT	OUT	OUT	OUT	OUT	OUT
DC Current (ma)	~~650~~ 380±20	380±20	250	300±20	280	340
Spark Rate (spm)	7200	7200	** 5	~~140~~ 130±50	10	>200
Section A2; AC Voltage (v)	SAME	SAME	SAME	SAME	SAME	SAME
AC Current (a)						
DC Voltage (Kv)						
DC Current (ma)						
Spark Rate (spm)						
Section A3; AC Voltage (v)	200±30	200±20	200±20	200±20	220±30	200±30
AC Current (a)	40±10	80±10	90±10	80±10	100±20	85±30
DC Voltage (Kv)	OUT	OUT	OUT	OUT	OUT	OUT
DC Current (ma)	420±30	400±20	400±20	400±20	480±40	400±40
Spark Rate (spm)	OUT	OUT	OUT	OUT	OUT	OUT
Section A4; AC Voltage (v)	SAME	SAME	SAME	SAME	SAME	SAME
AC Current (a)						
DC Voltage (Kv)						
DC Current (ma)						
Spark Rate (spm)						
Section B1; AC Voltage (v)	280±10	270±10	270±10	270±20	270±20	270±20
AC Current (a)	130±10	140±10	130±20	125±10	150±40	125±20
DC Voltage (Kv)	OUT	OUT	OUT	OUT	OUT	OUT
DC Current (ma)	650±40	600±20	640±20	600±40	720±20	550±50
Spark Rate (spm)	185	180	180	185	185	180
Section B2; AC Voltage (v)	SAME	SAME	SAME	SAME	SAME	SAME
AC Current (a)						
DC Voltage (Kv)						
DC Current (ma)						
Spark Rate (spm)						
Section B3; AC Voltage (v)	260	250	260	260	260	260
AC Current (a)	115	115	115	120±10	115	120
DC Voltage (Kv)	33	34	33	33	33	33
DC Current (ma)	600	620±20	580±20	580±20	560±20	620±20
Spark Rate (spm)	105	105	105	105	105	100
Section B4; AC Voltage (v)	SAME	SAME	SAME	SAME	SAME	SAME
AC Current (a)						
DC Voltage (Kv)						
DC Current (ma)						
Spark Rate (spm)						

* REHEATER STM OFF

** 1/2 OF A SECTION HAS BEEN GROUNDED DUE TO EXCESSIVE SPARKING

CHEROKEE STATION UNIT 4 DATA SHEET
(continued)

Scrubber	8/23/77	8/23/77	8/24/77	8/24/77	8/24/77	8/24/77
Fans: ID Discharge Pressure (in. H_2O)	-0.5	-0.5	-0.5	-0.5	-0.4	-0.4
Fan B Outlet Pressure (in. H_2O)	OUT	OUT	OUT	OUT	OUT	OUT
Fan C Outlet Pressure (in. H_2O)	13	12	12	12	~~[illegible]~~ 13	12.5
Fan D Outlet Pressure (in. H_2O)	11	12.5	12	12.5	12.5	12
Fan B Amps X 10	21	21	21	21	21	21
Fan C Amps X 10	23	23	22	22	22	22
Fan D Amps X 10	23	24	24	24	24	24
Stack Damper A, Pos. (% Opn)	0	0	0	0	0	0
Stack Damper B, Pos. (% Opn)	0	0	0	0	0	0
Pumps: Recirc. Pump B1 (amps)	13	13	13	13	13	13
Recirc. Pump B2 (amps)	16	16	16	16	16	16
Recirc. Pump B3 (amps)	13	13	13	13	13	13
Recirc. Pump C1 (amps)	12	12	12	12	12	~~[illegible]~~ 12
Recirc. Pump C2 (amps)	13	13	12	12	13	13
Recirc. Pump C3 (amps)	13	13	14	14	15	14
Recirc. Pump D1 (amps)	13	13	13	13	13	13
Recirc. Pump D2 (amps)	13	13	13	13	13	13
Recirc. Pump D3 (amps)	12	12	13	12	12	12
Reheater: Steam Flow (M lbs/hr)	20	OFF	55	55	55	55
Steam Temp. (°F)	–	–	–	–	–	–
Steam Pressure (psig)	450	–	~~[illegible]~~ 1700	1700	1700	1700
Section B: Presat. Water Flow (gpm)	185	190	190	190	185	185
Outlet Gas Temp. (°F)	125	125	125	125	125	125
Bed Diff. (in. H_2O)	9.0	8.4	8.4	8.4	8.8	8.6
Demister Diff. (in. H_2O)	0.9	0.9	0.9	0.9	0.9	0.9
RH Diff. (in. H_2O)	OUT	OUT	OUT	OUT	OUT	OUT
~~Gas Outlet Flow~~ (in. H_2O) RH STM PR (PSIG)	120	OFF	260	280	300	300
Section C: Presat Water Flow (gpm)	175	175	175 ~~[illegible]~~	180	175	155
Outlet Gas Temp. (°F)	135	120	145	155	155	155
Bed Diff. (in. H_2O)	7.8	9.0	4.2	12.4	14.4	13.8
Demister Diff. (in. H_2O)	0.4	0.4	0.2	0.4	0.4	0.4
RH Diff. (in. H_2O)	0.8	0.8	1.0	0.5	0.4	0.9
~~Gas Outlet Flow (in. H_2O)~~ RH STM PR (PSIG)	100	OFF	440	440	440	440
Section D: Presat. Water Flow (gpm)	190	190	190	190	190	185
Outlet Gas Temp. (°F)	145	125	155	155	155	160
Bed Diff. (in. H_2O)	6.4	9.6	OUT	~~[illegible]~~ 7.4	9.4	6.6
Demister Diff. (in. H_2O)	2.0	2.0	2.0	2.0	2.0	2.5
RH Diff. (in. H_2O)	OUT	OUT	OUT	OUT	OUT	OUT
~~Gas Outlet Flow (in. H_2O)~~ RH STM PR (PSIG)	50	OFF	420	420	420	420

Comments

CHEROKEE STATION UNIT 4 DATA SHEET

Date:	8/25/77	8/25/77							
Time:	0640	0845							
Plant FUEL	100% COAL	100% COAL							
Mw, Gross	365	360							
XS O_2	4%	4.2%							
Steam Flow (lbs/hr)	2400	2400							
Steam Pressure (psig)	2350	2350							
Steam Temperature (°F)	980	980							
Opacity, Bypass (%) LOCAL SIGH.	30%	26%							
Opacity, Scrubber (%) 4N/4S	28/28	30/18							
ESP									
Section A1; AC Voltage (v)	230	240							
AC Current (a)	60	110 ± 20							
DC Voltage (Kv)	OUT	OUT							
DC Current (ma)	240	520 ± 20							
Spark Rate (spm)	35	7200							
Section A2; AC Voltage (v)	SAME	SAME							
AC Current (a)									
DC Voltage (Kv)									
DC Current (ma)									
Spark Rate (spm)									
Section A3; AC Voltage (v)	200 ± 20	230							
AC Current (a)	85 ± 10	110							
DC Voltage (Kv)	OUT	OUT							
DC Current (ma)	380 ± 20	600 ± 20							
Spark Rate (spm)	OUT	OUT							
Section A4; AC Voltage (v)	270 ± 10	SAME							
AC Current (a)	130 ± 10								
DC Voltage (Kv)	OUT								
DC Current (ma)	600 ± 20								
Spark Rate (spm)	180								
Section B1; AC Voltage (v)	~~SAME~~	270 ± 10							
AC Current (a)		125 ± 10							
DC Voltage (Kv)		OUT							
DC Current (ma)		600 ± 20							
Spark Rate (spm)		180							
Section B2; AC Voltage (v)	SAME ~~260~~	SAME							
AC Current (a)	~~115~~								
DC Voltage (Kv)	~~33~~								
DC Current (ma)	~~600 ± 20~~								
Spark Rate (spm)	~~105~~								
Section B3; AC Voltage (v)	260	260							
AC Current (a)	115	120 ± 5							
DC Voltage (Kv)	33	32							
DC Current (ma)	600 ± 20	600 ± 20							
Spark Rate (spm)	105	105							
Section B4; AC Voltage (v)	SAME	SAME							
AC Current (a)									
DC Voltage (Kv)									
DC Current (ma)									
Spark Rate (spm)									

CHEROKEE STATION UNIT 4 DATA SHEET
(continued)

Scrubber	8/25/77	8/25/77
Fans: ID Discharge Pressure (in. H_2O)	-0.4	-0.4
Fan B Outlet Pressure (in. H_2O)	OUT	OUT
Fan C Outlet Pressure (in. H_2O)	14	14
Fan D Outlet Pressure (in. H_2O)	12	12
Fan B Amps	21	21
Fan C Amps	22	22
Fan D Amps	24	23
Stack Damper A, Pos. (% Opn)	0	0
Stack Damper B, Pos. (% Opn)	0	0
Pumps: Recirc. Pump B_1 (amps)	13	13
Recirc. Pump B_2 (amps)	16	16
Recirc. Pump B_3 (amps)	12	12
Recirc. Pump C_1 (amps)	12	12
Recirc. Pump C_2 (amps)	14	14
Recirc. Pump C_3 (amps)	14	14
Recirc. Pump D_1 (amps)	14	14
Recirc. Pump D_2 (amps)	13	13
Recirc. Pump D_3 (amps)	13	13
Reheater: Steam Flow (M lbs/hr)	60	60
Steam Temp. (°F)	–	–
Steam Pressure (psig)	1700	1700
Section B; Presat. Water Flow (gpm)	185	190
Outlet Gas Temp. (°F)	130	125
Bed Diff. (in. H_2O)	9	8.8
Demister Diff. (in. H_2O)	0.9	0.9
RH Diff. (in. H_2O)	OUT	OUT
~~Gas Outlet Flow~~ (in. H_2O) RH STM PR (PSIG)	360	360
Section C; Presat Water Flow (gpm)	175	175
Outlet Gas Temp. (°F)	155	155
Bed Diff. (in. H_2O)	4.4	6.4
Demister Diff. (in. H_2O)	0.4	0.4
RH Diff. (in. H_2O)	1.6	1.0
~~Gas Outlet Flow (in. H_2O)~~ RH STM PR (PSIG)	480	480
Section D; Presat. Water Flow (gpm)	190	190
Outlet Gas Temp. (°F)	160	160
Bed Diff. (in. H_2O)	OUT	OUT
Demister Diff. (in. H_2O)	2.2	2.2
RH Diff. (in. H_2O)	OUT	OUT
~~Gas Outlet Flow (in. H_2O)~~ RH STM PR (PSIG)	480	480

Comments

CHEROKEE STATION UNIT 4 DATA SHEET

Date:	8/19/77	8/19/77	8/23/77	8/23/77	[illegible] *	[illegible] *	8/28/77	8/28/77
Time:	1038	[illegible]	1739	1843	[illegible] +	[illegible]	0941	1048
Plant								
Mw, Gross	356	[illegible]	360	360	[illegible]	361	253	271
XS O_2 (%)	4.0	[illegible]	3.9	3.9	4.0	4.1	3.7	3.8
Steam Flow (lbs/hr) x10^3	2350	[illegible]	2400	2400	2400	2400	1450	1600
Steam Pressure (psig)	2350	[illegible]	2350	2350	[illegible]	2350	2350	2350
Steam Temperature (°F)	970	970	980	975	[illegible]	[illegible]	1000	1000
Opacity, Bypass (%)	25/20	30/10	35/15	32/16	60/27	43/[illegible]	28/22	33/23
Opacity, Scrubber (%)	24	25	45	48	40	31	26	26
ESP								
Section A1; AC Voltage (v)	230	230	230	230	226	225	235	235
AC Current (a)	125±10	125±10	75	70	[illegible]	125	105	100±10
DC Voltage (Kv)	Out	Out	Out	Out	Out	Out	Out	Out
DC Current (ma)	[illegible]±20	[illegible]±20	300	290	[illegible]	[illegible]	450	450±20
Spark Rate (spm)	>200	>200	30	10	>200	>200	>200	>200
Section A2; AC Voltage (v)	Same	Same	Same	Same	Same	Same	Same	Same
AC Current (a)								
DC Voltage (Kv)								
DC Current (ma)								
Spark Rate (spm)								
Section A3; AC Voltage (v)	220±[illegible]	200±20	200±10	200±20	[illegible]	220	190	200
AC Current (a)	[illegible]±5	80±5	85±5	85±10	[illegible]	90	90	100
DC Voltage (Kv)	Out	Out	Out	Out	[illegible]	Out	Out	Out
DC Current (ma)	[illegible]±10	[illegible]±[illegible]	410±10	400±10	[illegible]	[illegible]	420	400
Spark Rate (spm)	Out	Out	Out	Out	[illegible]	Out	Out	Out
Section A4; AC Voltage (v)	Same	Same	Same	Same	Same	Same	Same	Same
AC Current (a)								
DC Voltage (Kv)								
DC Current (ma)								
Spark Rate (spm)								
Section B1; AC Voltage (v)	[illegible]	280	270	270	[illegible]	240	305	305
AC Current (a)	140	[illegible]	135	135±10	[illegible]	[illegible]±[illegible]	160±10	165±10
DC Voltage (Kv)	Out	Out	Out	Out	Out	Out	Out	Out
DC Current (ma)	780	[illegible]	600	640±10	[illegible]	540	850±50	880±20
Spark Rate (spm)	184	185	185	185	185	185	186	185
Section B2; AC Voltage (v)	Same	Same	Same	Same	Same	Same	Same	Same
AC Current (a)								
DC Voltage (Kv)								
DC Current (ma)								
Spark Rate (spm)								
Section B3; AC Voltage (v)	250±[illegible]	[illegible]	260	260	230	235	230	230
AC Current (a)	95	[illegible]	120	130	110	105	90	80
DC Voltage (Kv)	32	[illegible]	33	33	[illegible]	[illegible]	29	29
DC Current (ma)	470	410	610	600	[illegible]	[illegible]	400	410
Spark Rate (spm)	95	95	105	105	[illegible]	[illegible]	105	105
Section B4; AC Voltage (v)	Same	Same	Same	Same	Same	Same	Same	
AC Current (a)								
DC Voltage (Kv)								
DC Current (ma)								
Spark Rate (spm)								

+ Cabinet doors on A1-A2, A3-A4, B3-B4, open w/ portable fan on, very hot

* A-1 section is grounded [illegible]

CHEROKEE STATION UNIT 4 DATA SHEET
(continued)

Scrubber										
Fans: ID Discharge Pressure (in. H_2O)	-.5	-.5	-1.2	-.5	-.6	-.5	-.5	-.5		
Fan B Outlet Pressure (in. H_2O)	out	out	out	out	[illegible]	out	out	out		
Fan C Outlet Pressure (in. H_2O)	21	22	12.5	12	[illegible]	12.5	8.5	9.5		
Fan D Outlet Pressure (in. H_2O)	11	10.5	13	11.5	[illegible]	[illegible]	7.0	7.5		
Fan A Amps	215	220	205	205	[illegible]	210	230	230		
Fan C Amps	235	[illegible]	220	220	[illegible]	[illegible]	220	230		
Fan D Amps	235	[illegible]	235	235	230	[illegible]	225	225		
Stack Damper A, Pos. (% Opn)	0	0	0	0	0	0	0	0		
Stack Damper B, Pos. (% Opn)	0	0	0	0	0	0	0	0		
Pumps: Recirc. Pump B1 (amps)	13	13	13	12.5	13	13	14	14		
Recirc. Pump B2 (amps)	16	16	16	16	16	16	16	16		
Recirc. Pump B3 (amps)	13	12.5	12.5	12.5	12	12	12.5	12.5		
Recirc. Pump C1 (amps)	13.5	13.5	11.5	11.5	12	12	12.5	12.5		
Recirc. Pump C2 (amps)	14	12	12.5	12.5	14	14	13.5	13.5		
Recirc. Pump C3 (amps)	14.5	14.5	14	14	14	14.5	13.5	13.5		
Recirc. Pump D1 (amps)	13	13	13	13	14	14	14	13.5		
Recirc. Pump D2 (amps)	13	13	13	12.5	12	13	14	13.5		
Recirc. Pump D3 (amps)	12	12	12.5	12.5	13	12	13.5	13.0		
Reheater: Steam Flow (M lbs/hr)	40	40	0	0	55	55	60	60		
Steam Temp. (°F)	—	—	—	—	—	—	—	—		
Steam Pressure (psig)	1,000	1000	0	0	1730	1730	1730	1730		
Section B: Presat. Water Flow (gpm)	185	185	185	185	185	185	185	185		
Outlet Gas Temp. (°F)	125	[illegible]	115	120	140	140	120	130		
Bed Diff. (in. H_2O)	6.2	7.6	8.7	8.7	9.2	8.6	5.4	5.9		
Demister Diff. (in. H_2O)	0.8	0.9	0.8	0.8	0.8	0.8	0.6	0.7		
RH Diff. (in. H_2O)	0.7	[illegible]	0	0	0	0	0	0		
Steam Press (psig) ~~Gas Outlet Flow~~ (in. H_2O)	270	220	30	30	3,90	[illegible]	300	300		
Section C: Presat Water Flow (gpm)	175	175	175	175	175	175	175	175		
Outlet Gas Temp. (°F)	155	155	117	117	[illegible]	150	160	160		
Bed Diff. (in. H_2O)	14.6	[illegible]	13.2	9.1	14.6	[illegible]	0	0		
Demister Diff. (in. H_2O)	0.2	0.2	0.3	0.3	[illegible]	[illegible]	0.2	0.2		
RH Diff. (in. H_2O)	1.2	1.3	0.7	1.4	[illegible]	0.3	1.3	1.6		
Gas Outlet Flow (in. H_2O)	330	330	30	30	420	410	410	410		
Section D: Presat. Water Flow (gpm)	185	175	185	185	185	185	185	185		
Outlet Gas Temp. (°F)	145	145	135	135	160	160	175	175		
Bed Diff. (in. H_2O)	6.4	[illegible]	5.7	4.0	14.0	11.2	4.3	4.6		
Demister Diff. (in. H_2O)	2.3	2.1	2.6	2.7	2.1	2.2	1.3	1.4		
RH Diff. (in. H_2O)	0.0	0.0	0.0	0	[illegible]	[illegible]	0	0		
Gas Outlet Flow (in. H_2O)	80	90	0	0	420	410	420	420		

Comments

APPENDIX B

SUMMARY OF VISIBLE EMISSION OBSERVATIONS
CHEROKEE STATION
PUBLIC SERVICE COMPANY OF COLORADO
July - August, 1977

APPENDIX B B-1

Summary of Visible Emission Observations
Unit 1 and 2 Stack - Cherokee Station
Public Service Co. of Colorado
(continued)

Date (1977)	Time of Observation	Average Opacity (%)	Opacity Range (%)	Meter† Reading	Unit† Load (MW)	Comments†
8/25	0734-0740	29	20-40	18/16	111/100	coal/25% gas and 1A1 recirc. pump out
8/28	1000-1006	30	20-45	24/12	105/83	coal/25% gas and 1A1 recirc. pump out
8/28	1014-1012	31	25-40	24/12	105/83	coal/25% gas and 1A1 recirc. pump out
10/4	1410-1416	19	15-30	12/8	106/100	coal/coal
10/7	1000-1009	31	25-40	12/7	113/115	gas/75% coal
10/11	1438-1447	34	30-50	12/12	115/110	coal/coal 30% bypass reheater plugged
10/12	1330-1340	39	35-40	22/10	117/115	coal/coal 100% bypass Unit 1
10/13	1045-1054	29	20-40	13/11	107/78	40% bypass
10/14	1000-1009	11	10-15	14/7	105/100	-
10/18	0910-0919	29	25-35	12/12	108/108	-

† *Unit 1/Unit 2.*

B-2

APPENDIX B

Summary of Visible Emission Observations
Unit 1 and 2 Stack - Cherokee Station
Public Service Co. of Colorado

Date (1977)	Time of Observation	Average Opacity (%)	Opacity Range (%)	Meter† Reading	Unit† Load (MW)	Comments†
7/27	1400-1406	10	10	0/15	116/113	gas/25% gas
7/29	1033-1039	22	10-35	0/17	116/111	gas/25% gas
7/30	1918-1924	5	5-10	5/13	109/91	coal/25% gas
8/1	1803-1809	26	15-45	7/12	118/104	coal 25% gas
8/4	1030-1036	27	20-30	10/10	113/111	coal/25% gas
8/4	1131-1137	32	25-40	10/10	113/111	coal/25% gas
8/4	1517-1523	20	20	13/13	113/111	coal/25% gas
8/6	1406-1412	21	15-25	10/0	99/75	coal/25% gas
8/8	1015-1021	23	20-30	7/12	118/108	coal/25% gas
8/8	1027-1033	23	15-35	7/12	118/108	coal/25% gas
8/9	1445-1451	16	5-30	8/10	117/108	coal/25% gas
8/9	1503-1509	22	15-40	8/10	117/108	coal/25% gas
8/12	1449-1455	14	5-30	9/5	116/102	gas/25% gas
8/12	1503-1509	11	5-40	9/5	116/102	gas/25% gas
8/13	1010-1016	29	20-40	9/5	112/99	coal/25% gas
8/13	1025-1031	29	20-40	9/5	112/99	coal/25% gas
8/15	1010-1017	14	10-20	15/13	116/112	coal/25% gas
8/15	1025-1031	18	15-20	15/13	116/112	coal/25% gas
8/19	1030-1036	15	10-20	10/9	94/113	coal/25% gas
8/19	1048-1054	6	5-10	10/9	94/113	coal/25% gas
8/22	1000-1006	31	30-35	22/19	118/114	coal/25% gas and 1A1 recirc. pump out
8/22	1012-1018	32	30-35	22/19	118/114	coal/25% gas and 1A1 recirc. pump out
8/23	1000-1006	29	25-40	17/13	113/109	coal/25% gas and 1A1 recirc. pump out
8/23	1012-1018	32	30-40	17/13	113/109	coal/25% gas and 1A1 recirc. pump out
8/23	1803-1809	21	15-30	19/14	117/113	coal/25% gas and 1A1 recirc. pump out
8/23	1809-1815	20	15-30	19/14	117/113	coal/25% gas and 1A1 recirc. pump out
8/24	1020-1026	30	25-35	19/15	112/99	coal/25% gas and 1A1 recirc. pump out
8/24	1037-1043	36	30-45	19/15	112/99	coal/25% gas and 1A1 recirc. pump out
8/24	1509-1515	32	25-40	21/15	116/115	coal/25% gas and 1A1 recirc. pump out
8/24	1550-1556	22	15-30	21/15	116/115	coal/25% gas and 1A1 recirc. pump out
8/25	0720-0726	30	20-40	18/16	111/100	coal/25% gas and 1A1 recirc. pump out

† *Unit 1/Unit 2.*

B-3

APPENDIX B
Summary of Visible Emission Observations
Unit 3 Stack - Cherokee Station
Public Service Co. of Colorado

Date (1977)	Time of Observation	Average Opacity (%)	Opacity Range (%)	Meter Reading	Unit Load (MW)	Comments
8/9	1451-1457	17	10-25	0	136	Scrubber Out - 75% Gas
8/9	1509-1515	14	5-20	0	136	Scrubber Out - 75% Gas
8/12	1442-1448	46	40-70	24	130	Scrubber Out - 50% Gas
8/12	1510-1516	42	30-60	24	130	Scrubber Out - 50% Gas
8/13	1018-1024	46	40-60	19	129	Scrubber Out - 50% Gas
8/13	1033-1039	48	40-60	19	129	Scrubber Out - 50% Gas
8/15	1018-1024	40	35-45	22	132	Scrubber Out - 50% Gas
8/15	1032-1038	42	40-45	22	132	Scrubber Out - 50% Gas
8/19	1036-1042	24	15-35	15	140	Scrubber Out - 50% Gas
8/19	1054-1100	21	10-30	15	140	Scrubber Out - 50% Gas
10/4	1016-1022	25	20-30	4	108	100% Coal 3B3 Recirc. Pump Out
10/11	1029-1038	92	70-100	23	165	75% Coal 3B Booster Fan Out 50% Bypass
10/12	1342-1351	57	55-60	10	103	50% Coal 100% Bypass
10/13	1054-1103	45	30-75	11	164	50% Coal 50% Bypass
10/14	1010-1019	13	10-15	5	155	50% Coal 50% Bypass
10/18	1009-1018	25	20-30	1	163	

B-4

APPENDIX B

Summary of Visible Emission Observations
Unit 4 Stack - Cherokee Station
Public Service Co. of Colorado

Date (1977)	Time of Observation	Average Opacity (%)	Opacity Range (%)	Meter Reading	Unit Load (MW)	Comments
7/27	1406-1411	15	15	20	356	
7/29	1020-1026	17	10-30	16	358	
7/30	1924-1930	8	5-20	21	343	
8/1	1809-1815	30	20-40	28	314	
8/4	1037-1043	19	15-20	26	355	
8/4	1140-1146	24	20-30	26	355	
8/4	1523-1528	20	20	22	355	
8/6	1414-1420	18	10-25	22	348	
8/8	1021-1027	16	15-25	22	353	
8/8	1033-1039	17	15-20	22	353	
8/9	1457-1503	9	5-20	19	355	
8/9	1515-1521	11	5-20	19	355	
8/15	1010-1017	6	5-10	22	270	Low reheat stm flow
8/19	1042-1048	6	5-10	24	355	Low reheat stm flow
8/19	1100-1106	5	5-10	24	355	Low reheat stm flow
8/22	1006-1012	24	20-30	30	358	
8/22	1018-1024	23	20-30	30	358	
8/23	1006-1012	18	15-25	40	360	No reheat stm
8/23	1018-1024	22	20-25	40	360	No reheat stm
8/24	1028-1034	11	5-15	31	362	1 ESP section out
8/24	1044-1050	8	5-10	31	362	1 ESP section out
8/24	1502-1508	5	5	27	355	1 ESP section out
8/24	1516-1522	5	5-10	27	355	1 ESP section out
8/25	0727-0733	27	20-35	28	362	1 ESP section out
8/25	0741-0747	26	20-35	28	362	1 ESP section out
8/28	1007-1013	17	10-25	26	262	
8/28	1021-1027	19	10-25	26	262	
10/4	1022-1028	10	5-15	18	190	
10/11	1420-1429	24	20-35	26	250	
10/12	1352-1401	25	25	24	241	
10/13	1103-1112	11	10-15	24	246	
10/14	1019-1027	13	10-20	21	230	
10/18	1028-1037	36	0-60	-	-	Unit start-up

APPENDIX C

ELECTROSTATIC PRECIPITATOR DATA
AND
CALCULATIONS

CHEROKEE STATION

PUBLIC SERVICE COMPANY OF COLORADO

July - August, 1977

DATE (1977)	T-R SET	PRIMARY VOLTAGE (V)	PRIMARY CURRENT (A)	POWER (KW)	SECONDARY VOLTAGE (kV)	SECONDARY CURRENT (mA)	POWER (kW)	SPARK RATE (SPM)	POWER EFFICIENCY (%)	CURRENT DENSITY mA/ft²	CURRENT DENSITY mA/m²	COMMENTS
7/27	A1-A2	180	53	9.5	33	180	5.9	0	62	6.17	.066	100% GHS
	B1-B2	160	53	8.5	—	220	—	0	—	7.54	.081	
7/29	A1-A2	180	50	9.0	33	160	5.3	0	59	6.49	.059	100% GHS
	B1-B2	155	55	8.5	—	210	—	0	—		.078	
7/30	A1-A2	180	68	12.2	33	170	5.6	>500	46	7.20	.063	HIGH SPARK RATE
	B1-B2	160	60	9.6	—	225	—	>500	—	7.72	.083	100% COAL
8/1	A1-A2	180	52	9.4	26	40	1.4	325	14	1.37	.015	LOW SEC. CURRENT
	B1-B2	165	35	5.8	—	115	—	280	—	3.99	.042	" POWER EFF.
8/3	A1-A2	180	50	9.0	38	125	4.5	450	50	4.29	.046	
	B1-B2	165	35	5.8	—	110	—	310	—	3.77	.041	
8/4	A1-A2	175	50	9.8	38	140	5.3	390	54	4.80	.052	
	B1-B2	170	38	6.5	—	100	—	290	—	3.43	.037	
8/6	A1-A2	190	28	5.3	38	110	4.2	300	79	3.77	.041	
	B1-B2	170	25	4.3	—	60	—	110	—	2.06	.022	LOW SEC. CURRENT
8/8	A1-A2	178	40	7.1	37	80	3.0	420	42	2.74	.030	
	B1-B2	155	35	5.4	—	95	—	195	—	3.26	.035	
8/9	A1-A2	178	40	7.1	36	80	2.9	420	41	2.74	.030	
	B1-B2	158	35	5.5	—	95	—	230	—	3.26	.035	
8/10	A1-A2	200	33	6.6	40	120	4.8	275	61	4.12	.044	
	B1-B2	170	30	6.1	—	100	—	335	—	3.43	.037	

SUMMARY OF UNIT 1 ESP
OPERATING DATA - JULY AUGUST 1977
CHEROKEE STATION PUBLIC SERVICE CO. OF COLORADO

DATE (1977)	T-R SET	PRIMARY VOLTAGE (V)	PRIMARY CURRENT (A)	POWER (KW)	SECONDARY VOLTAGE (KV)	SECONDARY CURRENT (mA)	POWER (KW)	SPARK RATE (SPM)	POWER EFFICIENCY (%)	CURRENT DENSITY μA/ft²	CURRENT DENSITY mA/m²	COMMENTS
8/12	A1-A2	195	28	5.5	41	80	3.3	210	60	2.74	.030	25% GAS
	B1-B2	170	30	5.1	—	65	—	150	—	2.23	.024	
8/13	A1-A2	190	28	5.3	40	75	3.0	200	57	2.57	.028	100% COAL FOR REMAINING DAYS
	B1-B2	170	30	5.1	—	65	—	175	—	2.23	.024	
8/15	A1-A2	175	35	6.1	38	80	3.0	295	50	2.74	.030	
	B1-B2	165	35	5.8	—	70	—	200	—	2.40	.026	
8/19	A1-A2	200	40	8.0	40	85	3.4	245	43	2.91	.031	
	B1-B2	178	35	6.2	—	120	—	395	—	4.12	.044	
8/22	A1-A2	180	35	6.3	37	140	5.2	240	82	4.80	.052	
	B1-B2	160	10	1.6	—	30	—	0	—	1.03	.011	LOW CURRENT NO SPARK
8/23 (AM)	A1-A2	180	40	7.2	37	105	3.9	420	54	3.60	.039	
	B1-B2	160	5	0.8	—	20	—	120	—	0.69	.007	LOW CURRENT
8/23 (PM)	A1-A2	168	45	7.6	35	80	2.8	>500	37	2.74	.030	XS SPARK RATE
	B1-B2	160	<25	3.2	—	45	—	180	—	1.54	.017	
8/24	A1-A2	180	45	8.1	36	135	4.9	450	60	4.63	.050	
	B1-B2	160	23	3.7	—	50	—	280	—	1.71	.018	
8/25	A1-A2	175	40	7.0	34	140	4.8	400	68	4.80	.052	
	B1-B2	170	10	1.7	—	35	—	±100	—	1.20	.013	SPARKING
8/26	A1-A2	168	40	6.7	33	85	2.8	400	42	2.91	.031	
	B1-B2	165	<25	3.3	—	25	—	0	—	0.86	.009	NO SPARK
8/28	A1-A2	180	40	7.2	36	60	2.2	410	30	2.05	.022	
	B1-B2	165	25	4.1	—	60	—	350	—	2.05	.022	

2/2

DATE (1977)	T-R SET	PRIMARY VOLTAGE (V)	PRIMARY CURRENT (A)	POWER (KW)	SECONDARY VOLTAGE (KV)	SECONDARY CURRENT (mA)	POWER (kW)	SPARK RATE (SPM)	POWER EFFICIENCY (%)	CURRENT DENSITY mA/ft²	CURRENT DENSITY mA/m²	COMMENTS
7/27	A1-A2	200	20	4.0	24	45	1.1	0/150	28	2.25	.024	75% COAL
	A3-A4	245	50	16.3	46	300	13.8	0/0	—	15.0	.162	
	B1-B2	270	27	7.3	27	65	2.2	0/0	—	6.38	.069	
	B3-B4	290	75	21.8	38	550	20.9	0/0	—	41.3	.445	
	C1-C2	290	67	19.4	OUT	—	—	0/0	—	—	—	
	C3-C4	253	92	23.3	38	550	20.9	10	90	41.3	.455	
7/29	A1-A2	178	18	3.2	23	39	0.9	>200/20	28	1.90	.020	
	A3-A4	290	60	17.4	43	270	12.2	0	70	14.5	.156	
	B1-B2	193	22	4.2	26	55	1.4	0/0	33	4.13	.045	
	B3-B4	285	93	26.5	37	540	20.0	0	75	40.5	.437	
	C1-C2	288	37	10.7	—	[illegible]	—	0/0	—	9.0	.097	
	C3-C4	248	92	22.8	36	525	18.9	10	83	39.4	.424	
7/30	A1-A2	325	58	18.9	36	198	7.1	0/5	38	9.9	.107	
	A3-A4	278	61	18.2	43	205	13.1	0	72	15.3	.164	
	B1-B2	TRIPPED	OUT									
	B3-B4	300	92	27.6	39	545	21.2	0	77	40.9	.440	
	C1-C2	312	56	17.5	—	198	—	0	—	14.9	.160	
	C3-C4	258	92	23.7	39	525	20.5	10	86	39.4	.424	
8/1	A1-A2	173	18	3.1	24	35	0.8	>200/100	26	1.75	.019	
	A3-A4	240	48	11.5	38	140	7.2	0	63	9.51	.102	
	B1-B2	265	10	2.6	36	43	1.5	0/0	58	3.23	.035	
	B3-B4	230	65	15.0	32	345	11.0	0	73	25.9	.279	
	C1-C2	318	35	11.1	—	120	—	0	—	9.0	.097	
	C3-C4	255	92	23.5	38	550	20.9	10	89	41.3	.445	

SUMMARY OF UNIT 2 ESP
OPERATING DATA JULY - AUGUST 1977
CHEROKEE STATION PUBLIC SERVICE CO. OF COLORADO

1/5

DATE (1977)	T-R SET	PRIMARY VOLTAGE (V)	PRIMARY CURRENT (A)	POWER (KW)	SECONDARY VOLTAGE (KV)	SECONDARY CURRENT (mA)	POWER (KW)	SPARK RATE (SPM)	POWER EFFICIENCY (%)	CURRENT DENSITY mA/ft²	CURRENT DENSITY mA/m²
8/2	A1-A2	350	56	20.3	40	190	7.6	10/8	37	9.51	.102
	A3-A4	250	55	13.8	38	250	9.5	0	69	12.5	.135
	B1-B2	315	47	14.8	37	150	5.6	0	38	11.3	.121
	B3-B4	270	83	22.4	35	420	14.7	0	66	31.5	.340
	C1-C2	310	43	13.3	—	150	—	0/0	—	11.3	.121
	C3-C4	273	93	25.4	41	545	22.3	10	88	41.9	.440
8/4	A1-A2	340	30	10.2	42	90	3.8	35/9	37	4.50	.048
	A3-A4	260	55	14.3	41	235	9.6	0	67	11.8	.127
	B1-B2	340	44	15.0	38	130	4.9	0	33	9.76	.105
	B3-B4	240	73	17.5	31	340	10.5	0	60	25.5	.275
	C1-C2	340	57	19.4	—	190	—	0	—	14.3	.154
	C3-C4	270	93	25.1	40	540	21.6	10	86	40.5	.437
8/6	A1-A2	350	47	16.5	42	165	6.9	25/20	42	8.26	.089
	A3-A4	275	58	16.0	40	285	11.4	0	71	14.3	.154
	B1-B2	315	48	15.1	36	150	5.4	0/0	36	11.3	.121
	B3-B4	290	91	26.4	38	520	20.0	0	75	39.0	.420
	C1-C2	320	57	18.2	—	200	—	0/0	—	15.0	.162
	C3-C4	255	92	23.5	37	530	19.6	10	83	39.8	.428
8/8	A1-A2	265	27	7.2	37	65	2.4	35/10	33	3.25	0.035
	A3-A4	210	49	10.3	34	160	5.4	0	53	8.00	0.086
	B1-B2	285	28	8.0	36	88	3.2	0	40	6.60	.071
	B3-B4	225	73	16.4	32	350	11.2	0	68	26.3	.283
	C1-C2	330	55	18.1	—	195	—	0	—	14.6	.158
	C3-C4	210	75	15.8	32	350	11.2	10	71	26.3	.283

UNIT 2

DATE (1977)	T-R SET	PRIMARY VOLTAGE (V)	PRIMARY CURRENT (A)	POWER (KW)	SECONDARY VOLTAGE (KV)	SECONDARY CURRENT (mA)	POWER (kW)	SPARK RATE (SPM)	POWER EFFICIENCY (%)	CURRENT DENSITY mA/ft²	CURRENT DENSITY mA/m²	COMMENTS
8/9	A1-A2	270	33	8.9	37	100	3.7	35/10	42	5.0	.054	
	A3-A4	215	50	12.8	34	175	6.0	0	55	8.76	.094	
	B1-B2	293	36	10.5	35	120	4.2	0	40	9.0	.097	
	B3-B4	220	70	15.4	31	370	11.5	0	74	27.8	.299	
	C1-C2	330	57	18.8	—	200	—	0	—	15.0	.162	
	C3-C4	205	73	15.0	33	360	11.9	10	79	27.0	.291	
8/10	A1-A2	333	60	20.0	37	205	7.6	2/5	38	10.3	.110	
	A3-A4	250	54	13.5	39	300	11.7	0	86	15.0	.162	
	B1-B2	280	47	13.2	29	150	4.4	0	33	11.3	.121	
	B3-B4	220	75	16.5	32	375	12.0	0	73	28.2	.303	
	C1-C2	280	56	15.7	—	200	—	0	—	15.0	.162	
	C3-C4	260	92	23.9	38	540	30.5	10	86	40.5	.437	
8/12	A1-A2	340	55	18.7	39	175	6.8	12/10	36	8.76	.094	
	A3-A4	190	50	9.5	30	180	5.4	0	57	9.0	.097	
	B1-B2	320	58	18.6	35	190	6.7	0	36	14.3	.154	
	B3-B4	210	73	15.3	28	385	10.8	0	70	28.9	.311	
	C1-C2	300	56	16.8	—	195	—	0	—	14.6	.158	
	C3-C4	200	75	15.0	31	390	12.1	10	81	29.3	.315	
8/13	A1-A2	220	23	5.1	26	43	1.1	7200/50	22	2.15	.023	
	A3-A4	185	48	8.9	30	165	5.0	0	55	8.26	.089	
	B1-B2	300	28	8.4	35	90	3.1	0	36	6.76	.073	
	B3-B4	210	75	15.8	27	400	10.8		68	30.0	.323	
	C1-C2	335	57	19.1	—	190	—	0	—	14.3	.154	
	C3-C4	200	75	15.0	31	395	12.2	10	82	29.7	.319	

UNIT 2

3/5

DATE (1977)	T-R SET	PRIMARY VOLTAGE (V)	PRIMARY CURRENT (A)	POWER (KW)	SECONDARY VOLTAGE (KV)	SECONDARY CURRENT (mA)	POWER (kW)	SPARK RATE (SPM)	POWER EFFICIENCY (%)	CURRENT DENSITY mA/ft²	CURRENT DENSITY mA/m²	COMMENTS
8/15	A1-A2	300	58	17.4	34	195	6.6	0/5	38	9.76	.105	
	A3-A4	233	58	13.5	34	300	10.2	0	76	15.0	.162	
	B1-B2	250	55	13.8	27	155	4.2	0/0	30	11.6	.125	
	B3-B4	250	91	22.8	33	540	17.8	0	78	40.5	.437	
	C1-C2	240	56	13.4	—	192	—	0/0	—	14.4	.155	
	C3-C4	230	92	21.2	34	520	17.7	10	83	39.0	.420	
8/19	A1-A2	305	50	15.3	35	160	5.6	0/5	37	8.0	.086	
	A3-A4	265	58	15.4	39	300	11.7	0/0	76	15.0	.162	
	B1-B2	240	47	11.3	25	140	3.5	0/0	31	10.5	.113	
	B3-B4	253	91	23.0	33	525	17.3	0	75	39.4	.421	
	C1-C2	240	56	13.4	—	193	—	0/0	—	14.5	.156	
	C3-C4	215	92	19.8	32	520	16.6	10	84	39.0	.420	
8/22	A1-A2	333	57	19.0	38	195	7.4	0/5	39	9.76	.105	
	A3-A4	323	58	18.7	47	300	14.1	0	75	15.0	.162	
	B1-B2	255	50	12.8	27	150	4.1	0	32	11.2	.121	
	B3-B4	275	91	25.0	36	525	18.9	0	76	39.4	.424	
	C1-C2	240	56	13.4	—	195	—	0	—	14.6	.158	
	C3-C4	220	91	20.0	32	520	16.6	10	83	39.0	.420	
8/23	A1-A2	370	58	21.5	43	200	8.6	3/5	40	10.0	.108	
	A3-A4	220	48	10.6	34	160	5.4	0	51	8.0	.086	
	B1-B2	300	59	17.7	33	190	6.3	0	35	14.3	.157	
	B3-B4	230	70	16.1	31	290	9.0	0	56	21.8	.234	
	C1-C2	250	56	14.0	—	190	—	0	—	14.3	.154	
	C3-C4	260	93	24.2	38	530	20.1	10	83	39.8	.428	

UNIT 2

DATE (1977)	T-R SET	PRIMARY VOLTAGE (V)	PRIMARY CURRENT (A)	POWER (KW)	SECONDARY VOLTAGE (kV)	SECONDARY CURRENT (mA)	POWER (kW)	SPARK RATE (SPM)	POWER EFFICIENCY (%)	CURRENT DENSITY µA/ft²	CURRENT DENSITY mA/m²	COMMENTS
8/24	A1-A2	345	57	19.7	38	190	7.2	0/5	37	9.51	.102	
	A3-A4	280	57	16.0	39	265	10.3	0/0	64	13.3	.143	
	B1-B2	285	58	16.5	31	185	5.7	0	35	13.9	.150	
	B3-B4	270	86	23.2	35	470	16.5	0	71	35.2	.380	
	C1-C2	240	56	13.4	—	190	—	0	—	14.3	.154	
	C3-C4	235	91	21.4	35	515	18.0	10	84	38.7	.416	
8/25	A1-A2	365	56	20.4	40	193	7.7	4/5	38	9.66	.104	
	A3-A4	295	55	16.2	43	260	11.2	0	69	13.0	.140	
	B1-B2	300	59	17.7	32	185	5.9	0	33	13.9	.150	
	B3-B4	275	85	23.4	38	475	18.1	0	77	35.7	.384	
	C1-C2	245	56	13.7	—	195	—	0	—	14.6	.158	
	C3-C4	238	92	21.9	36	530	19.1	10	87	39.8	.428	
8/26	A1-A2	415	56	23.2	45	200	9.0	3/5	39	10.0	.108	
	A3-A4	240	50	12.0	38	190	7.2	0	60	9.51	.102	
	B1-B2	320	59	18.9	36	190	6.8	0	36	14.3	.154	
	B3-B4	235	70	16.5	32	320	10.2	0	62	24.0	.259	
	C1-C2	260	55	14.3	—	190	—	0	—	14.3	.154	
	C3-C4	265	93	24.6	39	530	20.7	10	84	39.8	.428	
8/28	A1 A2	270	31	8.4	34	90	3.1	0/5	36	4.5	.048	
	A3 A4	278	56	15.6	40	310	12.4	0	79	15.5	.167	
	B1 B2	275	47	12.9	29	150	4.4	0	34	11.3	.121	
	B3 B4	288	93	26.8	38	550	20.9	0	78	41.3	.445	
	C1 C2	230	57	13.1	—	195	—	0	—	14.6	.158	
	C3 C4	235	92	21.6	35	530	18.6	10	86	39.8	.428	

UNIT 2

5/5

DATE (1977)	T-R SET	PRIMARY VOLTAGE (V)	PRIMARY CURRENT (A)	POWER (KW)	SECONDARY VOLTAGE (KV)	SECONDARY CURRENT (mA)	POWER (KW)	SPARK RATE (SPM)	POWER EFFICIENCY (%)	CURRENT DENSITY mA/ft²	mA/m²	COMMENTS
7/27	A1-A2	50	90	4.5	8	510	4.1	0	91			75% COAL
	B1-B2	170	105	17.9	40	600		0				
7/29	A1-A2	50	92		8	510		0				
	B1-B2	170	107		40	600		0				
7/30	A1-A2	50	92		8	515		0				
	B1-B2	165	106		40	590		0				
8/1	A1-A2	50	95		8	530		0				
	B1-B2	170	107		40	600		0				
8/3	A1-A2	50	95		8	520		0				
	B1-B2	170	110		41	600		0				
8/4	A1-A2	50	95		8	520		0				
	B1-B2	170	111		40	600		0				
8/5	A1-A2	50	95		8	530		0				
	B1-B2	170	108		41	600		0				
8/8	A1-A2	190	68	12.9	35	310	10.9	0	84			ALL GAS
	B1-B2	170	110		41	620		0				
8/9	A1-A2	220	65	14.3	38	280	10.6	0	74			25% COAL
	B1-B2	170	110		41	620		0				
8/10	A1-A2	235	130	30.6	40	710	28.4	0	93			50% COAL
	B1-B2	220	128		46	700		0				

SUMMARY OF UNIT 3 ESP
OPERATING DATA JULY-AUGUST 1977
CHEROKEE STATION PUBLIC SERVICE CO. OF COLORADO

DATE (1977)	T-R SET	PRIMARY VOLTAGE (V)	PRIMARY CURRENT (A)	POWER (KW)	SECONDARY VOLTAGE (KV)	SECONDARY CURRENT (mA)	POWER (kW)	SPARK RATE (SPM)	POWER EFFICIENCY (%)	CURRENT DENSITY mA/ft²	CURRENT DENSITY mA/m²	COMMENTS
8/12	A1-A2	235	125	28.8	38	690	25.4	5	88			50% COAL
	B1-B2	230	133		51	735		0				
8/13	A1-A2	235	125	28.8	37	710	26.2	100	91			50% COAL
	B1-B2	230	135		50	740		0				
8/15	A1-A2	230	125	28.8	36	710	25.6	280	89			50% COAL
	B1-B2	230	133		51	735		0				
8/19	A1-A2	235	123	28.9	37	615	22.8	115	79			50% COAL
	B1-B2	230	132	30.4	50	735	36.8	0				

UNIT 3 ESP

DATE (1977)	T-R SET	PRIMARY VOLTAGE (V)	PRIMARY CURRENT (A)	POWER (KW)	SECONDARY VOLTAGE (KV)	SECONDARY CURRENT (mA)	POWER (kW)	SPARK RATE (SPM)	POWER EFFICIENCY (%)	CURRENT DENSITY µA/ft²	mA/m²	COMMENTS
7/27	A1-A2	270	140	37.8	—	700	—	20	—	15.0	.161	
	A3-A4	250	110	27.5	—	530	—	—	—	11.3	.122	
	B1-B2	305	150	45.8	—	800	—	>200	—	17.1	.181	
	B3-B4	250	100	25.0	30	490	14.7	25	59	10.5	.113	
7/29	A1-A2	280	140	39.2	—	700	—	35	—	15.0	.161	
	A3-A4	250	120	30.0	—	600	—	—	—	12.8	.138	
	B1-B2	320	145	46.4	—	740	—	185	—	15.8	.170	
	B3-B4	250	100	25.0	30	480	14.4	35	58	10.3	.110	
7/30	A1-A2	265	125	33.1	—	665	—	86	—	14.2	.153	
	A3-A4	225	83	18.7	—	415	—	—	—	8.9	.095	
	B1-B2	300	148	44.4	—	750	—	>200	—	16.0	.172	
	B3-B4	235	85	20.0	31	375	11.6	45	58	8.0	.086	
8/1	A1-A2	230	128	29.4	—	670	—	85	—	14.3	.157	
	A3-A4	200	83	16.6	—	495	—	—	—	8.4	.091	
	B1-B2	285	140	39.9	—	690	—	185	—	14.7	.159	
	B3-B4	225	78	17.6	30	335	10	50	57	7.2	.077	
8/3	A1-A2	250	110	27.5	—	550	—	90	—	11.7	.126	
	A3-A4	200	75	15.0	—	370	—	—	—	7.9	.085	
	B1-B2	275	128	35.2	—	600	—	185	—	12.8	.138	
	B3-B4	230	70	16.1	30	300	9.0	58	56	6.4	.069	
8/4	A1-A2	250	120	30.0	—	675	—	83	—	14.4	.155	
	A3-A4	210	80	16.8	—	370	—	—	—	8.3	.090	
	B1-B2	280	130	36.4	—	620	—	185	—	13.2	.143	
	B3-B4	230	73	16.8	30	310	9.3	45	55	6.6	.071	

1/4

SUMMARY OF UNIT 4 ESP
OPERATING DATA JULY-AUGUST 1977
CHEROKEE STATION PUBLIC SERVICE OF COLORADO

DATE (1977)	T-R SET	PRIMARY VOLTAGE (V)	PRIMARY CURRENT (A)	POWER (KW)	SECONDARY VOLTAGE (KV)	SECONDARY CURRENT (mA)	POWER (KW)	SPARK RATE (SPM)	POWER EFFICIENCY (%)	CURRENT DENSITY mA/ft²	CURRENT DENSITY mA/m²	COMMENTS
8/6	A1-A2	270	133	35.9	–	650	–	85	–	13.9	.149	
	A3-A4	240	95	22.8	–	500	–	–	–	10.7	.115	
	B1-B2	310	150	46.5	–	800	–	125	–	17.1	.184	
	B3-B4	250	80	20.0	30	400	12	43	60	8.5	.092	
8/8	A1-A2	245	108	26.5	–	505	–	85	–	10.8	.116	
	A3-A4	200	65	13.0	–	280	–	–	–	6.0	.064	
	B1-B2	290	135	39.2	–	670	–	185	–	[illegible]	.154	
	B3-B4	213	60	12.8	31	240	7.4	45	58	5.1	.055	
8/9	A1-A2	250	115	28.8	–	475	–	90	–	10.1	.109	
	A3-A4	190	65	12.4	–	310	–	–	–	6.6	.071	
	B1-B2	280	130	36.4	–	615	–	185	–	13.1	.141	
	B3-B4	215	55	11.8	[illegible]	230	7.6	55	64	[illegible]	.053	
8/10	A1-A2	270	140	37.8	–	700	–	60	–	15.0	.161	
	A3-A4	220	78	17.2	–	375	–	–	–	8.0	.086	
	B1-B2	320	150	48.0	–	750	–	185	–	16.0	.172	
	B3-B4	250	70	17.5	36	300	10.8	35	62	6.4	.069	
8/12	A1-A2	250	120	30.0	–	675	–	90	–	14.4	.155	
	A3-A4	200	70	14.0	–	300	–	–	–	6.4	.069	
	B1-B2	280	128	35.8	–	650	–	>200	–	13.9	.149	
	B3-B4	220	60	13.2	34	240	8.2	60	62	5.1	.055	
8/15	A1-A2	260	70	18.2	–	400	–	165	–	8.5	.092	
	A3-A4	225	85	19.1	–	450	–	–	–	9.6	.103	
	B1-B2	315	120	37.8	–	580	–	20	–	12.4	.133	
	B3-B4	260	105	27.3	31	460	14.3	45	52	9.8	.106	

SUMMARY OF UNIT 4 ESP
OPERATING DATA JULY - AUGUST 1977

DATE (1977)	T-R SET	PRIMARY VOLTAGE (V)	PRIMARY CURRENT (A)	POWER (kW)	SECONDARY VOLTAGE (kV)	SECONDARY CURRENT (mA)	POWER (kW)	SPARK RATE (SPM)	POWER EFFICIENCY (%)	CURRENT DENSITY mA/ft²	CURRENT DENSITY mA/m²	COMMENTS
8/19	A1-A2	230	125	28.8	–	580	–	>200	–	12.2	.132	
	A3-A4	215	80	17.2	–	400	–	–	–	8.5	.092	
	B1-B2	280	135	37.8	–	720	–	185	–	15.0	.161	
	B3-B4	245	88	21.6	31	440	13.6	95	63	9.4	.101	
8/22	A1-A2	210	70	14.7	–	410	–	>200	–	8.8	.094	1 SECTION GROUNDED O.
	A3-A4	210	90	18.9	–	460	–	–	–	9.8	.105	
	B1-B2	270	140	38.8	–	580	–	185	–	12.4	.133	
	B3-B4	250	125	31.3	33	570	18.8	105	60	12.2	.131	
8/23	A1-A2	230	73	16.8	–	295	–	20	–	6.3	.068	1 SECT. GROUNDED OUT
	A3-A4	200	85	17.0	–	405	–	–	–	8.7	.092	
	B1-B2	270	130	35.1	–	620	–	185	–	13.2	.143	
	B3-B4	260	125	32.5	33	605	20.0	105	61	12.7	.137	
8/24	A1-A2	220	75	16.5	–	380	–	>200	–	8.1	.087	1 SECT. GROUNDED OUT
	A3-A4	200	80	16.0	–	410	–	–	–	8.8	.094	
	B1-B2	275	135	37.1	–	625	–	185	–	13.4	.141	
	B3-B4	255	115	29.3	33	610	20.1	105	69	15.0	.160	
8/25	A1-A2	235	85	20.0	–	380	–	>200	–	8.1	.087	1 SECT. GROUNDED OUT
	A3-A4	215	100	21.5	–	[illegible]	–	–	–	10.3	.110	
	B1-B2	270	130	35.1	–	630	–	180	–	12.8	.138	
	B3-B4	260	115	29.9	32	620	19.2	105	64	12.8	.138	
8/26	A1-A2	220	125	27.5	–	625	–	>200	–	13.4	.144	
	A3-A4	200	90	18.0	–	530	–	–	–	11.3	.122	
	B1-B2	255	105	26.8	–	520	–	185	–	11.1	.120	
	B3-B4	235	110	25.9	32	550	17.6	105	68	11.7	.126	

3/4

SUMMARY OF UNIT 4 ESP OPERATING DATA
JULY - AUGUST, 1977

DATE (1977)	T-R SET	PRIMARY VOLTAGE (V)	PRIMARY CURRENT (A)	POWER (KW)	SECONDARY VOLTAGE (KV)	SECONDARY CURRENT (mA)	POWER (kW)	SPARK RATE (SPM)	POWER EFFICIENCY (%)	CURRENT DENSITY mA/ft²	CURRENT DENSITY mA/m²	COMMENTS
8/28	A1-A2	235	105	24.7	–	450	–	>200	–	9.6	.103	
	A3-A4	195	95	18.5	–	410	–	–	–	8.8	.097	
	B1-B2	305	163	47.7	–	865	–	185	–	18.5	.199	
	B3-B4	230	85	19.6	29	405	11.7	105	60	8.7	.093	

SUMMARY OF UNIT 4 ESP
OPERATING DATA – JULY AUGUST 1977

APPENDIX D

ELECTROSTATIC PRECIPITATOR
STACK TEST SUMMARIES
CHEROKEE STATION
PUBLIC SERVICE COMPANY OF COLORADO

Public Service Company of Colorado
P O BOX 840 · DENVER, COLORADO 80201

October 26, 1977

OCT 26 1977

Mr. Irwin L. Dickstein
Director, Enforcement Division
U.S. Environmental Protection Agency
Region VIII
1860 Lincoln Street
Denver, Colorado 80203

Attention: Mr. Robert Gosik, NEIC

Dear Mr. Dickstein:

Subject: Request for Information,
42 U.S. 1857c-9(a)(ii)
Reference 8E-EL

Attached is our response to your request of September 29, 1977, for particulate emission information from outlet tests of the four Cherokee Station electrostatic precipitators. The attachment complies with your request to include stack test summaries identified by NEIC during the September 27 meeting.

These tests were performed using various methods to evaluate the amount of particulate emissions from the electrostatic precipitators on each of the four Cherokee units. Test results for unit number 2 represent particulate loadings entering the stack. Test results for units number 1, 3 and 4 represent inlet grain loadings to the scrubbers and do not represent stack particulate levels.

Sincerely,

George P. Green, Manager
Environmental Affairs and
Planning

ljk
attachments

cc: Mr. William Auberle, Director
Colorado Air Pollution Control Division

Environmental Protection Agency
Request for Information,
42 U.S. 1857c-9(a)(ii)
October 26, 1977

Test Date	Flow Rate ACFM	Temp. °F.	Grain Loading Inlet gr/SCF	Grain Loading Outlet gr/SCF
Precipitator - Cherokee #1				
11/4/65	528,000	300	.647	.228
11/5/65	537,000	300	.617	.303
8/25/66	508,508	300	.3702	.2132
3/15/68	517,000	287		.220
3/16/68				.317
3/18/68	532,000	303		.482
11/18/68	519,800	289		.248
11/19/68	555,800	290		.386
11/20/68	550,700	295		.318
8/24/71	549,600	299	.877	.240
8/25/71	516,600	298	.943	.314
8/26/71	515,800	285	.582	.442
8/27/71	491,600	296	.529	.403
5/6,7/76		260		.345
"		260		.333
"		260		.337

| rironmental Protection Agency
| juest for Information,
42 U.S. 1857c-9(a)(ii)
(:ober 26, 1977

Test Date	Flow Rate	Temp. °F.	Grain Loading Inlet gr/SCF	Grain Loading Outlet gr/SCF	Comments
ιιator - Cherokee #2					
ι 7/68	475,000			.0871	
6/7/68	470,000	277		.0855	Research Cottrell Test
/5/68	483,600	282		.150	Steam coil air heating leak during test.
/6/68	463,300	278		.178	
8/20/69	501,892	289	1.47	.0835	Research Cottrell Figures
: 20/69	507,000	289	1.28	.0840	PSCo Corrections to Above
/17/69			1.117	.266	Research Cottrell Tests*
12/19/69			1.1205	.2658	Research Cottrell Tests*
ι 2/70	452,000	280	.673	.125	
5/5/71	473,000	270	.8152	.0248	Research Cottrell Tests
' 5/71	473,000	270	.974	.0408	Research Cottrell Tests
' 5/71	519,000	270	1.05	.0530	Research Cottrell Tests
5/6/71	519,000	-270	.990	.0623	Research Cottrell Tests
7/71	480,600	286	.888	.0390	
10/6/72	455,000	264	.733	.0220	
4/76	513,800	292.6		.0374	
4/76	518,800	295.8		.0280	

* These tests are reported here for informational purposes only, since the accuracy of the test method used is questionable.

Environmental Protection Agency
Request for Information
42 U.S. 1857c-9(a)(ii)
October 26, 1977

Test Date	Flow Rate ACFM	Temp. °F.	Grain Loading Inlet gr/SCF	Grain Loading Outlet gr/SCF
Precipitator - Cherokee #3				
10/27/65	590,800	292		.192
10/28/65	573,600	287		.106
10/29/65	275,000	285	.246	.163*
11/1/65	289,500	303	.214	.203*
11/2/65	289,500	296	.182	.107*
2/14/68	144,200	265.5		.172*
"	637,100			.230
"	637,100			.211
2/17/68	640,000			.113
"	640,000			.120
2/7/69	142,887	291.2		.712*
12/11/69	687,500	293		.212
8/12/70	751,700	294	.327	.331
8/14/70	648,800	303	.315	.330
8/26/70			.208	.211
10/22/70	615,000	287	.368	.179
11/4/70	615,000	265	.785	.385
4/21/71	590,500			.237
5/20/71	641,300	295		.523**
5/24/71	611,100	292		.615**
5/25/71	631,700	296		.490**
5/27/71	633,000	291		.593**

* One-half of precipitator tested.

** These tests were performed without gas conditioning.

Environmental Protection Agency
Request for Information,
42 U.S. 1857c-9(a)(ii)
October 26, 1977

Test Date	Flow Rate	Temp. °F.	Grain Loading Inlet gr/SCF	Grain Loading Outlet gr/SCF
Precipitator - Cherokee #4				
11/4/69	1,421,807	272		.2067
11/5/69	1,442,966	271		.2542
1/21/70	1,390,000		.309	.167
"	1,490,000		.297	.196
1/22/70	1,490,000		.235	.170
1/23/70	1,520,000		.270	.124
1/27/70	1,530,000		.223	.114
1/29/70	1,500,000			.142
1/29/70	1,510,000			.138
1/26/71	1,340,000	275		.235
1/27/71	1,226,000	280		.223
1/28/71	1,254,000	277		.278
9/29/71	1,484,000	269		.088
10/5/71	1,570,000	279		.075
10/6/71	1,506,000	275		.113
10/8/71	1,519,000	277		.171
11/30/71	1,490,000	278		.312*
12/3/71	1,517,000	276		.405*
12/15/71	1,557,000	277		.265*
12/16/71	1,400,000	271		.332*
12/14/72	1,407,000	268		.19
12/19/72	1,436,000	271		.212
11/13/73	1,325,000	244		.167
11/15/73	1,334,000	267		.147
11/16/73	1,425,000	265		.146

* These tests were performed to evaluate the precipitator performance without gas conditioning.

APPENDIX E

CALIBRATION OF BAILEY BOLOMETER ON UNIT 2

CHEROKEE STATION

PUBLIC SERVICE COMPANY OF COLORADO

APPENDIX E

CALIBRATION OF BAILEY BOLOMETER ON UNIT No. 2

A. Opacity (O) Measurements

Reading	Screen - %	Bailey Meter - %
1	-	6
2	20	24-25
3	40	42
4	60	60.5
5	80	78
6	100	99

B. Optical Density (O.D.)

$$O.D. = -\log_{10}(1-O)$$

Reading	Screens	Bailey Meter
1	-	.027
2	.097	.119-.125
3	.222	.237
4	.398	.403
5	.699	.658
6	∞	2.000
15		

C. See Figure 16 for plot of data