DOE/MC/25137-3127
(DE93000212)
Distribution Category UC-103

Economic Evaluation Report

Topical Report

Work Performed Under Contract No.: DE-FC21-89MC25137

**For
U.S. Department of Energy
Office of Fossil Energy
Morgantown Energy Technology Center
P.O. Box 880
Morgantown, West Virginia 26507-0880**

**By
Colorado-Ute Electric Association, Inc.
P.O. Box 1149
Montrose, Colorado 81402**

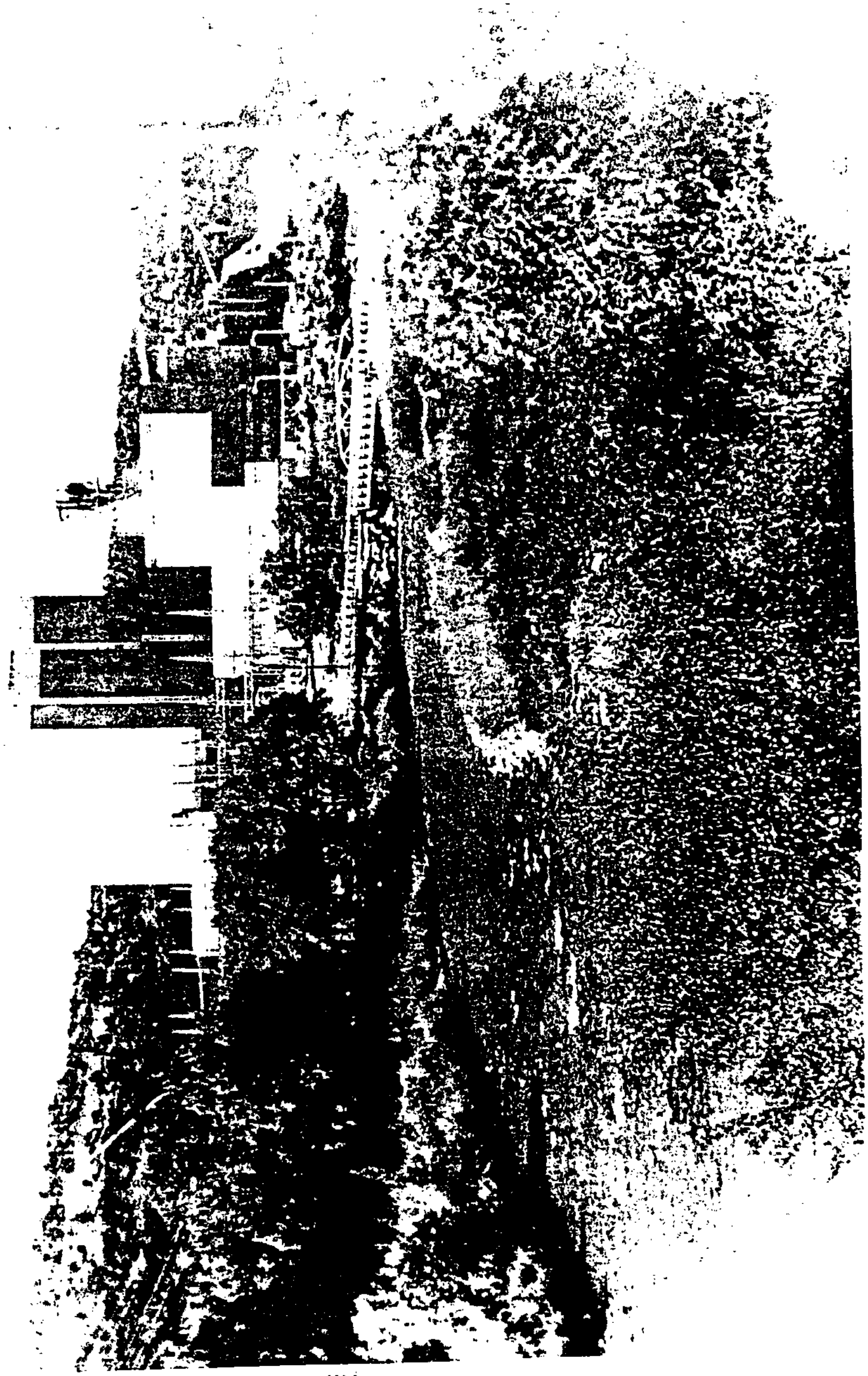
March 1992

Economic Evaluation Report

Table of Contents

Illustrations

Tables



FOREWORD

This Economic Evaluation Report on Colorado-Ute Electric Association, Inc.(CUEA) Nucla Circulating Fluidized Bed (CFB) Demonstration Project details costs for construction of the plant and for its subsequent operation from September 1988 through January 1991. This 29 month period covers the testing period of Cooperative Agreement No.DE-FC21-89MC25137 between the U.S. Department of Energy (DOE) and Colorado-Ute Electric Association, Inc.

The primary objective of this report is to provide a database of costs associated with the operation of a circulating fluidized bed boiler for electric power production. This information can be used by others evaluating this technology option for purposes of resource planning and for comparisons with competing technologies. Costs also are presented for engineering, construction and start-up of the Nucla CFB from early 1985 through August of 1987. These costs may be somewhat unique to this project due to the repowering approach taken by CUEA at the Nucla Station. In addition, the Nucla CFB represented the entrance of this technology into the U.S. utility marketplace. This, combined with the depressed nature of the power industry at the time, resulted in a relatively attractive total capital cost for the project.

Cost data associated with plant operations are presented based on the Rural Electrification Administration (REA) uniform system of accounts. This system is consistent with the Federal Energy Regulatory Commission's (FERC) methods of accounting for public utilities. The definition of terms used in compiling operations cost data for the Nucla CFB are presented in Appendix B of this report.

Final capital costs associated with the engineering, construction and start-up of the Nucla CFB were $112,329,681. This represents a cost of $1,123/net kW, which was approximately 21.9 percent over the published estimates made in 1984. Total power costs associated with operating the plant between September 1988 through January 1991 were $54,750,819 resulting in a normalized cost of power production of $63.6286/MWh. The average operating cost per month over this time period was $1,887,959. Fixed costs, including interest, taxes, insurance and depreciation, represented 61.54 percent of this total. Fuel expenses and maintenance costs accounted for 26.19 percent and 5.51 percent, respectively, of the total.

This report is divided into five sections. Section 1 presents an overview of the Nucla CFB Demonstration project and describes the purpose and manner in which this report was generated. Section 2 describes the history of the project and discusses the design of the boiler and balance-of-plant. Section 3 presents operating performance statistics for the reporting period including availabilities, capacity factors, heat rates and net plant generation. Section 4 presents capital costs for the engineering, construction and start-up of the plant and for its operation between September 1988 through January 1991. Section 5 discusses reliability issues which affected the plant availability during the reporting period. Detailed monthly and average cost data are presented in Appendices C and D.

In addition to this Economic Evaluation Report, a series of six reports have been prepared under this cooperative agreement covering details of the plant and boiler design, and results of the demonstration test program. These reports include: 1) the Detailed Public Design Report, 2) Quarterly Technical Progress Report for the Period October 1990 through January 18,1991, 3) Annual Technical Report for the Period from Start-Up through 1988, 4) Annual Technical Report for 1989, 5) Annual Technical Report for 1990 through Test Program Completion, 6) the Final Technical Report, and 7) Demonstration Program Performance Test Summary Reports.

Included in the Technical Reports are test results and information related to the following areas: cold-mode shakedown and calibration, hot-mode shakedown, plant commercial performance statistics, performance testing, unit start-up (cold, warm, and hot), load following and rates of load change (dynamic response), solids and gas mixing, heat transfer, hot cyclone performance, coal and limestone preparation and handling, ash handling system performance and operating experience, tubular air heater, baghouse operation and performance, materials monitoring, reliability monitoring, and alternate fuels testing.

These reports are a valuable resource for utilities, industrial users, and independent power producers planning new capacity and considering CFB technology as an option. The information contained in the above reports, along with the cost database presented in this Economic Evaluation Report, represent the most comprehensive and available resource of its kind in the CFB technology area.

This report was prepared by Combustion Systems Incorporated (CSI) for the Colorado-Ute Electric Association, Inc. All cost data contained in the appendices was compiled and prepared by CUEA. The following individuals from CUEA are responsible for the implementation of the DOE agreement:

Raymond E. Keith, Acting Project Manager, Business Contact
Thomas J. Heller, Technical Contact
Stuart A. Bush, Senior Engineer, Project Coordinator

Section 1

INTRODUCTION

This section gives a brief summary of the scope of the Nucla CFB project, discusses the demonstration test program and the objectives of the cooperative agreement, and describes how the Economic Evaluation Report fits into these objectives. The manner in which cost data were collected and presented is also discussed.

1.1 NUCLA CFB PROJECT BACKGROUND

CUEA's original Nucla Station was built in 1959 and consisted of three identical stoker-fired units, each rated at 12.5 MWe. Due to its reduced position on the dispatch order resulting from poor station efficiency and increased maintenance costs, the decision was made in 1984 to upgrade and repower the station with a new 925,000 lb/hr circulating fluidized bed boiler and 74 MWe turbine-generator. This followed a detailed review of existing technologies, including several bubbling and circulating fluidized bed designs.

At this time, there were several small bubbling FBC's operating in the United States, but it wasn't until 1985 that the first two industrial CFB's built by Pyropower came into commercial operation. The boiler contract for Nucla was eventually awarded to Pyropower for their proposed CFB design. Utilizing twin combustion chambers, each chamber represented a 2:1 scale-up in height and plan area from their pilot plant in Karhula, Finland.

Except for the old stoker-fired boilers, most of the equipment from the old plant, including the turbine-generator sets, was refurbished and reused bringing the total plant electrical gross output to 110 MWe. The project offered several advantages to CUEA including a station heat rate improvement of 15%, reduced fuel costs due to the inherent fuel flexibility of the CFB design, lower emissions required by New Source Performance Standards (NSPS), and life extension 30 years beyond the plant's original design.

The new CFB boiler generates 925,000 lb/h of steam at 1500 psig and 1005°F utilizing a twin combustion chamber design with a height of approximately 110 feet and a total plan area of approximately 1055 square feet. The plant was designed to burn a locally mined western bituminous coal with a high variability in fuel properties. Nominal properties for this fuel are as follows: moisture - 5.8%, volatiles - 26.9%, fixed carbon - 41.2%, ash - 26.1%, sulfur - 0.73% and heating value - 9693 Btu/lb. A more detailed discussion of the unit design and fuel properties is contained in Section 2 of this report.

Construction of the new CFB boiler began in the spring of 1985 and was completed over a two year period. First turbine roll was initiated in May 1987 and the first coal fires were achieved in June of that year. Following a start-up period which was prolonged by a two month outage from an overheat incident, acceptance tests on the design western bituminous coal were completed in October, 1988 and operational tests on a high ash (~33 wt.%) and high sulfur (~2.5 wt.%) western bituminous coals were completed the following year.

1.2 SUMMARY OF THE DEMONSTRATION TEST PROGRAM

Detailed planning for a test program was initiated by the Electric Power Research Institute (EPRI) in 1985. This included the development of test plans, resource planning, specifications and installation of additional instrumentation, data acquisition hardware and software, and specialized test equipment. Preparation for the test program commenced in February 1987 with the arrival of a permanent on-site testing staff.

In August 1988, after expressing interest in the Nucla project as part of its Clean Coal Technology Program, the U.S. Department of Energy awarded a Cooperative Agreement No.DE-FC21-89MC25137 to the Colorado-Ute Electric Association, Inc. as co-sponsors of the test program along with EPRI. This was done after careful review of the overall scope and objectives of the Nucla project to verify the DOE's criteria for demonstrating clean coal technology in new and retrofit/upgrade applications. Administration of the cooperative agreement was performed by the DOE's Morgantown Energy Technology Center (METC) located in Morgantown, West Virginia.

The objective of the DOE Cooperative Agreement was to conduct a cost-shared Clean Coal Technology Project to demonstrate the feasibility of circulating fluidized bed combustion technology and to evaluate economic, environmental, and operational benefits of CFB steam generators on a utility scale. This report addresses the economic performance of the Nucla CFB over the 29 month operating period covered by the cooperative agreement.

To address the operational and environmental benefits of the technology, a total of 72 steady-state performance tests were completed during the test program. Of these tests, 8 were conducted on a local Nucla coal and 4 on a local Dorchester coal as part of alternate fuels testing, and 60 were completed on Salt Creek coal. This latter coal was the baseline fuel used for the test program. A total of 22 tests were performed at 50% maximum continuous rating (MCR), 6 tests at 75% MCR, 2 tests at 90% MCR, and 42 tests at full load (110 MWe). Except for limestone sizing tests, which were not possible with existing plant preparation equipment, all independent process variables proposed in the original test matrix were completed.

Test results and information collected to satisfy the project's objectives have been documented in a series of test reports issued by CUEA as part of the DOE Cooperative Agreement. These reports include a Final Report summarizing results over the duration of the test program, three Annual Technical Reports covering the period from unit start-up through 1988, 1989, and 1990 through test completion, one Quarterly Technical Progress Report for the period from October 1990 through January 1991, and a Summary Report of all of the performance test data. The information in these reports are broken down into various study plan areas which include cold-mode shakedown and calibration, hot-mode shakedown, plant commercial performance statistics, performance testing, unit start-up (cold, warm, and hot), load following and rates of load change (dynamic response), solids and gas mixing, heat transfer, hot cyclone performance, coal and limestone preparation and handling, ash handling system performance and operating experience, tubular air heater, baghouse operation and performance, materials monitoring, reliability monitoring, and alternate fuels testing.

1.3 SUMMARY OF THE ECONOMIC REPORT

The objective of this report is to establish a database of costs associated with operating a circulating fluidized bed boiler for electric power production in a utility environment. Such data and information can be used by others for resource planning and for comparisons with competing technologies. Costs are also presented for the engineering, construction and start-up of the Nucla CFB. These are compared with estimates made in 1984 prior to completing detailed engineering.

Detailed monthly operating costs over the testing period covered by the Cooperative Agreement, from September 1988 through January 1991, are presented in Appendix D. An overall summary of cost data for this period is presented in the same format in Appendix C. These data were generated by CUEA using reporting requirements established by the Rural Electrification Administration's Uniform System of Accounts. This accounting system is consistent with that used by the Federal Energy Regulatory Commission's Uniform System of Accounts, which is prescribed for public utilities and licensees subject to the provisions of the Federal Power Act. The definitions of terms used in the REA.code of accounts are contained in Appendix B.

To fulfill REA reporting requirements for research and development facilities, CUEA submits the top portion of REA Form 12d, shown in Appendix A, for each month of unit operation. The remainder of Form 12d groups the detailed costs contained in Appendix D into major cost categories. These include operations expenses which consist of fuel expenses (coal and propane), non-fuel expenses (steam, electric, miscellaneous steam power expenses and rents, and costs associated with supervision and engineering), maintenance expenses (supervision and engineering, structures, boiler plant, electric plant and miscellaneous plant). For total power costs, total fixed costs (depreciation, taxes, interest and insurance) are added to total production expenses. CUEA has completed the remainder of Form 12d for each month of unit operation to satisfy internal accounting practices and requirements of the Cooperative Agreement.

Detailed costs in Appendix D form the back-up for completing the major cost categories in REA Form 12d. For example, steam expense, shown on line 7 of Form 12d under non-fuel expenses, is subdivided in Appendix D into boiler operation, pulverizer operation, on-site ash handling, stack monitoring, boiler water treatment, waste water management, National Pollution Discharge Elimination System (NPDES) permitting and testing, environmental auditing, laboratory operation, miscellaneous and special services, baghouse operations, and SO_2 removal. The subcategories in Appendix D for the other major line item expenses on Form 12d are summarized in Section 4.2. In addition, the costs in Appendix D are further subdivided into direct labor, labor overhead, supplies, travel and transportation, meals, consultants, outside services, and other costs by internal CUEA accounting practices.

Costs in Appendix C and Appendix D are also listed on a cost per megawatt-hour basis. This is based on the monthly and total net generation for the reporting period from September 1988 through January 1991. These values are summarized in Table 3-1 of Section 3 and are listed for each month in Appendix D.

Section 4 of this report presents monthly operating costs for the reporting period based on the major category listings in the REA Form 12d. Total costs are shown for each month of operation in tabular form and with line graphs. Total costs over the entire reporting period for each major and minor category are presented in tabular form along with costs per megawatt-hour, average costs per month, and percentages of total power cost. Pie charts are used where appropriate to visually represent these percentages. Total monthly costs and costs per megawatt hour are also plotted as a function of the net plant capacity factor. These data are also shown in tabular form.

Specific costs associated with limestone, used by the process for SO_2 control, are highlighted in Section 4. Also presented in more detail are costs associated with ash disposal. These costs differ somewhat from a pulverized coal plant due to differences in the nature and quantity of the waste product produced.

Capital costs associated with engineering, construction and start-up of the Nucla CFB are presented in Section 4.1. These costs are divided into the following major category headings: 1) boiler, 2) turbine-generator, 3) architect/engineer, 4) earthwork, 5) concrete, 6) structural and architectural, 7) mechanical equipment, 8) piping, 9) instrumentation and controls, 10) electrical equipment, 11) painting, 12) demolition, relocation and modification, 13) field distributables and contractor home office, 14) CUEA engineering for start-up and construction management, 15) allowance for funds during construction, 16) accumulated interest, taxes, and insurance, 17) book value of old plant, and 18) project participation. Costs are compared to published estimates made in 1984 prior to completing detailed engineering for the repowered station. Causes for cost overruns in some of the above categories are also presented.

Section 4.3 lists unit costs for coal, limestone and ash removal, tabulates monthly and total quantities of coal and limestone consumed and ash generated. It also shows a breakdown of staffing requirements of the plant over the course of the test program. This information can be used by others to adjust costs of labor, fuel, limestone and ash disposal for other applications and situations where CFB technology is used. These may include differences in fuels (higher or lower sulfur and ash contents), in ash disposal requirements, and in staffing philosophies.

Section 2

PROJECT OVERVIEW

2.1 PROJECT ORIGINS

The Nucla Circulating Fluidized Bed Demonstration Project's origins began in 1982. At that time, Colorado-Ute Electric Association, Incorporated began a study to evaluate options for upgrading and extending the life of the Nucla Power Station. Located in southwestern Colorado near the town of Nucla (see Figure 2-1), this station was commissioned in 1959 with a local bituminous coal as the design fuel for three identical 12.5 MWe stoker-fired units. Due to poor station efficiency, high fuel costs, and spiraling maintenance costs, the Nucla Station was forced into a low priority in the CUEA dispatch order during the beginning of the 1980's.

Among the options considered by CUEA was using the site as a host for the demonstration of Atmospheric Fluidized Bed Combustion (AFBC) technology. The anticipated low environmental impact and attractive economics of a circulating AFBC led to CUEA's decision to proceed with the design and construction of a demonstration project in 1984 at the Nucla facility.

Studies produced by CUEA in 1983 and 1984 indicated that the new circulating AFBC boiler technology would provide the following benefits:

- Increase plant capacity from 36 MWe gross to 110 MWe gross for an investment of approximately $840/kW.
- Improve the station heat rate by approximately 15%.
- Reduce fuel costs (approximately 30%) by burning a local, lower quality fuel.
- Reduce emissions to the point where anticipated New Source Performance Standards for SO_2 and NO_x could be met.
- Extend the plant operating life by approximately 30 years.

The decision to proceed with the demonstration project was based on many factors. Among these were two boiler design studies conducted by Combustion Engineering/Lurgi and Pyropower Corporation in late 1983. These design studies for a circulating AFBC retrofit of the Nucla Station were

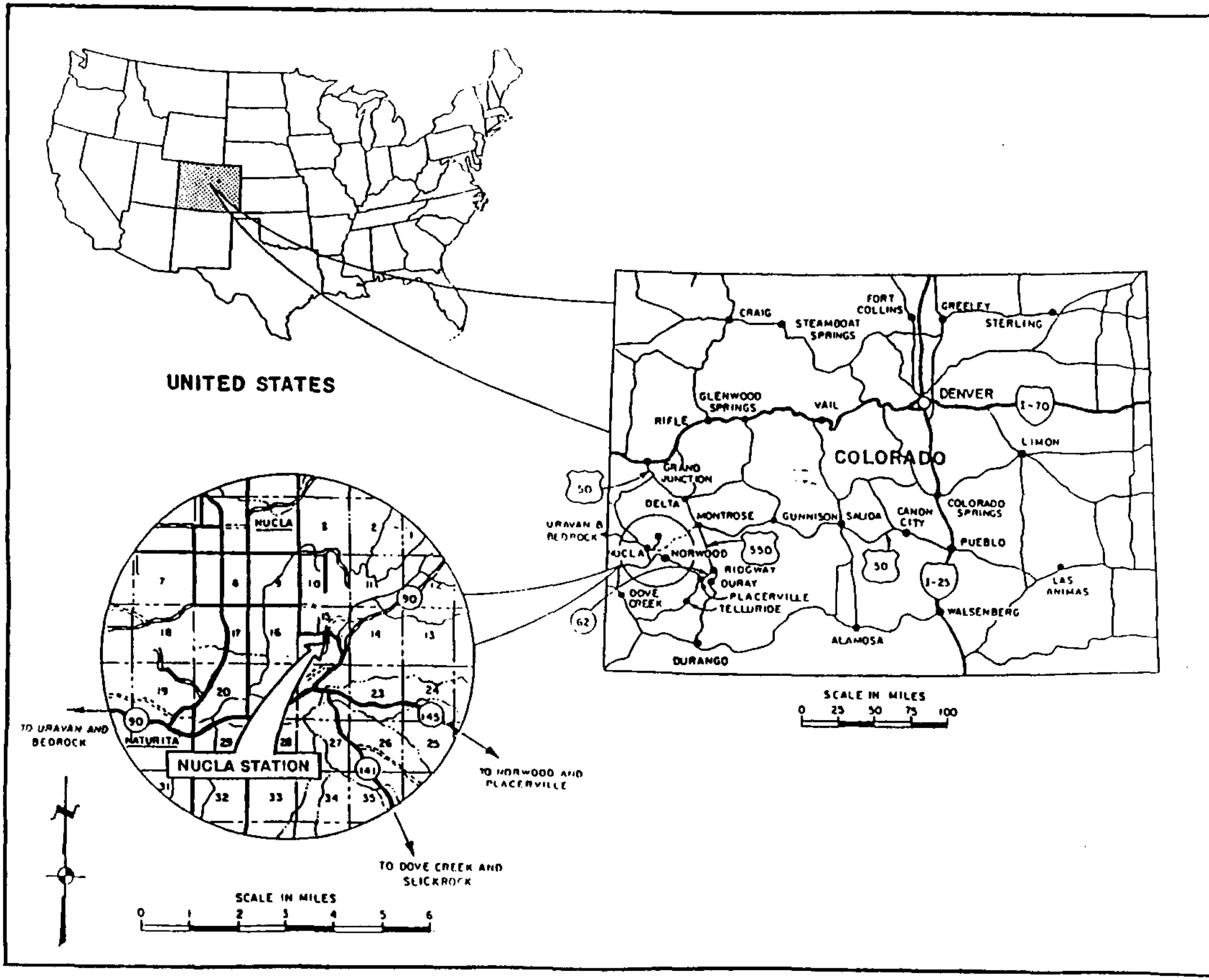


Figure 2-1. Location of CUEA's Nucla Station.

sponsored by the Electric Power Research Institute (EPRI). In the evaluation, CUEA completed the following:

- Reviewed the design, back-up data, and experience base cited by the manufacturers.
- Identified areas of possible technical risk.
- Identified design studies and test programs that could mitigate these risks.
- Developed fall-back designs in the event that selected designs did not perform as predicted.
- Assessed the risks to the utility.
- Developed a strategy for negotiating with the equipment suppliers and others.

CUEA judged that Pyropower's proposal had a lower combined capital and life cycle cost, and therefore awarded them the Nucla Station circulating AFBC boiler contract. Tests of the local Nucla coal and limestone at Ahlstrom's (Pyropower is a subsidiary of Ahlstrom) small scale pilot circulating AFBC plant in Finland produced results that enabled further refinement of the design for the boiler and auxiliary equipment.

To reduce the potential technical risks assumed by CUEA in this first utility-sized circulating AFBC demonstration in the United States, the following were negotiated:

- The various equipment vendors and the architect/engineer of the project agreed to postpone payments until the unit was operational.
- The Electric Power Research Institute funded a two-year test program to characterize performance of the plant, and assumed the risk for noneconomical operation during that same period.

In 1984, the National Rural Utilities Cooperative Finance Corporation (CFC) approved a loan for the total project cost of $87 million. Regarding permits and licensing, the Rural Electrification Administration gave approval on the basis of the borrower's environmental report in a relatively short time period. This was possible because an environmental impact statement was not required.

Construction of the new circulating AFBC boiler began in the spring of 1985 and was completed over a two year period. First turbine roll was initiated in May 1987 and first coal fires were achieved in June of that year. Following a one year start-up and shakedown period, acceptance tests on the local design bituminous coal were performed in October 1988, and operational tests with a high ash (~ 33 wt.%) and high sulfur (~1.5 wt.%) coals were completed the following year.

2.2 PLANT AND EQUIPMENT OVERVIEW

The Nucla Circulating AFBC demonstration project consisted of in-place retirement of the three stoker-fired boilers and replacement with a new circulating AFBC boiler and balance-of-plant equipment to increase the station's gross generating capacity from 36 MWe to 110 MWe. The original station is shown in Figure 2-2. Construction of the new boiler began in 1985. The completed boiler house superstructure is shown in Figure 2-3. The completed plant is shown in Figure 2-4. A simplified overall plant layout diagram is presented in Figure 2-5.

The new circulating AFBC boiler generates 925,000 lb/h of steam at 1510 psig and 1005 °F, utilizing a twin combustion chamber design with a height of approximately 110 feet and a total plan area of 1055 square feet. During design stages, the twin chamber arrangement allowed for a safer 2:1 scale-up from earlier industrial designs. This represented a significant scaling step in the use of this technology. As mentioned, the scale-up did not appear to compromise the benefits of lowered capital costs and improved environmental performance when compared to other generation technologies.

The two combustion chambers have individual systems for fuel, air, and sorbent supply and ash removal. Because both chambers share a common steam/water circuit and steam drum, independent firing is not possible. Coal is gravity fed at two locations along the front wall and to the recycle loop seal return leg along the rear wall of each chamber. Limestone is pneumatically conveyed in the vicinity of the coal feed points along the front and rear walls and to a single location along the side wall of each chamber.

Figure 2-6 is a general arrangement side view of the combustion chambers, cyclone separator, convection pass, and tubular air heater. Each combustion chamber is equipped with four panels of wrap-around, radiant superheater surface along three walls in the upper furnace section. The cyclones are approximately 23 feet in diameter and are refractory lined with a combined 1 foot layer of insulating and abrasion resistant refractory surface. The outlets of the cyclones join together and enter a common convection pass. Captured solids are recycled to the combustion chambers through loop seals located near the bottom of each chamber. Flue gas flows through a common convection pass, tubular air heater, shake/deflate type baghouses (three from the original stoker-fired units and a fourth new baghouse), and induced draft fan to the stack.

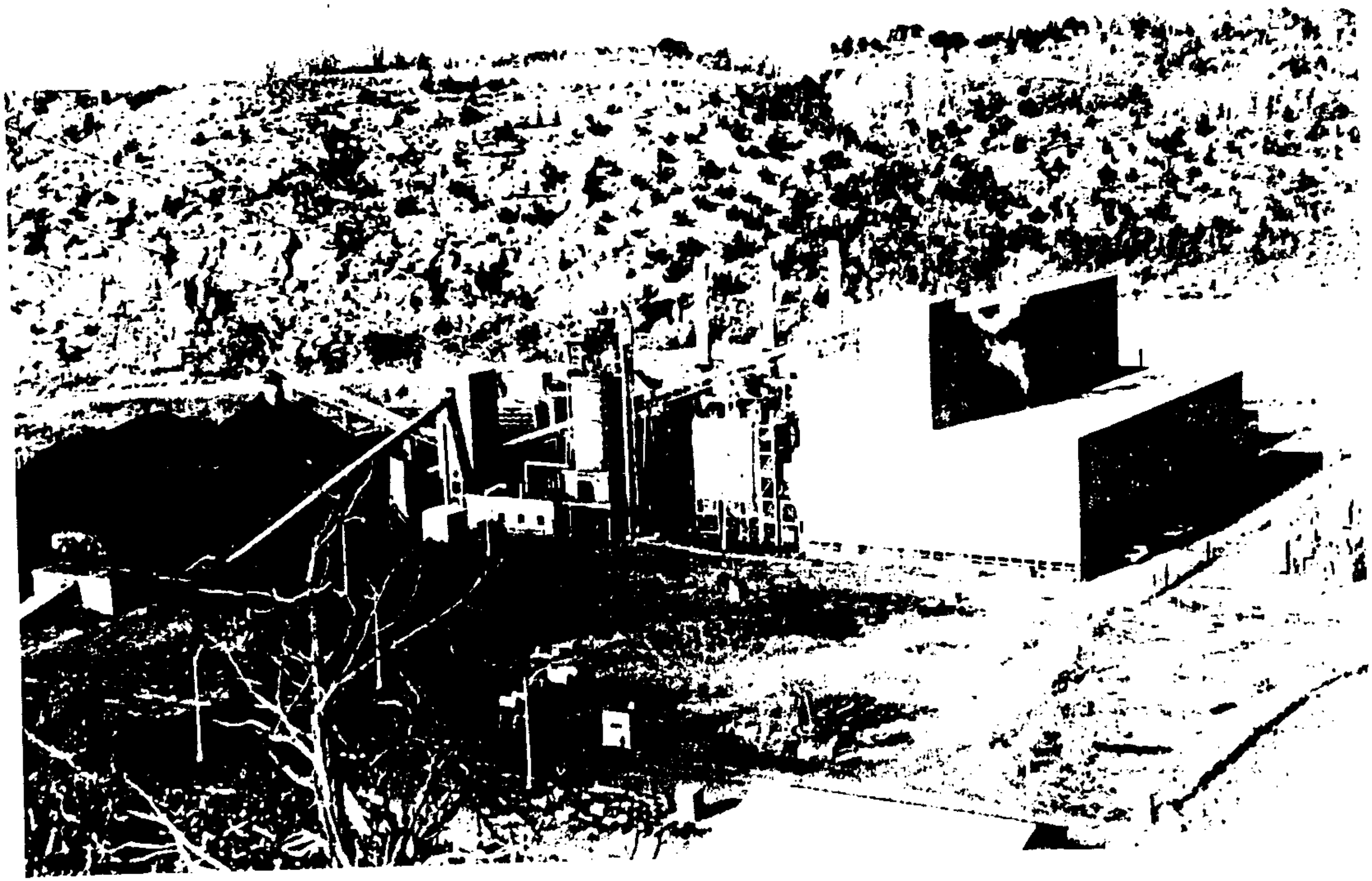


Figure 2-2. Original 36 MWe Nucla Station.

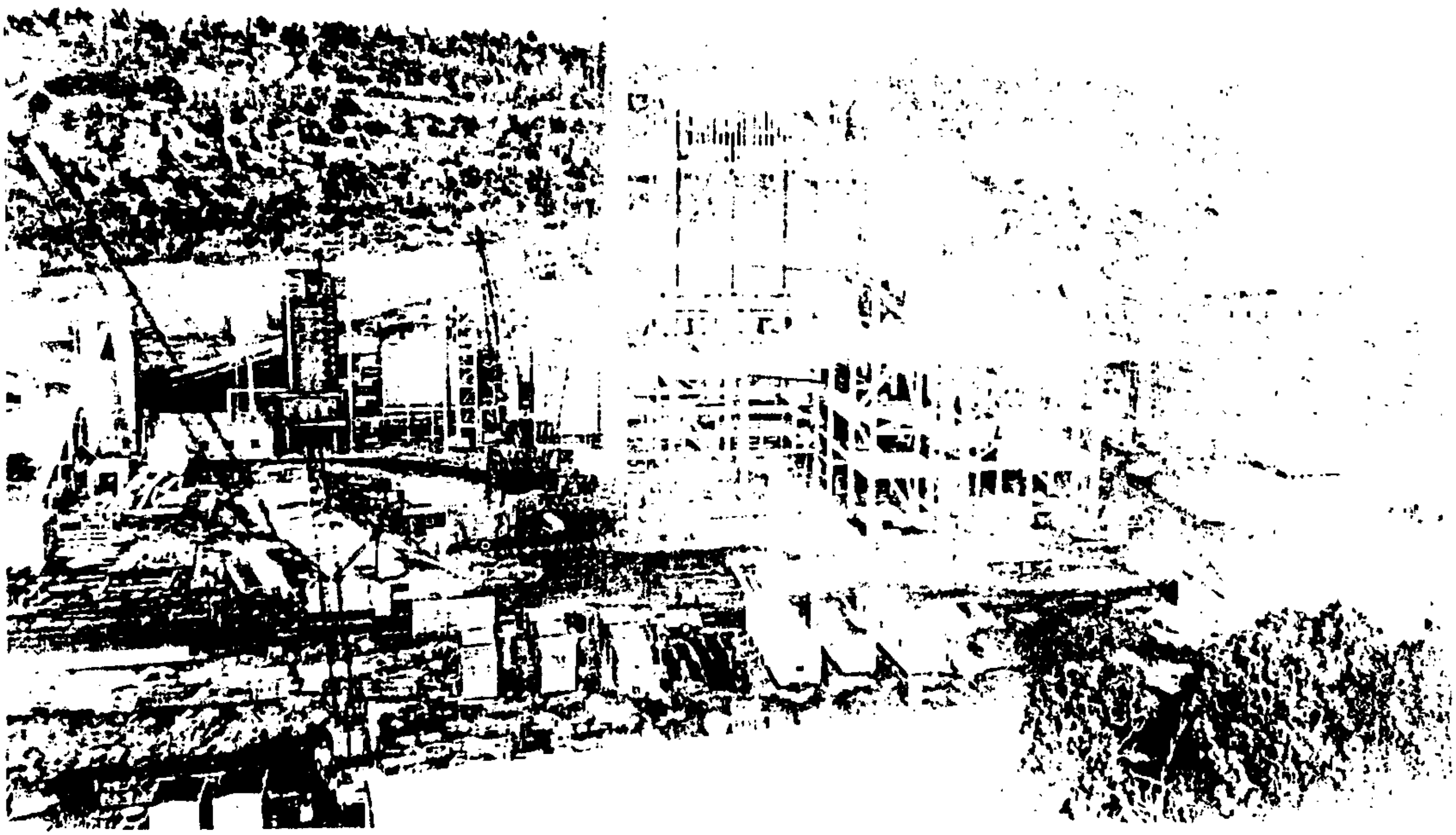
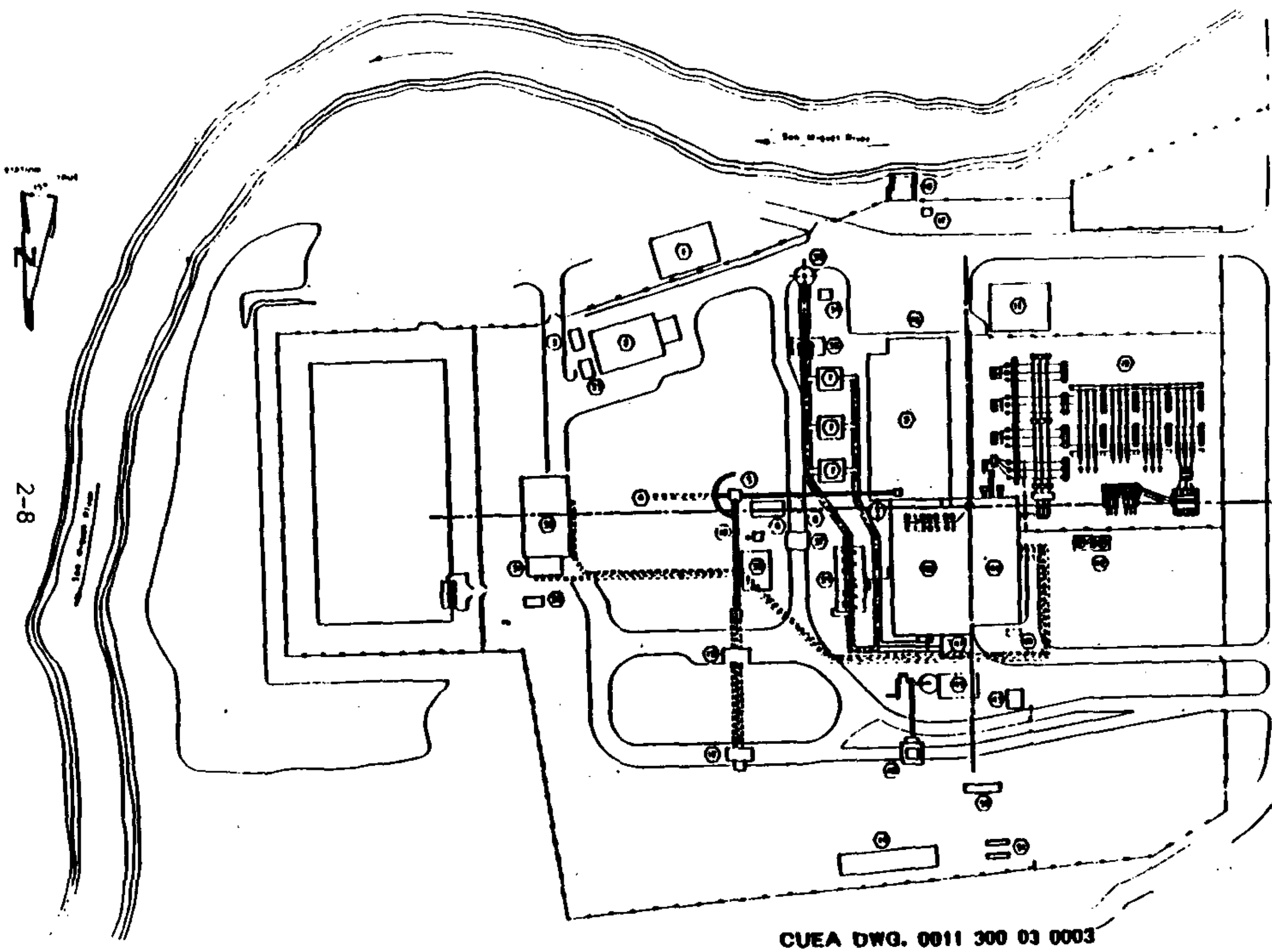


Figure 2-3. Construction of the New 110 MWe CFB Boiler.

Figure 2-4. Completed 110 MWe Nucla Station with CFB Boiler.



Existing Equipment/Buildings

1. Absorption Field
2. Cooling Tower
3. Acid Tank (Relocated)
4. Reclaiming Hopper
5. Transfer House
6. Ash Blower Building
7. Baghouses
8. Ash Silo
9. Power Plant Building
10. Intake Structure
11. Construction Office
12. Coal Truck Hopper & Primary Crusher
13. Secondary Crusher
14. Warehouses
15. Substation
16. Coal Handling System Electrical Building
17. Chlorine Building
18. (Deleted)

New Equipment/Buildings

30. Cooling Tower
31. Circulating Water Pump Pit
32. Cooling Tower Electrical Building
33. Cooling Tower Chemical Building
34. Stack Monitoring Equipment
35. Stack
36. I.D. Fan
37. Ash Silo
38. Ash Blower Building
39. Baghouse
40. CFB Building
41. T.G. Building
42. Lube Oil Storage
43. H_2 & CO_2 Storage
44. Septic Tank
45. Limestone Preparation Facility
46. (Deleted)
47. VSD Transformers and Reactors
48. Limestone Truck Hopper & Primary Crusher
49. First Aid Unit
50. Propane Storage Tank
51. Propane Vaporizers

Figure 2-5. Overall Plant Layout Diagram of the Nucla Station Including the New CFB Boiler.

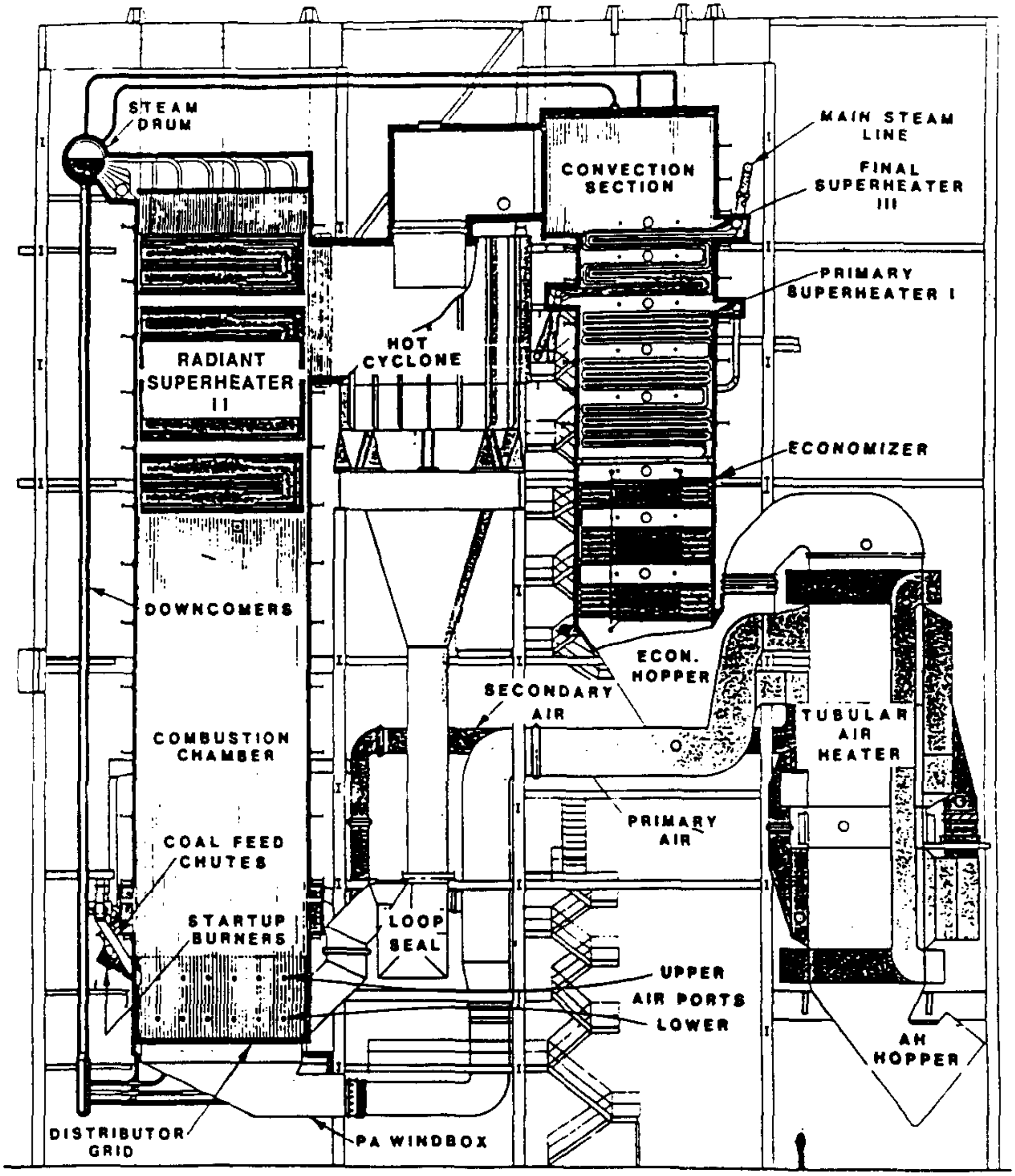


Figure 2-6. Side View of 110 MWe Nucla CFB Boiler.
(Source: Pyropower Corporation)

Extensive use of existing equipment was made during the plant modifications. This includes the coal receiving, preparation and storage equipment, baghouses, feed water systems, condensers, and the three 12.5 MWe turbine generators. Extraction steam from a new 74 MWe turbine is used to supply the existing 610 psig turbines. The three old stoker units, including their feed and draft systems and high pressure feed water heaters, represent the major equipment items retired for the upgrade. A summary of the new and refurbished/reused equipment items used on the project are listed below. A simplified schematic of the entire Nucla Plant arrangement is shown in Figure 2-7.

1. Boiler pressure parts consist of membrane wall construction. These include the water-cooled primary air distributor, combustion chambers and convection section. Also included in the design are superheater sections (including radiant sections located in the upper freeboard regions of the combustors), economizer, steam drum and downcomers, desuperheaters (attemperators), and boiler interconnecting piping.

2. Variable speed controlled primary air, secondary air, and induced draft fans.

3. Bed ash removal and cooling equipment including four fluid bed cooler/classifiers, four rotary airlock valves, two water-cooled screw conveyors, and an ash cooling fan.

4. Coal feed equipment including six gravimetric feeders and six rotary airlock valves.

5. Limestone feed equipment including two gravimetric feeders, eight rotary airlock valves, and eight pneumatic transport systems and lines from the gravimetric feeders to the combustion chambers.

6. Bed recycle equipment including refractory lined hot cyclones and loop seals, and two high pressure blowers for fluidizing air (one blower is a back-up).

7. Six in-bed startup burners and two duct burners.

8. Tubular air heater with clean air on the shell side and hot flue gas on the tube side.

9. Miscellaneous boiler items, including insulation, lagging, casing, sootblowers, and boiler vent and drain equipment.

10. New limestone receiving, storage, preparation and conveying equipment from the preparation area outside

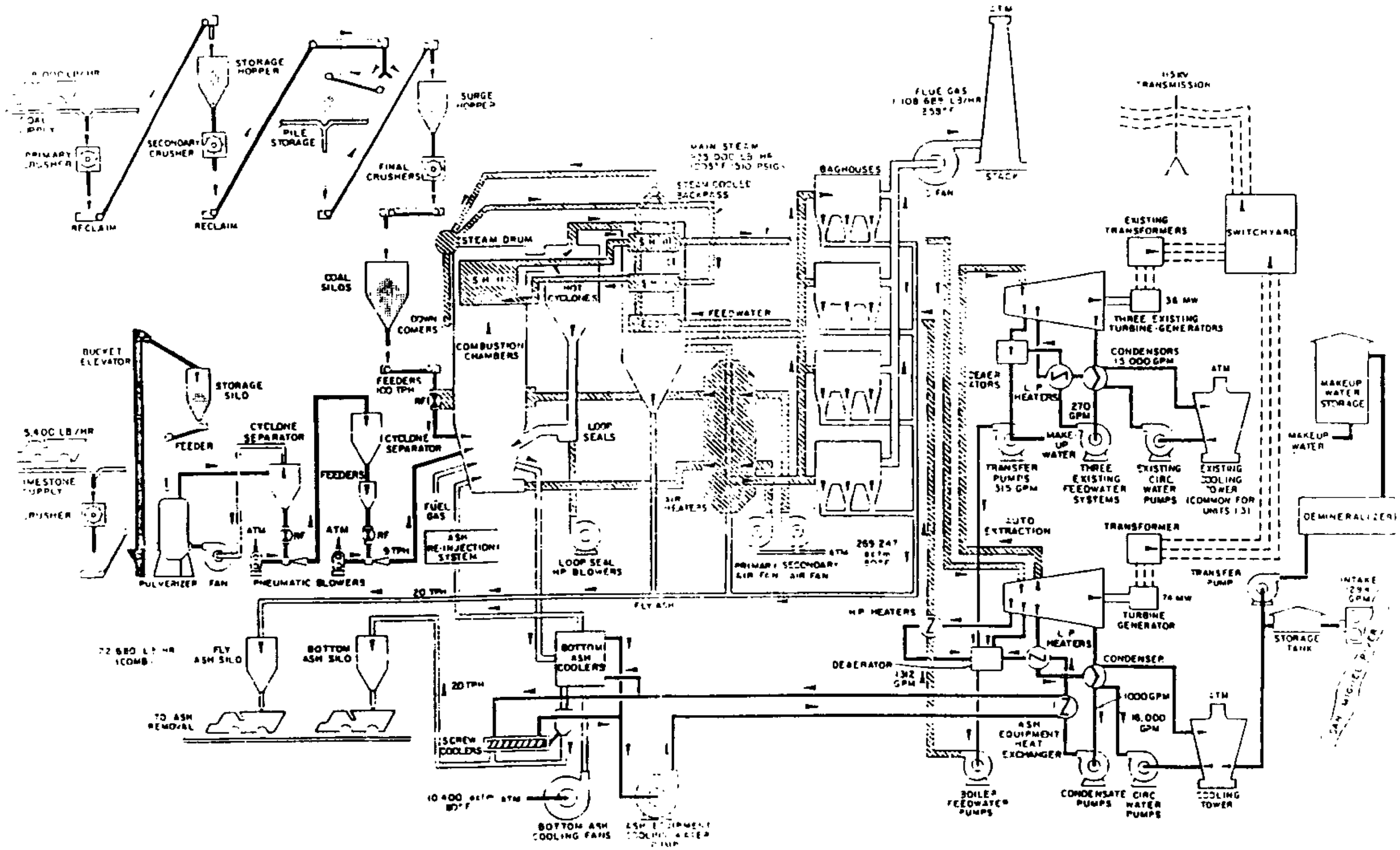


Figure 2-7. Simplified Schematic of Nucla Plant Arrangement.

the boiler building to the in-plant storage silos located above the gravimetric feeders.

11. A new steel stack.

12. A refurbished plant coal handling system and new coal handling equipment to prepare and deliver coal to the two day silos located inside the boiler building.

13. Three refurbished baghouses and a new baghouse, all of which operate in parallel and remove particulate matter from the flue gas stream of the new AFBC boiler.

14. Refurbished, modified, and new equipment combinations on the bottom ash and fly ash handling and storage equipment.

15. The original three 12.5 MWe turbine-generators now operate off of a new 74 MWe single automatic extraction turbine-generator.

16. Piping systems have been added for main steam, extraction steam (including a controlled extraction line from the new turbine to the three existing 12.5 MWe turbines), and auxiliary steam.

17. New high pressure feed water cycle equipment has been added including boiler feed pumps and high pressure feed water heaters.

18. One refurbished and one new plant circulating water cooling system have been added, each consisting of a mechanical draft evaporative cooling tower and circulating water pumps.

19. Refurbished and new low pressure feed water cycle equipment have been added for each turbine-generator unit. This includes condensers, condensate hotwell pumps, low pressure feed water heaters, deaerators, and new condensate forwarding pumps.

20. Refurbished and new plant water systems have been added including a new boiler make-up demineralizer system.

21. Refurbished and new miscellaneous mechanical equipment has been added including heating, ventilating and air conditioning (HVAC) equipment, air compressors, fire protection system, and new propane system.

22. Plant instruments and controls have been added on the new boiler system including a new plant distributed digital control system.

23. Plant electrical equipment and systems.

A summary of the major equipment specifications for the Nucla CFB is shown in Table 2-1. The list includes the new CFB boiler, fans, baghouses, ash handling facilities, new 74 MWe turbine generator, existing three 12.5 MWe turbine generators, condenser, boiler feed pumps, feed water heaters, and deaerator. Full-load performance parameters are summarized in Table 2-2.

The plant was designed to burn a locally mined western bituminous coal with a high variability in ash, heating value, moisture, and sulfur content. Table 2-3 summarizes the properties of this coal and the ranges of values burned. The coal supply was changed in the summer of 1989 to take advantage of a more economical fuel supply. The new coal, Salt Creek, is also a western bituminous coal, but is more homogeneous and has less ash than the design coal. The properties of Salt Creek coal are also listed in Table 2-3. The state emission regulations are compatible with the New Source Performance Standards for this size unit and are shown in Table 2-4. Supplemental NO_x control schemes were not required to meet these standards. SO_2 emissions are controlled with limestone addition to the lower region of the combustion chambers.

Table 2-3. Properties of Peabody and Salt Creek Coals

	Peabody	Salt Creek
Heating Value, Btu/lb	7,490-11,840	10,460
Sulfur, wt %	0.51-2.75	0.44
Ash, wt %	9.8-42.8	14.6
Moisture, wt %	4.1-14.9	10.0
Fixed Carbon (acceptance test value)	43.5	43.4
Volatiles, wt % (acceptance test value)	28.4	32.3

Table 2-4. Nucla Plant Emission Requirements

Particulates	0.03 lb/MBtu
NO_x	0.5 lb/MBtu
SO_2	0.4 lb/MBtu
CO	No Requirements

2.3 THE DEMONSTRATION TEST PROGRAM

Because of the potential offered by the use and commercialization of circulating AFBC technology to the electric power industry, CUEA and EPRI initiated a test program to study the Nucla circulating AFBC boiler and its

Table 2-1. Summary of Equipment Specifications

Boiler	
- Manufacturer	Pyropower Corporation
- Type	Dual combustion chamber, circulating fluidized bed combustor
- Steam flow, lb/h at MCR	925,000
- Superheater outlet pressure, psig	1,510
- Superheater outlet temperature, °F	1,005
- Combustion rate, Btu/h * 10^6	1,128.3
- Coal consumption, ton/h	58.2
- Number of coal feeders	6
- Limestone consumption, ton/h	2.2
- Number of limestone feeders	1 per combustor
- Number of limestone feed points	4 per combustor
Primary Air Fan	
- Manufacturer	American Davidson
- Capacity, 1000 acfm at boiler rating	213.9
- Drive	
Type	Adjustable frequency synchronous motor
HP	3,500
Manufacturer	Westinghouse
Induced Draft Fan	
- Manufacturer	American Davidson
- Capacity, 1000 acfm at boiler rating	447.8
- Drive	
Type	Adjustable frequency synchronous motor
HP	3,250
Manufacturer	Westinghouse
Secondary Air Fan	
- Manufacturer	American Davidson
- Capacity, 1000 acfm at boiler rating	66.1
- Drive	
Type	Adjustable frequency synchronous motor
HP	700
Manufacturer	Westinghouse

Table 2-1. Summary of Equipment Specifications (continued)

Baghouses	
- Three existing baghouses (50% of total flue gas flow)	Wheelabrator-Frye
- One new baghouse (50% of flow)	Research-Cottrell
- Effluent particulate loading	0.03 lb/10^6 Btu
Fly Ash Handling Facilities	
- Manufacturer	United Conveyor on all new equipment. Allen-Sherman-Hoff on existing equipment.
- Type	Vacuum pneumatic
- Capacity, ton/h	30
- Silo Storage, cu. ft.	60,000
Bottom Ash Handling Facilities	
- Manufacturer	United Conveyor on all new equipment. Allen-Sherman-Hoff on existing equipment.
- Type	Vacuum pneumatic
- Capacity, ton/h	20
- Silo Storage	10,940
New Turbine Generator	
- Manufacturer	Westinghouse
- Type	Single casing, auto-extraction, condensing
- Continuous Output, MWe with full extraction	74 MWe
- Throttle Steam Flow, lb/h with full extraction	925,000
- Generator continuous, kVA	88,200
- Extraction Steam Pressure, psig	625
- Extraction Steam Temperature, °F	800
Existing Turbine Generators 1,2,3	
- Manufacturer	Delaval
- Output, MWe each	12.6
- Steam source	Unit 4 extraction
- Throttle steam flow, lb/h each	123,000

Table 2-1. Summary of Equipment Specifications (continued)

Condenser	
- Manufacturer	Southwestern
- Surface Area, 1000 sq.ft.	45.7
- Number of water passes	2
- Air removal equipment	Steam jet air ejector
Boiler Feed Pumps	
- Manufacturer	Byron Jackson
- Number	2
- Capacity of each, gpm	1,312
- Total head developed, ft	4,368
- Drive	
Type	Motor
HP of each	1,750
Manufacturer	Westinghouse
Feedwater Heaters	
- Manufacturer	Southwestern
- Number of closed heaters, HP/LP	2/2
- Final feedwater temperature, °F	439
Deaerator	
- Manufacturer	Graver
- Number	1
- Type	Direct Contact

(Source: Detailed Public Design Report)

Table 2-2. Full-Load Boiler Performance Summary

• Superheater outlet	
- Steam flow	925,000 lb/h
- Steam temperature	1005 ± 10 °F
- Steam pressure	1510 psig
• Boiler Design Pressure	1760 psig
• Sootblowing Steam	
- Flow	27,000 lb/h
- Pressure	1610 psig
- Temperature	801 °F
• Fuel Input	
- Design Coal A	116,400 lb/h
- Design Coal B	143,200 lb/h
• Drum Pressure	1655 psig
• Economizer	
- Inlet pressure	1689 psig
- Inlet temperature	440 °F
- Outlet temperature	536 °F
• Excess Air	20%
• Primary Air Temperature	374 °F
• Secondary Air Temperature	363 °F
• Flue Gas Flow	1,103.7 klb/h
• Heat Release	1,128 MBtu/h
• Boiler Efficiency	88.27%
• Flue Gas Temperatures	
- Leaving combustors	1600 °F
- Leaving air heater	258 °F
• Boiler Emission Limits	
- Particulates	0.03 lb/MBtu
- NOx	0.5 lb/MBtu
- SO_2	0.4 lb/MBtu

(Source: Detailed Public Design Report).

operating characteristics. The test program was conducted in conjunction with two other EPRI-sponsored AFBC demonstration projects: Northern States Power Company's bubbling 130 MWe Black Dog conversion project and Tennessee Valley Authority's bubbling 160 MWe Shawnee repowering project.

Detailed planning for a test program was initiated by EPRI in 1985. Test plans were developed to accommodate data collection in seventeen topical areas. During the construction phase of the new boiler, EPRI installed special hardware for the test program including instrumentation, data acquisition and processing equipment, and solids sampling and preparation equipment necessary for the two year test program. On-site preparation for the test program commenced in February 1987 with the arrival of the permanent testing staff.

Through the third quarter of 1988, the Cold-Mode Shakedown Plan was implemented. This involved calibrating instruments,commissioning the data acquisition system, developing specialized software, procuring and commissioning equipment for the solids preparation laboratory and other specialized test instrumentation, developing procedures, and training test personnel. This work was largely completed by October 1988. Also during this period and through the remainder of the test program, data were collected to satisfy the requirements of the topical test plans.

In August 1988, after expressing interest in the Nucla project as part of its Clean Coal Technology Program, the U.S. Department of Energy awarded a Cooperative Agreement No.DE-FC21-89MC25137 to CUEA as co-sponsors of the Demonstration Project. This was after careful review of the overall scope and objectives of the Nucla project to verify the DOE's criteria for demonstrating clean coal technology in new and retrofit/upgrade applications. The primary objective of this Cooperative Agreement was to conduct a cost shared clean coal technology project to demonstrate the feasibility of circulating AFBC technology and to evaluate the economic, environmental, and operational benefits on a utility scale. The Cooperative Agreement was administered by DOE's Morgantown Energy Technology Center located in Morgantown, West Virginia.

Phase I of the demonstration test program began in February 1987 and was completed in June 1990. This segment of the test program was jointly sponsored by EPRI and the DOE. Phase II of the test program commenced at the conclusion of this period and was completed in January 1991 with sole sponsorship by the DOE. The database and information generated during these two phases represents the most comprehensive and available resource of its kind in the circulating AFBC technology area. The information has been compiled into a series of reports prepared by CUEA for the

DOE as part of the Cooperative Agreement. These reports include:

1. Detailed Public Design Report

2. Quarterly Technical Progress Report: covering period from October 1990 through December 1990.

3. Annual Technical Progress Report: Start-up through 1988

4. Annual Technical Progress Report: 1989

5. Annual Technical Progress Report: 1990 through Test Completion

6. Final Technical Report: August 1986 through January 1991

7. Economic Evaluation Report

8. Demonstration Program Performance Test Summary Reports

The information and data presented in this report satisfies the Economic Evaluation Report listed as item 6 above.

Section 3

PLANT OPERATIONAL STATISTICS

3.1 SUMMARY

This section summarizes plant operational statistics for the period from September 1988 through the conclusion of the Phase II test program in January 1991. This interval coincides with the monthly economic data presented in this report. Monthly operational statistics are presented in order to equate the various plant operating costs with factors such as operating availability, equivalent availability, capacity factor, net plant heat rate and net generation. For example, monthly fuel costs will increase along with the monthly capacity factor.

Table 3-1 shows the monthly plant commercial performance statistics including operating availability, equivalent availability, capacity factor, net plant heat rate and net generation. These items are also shown graphically in Figures 3-1 through 3-5. Detailed monthly operating statistics are presented in the Annual Technical Progress Reports (Start-up through 1988, 1989, and 1990 through Test Completion) and in the Final Technical Report covering the period from start-up in 1987 through test completion in 1991. Section 3.2 presents the definitions used in determining these statistics.

During the 1988-1991 period, the average operating availability was 60.1%, equivalent availability was 56.5%, capacity factor was 40.6%, and net plant heat rate was 12,055 Btu/NkWh. The highest operating availability of 97.9% was achieved in December 1990. The highest unit capacity factor of 85.7% was achieved in November 1990. The lowest average on-line net plant heat rate of 11,102 Btu/NkWh was achieved in January 1991. The lower values for operating availabilities (less than 50%) shown in Figure 3-1 were the result of forced and planned outages that are described below. Equivalent availabilities and capacity factors shown in Figures 3-2 and 3-3 are correspondingly low for these periods.

- September 1988. Planned outage from August 11 through September 16, 1988 to upgrade the bottom ash transport system and to replace bubble cap retaining washers in the lower combustion chambers, ash coolers, and loop seals.

Month	Operating Avail. (%)	Equivalent Avail. (%)	Capacity Factor (%)	Heat Rate (Btu/NkWh)	Net Gen. (MWh)
Sep-88	23.5	na	12.6	12,427	9,895
Oct-88	68.1	na	47.6	12,168	34,989
Nov-88	78.9	na	48.5	11,673	34,284
Dec-88	81.6	na	46.1	12,301	33,790
Jan-89	14.3	na	9.3	11,883	5,912
Feb-89	26.0	na	13.0	13,424	7,799
Mar-89	83.0	na	60.2	11,710	43,856
Apr-89	69.1	na	46.2	12,069	32,446
May-89	48.5	na	17.0	13,131	11,735
Jun-89	75.5	na	53.3	11,800	37,592
Jul-89	70.1	64.9	50.4	11,911	37,126
Aug-89	52.5	29.2	23.8	12,429	16,655
Sep-89	40.0	36.0	30.4	12,064	21,453
Oct-89	12.5	12.5	10.0	11,876	6,823
Nov-89	63.9	60.3	57.9	11,854	42,006
Dec-89	65.5	64.8	56.2	11,934	41,317
Jan-90	72.5	57.0	54.3	11,817	40,142
Feb-90	27.3	18.4	14.9	11,638	10,297
Mar-90	92.1	79.9	78.3	11,672	58,344
Apr-90	87.8	75.1	83.9	11,596	59,526
May-90	33.1	30.9	26.2	12,127	17,499
Jun-90	69.4	69.0	54.2	12,313	39,437
Jul-90	36.1	29.9	21.4	12,456	15,279
Aug-90	51.8	51.7	11.4	12,585	7,763
Sep-90	45.8	45.7	18.3	11,992	12,602
Oct-90	63.0	62.5	31.3	12,258	23,165
Nov-90	97.2	97.0	85.7	11,604	61,012
Dec-90	97.9	97.6	56.2	11,767	54,964
Jan-91	96.0	92.0	57.5	11,102	42,767
Averages	60.1	56.5	40.6	12,055	29,672
(na - not available)				Total	860,475

Table 3-1. Nucla CFB Operational Performance Statistics.

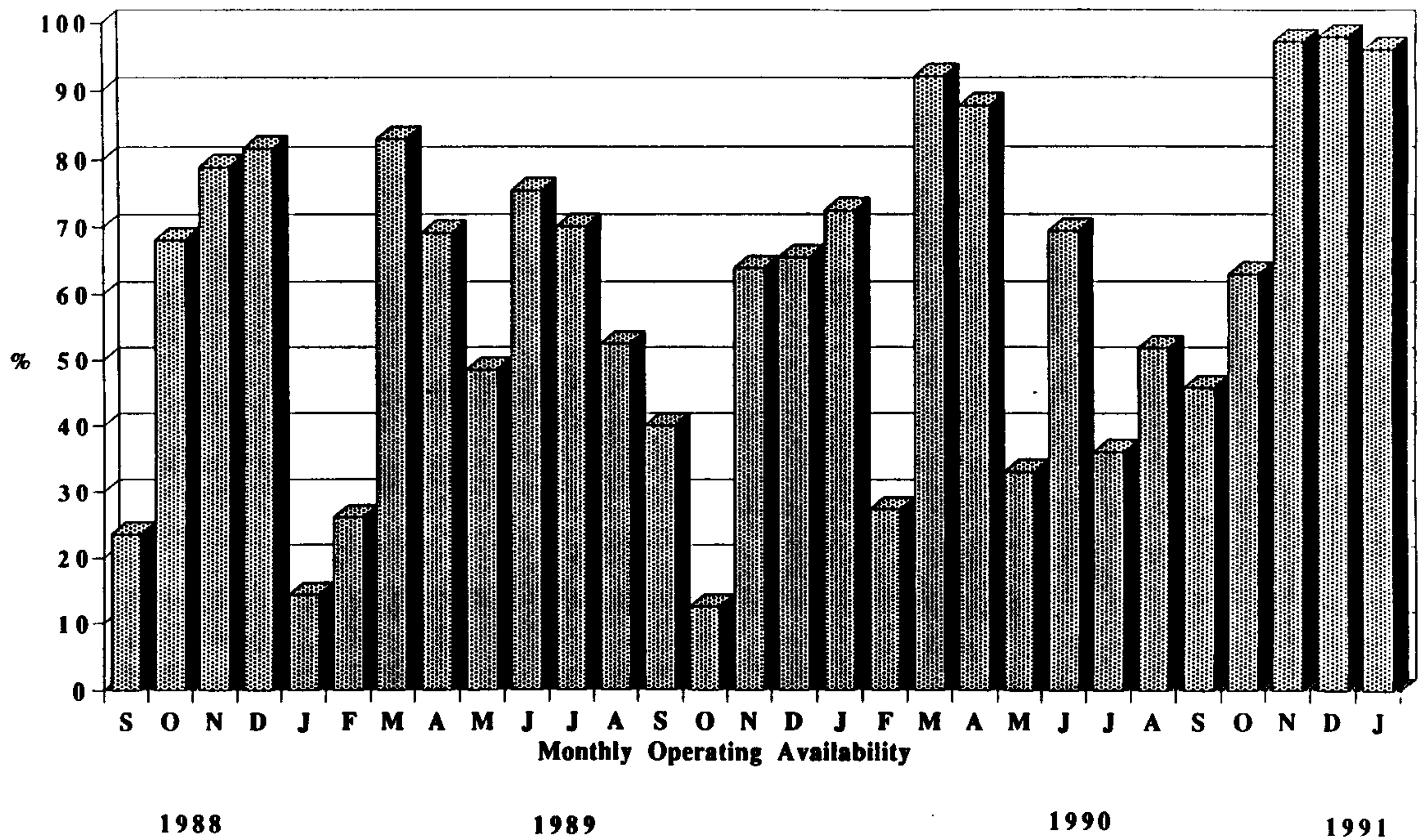


Figure 3-1. Nucla CFB Operating Availability: September 1988 through January 1991.

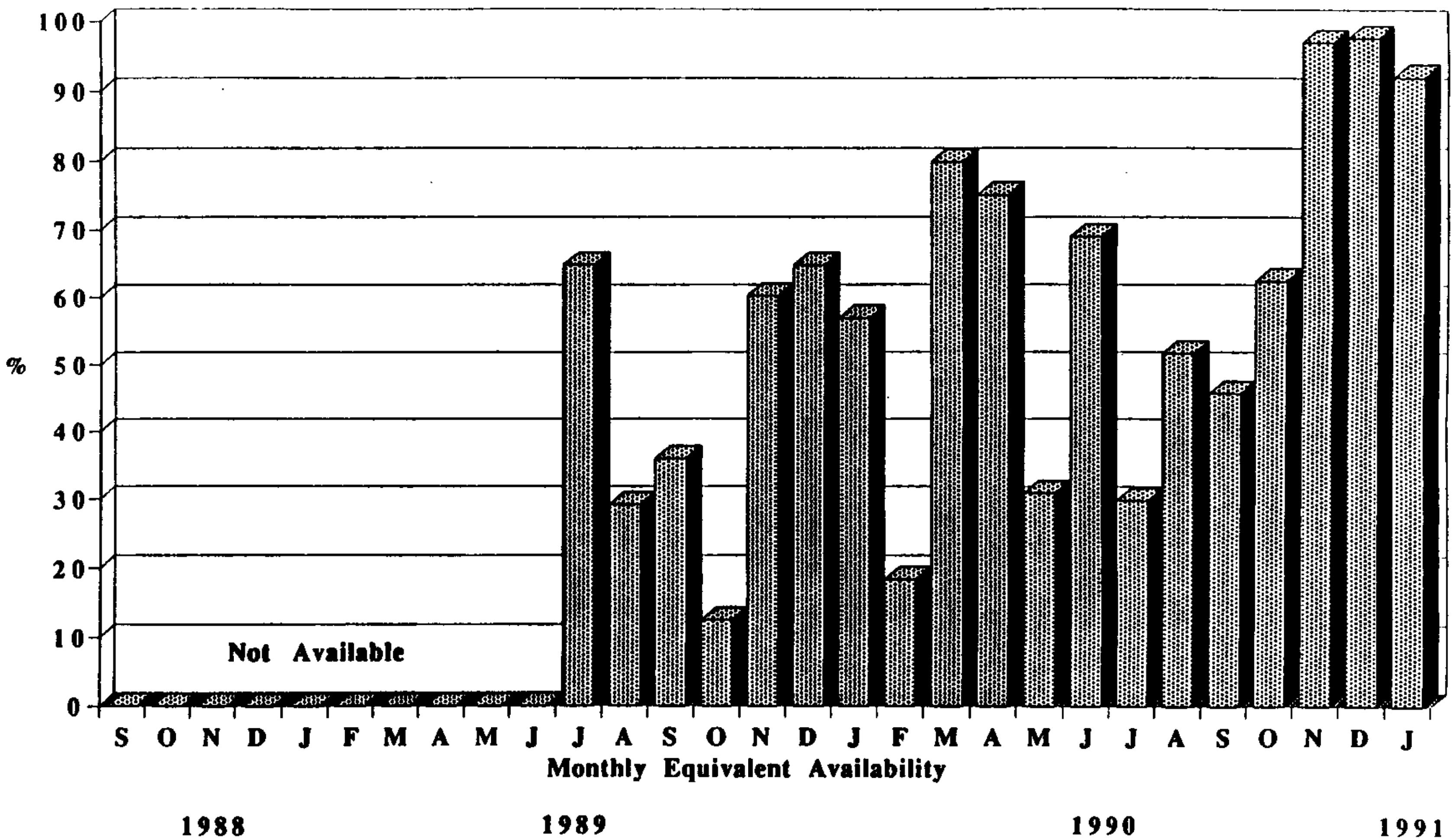


Figure 3-2. Nucla CFB Equivalent Availability: September 1988 through January 1991.

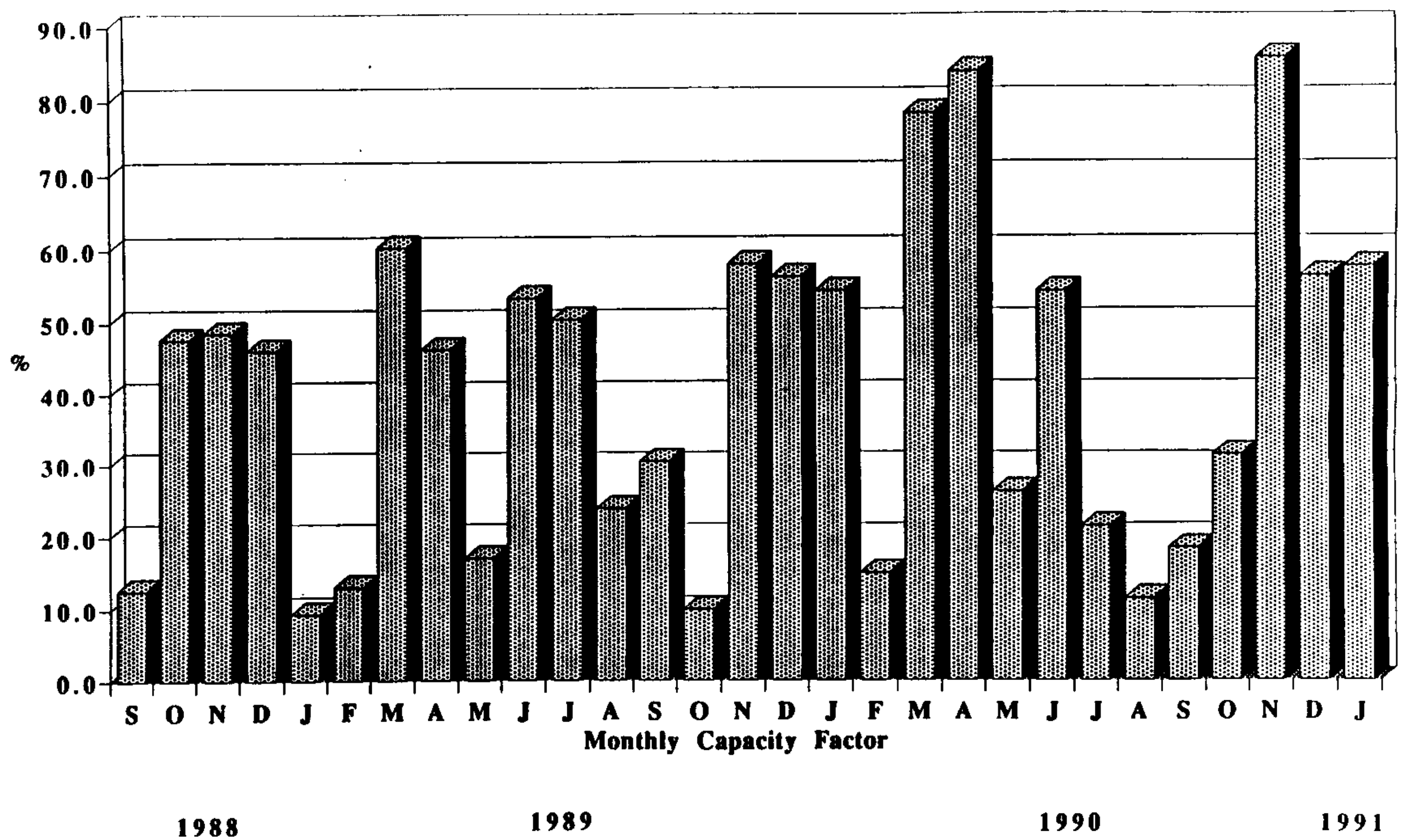


Figure 3-3. Nucla CFB Capacity Factor: September 1988 through January 1991.

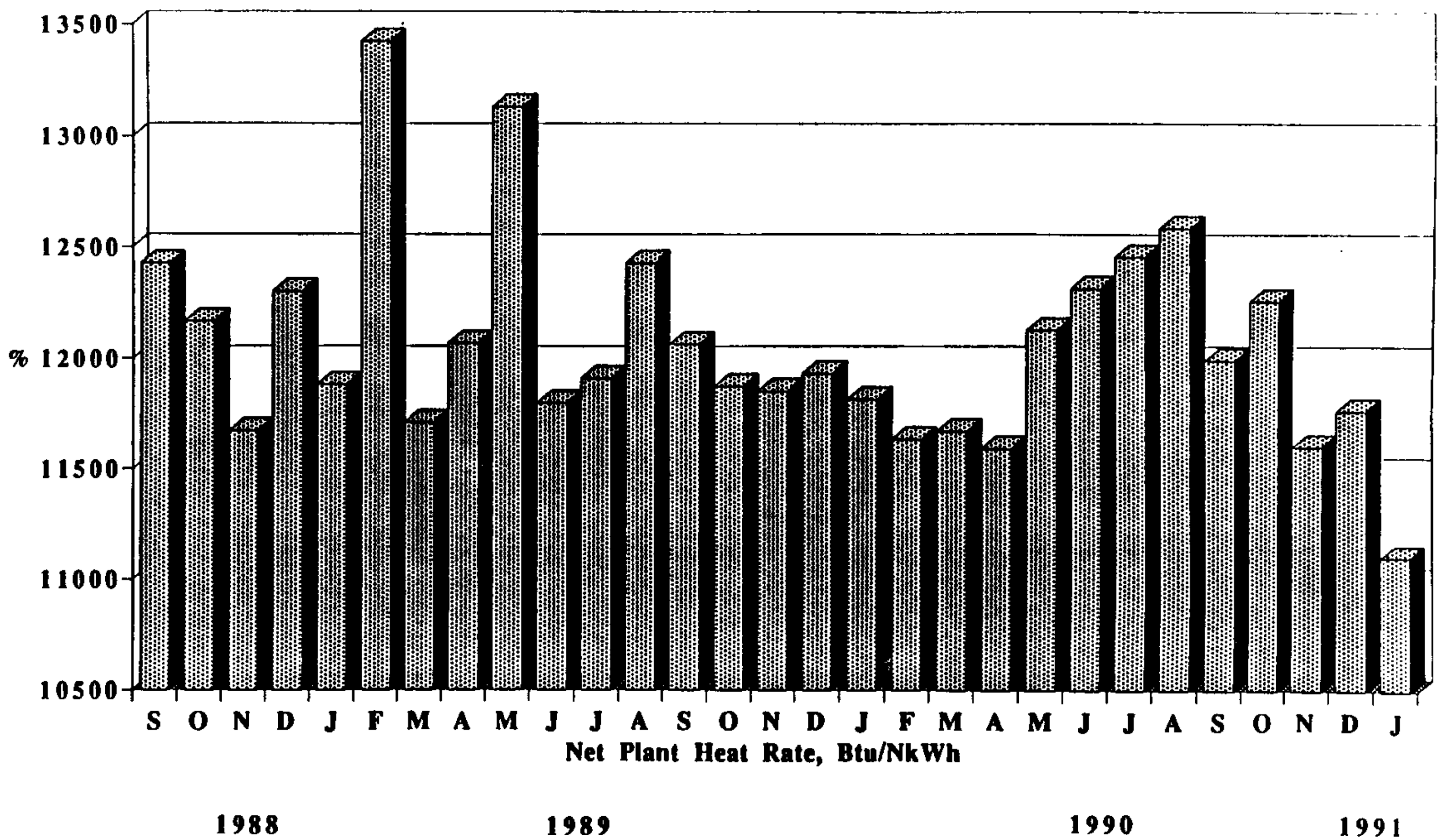


Figure 3-4. Nucla CFB Net Plant Heat Rate: September 1988 through January 1991.

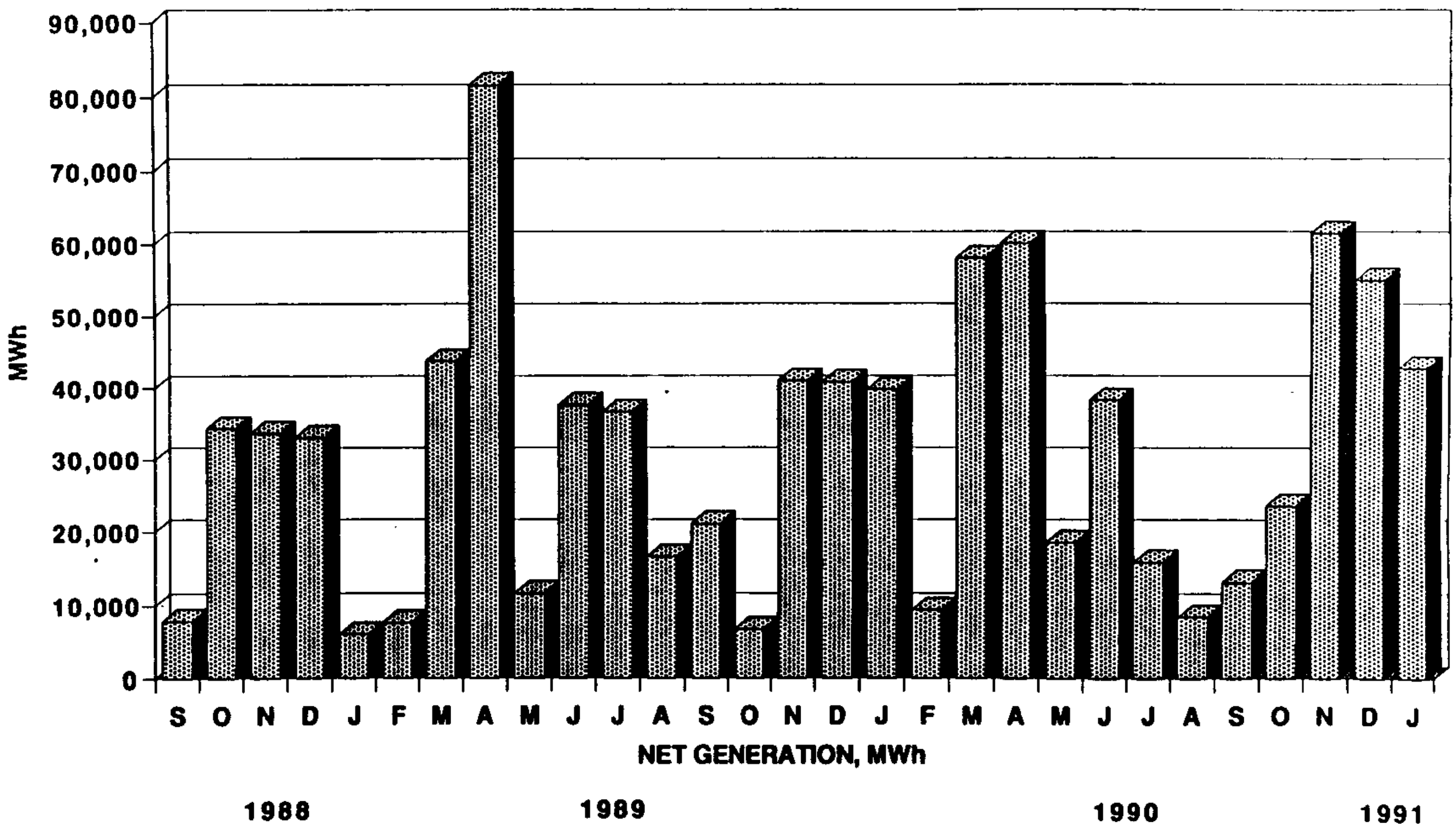


Figure 3-5. Nucla CFB Net Generation: September 1988 through January 1991.

- January/February 1989. Outage from January 5 through February 13, 1989 to repair/replace damaged refractory in the cyclones, loop seals and lower combustion chambers.

- May 1989. Forced outages from April 27 through May 10, 1989 and from May 14 through May 22, 1989 to repair/replace boiler feed pumps.

- September 1989. Planned outage from September 23 through October 9, 1989 to replace the primary air fan wheel.

- October 1989. In addition to the outage listed above, a second forced outage was required from October 13 through November 11, 1989 due to a tube failure on the secondary superheater in combustor B.

- February 1990. Forced outage from February 10 through February 21, 1990 due to a secondary superheater tube failure in combustor A.

- May 1990. Forced outage from May 2 through May 20, 1990 due to a secondary superheater tube failure in combustor A.

- July 1990. Forced outage from June 28 through July 10, 1990 and from July 17 through July 28, 1990 resulting from secondary superheater tube failures on combustor A.

- August 1990. Forced outage from August 1 through August 19 due to water-wall tube failures on combustor A.

- September 1990. Forced outage from September 16 through October 6, 1990 due to a secondary superheater tube failure on combustor A.

The high availabilities during November and December of 1990 and January 1991 reflect a temporary resolution to problems with secondary superheater tube failures in combustor A. A summary of all unit outages and more detailed descriptions of the above events are contained in the Annual Technical Reports and in the Final Technical Report for this project.

In general, the unit was base-loaded during the operating period shown in Figure 3-3. Exceptions include planned deratings to complete low load performance tests as part of the test program and short-term forced derates. The latter were required to repair or modify equipment components including cooling tower circulation pumps, boiler feed pumps, coal delivery equipment, the limestone feed system, the bottom ash removal system, and forced draft fans.

3.2 DEFINITION OF TERMS

The following definitions apply to the data presented above and are consistent with those used by the North American Electric Reliability Council/Generating Availability Data System (NERC/GADS).

Operating Availability - (Available hours/Period hours)*100%.

Available - State in which the unit is capable of providing service, whether or not it is actually in service, regardless of the capacity level that can be provided.

Available Hours - Sum of all service hours and reserve shutdown hours. Stated in another way, these hours represent the period hours less planned outage hours, forced outage hours, and maintenance outage hours.

Average Period Heat Rate (On-line,net) - [Coal Higher Heating Value (HHV) * Coal Consumed] + [(Gas HHV * Gas Consumed (on-line))/Net Generation].

Capacity Factor - (Gross Generation/Gross Maximum Capacity) * 100%. Note that capacity factors presented in Table 3-1 and Figure 3-3 use this equation prior to July 1990 and use the net capacity factor equation following July 1990.

Equivalent Availability - [(Available hours - (Planned Derate + Unplanned Derate))/Period hours]*100%. Note that equivalent availabilities presented in Table 3-1 and Figure 3-2 use the definition for gross equivalent availability prior to July 1990 and use the above equation following July 1990.

Forced Derating/Curtailment - An unplanned component failure or other condition that requires the load on the unit be reduced immediately or before the next weekend.

Forced Outage - An unplanned component failure or other condition that requires the unit be removed from service immediately or before the next weekend.

Gross Actual Generation - Actual number of electrical megawatt hours generated by the unit during the period being considered.

Gross Capacity Factor - (Gross Actual Generation / (Period hours * Gross Maximum Capacity)) * 100%.

Gross Equivalent Availability - (Gross Maximum Capacity * Available hours - Megawatt hour (MWh) loss due to Derating) / (Gross Maximum Capacity * Period hours). Note in Table 3-1 and Figure 3-2, equivalent availabilities use this definition prior to July 1990 and the equivalent availability equation listed above following July 1990.

Gross Maximum Capacity - Maximum capacity a unit can sustain over a specified period of time when not restricted by seasonal or other deratings.

Maintenance Derating - The removal of a component for scheduled repairs that can be deferred beyond the end of the next weekend, but requires a reduction of capacity before the next planned outage.

Maintenance Outage - The removal of a unit from service to perform work on specific components that can be deferred beyond the end of the next weekend, but requires the unit be removed from service before the next planned outage. Typically, a maintenance outage may occur anytime during the year, may have flexible start dates, and may or may not have a predetermined duration.

Net Actual Generation (MWh) - Actual number of electrical megawatt hours generated by the unit during the period being considered less any generation (MWh) utilized for that unit's station service or auxiliaries.

Net Capacity Factor - [Net Actual Generation/(Period Hours * Net Maximum Capacity)] * 100%. Note in Table 3-1 and Figure 3-3, capacity factors are calculated using the capacity factor equation prior to July 1990, and the above definition following July 1990.

Net Maximum Capacity - Gross maximum capacity less the unit capacity utilized for that unit's station service or auxiliaries.

Number of Unit Starts - The number of times the Unit 4 generator was electrically connected to the system during the reporting period.

Period Hours - Number of hours a unit was in the active state.

Planned Derating - The removal of a component for repairs that is scheduled well in advance and has a predetermined duration.

Planned Outage - The removal of a unit from service to perform work on specific components that is scheduled well in advance and has a predetermined duration (e.g., annual overhaul, inspections, testing, etc.).

Reserve Shutdown - A state in which a unit is available but not in service for economic reasons.

Scheduled Derating Extension - The extension of a maintenance or planned derating.

Scheduled Deratings/Curtailments - Scheduled deratings are a combination of maintenance and planned deratings.

Scheduled Outage Extensions - The extension of a maintenance or planned outage.

Scheduled Outages - Scheduled outages are a combination of maintenance and planned outages.

Service Hours - Total number of hours a unit was electrically connected to the system.

Unavailable - State in which a unit is not capable of operation because of the failure of a component, external restriction, testing, work being performed, or some adverse condition.

Unavailable Hours - Sum of all Forced Outage Hours, Maintenance Outage Hours, and Planned Outage Hours.

Unplanned Derate - Sum of all hours experienced during Forced Deratings, Maintenance Deratings and Scheduled Derating Extensions of any Maintenance Deratings.

Unplanned Outage - Sum of all hours experienced during Forced Outages, Maintenance Outages, and Scheduled Outage Extensions of any Maintenance Outage.

Section 4

ECONOMIC DATA PRESENTATION

This section provides data and information related to plant capital costs for engineering, construction and start-up of the Nucla CFB repowering project. Monthly operating costs are shown for the 29 month testing period covered by the Cooperative Agreement (September 1988 through January 1991) which followed the start-up period. In addition, unit costs for coal, limestone and ash disposal are presented along with total quantities consumed or generated during the reporting period. These quantities, along with staffing requirements for the plant, will allow adjustments to be made to the cost data for other CFB applications and operating philosophies.

4.1 CAPITAL COST SUMMARY

This section presents capital costs for engineering, construction and unit start-up and compares these with estimated capital costs made in 1984 prior to project approval. Although electric generation was first achieved in May 1987, full power production at 110 MWe gross was not accomplished until March 1988. Following further equipment shakedown and debugging, the plant completed the first set of acceptance tests on design coal in July 1988 and a second set in October 1988. The engineering, construction and start-up costs are based on expenses accrued between the start of the project in 1985 through August 1988.

4.1.1 Capital Cost Estimate

Table 4-1 shows a comparison of published estimated versus actual capital costs for the Nucla CFB Demonstration Project. The estimated capital costs appeared as Table 5 on page 38 in the "Detailed Public Design Report" prepared for the U.S. Department of Energy under Instrument No.DE-FC21-89MC25137. The categories and procedures used for these estimates were based on United Engineers and Constructors Estimating Standards applicable at the time.

The original 1984 estimate for the total project cost of $86,670,000 shown in Table 4-1 was made after obtaining firm price quotations for some of the major equipment items. Despite not having completed detailed planning at the time of the original estimate, this total project cost represented a capital cost for installed generation of $788/kW. This was lower than the cost estimate for a 100 MWe pulverized coal-fired unit and considerably less than the incremental

Table 4-1. Comparison of Projected versus Actual Capital Costs.

Component	Estimate, $ Sept. 1984	Actual 1991, $	Percent Overrun
• Boiler	29,980,000	31,070,283	3.6
• Turbine-Generator	7,000,000	7,283,777	4.1
• Architect/Engineer	3,200,000	7,318,314	128.7
• Earthwork	360,000	472,107	31.1
• Concrete	1,360,000	1,828,621	34.5
• Structural and Architectural	870,000	2,547,248	192.8
• Mechanical Equipment	9,230.000	10,040,490	8.8
• Piping	2,810,000	4,580,003	63.0
• Instrumentation and Controls	430,000	2,153,089	400.0
• Electrical Equipment	3,450,000	6,597,932	91.2
• Painting	10,000	0	N/A
• Insulation	920,000	838,571	(8.9)
• Demolition, Relocation & Modification	400,000	754,925	88.7
• Field Distributables & Contractor Home Office	9,430,000	11,497,889	21.9
Subtotal	69,450,000	86,983,276 1)	25.3
• CUEA Engineering, Start-up & Construction Management	5,600,000	9,231,009	64.8
• Contingency	6,230,000	0	N/A
Total Plant Cost	81,280,000	96,214,285	18.4
• Allowance for Funds During Construction	5,390,000	9,572,329	77.6
Total Project Cost	86,670,000	105,786,615	22.1
• Accumulated Interest, Taxes, & Insurance	2,430,000	3,821,979	57.3
Total Cost-Construction and Start-up	89,100,000	109,608,593 2)	23.0
• Book Value of Old Plant	5,790,000	5,261,088	N/A
• Project Participation	(2,740,000)	(2,540,000)	N/A
Total Plant Investment	92,150,000	112,329,681 3)	21.9

1) General Ledger Amount Used. See Appendix E Notes.
2) Reference Appendix E Breakdown Detail.
3) Includes Unpaid Retention of $3,842,303.

installed cost of CUEA's newest Unit 3 at the Craig Station. The latter was placed in service in early 1984 at an installed cost of $1183/kW.

Several efforts were made to minimize the Nucla project costs including: 1) using much of the equipment from the existing facility, 2) minimizing refurbishment costs by having this work performed in-house, 3) performing some engineering in-house, 4) negotiating favorable contract terms and prices, and 5) limiting the overall project schedule to three years. The favorable contracts were possible in part because of the depressed state of activity in the power industry at the time. The schedule was made possible by preplanning, by minimizing engineering, construction, and start-up schedule overlaps, and by not being required to prepare an environmental impact statement.

Busbar power costs for the first year of operation were projected to be 33.40 mills/kWh based on the facility being base-loaded (80% capacity factor). The existing 36 MWe Nucla plant, while not economically feasible to operate, had an outstanding debt of approximately $8.9 million. The net book value of the plant was approximately $5.8 million. Assigning the remaining plant debt and book value to the circulating AFBC demonstration project increased the busbar power cost by 1.58 mills/kWh to 34.98 mills/kWh. This compared favorably with CUEA's 1984 wholesale rate to members of 41.17 mills/kWh. The assumptions for determining this estimate and related costs are presented in Table 4-2.

4.1.2 Actual Capital Costs

As shown in Table 4-1, the final total plant investment as of August 1988 was $112,329,681, or 21.9% higher than the published cost estimate completed in 1984. There are three basic reasons for the increase in actual costs. First, detailed design, planning and scheduling were not complete at the time the estimates were developed. All estimates were based on preliminary plans with some firm price quotations on major equipment items only. Second, plant improvements and operational enhancements were made beyond the original scope of the project. Third, delays in unit start-up and acceptance testing resulted in additional costs that went beyond contingency estimates.

In order to maintain the desired project schedule for unit start-up and check-out by the spring of 1987, detailed planning was not complete at the time construction commenced in 1985. The design information available for the estimate consisted of general arrangement drawings, a limited number of piping and instrumentation diagrams, and some preliminary concrete, steel, piping, and electrical drawings. As a result, a "target manhour" type of contract was selected for

Table 4-2. Projected First Year Operating Costs

Assumptions

• Total Project Cost	$105.79 million (Table 4-1)
• Pollution Control Cost	$15 million
• Interest Rate	12.0%
• Pollution Bond Rate	6.5%
• Limestone Cost	$16/ton
• Coal Cost	$19/ton
• Depreciation Rate	3.1%/year
• Property Tax Rate	1.17%
• Insurance Rate	0.15%
• Net Plant Capacity	100 MWe
• Net Plant Heat Rate	11,500 Btu net kWh
• Annual Capacity Factor	80%
• Coal Required	415,000 tons/year
• Net Generation	701 GWh/year

Operating Costs Category	Costs ($ millions)	Busbar Costs (mills/kWh)
• Interest Costs	9.428	13.20
• Depreciation, Insurance, and Taxes	3.706	5.29
• Fixed O&M	1.420	2.03
• Variable O&M	0.608	0.87
• Coal	7.893	11.26
• Limestone	0.219	0.31
• Ash Disposal	0.163	0.23
• Water	0.046	0.06
• Natural Gas (propane)	0.075	0.11
• General Chemicals	0.030	0.04
Total	23.408	33.40
• Costs Related to Existing Plant (value & debt)	1.104	1.58
Total	24.448	34.98

CUEA's 1984 firm wholesale rate to members = 41.17.

the General Construction Contract and contractual, firm bid services/equipment procurement was used to turnkey various project phases. Therefore, a breakdown into subcategories (i.e., labor, materials, installation, etc.) cannot be shown. Also, many of the unforeseen design problems and additional equipment items were not included in the published estimate. These include the following:

1. In the boiler area, additional steel was required because of the reorientation of the boiler building. Additions to the scope included an extension on the I.D. fan outlet flue, and the coal and ash handling systems.

2. The original estimate for Instrumentation and Controls only included that of the turbine valve controls. The boiler controls were later added to this area. Originally, it was anticipated that control for the new boiler could be adapted to the existing control system and that the existing control room could be used. Ultimately, a new digital control system was selected and a new control and logics room were constructed.

3. Additional commodity quantities that were necessary during construction increased the target manhour and material cost over estimates. Actual manhours increased by over 178,000 beyond that targeted.

4. Difficulties were encountered drilling piers during construction. As a result, the total number of piers was increased from 103 to 155 and the time required to complete drilling increased form approximately 30 days to 61 days.

5. The propane storage system used for boiler start-up was a necessary but unplanned cost. Originally, it was assumed that a natural gas supply line would be installed at no cost (except for site-specific expenses).

6. Additional requirements for compressed air on the new CFB forced the decision to replace the existing air compressors with larger capacity units.

7. The size of the water treatment equipment was increased because of additional capacity requirements beyond the original forecasts.

8. Outside engineering and professional services, coal and limestone testing, labor relations, test core drilling, water quality testing, an ash disposal site study, preparation of the demonstration test program proposal to the Electric Power Research Institute, coal negotiations, and engineering and construction clearing costs represented additional unplanned costs.

9. The refurbishment of the existing units, particularly the repair of the old baghouses, exceeded original cost estimates.

10. The new cooling tower had to be relocated for environmental reasons, resulting in additional piping and structural requirements.

11. The addition of variable speed drives on the three large fan motors was not considered in the original electrical estimates. An estimated 25% of the plant wiring is associated with the variable speed drive service. This caused an increase in the required wiring, electrical equipment and manhours to accomplish the additional services needed.

12. The plant was originally planned with one feed water pump, one vertical condensate pump, and one circulating water pump. Each of these quantities were increased to two, requiring additional concrete, piping, electrical, auxiliary equipment and manhour requirements.

13. In-house cost increases resulted from additional CUEA personnel being assigned to the project over that which was originally anticipated in order to meet time constraints.

14. Additional design and specification work was required over that which was originally specified. This was assigned to the Architect and Engineering firm.

In addition to these changes, several enhancements were made to the plant to increase reliability, availability and to enhance operational performance. These included:

1. The addition of sootblowers on the economizer tube bundles.

2. The addition of a plant elevator to accommodate the new boiler building, which is over twice as high as the existing 36 MWe plant.

3. As mentioned in item 12 above, second pumps were added to the boiler feed water system, condensate system, and circulating water system to improve plant reliability and availability.

4. Increased storage capacity was added to the existing holding ponds due to the new boiler capacity.

5. Additional valves were added to the steam/water circuitry to improve reliability and availability.

6. An uninterruptable power supply was added to the system to improve reliability, particularly as the result of the purchase of the new digital control system.

7. An auxiliary boiler was added for building heat since only a single power unit would be available at any one time.

8. An upgraded water sampling system was installed.

9. The limestone preparation system was upgraded to accommodate 10 inch as-received limestone.

10. Two additional coal feeders were added to the system to improve combustion performance. This required two additional gravimetric feeders, two horizontal and inclined drag chains, additional rotary valves, engineering, mechanical supports, structural changes and electrical wiring. In addition, the bottoms of the coal silos were modified to accommodate the increased feeder quantities.

11. The refractory in the lower combustion chambers was modified during construction to improve overall boiler performance.

12. An as-fired coal sampling system, cooling tower control panel, and auxiliary control panel were added to the system to improve unit operability.

13. The logic room for the digital control system required separate air conditioning to maintain equipment reliability.

Taking into account the items listed above resulting from unforeseen changes and plant enhancements, a total of over 125 change orders and 3 amendments were submitted to the General Construction Contract, and over 340 additions were made to the as-bid equipment list. In addition, interest charges on construction and start-up were assumed at 6% based on projected environmental bond rates and sales. However, an actual interest rate of 12% was paid on construction and start-up loans through the Cooperative Finance Corporation.

Despite the above factors, plus the added costs of construction and start-up delays, the total plant investment by CUEA overran the original estimate by only 21.9% with a total cost of $112,329,679 or $1,123/net kW. Although considerably higher than projected, this cost compares favorably with a single 200 MWe AFBC plant outlined in EPRI Report #CS-5296, and is still below the cost of Craig Station's Unit 3.

4.2 SUMMARY OF MONTHLY OPERATING COSTS

This section summarizes the monthly power cost data presented in Appendices C and D of this report for the testing period from September 1988 through January 1991. These dates represent the testing interval covered by the Cooperative Agreement No.DE-FC21-89MC25137 between the U.S. Department of Energy and Colorado-Ute Electric Association, Inc.

Data have been compiled using the Rural Electrification Administration Form 12d from the Uniform System of Accounts for Steam Power Production. The various cost categories and their definitions can be seen in the blank REA Form 12d contained in Appendix A and in the definitions of accounts contained in Appendix B. A detailed breakdown of the major line item cost categories listed in Form 12d is presented in Appendix C for the entire 29 month reporting period. Detailed monthly cost breakdowns are contained in Appendix D. Both of these appendices contain unit costs of generation for labor, labor overhead, supplies, travel and transportation, meals, consultants, outside services and other costs. These unit costs are based on CUEA accounting practices.

4.2.1 Data Presentation

Total monthly cost data for the major REA accounts is summarized for 1988 through 1991 in Tables 4-3, 4-4, 4-5, and 4-6. Tables 4-3 and 4-6 summarize monthly cost data for the entire years of 1988 and 1991, respectively. This is despite the shorter period covered by the Cooperative Agreement for these years. Yearly totals for each category are presented for each table. Data are categorized into fuel, non-fuel, operating, maintenance, production, fixed costs and total power costs which is consistent with the major category headings in Form 12d. To avoid possible confusion, note that "Operation, Supervision and Engineering" expenses listed as item #1 in the above tables is summed into Non-Fuel Expense totals listed as item #11. This is consistent with accounting procedures used on REA Form 12d.

Data contained in Tables 4-3 through 4-6 have been plotted in three different ways in Figures 4-1 through 4-22. Figures 4-1 through 4-16 display the monthly costs associated with the major category headings in the form of line graphs covering the period from September 1988 through January 1991. Total cost breakdowns for each category over the entire period are then presented in the form of pie charts. For each major category, one line graph and one pie chart have been grouped together on a single page according to the following:

Item	Description	REA No.	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	LINE TOTALS
1	OPERATION, SUPERVISION & ENGINEERING	500	27,120	27,703	30,322	28,498	28,137	31,686	24,776	32,874	30,704	28,827	48,754	41,996	381,516
2	FUEL COAL	501.1	404,407	514,843	376,866	359,773	360,256	461,265	514,383	38,084	139,200	479,117	481,200	513,958	4 652 252
3	FUEL OIL	501.2	0	0	0	0	0	0	0	0	0	0	0	0	0
4	FUEL GAS	501.3	9,357	33,002	38,545	21,048	13,968	41,763	16,710	18,886	34,520	37,585	28,220	30,402	323,986
5	FUEL OTHER	501 4	0	0	0	0	0	0	0	0	0	0	0	0	0
6	FUEL SUBTOTAL (sum 2, 3, 4 and 5)	501	413,764	547,845	415,211	380,821	383 224	503,028	531,093	56,960	173,810	516,702	509,420	544,360	4 976,238
7	STEAM EXPENSE	502	20,333	17,703	40,312	39,292	34,360	35,006	64,178	52,247	24,246	23,232	64,658	62,021	477 876
8	ELECTRIC EXPENSE	505	11,160	15,061	14,035	11,012	11,868	17,272	16,523	18,680	12,260	11,803	15,747	20,186	175 616
9	MISCELLANEOUS STEAM EXPENSE	506	8,734	10,659	10,775	6,057	21,460	8,977	13,133	13,030	14,539	15,883	12,191	10,189	148,437
10	RENTS	507	0	0	0	0	0	0	0	0	0	0	0	0	0
11	NON-FUEL SUBTOTAL (sum 1, 7, 8, 9, and 10)		68,356	71,216	95,444	84,859	85,825	82,861	118,608	116,840	81,749	78,855	141,550	134,392	1,181 445
12	OPERATION EXPENSE (sum 6 and 11)		482,120	619,061	510,655	465,680	470,049	585,879	649,701	173,800	255,559	596,357	650,970	678,752	6 157 683
13	MAINTENANCE, SUPERVISION & ENGINEERING	510	8,380	8,821	9,484	6,866	6,427	9,303	8,054	10,181	23,244	11,366	17,671	11 235	135 312
14	MAINTENANCE OF STRUCTURES	511	3,830	1,003	2,789	4,340	5,214	5,421	3,622	5,519	3,782	11,103	15,715	6,631	69 044
15	MAINTENANCE OF BOILER PLANT	512	30,480	20,146	24,607	43,287	26,275	21,722	32,608	48,726	61,574	31,086	38,988	38,196	425 605
16	MAINTENANCE OF ELECTRIC PLANT	513	13,408	12,731	15,410	17,376	6,648	12,189	16,840	10,449	18,608	8,855	18,386	20,550	181 458
17	MAINTENANCE OF MISCELLANEOUS PLANT	514	10,605	4,315	8,070	11,868	18,861	13,378	3,082	8,306	7,477	9,257	2,097	78,442	177,658
18	TOTAL MAINTENANCE EXPENSE (sum 13, 14, 15, 16, and 17)		72,709	47,016	61,159	85,847	65,425	62,013	64,306	93,161	115,563	71,757	93,087	157,054	989,077
19	TOTAL PRODUCTION EXPENSE (Direct Cost = sum 12 and 18)		554,829	666,077	571,814	551,527	544,474	657,892	714,007	266,961	371,122	668,114	744,037	835,806	7,146 760
20	DEPRECIATION	403 1	0	0	0	0	0	0	0	0	0	0	0	0	0
21	TAXES	408	7,864	7,939	9,159	8,491	87,968	78,646	87,787	88,472	89,590	88,818	80,702	11,421	656 653
22	INTEREST	427	24,108	34,707	28,557	31,807	1,016,271	1,049,857	633,589	640,349	647,549	686,608	730,315	931,021	6,455 836
23	INSURANCE	924 925 926	33,403	34,347	37,530	30,071	46,018	51,084	43,485	146,098	75,482	70,346	80,074	81,443	738,371
24	TOTAL FIXED COSTS (Indirect Costs=sum 20, 21, 22, and 23)		65,173	76,893	76,246	79,359	1,150,257	1,179,897	764,841	874,919	912,629	845,770	901,081	1,023,885	7,850,860
25	TOTAL POWER COSTS (sum 19 and 24)		620,002	743,070	648,060	630,886	1,694,731	1,837,689	1,478,848	1,141,880	1,183,751	1 513,884	1,645,128	1,859,691	14 997 620

Table 4-3. Summary of 1988 Nucla CFB Power Costs.

Item	Description	REA No.	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	LINE TOTALS
1	OPERATION SUPERVISION & ENGINEERING	500	40,429	40,471	36,691	32,754	34,135	34,874	29,700	41,641	33,083	39,968	33,222	25,732	422 700
2	FUEL COAL	501.1	127,411	138,685	613,691	511,608	221,463	590,642	572,176	339,863	359,173	134,381	647,531	659,246	4 915 870
3	FUEL OIL	501.2	0	0	0	0	0	0	0	0	0	0	0	0	0
4	FUEL GAS	501.3	29,843	33,983	9,188	26,104	25,475	5,110	6,630	8,476	22,809	7,713	20,229	25,427	220 987
5	FUEL OTHER	501.4	0	0	0	0	0	0	0	0		0	0	0	0
6	FUEL SUBTOTAL (sum 2, 3, 4 and 5)	501	157,254	172,668	622,879	537,712	246,938	595,752	578,806	348,339	381,982	142,094	667,760	684,673	5 136 857
7	STEAM EXPENSE	502	61,137	26,814	47,837	51,952	65,055	29,933	32,106	46,382	78,940	48,987	47,424	43,504	579 641
8	ELECTRIC EXPENSE	505	16,134	10,646	14,185	18,283	11,063	12,702	18,198	28,308	37,371	12,600	22,521	14,374	214 385
9	MISCELLANEOUS STEAM EXPENSE	506	13,393	11,191	8,759	13,623	9,424	9,201	9,286	8,871	6,312	12,014	9,857	6,979	118 900
10	RENTS	507	0	0	0	0	0	0	0	0	0	0	0	0	0
11	NON-FUEL SUBTOTAL (sum 1, 7, 8, 9 and 10)		130,083	88,924	107,272	116,612	118,677	86,710	90,378	123,202	155,706	113,449	113,024	90,569	1 335 626
12	OPERATION EXPENSE (sum 6, and 11)		287,337	261,592	730,151	654,324	366,615	682,462	669,184	471,541	537,688	255,543	780,784	775,262	6 472 483
13	MAINTENANCE, SUPERVISION & ENGINEERING	510	11,701	12,825	20,683	8,850	16,832	10,081	8,166	11,063	10,400	11,383	11,050	10,095	149 519
14	MAINTENANCE OF STRUCTURES	511	24,420	3,098	4,702	3,025	4,771	2,314	2,782	5,321	979	1,520	909	1,985	56 742
15	MAINTENANCE OF BOILER PLANT	512	26,640	41,112	40,989	32,822	72,148	30,845	44,330	31,142	70,931	78,720	104,127	91,226	665,132
16	MAINTENANCE OF ELECTRIC PLANT	513	19,029	13,259	15,749	11,098	9,264	12,427	3,517	12,860	6,641	6,606	10,341	21,210	142 101
17	MAINTENANCE OF MISCELLANEOUS PLANT	514	5,288	7,083	6,940	5,934	8,231	6,554	3,429	10,508	15,809	21,683	22,007	4,185	117 631
18	TOTAL MAINTENANCE EXPENSE (sum 13, 14, 15, 16, and 17)		87,178	77,557	95,063	62,729	111,346	62,321	62,224	70,894	104,780	118,920	148,434	128,701	1 131 125
19	TOTAL PRODUCTION EXPENSE (Direct Cost = sum 12 and 18)		374,513	339,149	825,214	717,053	477,961	744,783	731,408	542,435	642,440	375,463	929,218	903,963	7,603 608
20	DEPRECIATION	403.1	0	0	0	0	0	0	0	0	0	0	0	0	0
21	TAXES	408	95,060	96,203	97,638	95,372	95,219	97,036	94,651	96,733	95,666	95,915	96,787	158,704	1 197,102
22	INTEREST	427	961,237	874,318	1,025,121	1,062,481	1,074,807	1,002,478	1,052,587	1,029,975	1,061,824	1,099,602	1,047,018	1,066,877	12,358 207
23	INSURANCE	924 925 928	70,853	72,579	82,217	67,466	73,307	69,133	84,272	78,488	76,232	95,171	81,085	72,466	903,366
24	TOTAL FIXED COSTS (Indirect Costs=sum 20, 21, 22, and 23)		1,126,150	1,043,100	1,204,976	1,225,319	1,243,432	1,168,648	1,211,490	1,205,194	1,233,722	1,270,688	1,224,900	1,298,047	14 458 675
25	TOTAL POWER COSTS (sum 19 and 24)		1,502,672	1,382,249	2,030,190	1,942,372	1,721,393	1,913,431	1,942,898	1,747,629	1,876,170	1,646,151	2,154,118	2,203,010	22 062 283

Table 4-4. Summary of 1989 Nucla CFB Power Costs.

Item	Description	REA No.	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	LINE TOTALS
1	OPERATION SUPERVISION & ENGINEERING	500	32,086	27,278	26,348	29,155	26,670	33,783	33,980	34,671	34,755	45,671	158,824	119,712	602,831
2	FUEL, COAL	501.1	832,681	192,012	805,960	865,009	344,013	624,516	316,258	164,339	225,782	375,650	909,470	860,005	6,417,695
3	FUEL, OIL	501.2	0	0	0	0	0	0	0	0	0	0	0	0	0
4	FUEL, GAS	501.3	21,087	78,980	24,894	10,687	13,259	24,577	10,979	20,296	24,396	27,057	25,942	33,327	315,481
5	FUEL, OTHER	501.4	0	0	0	0	0	0	0	0	0	0	0	0	0
6	FUEL SUBTOTAL (sum 2, 3, 4 and 5)	501	853,768	270,992	830,854	875,696	357,272	649,093	329,237	184,635	250,178	402,707	935,412	893,332	6,733,176
7	STEAM EXPENSE	502	88,157	80,312	89,681	31,484	80,555	63,692	73,850	55,775	40,864	42,300	52,240	71,798	750,808
8	ELECTRIC EXPENSE	505	34,298	16,136	13,582	15,377	18,158	23,328	20,338	14,631	10,748	16,684	15,965	14,090	213,333
9	MISCELLANEOUS STEAM EXPENSE	506	12,860	8,080	12,759	12,214	17,507	12,289	17,870	17,351	13,334	20,072	22,279	22,143	188,558
10	RENTS	507	0	0	0	0	0	0	0	0	0	0	0	0	0
11	NON-FUEL SUBTOTAL (sum 1, 7, 8, 9, and 10)		147,201	131,806	142,368	88,230	142,890	133,092	145,939	122,428	99,789	124,727	249,308	227,743	1,755,530
12	OPERATION EXPENSE (sum 6 and 11)		800,968	402,798	1,073,222	963,926	500,162	782,185	475,175	307,063	349,977	527,434	1,184,720	1,121,075	8,488,706
13	MAINTENANCE, SUPERVISION & ENGINEERING	510	14,231	13,431	14,077	11,286	13,611	11,151	12,032	13,110	12,537	15,929	14,778	13,282	160,564
14	MAINTENANCE OF STRUCTURES	511	2,548	2,439	17,646	3,915	4,057	6,865	4,837	2,233	1,478	2,884	1,010	2,428	53,141
15	MAINTENANCE OF POWER PLANT	512	85,611	62,740	152,229	30,589	100,183	96,479	61,803	110,650	38,518	88,440	41,951	30,958	807,136
16	MAINTENANCE OF ELECTRIC PLANT	513	18,890	19,884	15,122	10,547	8,542	7,582	4,271	11,896	5,246	10,273	8,319	4,121	125,372
17	MAINTENANCE OF MISCELLANEOUS PLANT	514	8,840	8,181	8,173	4,674	3,705	8,286	5,828	8,287	8,112	4,383	8,853	6,632	84,373
18	TOTAL MAINTENANCE EXPENSE (sum 13, 14, 15, 16, and 17)		130,820	106,675	208,144	70,021	131,078	128,343	88,471	147,195	63,889	121,909	75,911	57,421	1,330,586
19	TOTAL PRODUCTION EXPENSE (Direct Cost = sum 12 and 18)		931,498	509,473	1,282,368	1,033,947	631,240	910,528	563,646	454,258	413,866	649,343	1,260,631	1,178,496	9,819,292
20	DEPRECIATION	403.1	290,503	290,503	290,503	290,503	290,503	288,587	290,352	290,352	290,352	290,352	290,352	290,352	3,484,224
21	TAXES	408	118,921	114,743	114,940	114,425	114,660	91,250	80,437	58,506	57,349	59,898	61,547	109,600	1,084,376
22	INTEREST	427	830,165	739,984	819,456	803,385	840,915	803,463	830,188	819,488	782,690	808,780	772,311	787,353	9,636,189
23	INSURANCE	924 925 926	25,558	24,118	24,220	23,170	24,368	19,907	19,095	20,374	18,348	15,071	26,099	24,313	264,541
24	TOTAL FIXED COSTS (Indirect Costs=sum 20, 21, 22, and 23)		1,263,147	1,169,348	1,249,119	1,231,483	1,270,446	1,193,217	1,220,082	1,188,721	1,148,739	1,175,101	1,150,309	1,211,618	14,471,330
25	TOTAL POWER COSTS (sum 19 and 24)		2,194,645	1,678,821	2,531,485	2,265,430	1,901,686	2,103,745	1,783,728	1,642,979	1,562,605	1,824,444	2,410,940	2,390,114	24,290,622

Table 4-5. Summary of 1990 Nucla CFB Power Costs.

Item	Description	REA No.	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	LINE TOTALS
1	OPERATION, SUPERVISION & ENGINEERING	500	34,261	142,858	158,277	103,862	69,710	64,284	62,317	73,559	54 818	59,847	63,747	63,878	949,018
2	FUEL COAL	501.1	898,172	86,966	91,311	715,235	614,019	650,417	507,311	669,403	531,699	654,532	350,701	9,577	5,577,343
3	FUEL OIL	501.2	0	0	0	0	0	0	0	0	0	0	0	0	
4	FUEL GAS	501.3	29,928	23,235	35,134	36,363	12,419	10,409	15,143	5,759	3,200	30,266	32,519	25,028	259,403
5	FUEL OTHER	501.4	0	0	0	0	0		0	0	0	0	0	0	0
6	FUEL SUBTOTAL (sum 2, 3, 4 and 5)	501	726,100	110,201	126,445	751,598	626,438	660,826	522,454	675,162	534,899	684,798	383,220	34,605	5 836,746
7	STEAM EXPENSE	502	79,836	82,785	29,075	39,476	68,050	58,010	63,128	57,325	61,031	57,864	52,861	21,624	669,065
8	ELECTRIC EXPENSE	505	37,481	16,871	12,890	16,448	16,690	13,621	25,771	13,258	33,156	17,412	19,054	12,536	235 198
9	MISCELLANEOUS STEAM EXPENSE	506	16,388	19,545	32,317	27,271	26,296	26,145	18,649	30,743	29,107	36,089	24,444	17,215	304 219
10	RENTS	507	0	0	0	0	0	0	0	0	0	0	0	0	0
11	NON-FUEL SUBTOTAL (sum 1, 7, 8, 9, and 10)		187,986	282,059	230,559	188,867	178,746	162,080	160,865	174,805	178,112	171,012	160,106	115,253	2 157 500
12	OPERATION EXPENSE (sum 6, and 11)		804,086	372,260	357,004	938,455	805,184	822,886	682,319	850,047	713,011	855,810	543,326	149,858	7 994 246
13	MAINTENANCE, SUPERVISION & ENGINEERING	510	10,118	14,261	13,753	14,474	18,573	15,112	17,628	15,300	18,056	10,230	13,867	15,033	- 193 304
14	MAINTENANCE OF STRUCTURES	511	5,306	999	6,521	3,898	10,021	10,788	23,087	5,180	-34,818	8,117	4,258	7,685	62 204
15	MAINTENANCE OF POWER PLANT	512	81,308	64,298	143,074	33,328	70,592	43,543	63,006	33,428	54,582	76,878	69,469	85,598	819 115
16	MAINTENANCE OF ELECTRIC PLANT	513	6,642	4,604	11,373	19,243	7,560	17,357	26,297	13,525	57,103	26,240	70,282	269,125	528 261
17	MAINTENANCE OF MISCELLANEOUS PLANT	514	6,014	6,525	6,277	8,160	11,356	6,704	5,612	11,034	5,268	5,304	6,486	16,590	94 338
18	TOTAL MAINTENANCE EXPENSE (sum 13, 14, 15, 16, and 17)		117,568	90,688	180,998	79,111	125,002	98,504	135,630	78,537	100,203	132,778	164 172	394,031	1 697 222
19	TOTAL PRODUCTION EXPENSE (Direct Cost = sum 12 and 18)		1,011,654	462,948	538,002	1,017,566	930,186	921,390	827,949	928,584	813,214	988,588	707,498	543,889	9 691 468
20	DEPRECIATION	403.1	290,368	290,368	290,368	290,368	290,368	290,368	290,368	290,368	290,368	282,482	289,180	322,173	3 517,157
21	TAXES	408	84,632	80,407	82,549	83,464	84,628	82,044	84,085	91,890	91,515	92,824	80,137	177,785	1 126 041
22	INTEREST	427	776,636	662,786	690,862	647,570	636,958	606,268	626,285	626,229	606,056	594,044	543,840	530,513	7,548 147
23	INSURANCE	924 925 926	27,161	23,194	26,172	27,866	30,133	26,813	30,304	30,121	26,005	45,306	38,115	33,782	362 772
24	TOTAL FIXED COSTS (Indirect Costs=sum 20, 21, 22, and 23)		1,178,797	1,056,765	1,090,051	1,049,068	1,042,088	1,005,493	1,031,022	1,038,608	1,013,944	1,024,756	950,282	1,064,253	12 554 117
25	TOTAL POWER COSTS (sum 19 and 24)		2,190,451	1,519,703	1,628,053	2,066,634	1,972,274	1,926,883	1,858,971	1,967,192	1,827,158	2,013,344	1,666,780	1,608,142	22,245 585

Table 4-6. Summary of 1991 Nucla CFB Power Costs.

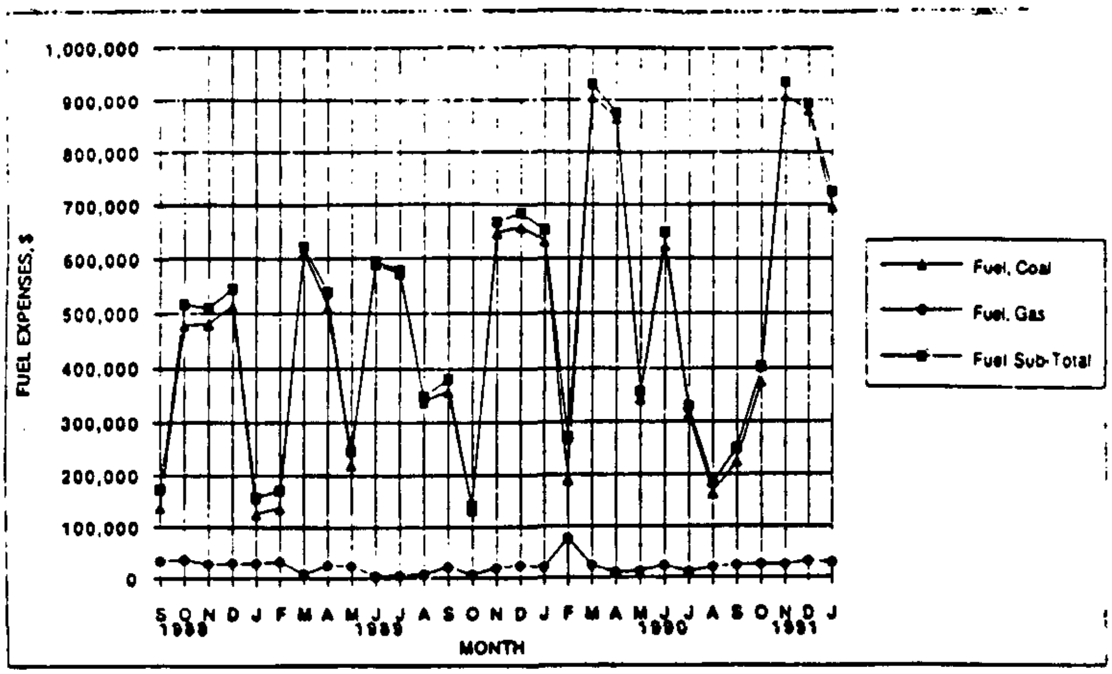


Figure 4-1. Summary of Monthly Coal, Propane, and Total Fuel Costs.

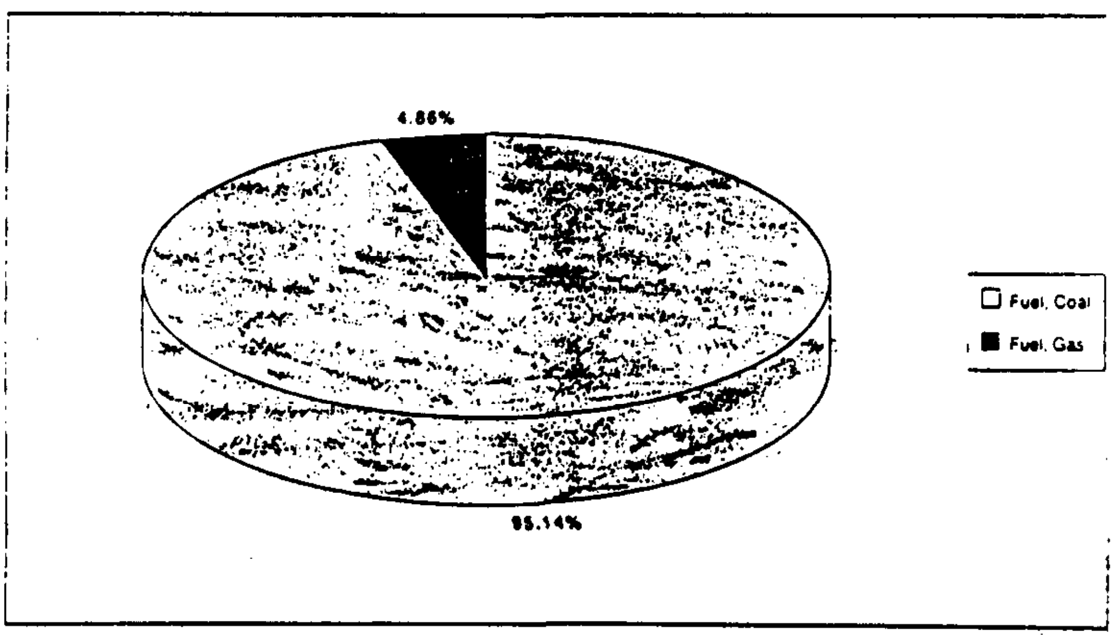


Figure 4-2. Breakdown of Total Fuel Costs from Sept. 1988 through Jan. 1991.

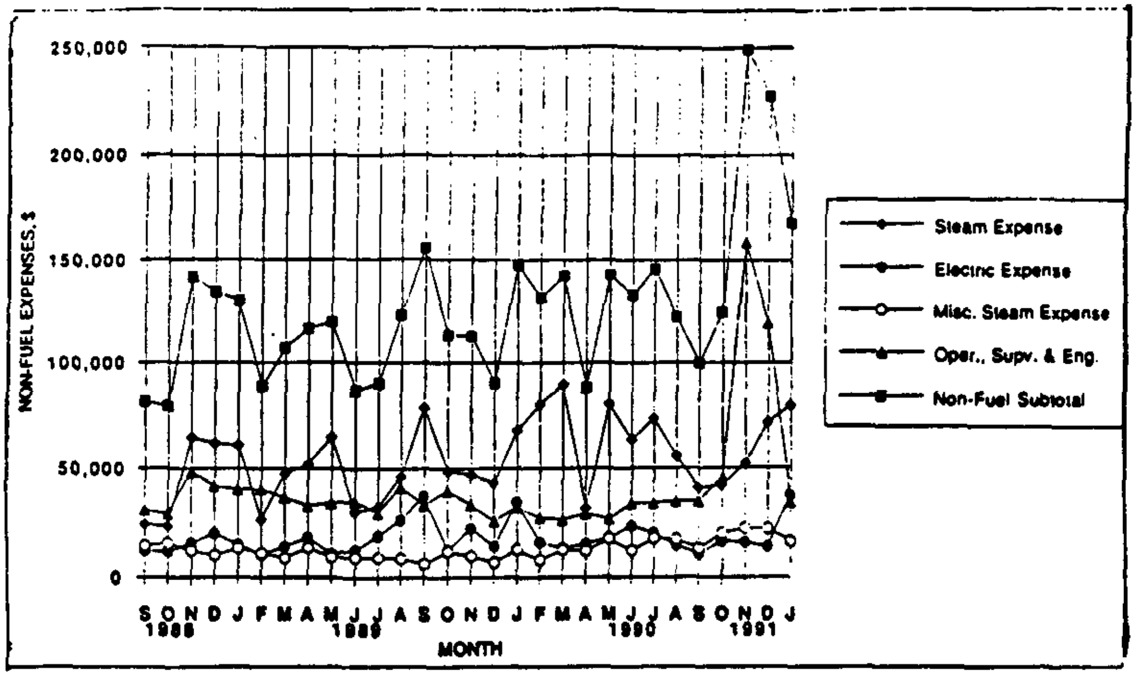


Figure 4-3. Summary of Monthly Non-Fuel Expenses.

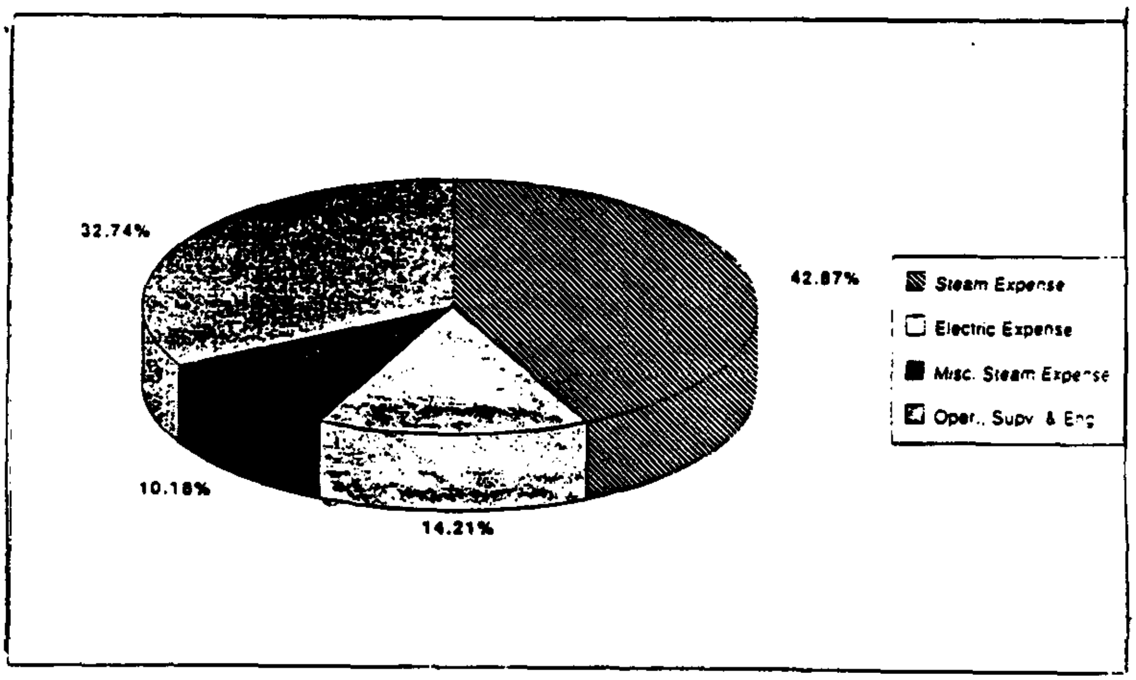


Figure 4-4. Breakdown of Total Non-Fuel Expenses from Sept. 1988 through Jan. 1991.

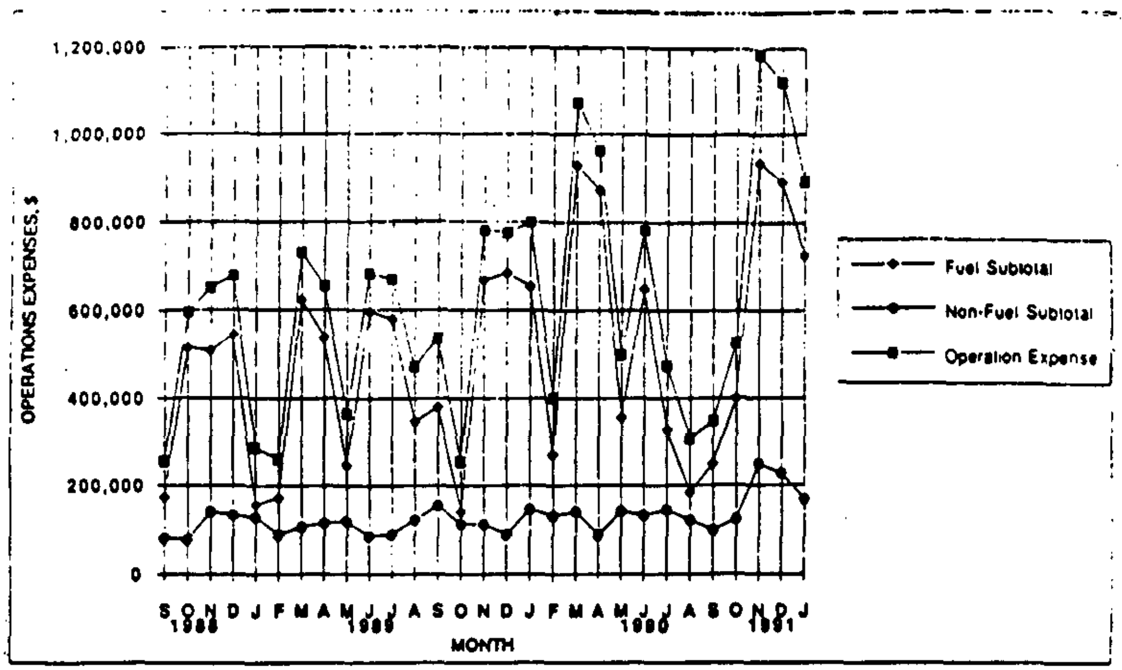


Figure 4-5. Summary of Monthly Operations Expenses (Fuel and Non-Fuel Costs)

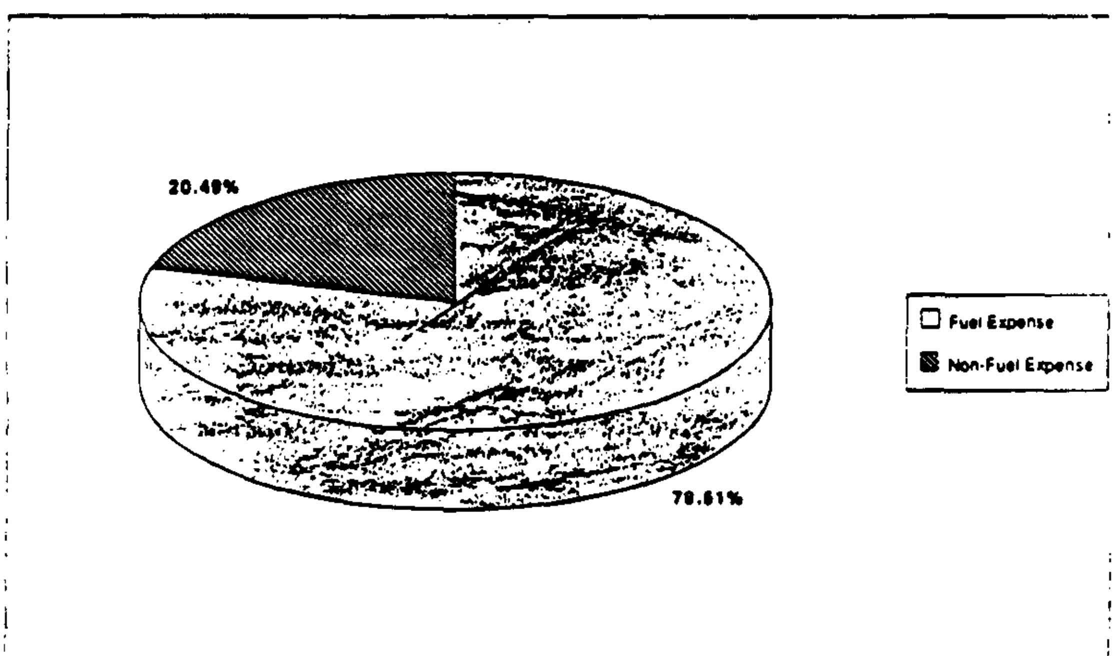


Figure 4-6. Breakdown of Total Operations Expenses from Sept. 1988 through Jan. 1991.

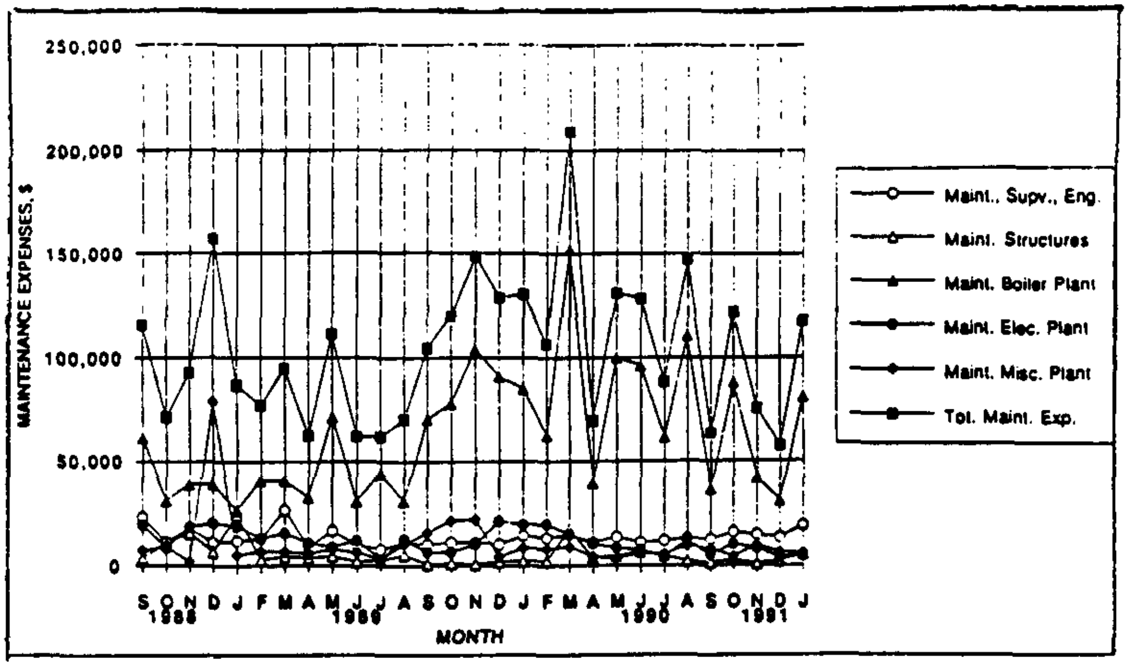


Figure 4-7. Summary of Monthly Maintenance Expenses

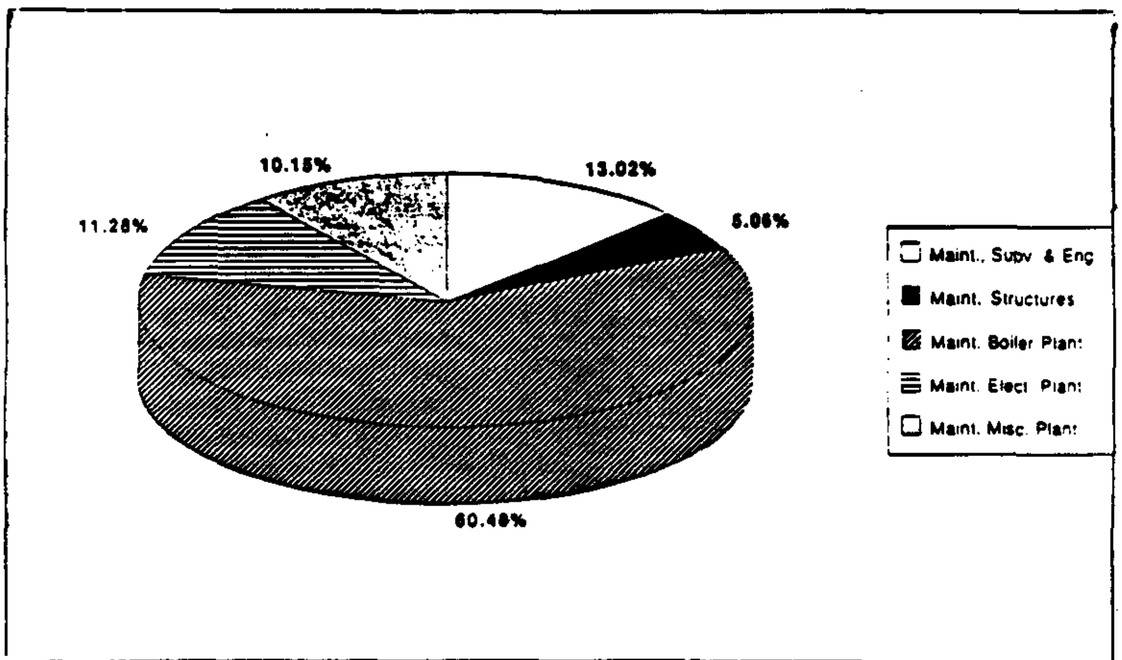


Figure 4-8. Breakdown of Total Maintenance Expenses from Sept. 1988 through Jan. 1991.

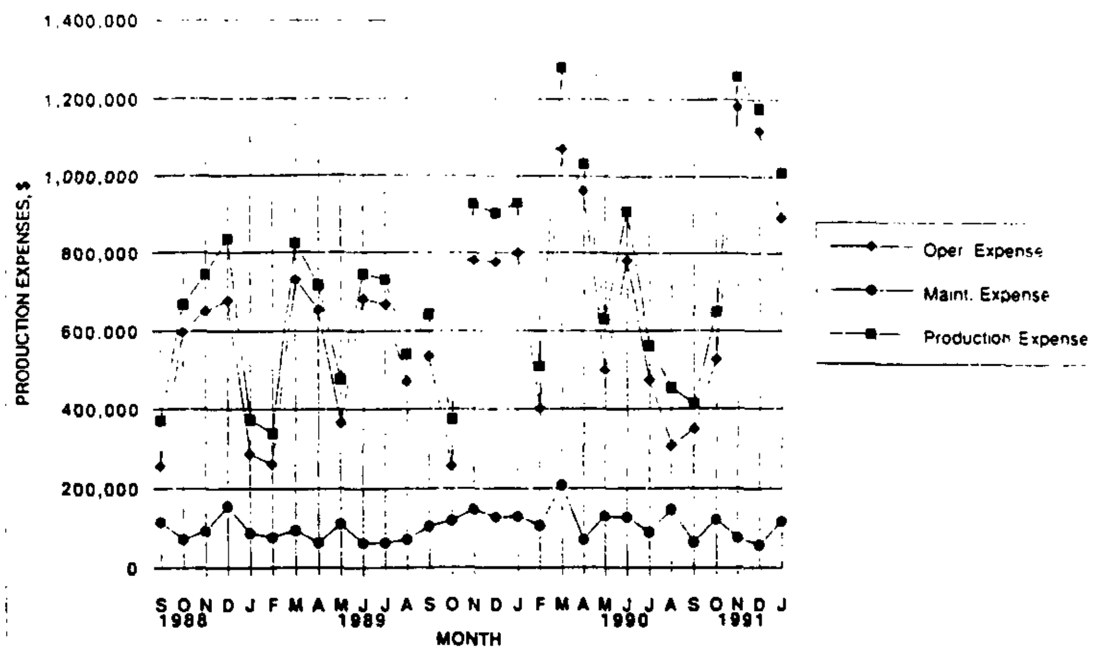


Figure 4-9. Summary of Monthly Production Expenses (Operations and Maintenance Costs).

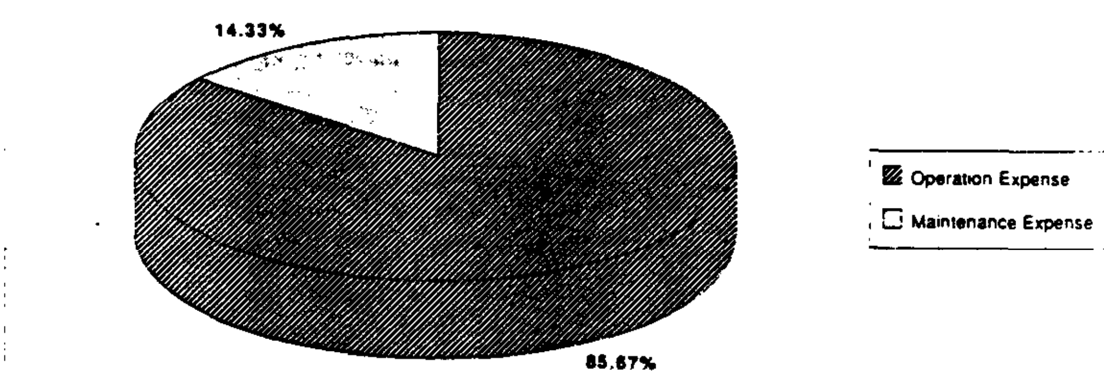


Figure 4-10. Breakdown of Total Production Expenses from Sept. 1988 through Jan. 1991.

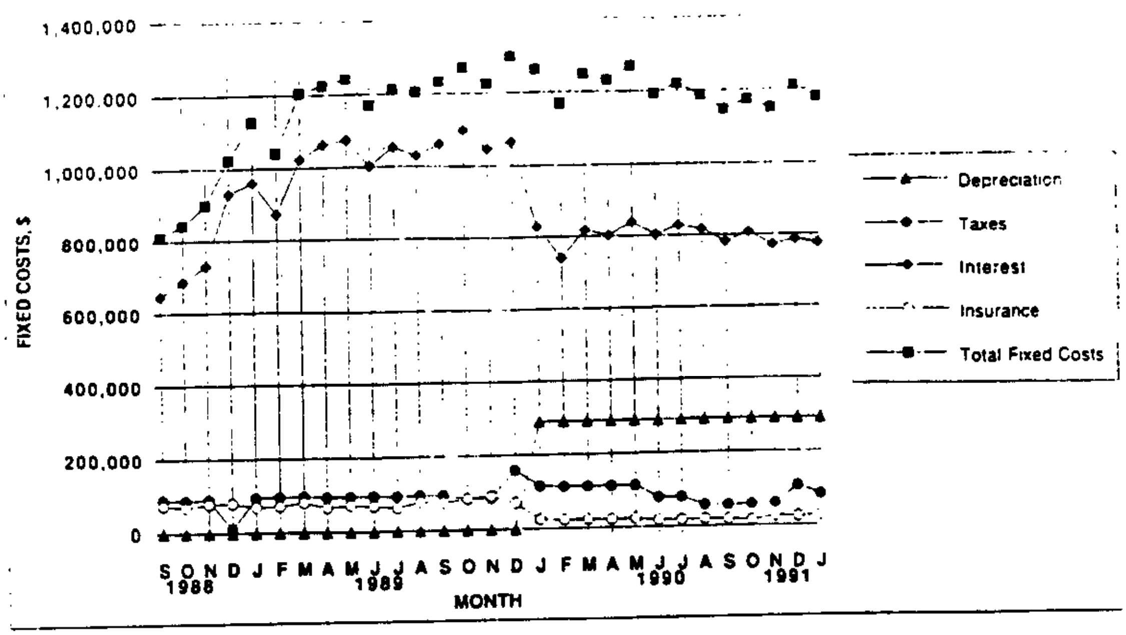


Figure 4-11. Summary of Monthly Fixed Costs (Taxes, Interest, Insurance & Depreciation).

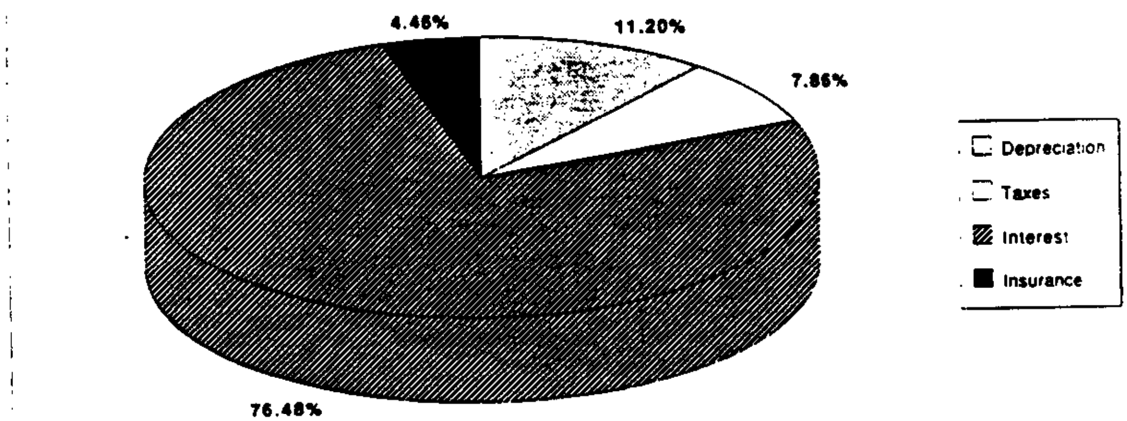


Figure 4-12. Breakdown of Total Fixed Costs from Sept. 1988 through Jan. 1991.

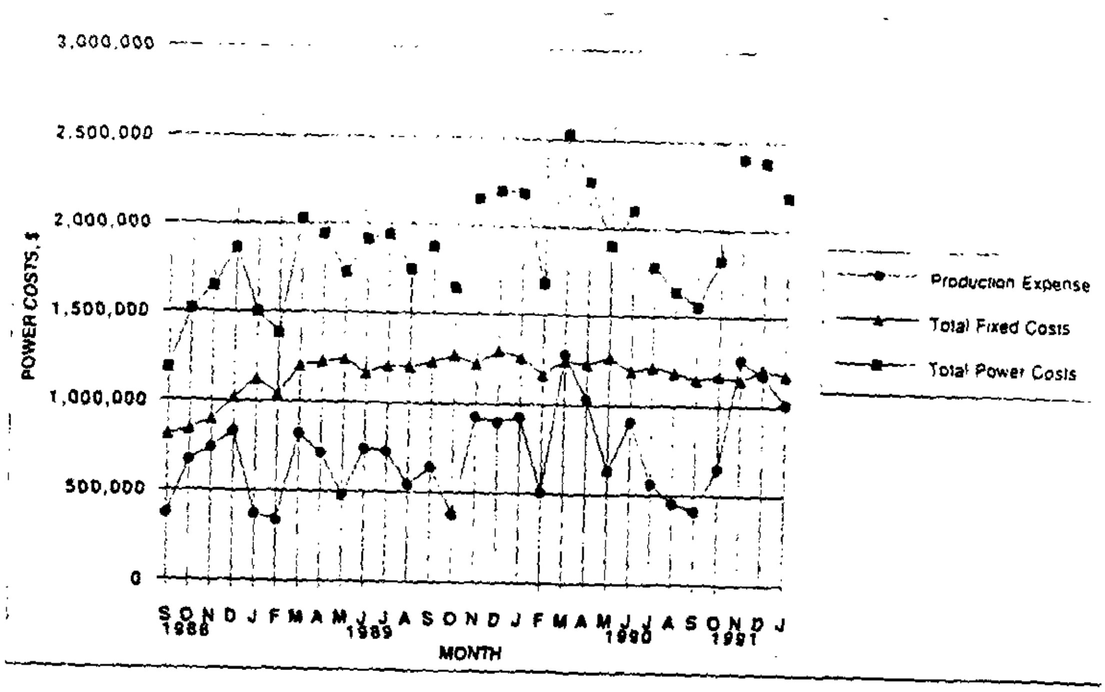


Figure 4-13. Summary of Monthly Power Costs (Production and Fixed Costs)

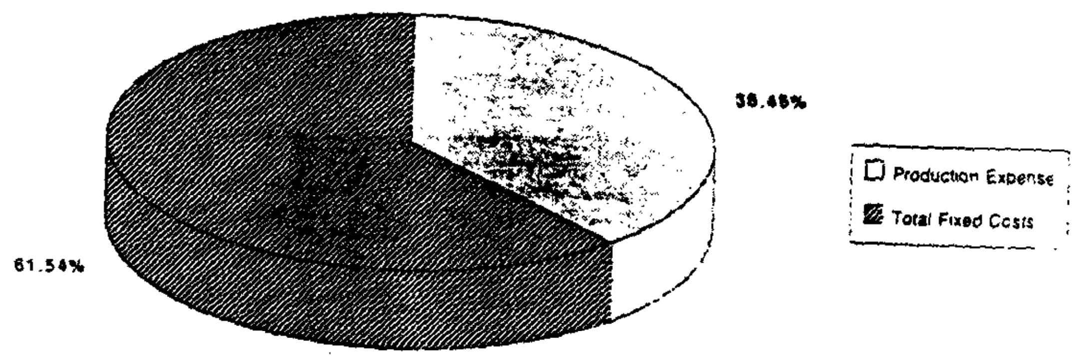


Figure 4-14. Breakdown of Total Power Costs from Sept. 1988 through Jan. 1991.

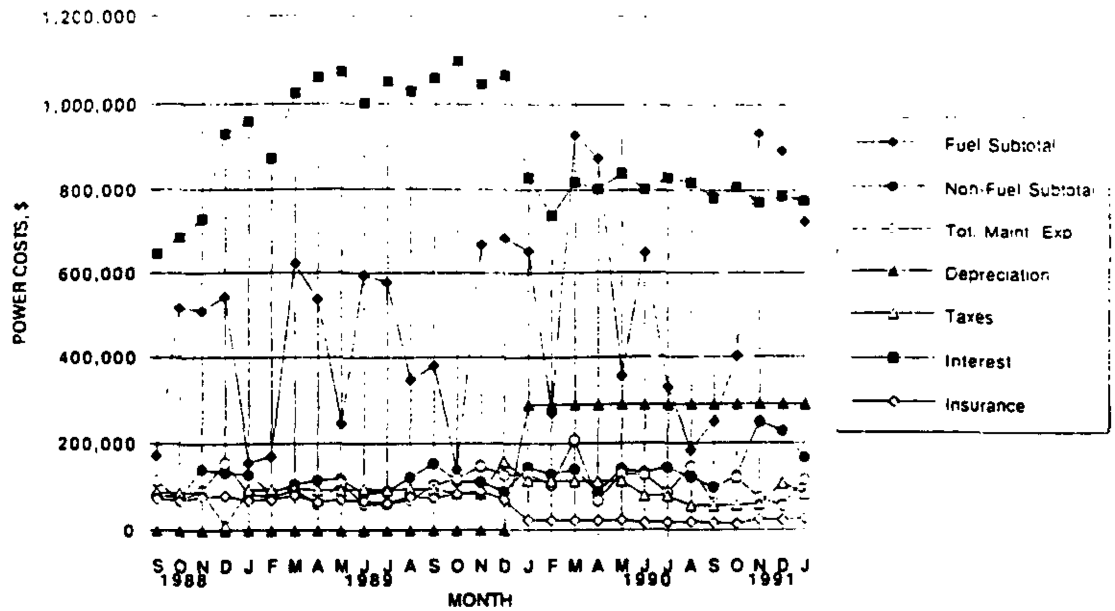


Figure 4-15. Summary of Monthly Power Costs Showing Additional Detail.

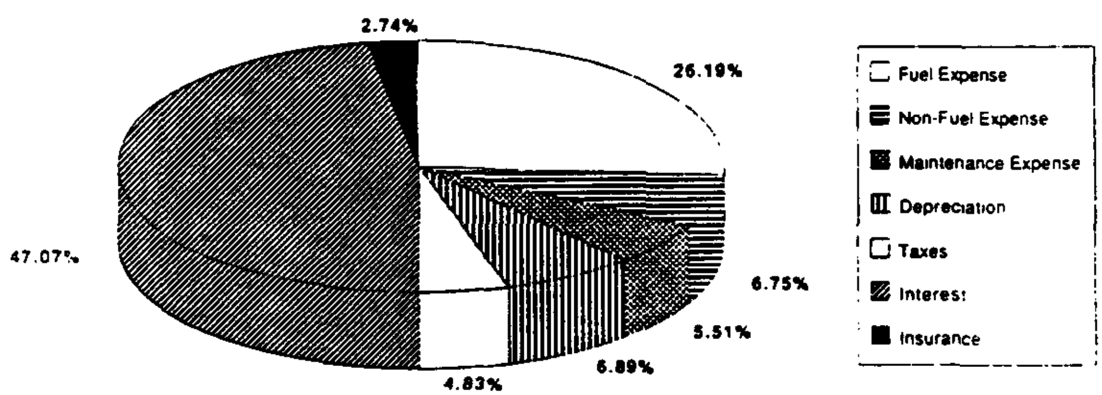


Figure 4-16. Breakdown of Total Power Costs from Sept. 1988 through Jan. 1991 (Additional Detail Shown)

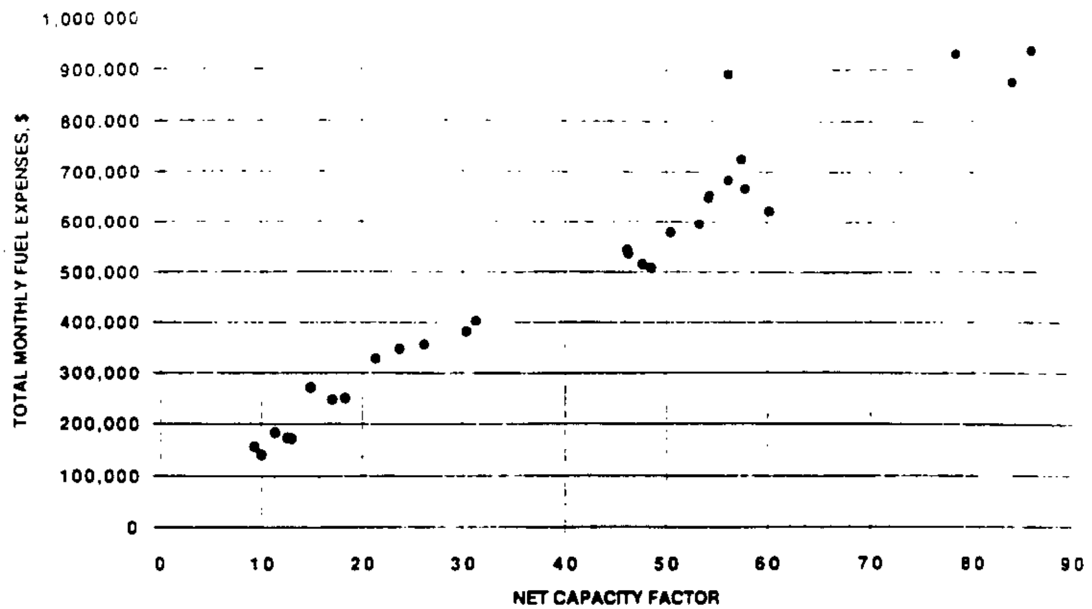


Figure 4-17. Monthly Fuel Expenses vs. Net Capacity Factor (Sept.1988-Jan.1991).

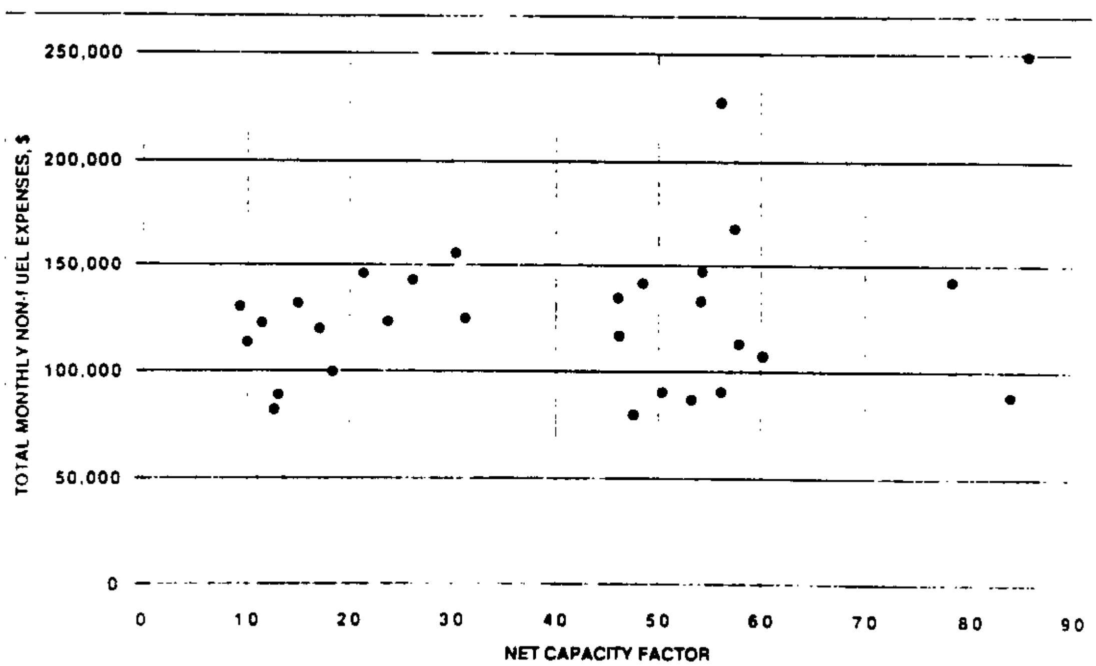


Figure 4-18. Monthly Non-Fuel Expenses vs. Net Capacity Factor (Sept.1988-Jan.1991).

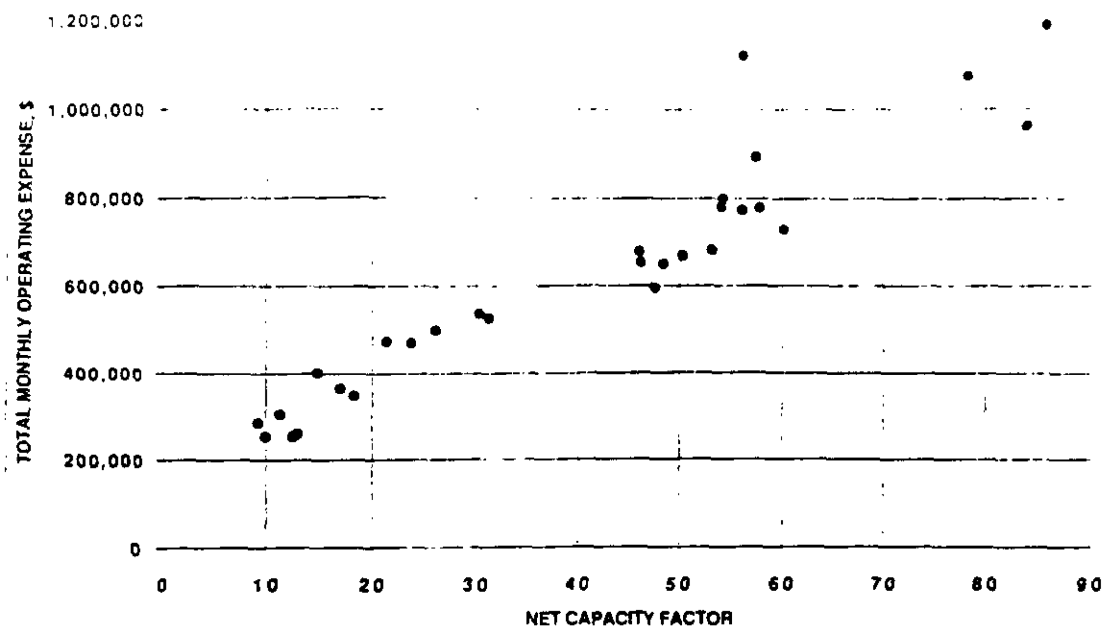


Figure 4-19. Monthly Operating Expenses vs. Net Capacity Factor (Sept.1988-Jan.1991).

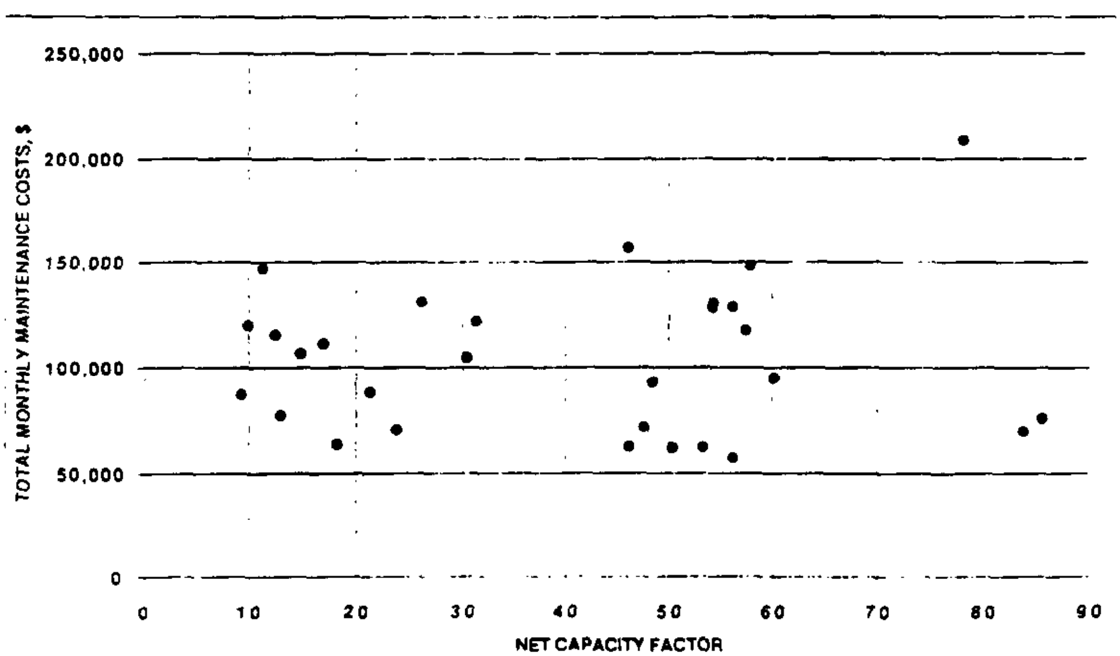


Figure 4-20. Monthly Maintenance Expenses vs. Net Capacity Factor (Sept.1988-Jan.1991).

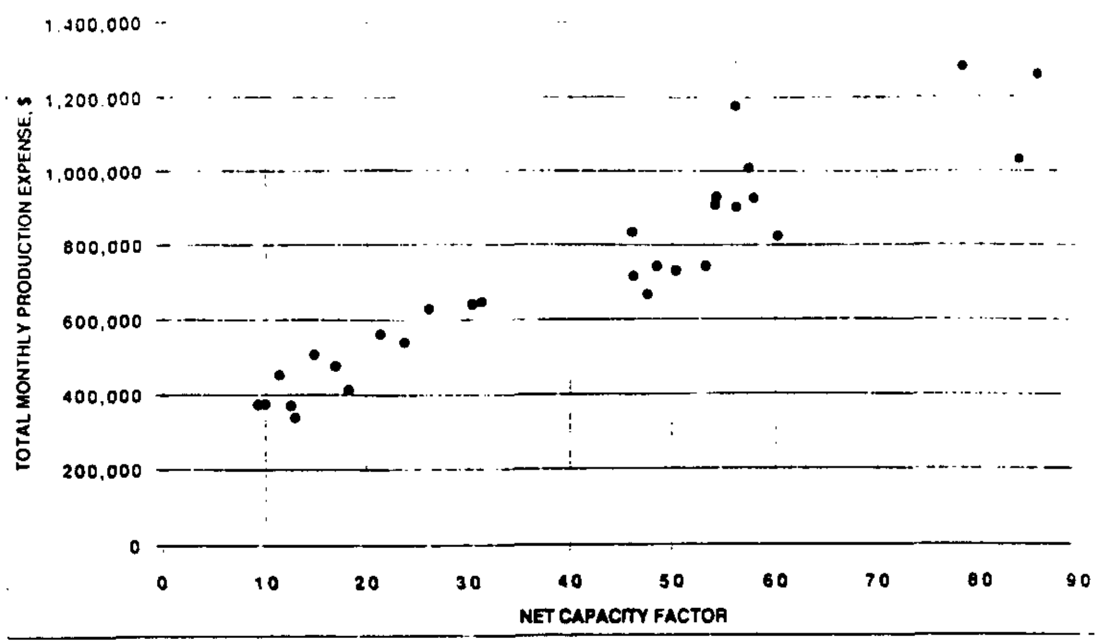


Figure 4-21. Monthly Production Expenses vs. Net Capacity Factor (Sept.1988-Jan.1991).

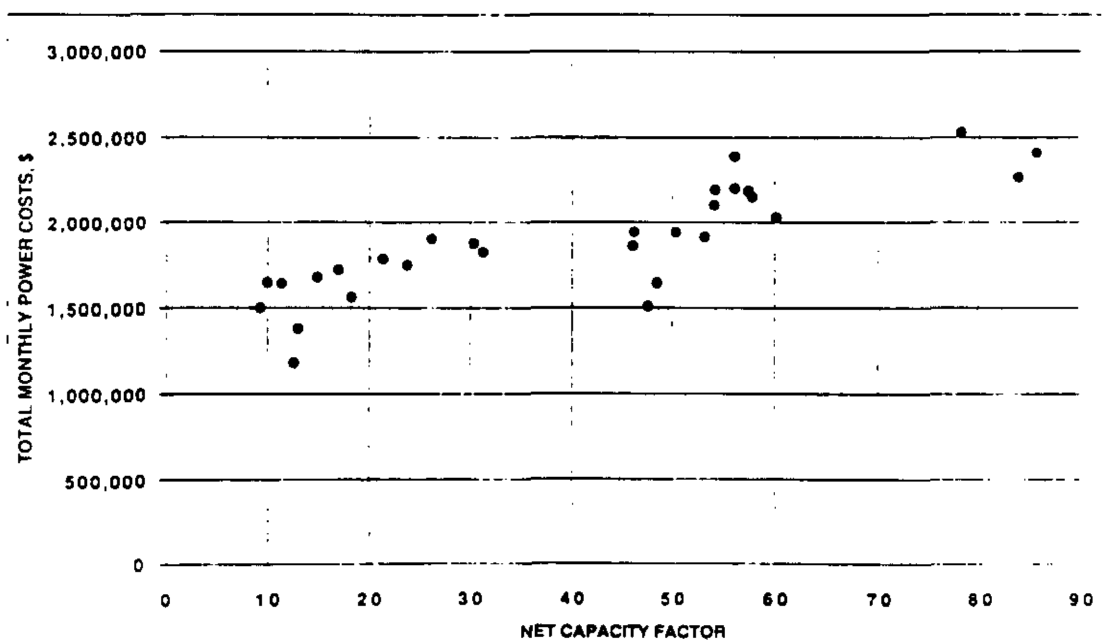


Figure 4-22. Monthly Power Costs vs. Net Capacity Factor (Sept.1988-Jan.1991).

- Figures 4-1 and 4-2 — Summary of monthly and total fuel costs. Total fuel costs include propane and coal costs.
- Figures 4-3 and 4-4 — Summary of monthly and total non-fuel costs. Non-fuel costs include steam expenses, electric expenses, miscellaneous steam expenses and operations, supervision and engineering associated with the above.
- Figures 4-5 and 4-6 — Summary of monthly and total operations expenses. Operations expenses include fuel and non-fuel costs.
- Figures 4-7 and 4-8 — Summary of monthly and total maintenance expenses. Maintenance expenses include maintenance of structures, boiler plant, electric plant, miscellaneous plant and the supervision and engineering associated with these categories.
- Figures 4-9 and 4-10 — Summary of monthly and total production expenses. Production expenses include total operations and maintenance costs.
- Figures 4-11 and 4-12 — Summary of monthly and total fixed costs. Total fixed costs include taxes, interest, insurance and depreciation.
- Figures 4-13 and 4-14 — Summary of monthly and total power costs. Total power costs include total production and fixed costs.
- Figures 4-15 and 4-16 — Summary of monthly and total power costs. These figures show total power cost in greater detail including expenses for fuel, non-fuel, maintenance, depreciation, taxes, interest and insurance.

In addition, total monthly costs for each of the above categories, except for fixed costs, are presented as a function of the monthly net capacity factor. These six figures are summarized as follows:

- Figure 4-17 — Monthly fuel expenses versus monthly net capacity factor.
- Figure 4-18 — Monthly non-fuel expenses versus monthly net capacity factor.
- Figure 4-19 — Monthly operating expenses versus monthly net capacity factor.
- Figure 4-20 — Monthly maintenance expenses versus monthly net capacity factor.
- Figure 4-21 — Monthly production expenses versus monthly net capacity factor.
- Figure 4-22 — Monthly power costs versus monthly net capacity factor.

The breakdown of costs associated with each of these major categories is shown in detail in Appendices C and D. This breakdown is summarized below. In addition to the categories shown, costs are subdivided further in the Appendices according to the unit costs for labor, labor overhead, supplies, expenses, travel and transportation, meals, consultants, outside services and other costs. Note that for the listings below, the numbers in front of each of the categories are consistent with the same reference numbers in Tables 4-3 through 4-6. The major categories are underlined.

1. <u>Operation, Supervision and Engineering</u>.
   - general supervision: power plant
   - general management: headquarters
   - engineering and performance testing

6. <u>Fuel Expenses</u>.
   - 2. supervision, analysis and testing: plant
   - 2. supervision, analysis and testing: headquarters
   - 2. handling of coal and oil
   - 2. purchasing coal
   - 2. waste disposal
   - 4. purchasing propane

11. <u>Non-Fuel Expenses</u>.
    - 7. <u>Steam Expenses</u>
      * boiler operation
      * pulverizer operation
      * on-site ash handling
      * stack monitoring
      * boiler water treatment
      * waste water treatment
      * National Pollution Discharge Elimination System(NPDES) permit and testing
      * environmental auditing

* laboratory operation
* miscellaneous and special services
* baghouse operations
* SO_2 removal system

- 8. <u>Electric Expenses</u>
  * turbine-generator and aux. equipment operation
  * cooling water systems operation
  * circ. water treatment
  * electric equipment operations

- 9. <u>Miscellaneous Steam Expenses</u>
  * plant office/headquarters expenses
  * buildings and grounds: plant
  * safety
  * miscellaneous
  * training

18. <u>Total Maintenance Expense</u>.

- 13. <u>Maintenance Supervision and Engineering</u>
  * maintenance supervision
  * maintenance engineering

- 14. <u>Maintenance of Buildings and Grounds</u>

- 15. <u>Maintenance of Boiler Plant</u>
  * maintenance of boilers
  * maintenance of coal handling equipment
  * maintenance of pulverizer and stoker equipment
  * maintenance of oil and gas equipment
  * maintenance of stack monitoring equipment
  * maintenance of boiler water treatment system
  * maintenance of waste water management system
  * maintenance of environmental station
  * maintenance of laboratory equipment
  * maintenance of ash handling system
  * maintenance of air & gas handling systems
  * maintenance of baghouse
  * maintenance of SO_2 removal system
  * maintenance of feed water system
  * maintenance of combustion control system

- 16. <u>Maintenance of Electric Plant</u>
  * maintenance of turbine & auxiliary equipment
  * maintenance of circ. & cooling water systems
  * maintenance of condensate system
  * maintenance of water treatment system
  * maintenance of electrical equipment
  * maintenance of liquid dielectric

- 17. <u>Maintenance of Miscellaneous Plant</u>
  * maintenance of service equipment
  * maintenance of compressed air equipment

ACCOUNT	Total Cost Test Period 9/88-1/91	Average Cost per Month	Cost per MWh Total	Percent of Total Power Cost (%)
OPERATION, SUPERVISION & ENGINEERING	1,210,175	41,730	1.4064	2.2[illegible]
- general supervision power plant	815.790	28.131	0.9481	1.49
- general management: headquarters	265,069	9,140	0.3080	0.48
- engineering and performance testing	129,316	4,459	0.1503	0.24
FUEL EXPENSES	**14,340,427**	**494,497**	**16.6657**	**26.19**
COAL EXPENSE	**13,643,303**	**470,459**	**15.8555**	**24.92**
- supervision, analysis and testing: plant	65,548	2,260	0.0762	0.12
- supervision, analysis and testing: headquarters	35,235	1,215	0.0409	0.06
- handling of coal	300,055	10,347	0.3487	0.55
- purchasing of coal	12,595,822	434,339	14.6382	23.01
- waste disposal	646,643	22,298	0.7515	1.18
PROPANE EXPENSE	**697,124**	**24,039**	**0.8102**	**1.27**
- purchasing propane	697,124	24,039	0.8102	1.27
NON-FUEL EXPENSES	**3,701,491**	**127,638**	**4.3017**	**6.76**
STEAM EXPENSES	**1,584,642**	**54,643**	**1.8416**	**2.89**
- boiler operation	213,949	7,378	0.2486	0.39
- pulverizer operation	162,633	5,608	0.1890	0.30
- on-site ash handling	178,204	6,145	0.2071	0.33
- stack monitoring	45,670	1,575	0.0531	0.08
- boiler water treatment	137,223	4,732	0.1595	0.25
- waste water management	13,167	454	0.0153	0.02
- NPDES permit and testing	26,637	919	0.0310	0.05
- environmental auditing	25,076	865	0.0291	0.05
- laboratory operation	69,027	2,380	0.0802	0.13
- misc. and special services	4,589	158	0.0053	0.01
- baghouse operations	-89	-3	-0.0001	0.00
- SO2 removal	708,556	24,433	0.8234	1.29
ELECTRIC EXPENSES	**530,205**	**18,283**	**0.6162**	**0.97**
- turbine-generator & auxiliary equipment	142,998	4,931	0.1662	0.26
- cooling water system operation	107,404	3,704	0.1248	0.20
- circ. water treatment system	171,589	5,917	0.1994	0.31
- electric equipment operation	108,214	3,732	0.1258	0.20
MISCELLANEOUS STEAM EXPENSES	**376,469**	**12,982**	**0.4375**	**0.69**
- plant office expenses	49,464	1,706	0.0575	0.09
- buildings and grounds	108,104	3,728	0.1256	0.20
- safety	49,573	1,709	0.0576	0.09
- miscellaneous	26,376	910	0.0307	0.05
- training	142,951	4,929	0.1661	0.26
OPERATION EXPENSE	**18,041,918**	**622,135**	**20.9674**	**32.95**
FUEL EXPENSE	**14,340,427**	**494,497**	**16.6657**	**26.19**
NON-FUEL EXPENSE	**3,701,491**	**127,638**	**4.3017**	**6.76**

Table 4-7. Summary of Total Power Costs from September 1988 through January 1991.

ACCOUNT	Total Cost Test Period 9/88-1/91	Average Cost per Month	Cost per MWh Total	Percent of Total Power Cost (%)
MAINTENANCE EXPENSES	3,016,722	104,025	3.5059	5.51
SUPERVISION AND ENGINEERING	392,918	13,549	0.4566	0.72
- supervision	289,789	9,993	0.3368	0.53
- engineering	103,129	3,556	0.1199	0.19
BUILDINGS AND GROUNDS	152,770	5,268	0.1775	0.28
- buildings and grounds	152,770	5,268	0.1775	0.28
BOILER PLANT	1,824,419	62,911	2.1202	3.33
- boilers	547,986	18,896	0.6368	1.00
- coal handling	281,153	9,695	0.3267	0.51
- pulverizer	6,374	220	0.0074	0.01
- propane equipment	28,873	996	0.0336	0.05
- stack monitoring equipment	48,068	1,658	0.0559	0.09
- boiler water treatment system	50,595	1,745	0.0588	0.09
- waste water management system	4,346	150	0.0051	0.01
- environmental station	0	0	0.0000	0.00
- laboratory equipment	3,713	128	0.0043	0.01
- ash handling system	219,255	7,561	0.2548	0.40
- air and gas handling system	31,187	1,075	0.0362	0.06
- baghouse	90,259	3,112	0.1049	0.16
- SO2 removal system	92,412	3,187	0.1074	0.17
- feedwater system	246,583	8,503	0.2866	0.45
- combustion control system	173,615	5,987	0.2018	0.32
ELECTRIC PLANT	340,323	11,735	0.3955	0.62
- turbine and auxiliary equipment	146,657	5,057	0.1704	0.27
- circ. & cooling water system	102,835	3,546	0.1195	0.19
- condensate system	21,526	742	0.0250	0.04
- water treatment system	27,213	938	0.0316	0.05
- electrical equipment	42,091	1,451	0.0489	0.08
MISCELLANEOUS PLANT	306,292	10,562	0.3560	0.56
- service equipment	25,494	879	0.0296	0.05
- compressed air equipment	88,544	3,053	0.1029	0.16
- common equipment	4,689	162	0.0054	0.01
- tools and test equipment	129,308	4,459	0.1503	0.24
- fire safety equipment	20,594	710	0.0239	0.04
- training equipment	16,257	561	0.0189	0.03
- vehicles	19,733	680	0.0229	0.04
- miscellaneous	1,673	58	0.0019	0.00
TOTAL PRODUCTION EXPENSE	21,058,640	726,160	24.4733	38.46
OPERATION EXPENSE	18,041,918	622,135	20.9674	32.95
MAINTENANCE EXPENSE	3,016,722	104,025	3.5059	5.51

Table 4-7. Summary of Total Power Costs from September 1988 through January 1991 (continued).

ACCOUNT	Total Cost Test Period 9/88-1/91	Average Cost per Month	Cost per MWh Total	Percent of Total Power Cost (%)
TOTAL FIXED COSTS	33,692,178	1,161,799	39.1553	61.54
DEPRECIATION	3,774,590	130,158	4.3866	6.89
TAXES	2,646,649	91,264	3.0758	4.83
-property taxes	2,345,678	80,885	2.7260	4.28
- taxes-FICA	282,929	9,756	0.3288	0.52
- taxes-CUTA	11,556	398	0.0134	0.02
- taxes-FUTA	6,486	224	0.0075	0.01
INTEREST	**25,768,524**	**888,570**	**29.9469**	**47.07**
- long term interest	23,805,216	820,870	27.6652	43.48
- interest during construction	1,963,308	67,700	2.2817	3.59
INSURANCE	**1,502,415**	**51,807**	**1.7460**	**2.74**
- property insurance	197,945	6,826	0.2300	0.36
- injury and property damage	169,802	5,855	0.1973	0.31
- pension and benefit	318,765	10,992	0.3705	0.58
- general and administrative	815,904	28,135	0.9482	1.49
TOTAL POWER COSTS	**54,750,819**	**1,887,959**	**63.6286**	**100.00**
TOTAL PRODUCTION EXPENSE	**21,058,640**	**726,160**	**24.4733**	**38.46**
TOTAL FIXED COSTS	**33,692,178**	**1,161,799**	**39.1553**	**61.54**

NOTE: 29 MONTHS USED IN AVERAGE MONTHLY COST CALCULATION.
COST PER MWh BASED ON 860,475 MWh GENERATED BETWEEN 9/88 AND 1/91.

Table 4-7. Summary of Total Power Costs from September 1988 through January 1991 (continued).

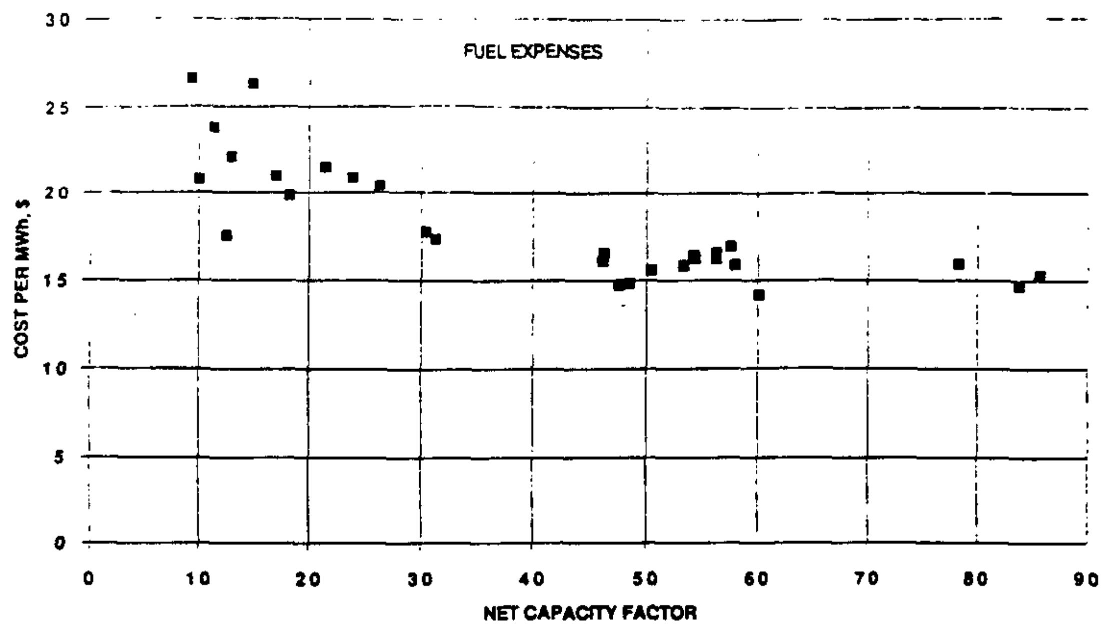


Figure 4-23. Monthly Fuel Expenses per MWh versus Net Capacity Factor: 9/88 - 1/91.

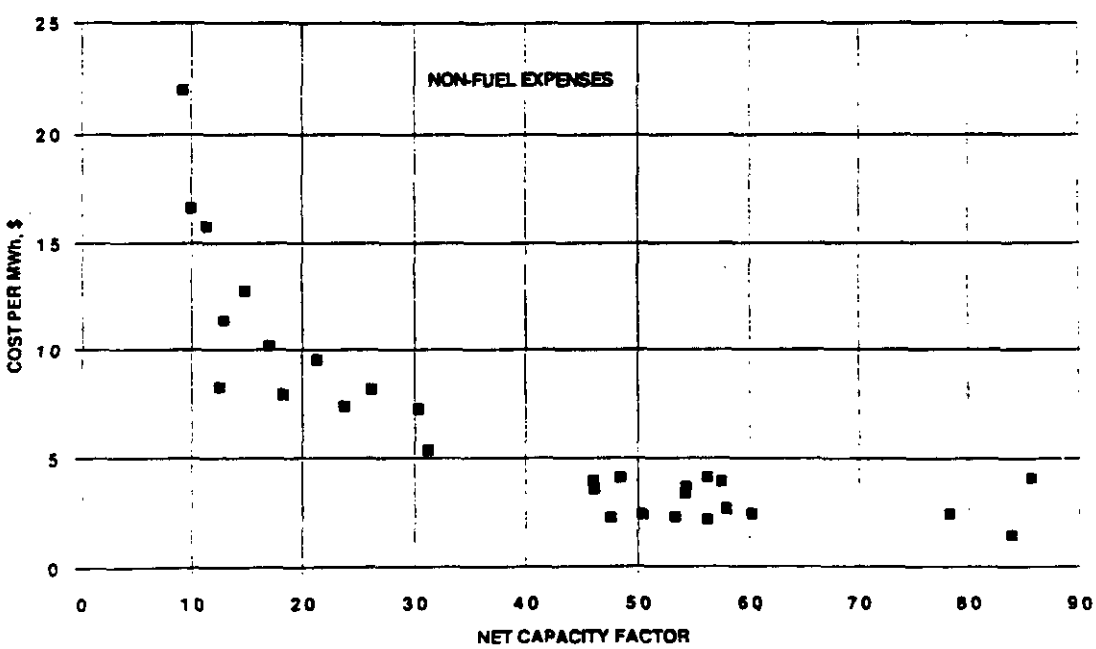


Figure 4-24. Monthly Non-Fuel Expenses per MWh versus Net Capacity Factor: 9/88 - 1/91.

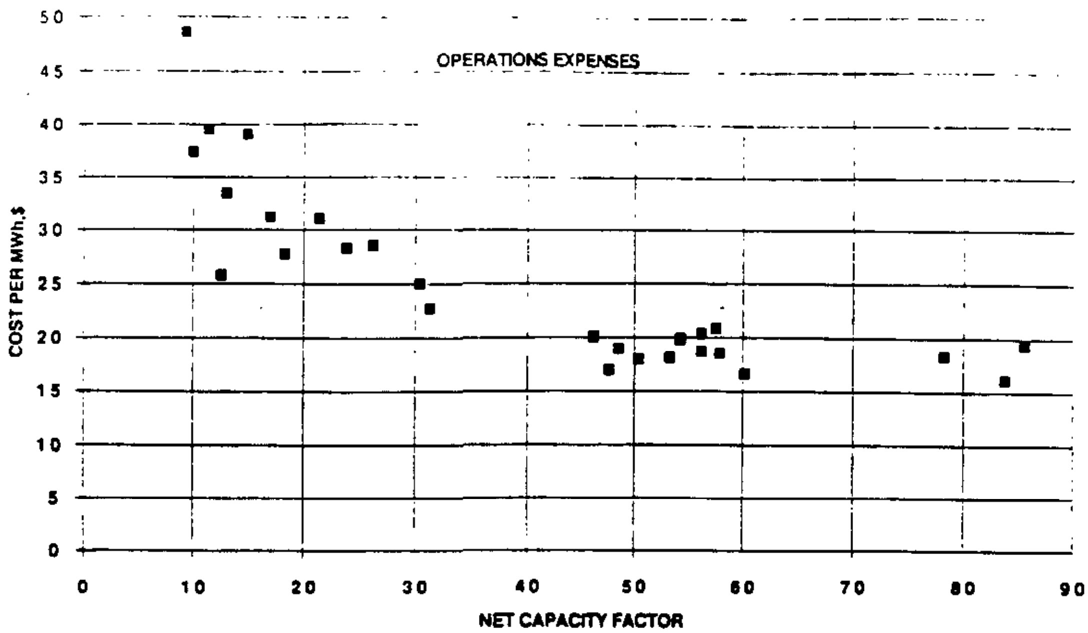


Figure 4-25. Monthly Operations Expenses per MWh vs. Net Capacity Factor: 9/88 - 1/91.

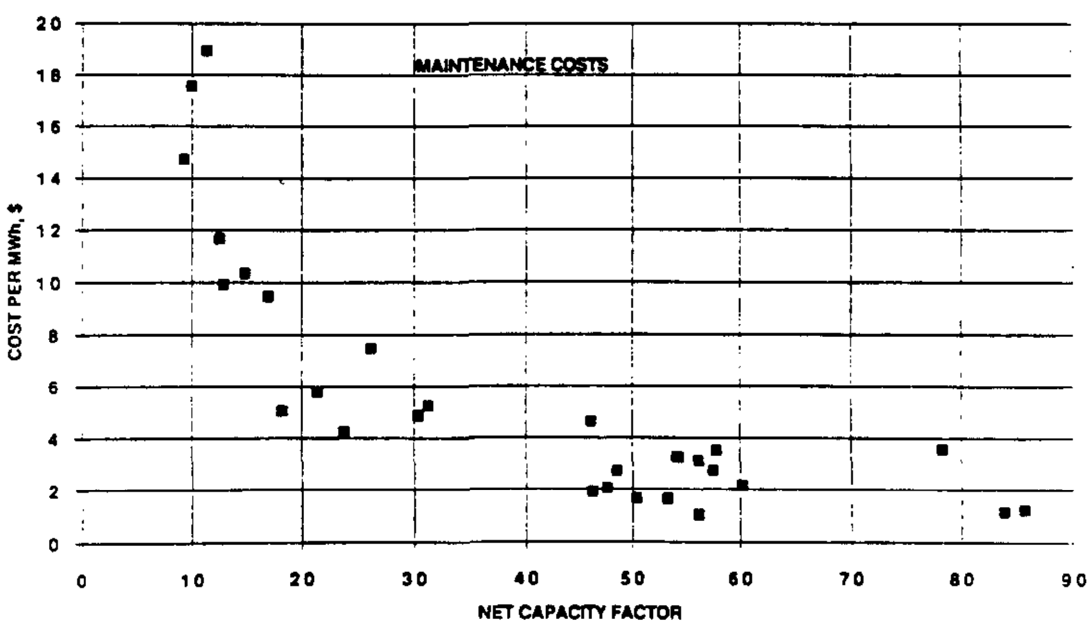


Figure 4-26. Monthly Maintenance Expenses per MWh vs. Net Capacity Factor: 9/88 - 1/91.

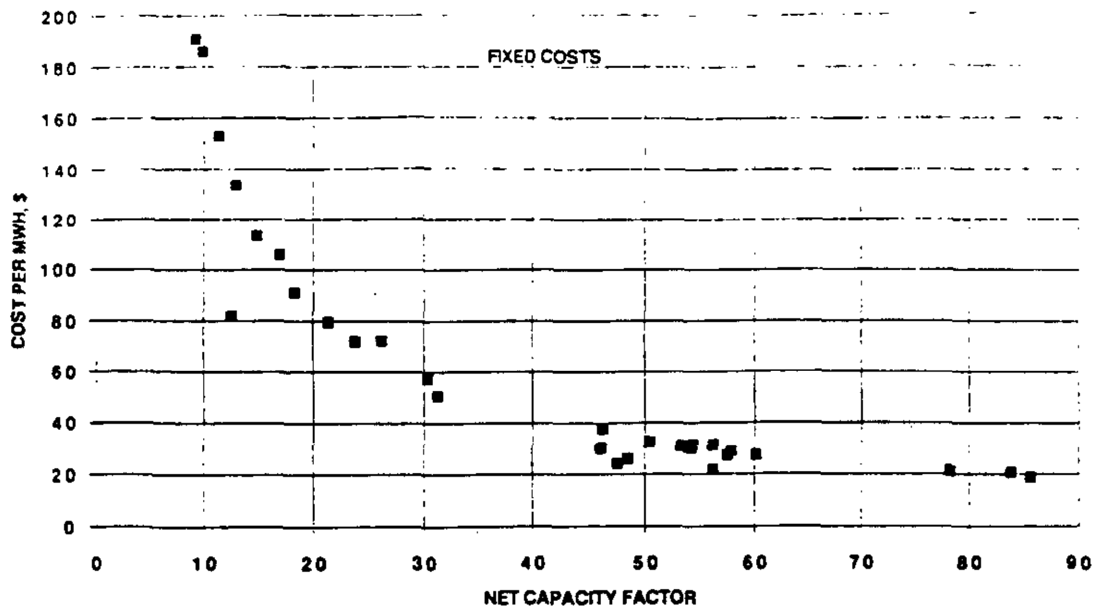


Figure 4-27. Monthly Fixed Costs per MWh versus Net Capacity Factor: 9/88 - 1/91.

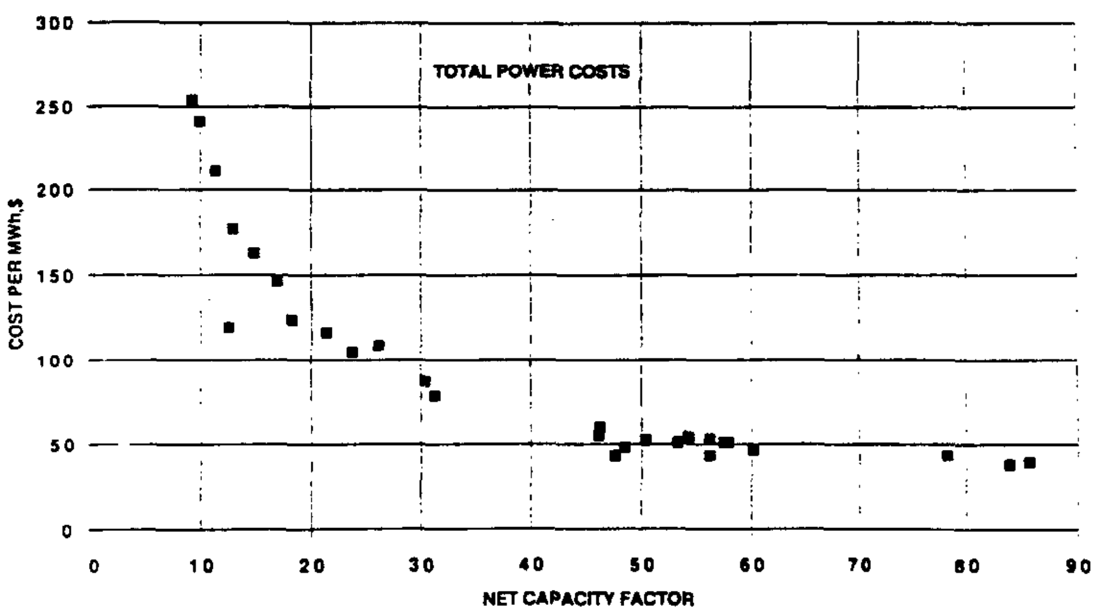


Figure 4-28. Monthly Power Costs per MWh versus Net Capacity Factor: 9/88 - 1/91.

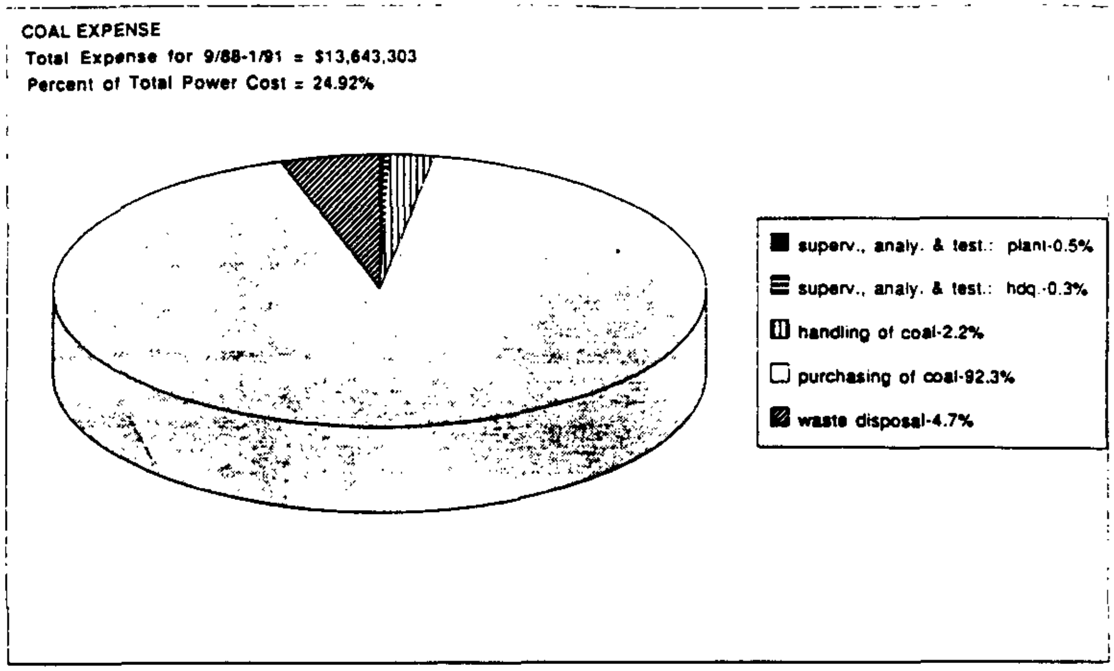


Figure 4-29. Breakdown of Total Coal Expense from Sept.1988 - Jan.1991.

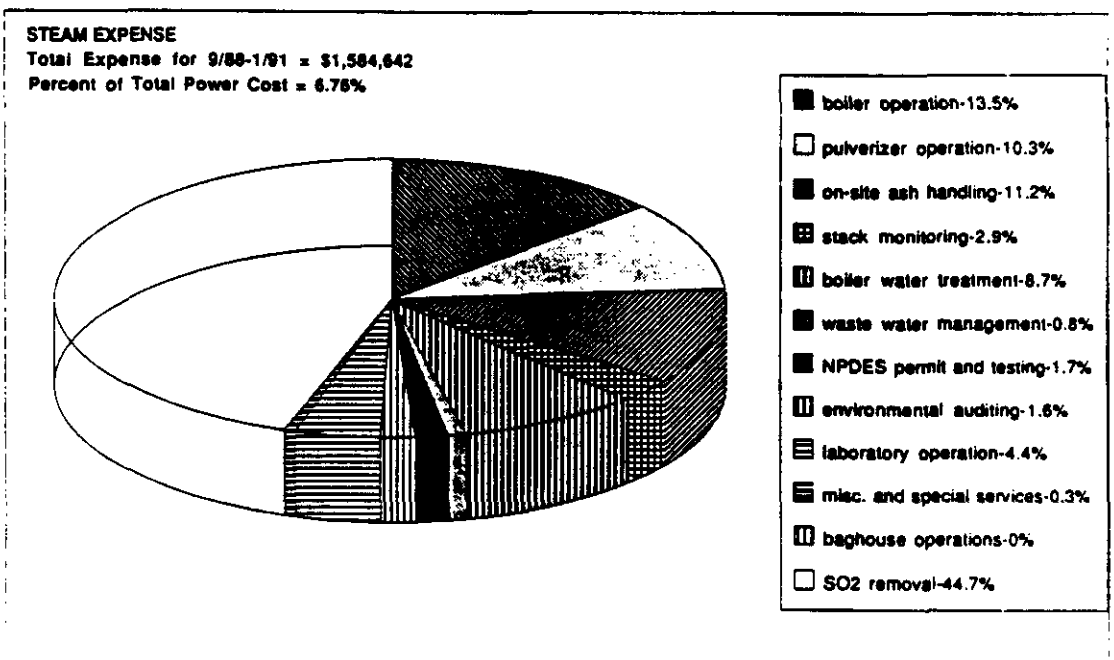


Figure 4-30. Breakdown of Total Steam Expenses from Sept.1988 - Jan.1991.

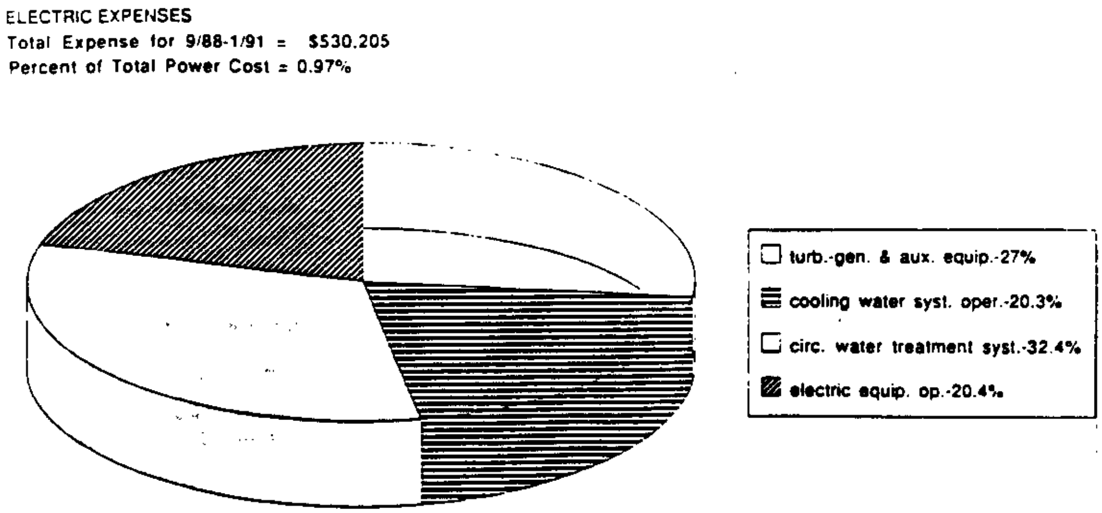


Figure 4-31. Breakdown of Total Electric Expenses from Sept.1988 - Jan.1991.

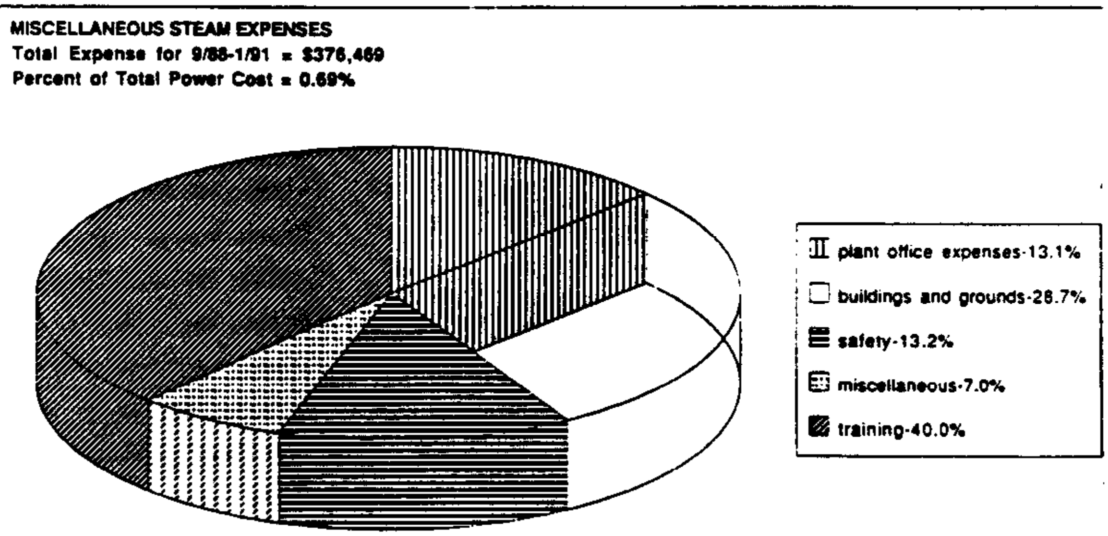


Figure 4-32. Breakdown of Total Miscellaneous Steam Expenses from Sept.1988 - Jan.1991.

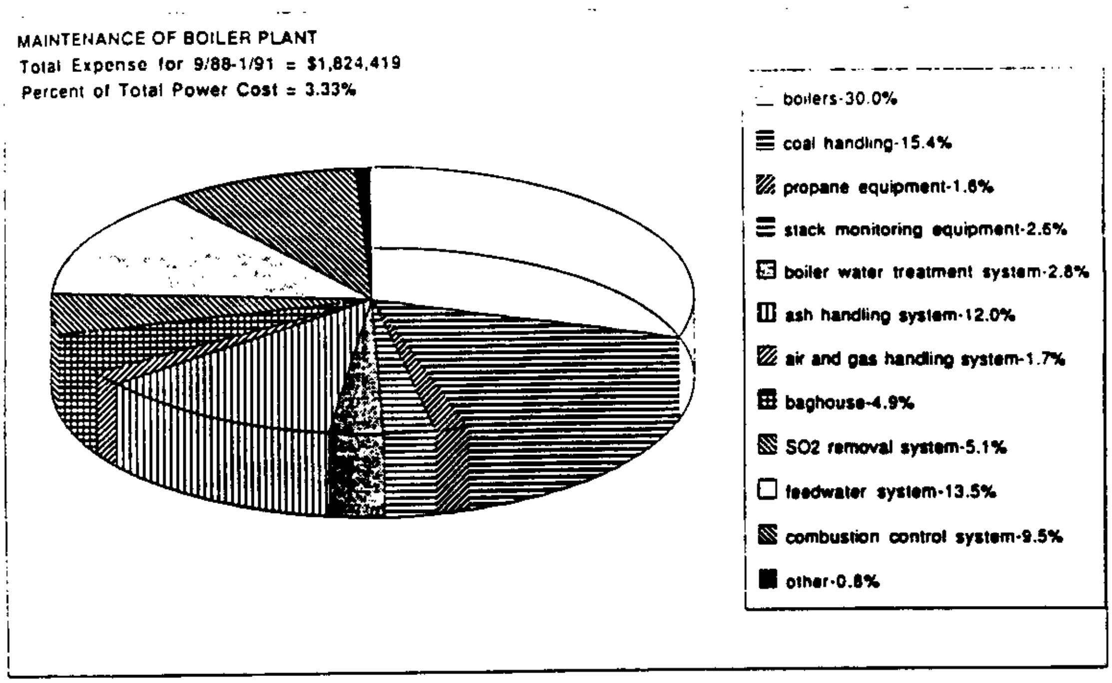


Figure 4-33. Breakdown of Boiler Plant Maintenance Expenses from Sept.1988 - Jan.1991.

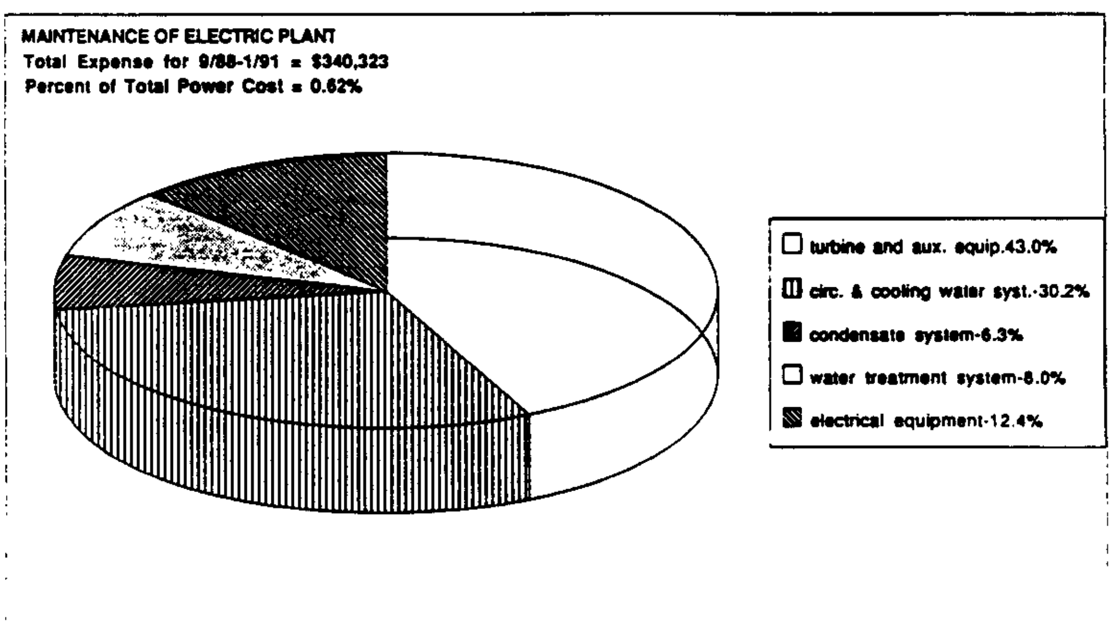


Figure 4-34. Breakdown of Electric Plant Maintenance Expenses from Sept.1988 - Jan.1991.

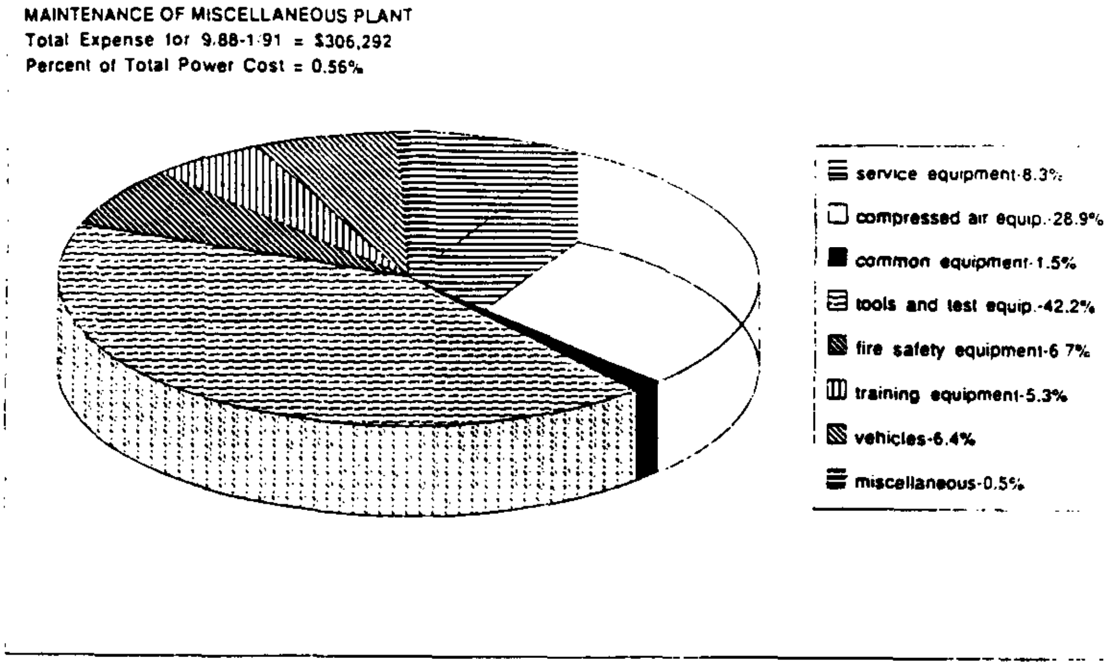


Figure 4-35. Breakdown of Miscellaneous Plant Maintenance Expenses from Sept.1988 - Jan.1991.

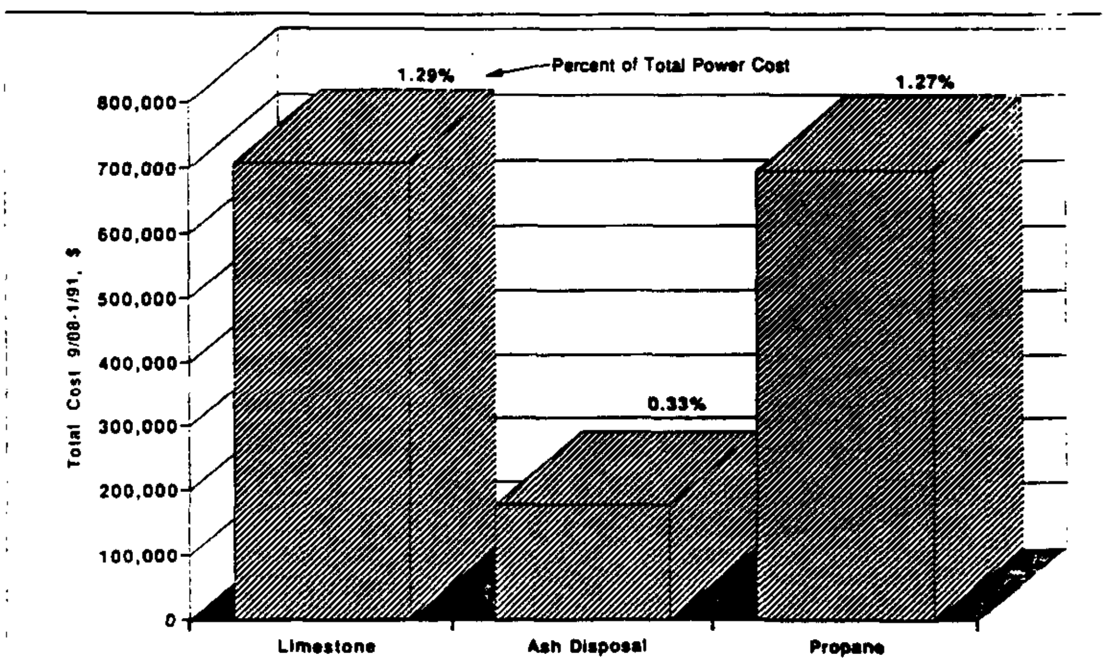


Figure 4-36. Summary of Total Limestone, Ash Disposal, and Propane Costs from Sept.1988 - Jan.1991.

* maintenance of communication equipment
* maintenance of tools and test equipment
* maintenance of fire safety equipment
* maintenance training
* maintenance of vehicles
* maintenance of miscellaneous

19. Total Production Expense.

- 12. Operation Expense
- 18. Maintenance Expense

24. Total Fixed Costs.
- 20. Depreciation
- 21. Taxes
  * property taxes
  * taxes - FICA (Federal Insurance Contribution Act)
  * taxes - CUTA (Colorado Unemployment Tax Act)
  * taxes - FUTA (Federal Unemployment Tax Act)

- 22. Interest
  * long term interest
  * interest during construction
  * other interests

- 23. Insurance/General Administrative
  * property insurance
  * injury and property damage
  * pension and benefit
  * general and administrative

25. Total Power Costs.
- 19. Total Production Costs
- 24. Total Fixed Costs

The cost data for the entire test period has been broken down further in Table 4-7 and in Figures 4-23 through 4-36. Since the previous tables (4-3 through 4-6) listed total costs of only the major categories on an annual basis, Table 4-7 summarizes the major and minor category costs for the entire test period from September 1988 through January 1991 according to the same major categories shown in Form 12d and the minor cost categories in Appendices C and D. In addition, the table shows the average cost of each category per month based on a 29 month accumulated cost period. It also shows the cost per megawatt hour of net electricity generated based on a total for the period of 860,475 MWh. The final column of this table shows the percent of the Total Power cost accounted for by a given category.

Figures 4-23 through 4-28 show power costs on a megawatt hour basis versus the net plant capacity factor for the major category areas. Figures are shown for fuel, non-fuel, operations, maintenance, fixed and total power costs. The monthly megawatt hour generation quantities are contained in Appendix D and are summarized in Table 3-1 of Section 3. Presentation of cost data in this fashion (as opposed to total monthly costs shown in Figures 4-17 through 4-22) reveals the influence of capacity factor on normalized power costs.

Figures 4-29 through 4-35 show the breakdown of the major category costs shown in Table 4-7 using pie charts to show the relative magnitude of each minor category. Each of these figures lists the percentage of the total major category cost represented by the minor category, and also lists the total expense and percentage of total power costs contributed by the major category. Pie charts have been included for detailed coal expenses, steam expenses, electric expenses, miscellaneous steam expenses, maintenance of boiler plant, maintenance of electric plant, and maintenance of miscellaneous plant.

Costs associated with limestone for SO_2 control, and ash removal (fly ash and bottom ash) are listed under steam expenses in Tables 4-3 through 4-7. Limestone costs include the cost of raw limestone, preparation, and feed. These costs are depicted graphically in Figure 4-36. The cost of propane for unit start-up has been added to this figure to indicate relative magnitudes of these expenses. The percentage each of these contribute to total power costs is also listed in the figure.

4.2.2 Discussion of Monthly Power Costs

4.2.2.1 Overview.

The total power cost for the period from September 1988 through January 1991, including operations (fuel and non-fuel costs), maintenance, and fixed costs (depreciation, interest, taxes and insurance), was $54,750,819. During this period, the Nucla Station generated and sold 860,475 net MWh of electricity. This results in an average cost for generation of $63.6286 per MWh. The average net capacity factor for this interval was 40.6 percent. The plant availability and equivalent availability for this period was 60.1 percent and 56.5 percent, respectively. Based on these figures, it can be estimated that the unit operated, on average, between 65% and 75% capacity factors during available periods.

A comparison of these operating availabilities and capacity factors with averages compiled by the North American Reliability Council Generating Availability Data System for coal-fired units in the 100-199 MWe size range between 1984 and 1988 lists average operating availability and capacity factors of 83.9% and 49.7%, respectively. The lower values for the Nucla CFB are the result of several factors including equipment reliability, part-load testing as part of the demonstration program and lack of demand for power during certain periods. Equipment reliability problems are discussed in more detail in Section 5 of this report.

Monthly costs for power generation for 1988 through 1991 are summarized in Tables 4-3 through 4-6 in Section 4.2.1 using a format consistent with REA Form 12d. The tables also indicate the REA account number and totals for the year. Data in these tables were then used to generate Figures 4-1 through 4-28.

4.2.2.2 Fuel Costs.
Figures 4-1 and 4-2 show monthly fuel costs for the duration of the test period between September 1988 and January 1991, along with a breakdown of total fuel costs for this period. Coal costs accounted for approximately 95 percent of the total fuel costs. The wide range in total fuel costs between $157k and $893k represents the variation in unit capacity factor for the period, and therefore, in the quantity of coal consumed. This is shown graphically in Figure 4-17. Propane, used for unit start-up, accounted for approximately 5 percent of the total fuel costs, as shown in Figure 4-2. This cost should decrease as plant availability increases and the number of unit start-ups decreases.

Between 1987 and 1989, coal was purchased from a local mine at a cost of $1.08/MMBtu. Following the termination of the contract period for this fuel, competitive bids were solicited and a new lowest cost fuel was selected from the Salt Creek coal mine at $1.26/MMBtu. This mine is located approximately 150 miles north of the Nucla station with no rail access. The new cost represents a 17 percent increase in coal costs which, as will be seen in Section 4.2.2.4, account for almost 80 percent of the total operating costs. There are limited quantities of minable coal available in close proximity (i.e., less than 25 miles) to the Nucla Station. Over time, these reserves could supply a more cost effective fuel source to the Nucla Station, yet the transportation factor may become a major consideration.

4.2.2.3 Non-Fuel Costs.
These are costs associated with operating the plant subdivided into steam, electric, miscellaneous steam, and operation, supervision and engineering expenses. Figures 4-3 and 4-4 show total monthly expenses for these quantities along with the breakdown of the totals for the testing period from September 1988 through January 1991. Steam and electric expenses account for approximately 75 percent of the total operating cost. Non-fuel expenses are also plotted versus

the net capacity factor in Figure 4-18. Except for additional costs associated with the test program from November 1990 through January 1991, non-fuel expenses remained relatively constant with capacity factor.

4.2.2.4 Operations Expenses.
Operations expenses represent the sum of fuel and non-fuel expenses. Monthly totals are presented in Figures 4-5 and 4-6 and are plotted versus capacity factor in Figure 4-19. The monthly variability reflects the changes in fuel costs associated with different unit capacity factors. As shown in Figure 4-6, fuel expenses represent approximately 80 percent of the operations expenses.

4.2.2.5 Maintenance Expenses.
A breakdown of monthly and total maintenance expenses is shown in Figures 4-7 and 4-8 and is plotted versus net capacity factor in Figure 4-20. The costs show no discernable trend with capacity factor, but do show a slight increase in 1990. This increase reflects the occurrence of several tube leaks during that year (a total of 6 instances in 1990). Maintenance costs were also high in April 1990 due to an outage to repair boiler feed pumps and a cyclone vortex finder. As shown in Figure 4-8, maintenance of the boiler plant accounted for over 60 percent of the total plant maintenance costs. Supervision and engineering, structures and electrical plant maintenance costs were nearly equal. These account for 10 to 13 percent of the total operating expense.

4.2.2.6 Production Expenses.
Production expenses are the sum of total maintenance and operations expenses. Monthly production expenses are plotted in Figures 4-9 and 4-10 along with a breakdown of the total expense for the testing period from September 1988 through January 1991. Production expenses are also plotted versus net capacity factor in Figure 4-21. Note that operations expenses, 80 percent of which are fuel expenses, account for over 85 percent of total production expenses. Figure 4-21 shows an increase in total monthly production cost with capacity factor, reflecting the increase in fuel expenses.

4.2.2.7 Fixed Costs.
Fixed costs include depreciation, taxes, interest and insurance costs. These monthly expenses are plotted in Figure 4-11. As shown in Figure 4-12, interest charges account for over 75 percent of the fixed costs. Insurance, taxes and depreciation account for approximately 5 percent, 8 percent, and 11 percent of total fixed costs respectively. Note that depreciation expense changed during January 1990 as the result of a change in the method of accounting for Nucla costs. Prior to this date, the CPUC (Colorado Public Utilities Commission) had ordered that all expenses of

operation, including depreciation, be deferred until certain testing activities were completed. Following this change in accounting, all costs related to research and development, demonstration, operation and testing activities were expensed. This change was retroactive to August 1988.

Interest expenses for the Nucla facility decreased during the second quarter of 1990 as a result of a Chapter 11 bankruptcy filing by CUEA. Under the bankruptcy code, interest on unsecured debt is suspended pending resolution of the bankruptcy. Since approximately $13 million of the capital cost of the project at that time was still funded by unsecured debt, interest related to that funding was no longer calculated and charged to the project.

4.2.2.8 Total Power Costs.
Total power costs include fixed costs and production expenses. As mentioned, the latter includes maintenance and operations expenses. Monthly total power costs are shown in Figures 4-13 and 4-14. These are also plotted versus the net plant capacity factor in Figure 4-22. The increase in total monthly power costs with capacity factor reflects the increase in fuel cost. Figure 4-14 shows that fixed costs, over 75 percent of which is interest on debt, account for over 60 percent of the total power costs.

Figures 4-15 and 4-16 show the breakdown in total power costs in greater detail by separating fuel, non-fuel, maintenance, depreciation, taxes, interest and insurance costs. As can be seen in Figure 4-16, interest expenses account for over 47 percent of the total power costs. Fuel expenses, 95 percent of which are coal costs, account for over 26 percent of the total. Except for insurance, the remaining expenses, including taxes, depreciation, maintenance and non-fuel expenses, average individually between 4.5 and 7 percent of the total. Insurance and general and administrative expenses account for 2.74 percent of the total power cost.

4.2.2.9 Costs per Megawatt-Hour.
Figures 4-23 through 4-28 show normalized monthly fuel, non-fuel, operations, maintenance, fixed costs and total power costs on a per megawatt-hour basis plotted versus the net capacity factor for the month. Totals for the period from September 1988 through January 1991 are also shown in the fourth column of Figure 4-7. In addition, this table shows the total cost for the period, the average cost per month, and the percent of the total power cost for all major and minor categories. The minor category expenses were extracted from the detailed monthly summaries in Appendix D.

Figures 4-23 through 4-28 all show normalized costs decreasing exponentially with increasing capacity factor. From the data, it can be seen that normalized costs begin to rise when capacity factors are less than 50 percent. Above 50 percent capacity factor, normalized costs decrease more slowly. Note that in Figure 4-28, total power costs per megawatt hour for capacity factors less that 30 percent begin to escalate sharply, approaching $100/MWh with capacity factors of approximately 25 percent. However, at 80 percent capacity factor, normalized power costs fall to approximately $40-$45/MWh. A capacity factor of at least 50 percent represents an important target for optimizing power production expenses at the Nucla Station. Since the unit averaged between 70 and 80 percent capacity factor when operating, increasing the overall value requires operating with a higher plant availability. Factors affecting plant availability during the reporting period are discussed in more detail in Section 5.

4.2.2.10 Further Breakdown of Power Costs. The detailed cost breakdown of major category headings shown in Table 4-7 is shown graphically in Figures 4-29 through 4-36. Coal expenses are graphically displayed and indicate that the cost of coal represents 92 percent of the total. Also shown in the upper left corner of the figure, coal expenses for the period from September 1988 through January 1991 represent nearly one-fourth, or 24.92 percent of the total power cost.

Figure 4-30 shows a breakdown of the total steam expenses for the testing period covered by the Cooperative Agreement. These costs represent 6.76 percent of the total power cost and consist of boiler operation, pulverizer operation, on-site ash handling, stack monitoring, boiler water treatment, waste water management, NPDES permitting and testing, environmental auditing, laboratory operation, baghouse operation, sulfur removal, and miscellaneous and special services. Note that the largest steam expense is for sulfur removal. This accounts for almost 45 percent of the total. This reflects costs for raw limestone, limestone preparation, and limestone feed. These costs are shown in more detail in Figure 4-36 along with ash disposal costs and propane. Propane costs have been added to this figure to indicate the relative magnitudes of the other costs. Note that limestone expenses account for approximately 1.3 percent of the total power costs, which is similar to propane costs. Ash disposal costs only accounted for approximately 0.33 percent of the total power cost.

Figure 4-31 shows a breakdown of the total electric expenses which accounted for approximately 1 percent of the total power cost. Operating expenses for the turbine-generators and auxiliary equipment, cooling water system, circulating water treatment, and electrical equipment are split somewhat equally and account for between 20 and 30 percent of the total electric expense.

The breakdown of miscellaneous steam expenses, which account for 0.69 percent of the total power cost as shown in Figure 4-32, includes plant office expenses, buildings and grounds, safety, training and miscellaneous. Training accounted for approximately 40 percent of these expenses and indicates requirements for the start-up of a new technology.

Figure 4-33 shows a breakdown of the total boiler plant maintenance expenses for the period from September 1988 through January 1991. These expenses account for 3.33 percent of the total plant power costs and, as shown in Figure 4-8, over 60 percent of the total plant maintenance costs. Maintenance to the boiler accounted for 30 percent of the total boiler plant costs. The coal handling equipment, ash handling system, and feed water system accounted for 15.4, 12.0 and 13.5 percent, respectively. Other equipment areas shown in the figure include propane equipment, stack monitoring equipment, boiler water treatment system, air and gas handling systems (fans, dampers, flow monitors and ductwork), baghouses (including bag replacement), SO_2 removal system (limestone preparation and feed and SO_2 monitors), combustion control equipment, and other. Other includes pulverizers, waste water management system, the environmental station, and laboratory equipment.

Figure 4-34 shows a breakdown of the electric plant maintenance expenses between September 1988 and January 1991. This area accounted for 0.62 percent of the total power costs for the testing period. Areas include the maintenance of turbine and auxiliary equipment, circulating and cooling water systems, condensate system, water treatment system, and electrical equipment. Maintenance of the turbine-generator and auxiliary equipment accounted for 43 percent of the total electric plant expense while circulating and cooling water systems accounted for over 30 percent. As will be seen in the next section, much of these costs were associated with the existing three 12.5 MWe turbine-generator systems.

Figure 4-35 shows a breakdown of miscellaneous plant maintenance expenses for the testing period covered by the cooperative agreement. This accounts for 0.56 percent of the total power cost for the period and includes service equipment, compressed air equipment, common equipment, tools and test equipment, fire safety equipment, training equipment, vehicles and miscellaneous. Maintenance of tools and test equipment, some of which was associated with the test program, accounts for over 42 percent of this total. Compressed air equipment accounted for nearly 30 percent of the total.

4.3 OTHER COST/QUANTITY INFORMATION

This section presents unit costs for coal, limestone and ash disposal along with the total quantities consumed or generated over the reporting period. In addition, staffing requirements for the Nucla CFB Demonstration Project over the course of the test program are listed. This information can be used by others to adjust labor, fuel, limestone and ash disposal costs for applications of CFB technology which may differ in the above areas depending on location and operating philosophies.

Table 4-8 shows a summary of coal costs on a $\$/10^6$ Btu basis. Two values are listed as the result of a fuel switch at the beginning of 1990. Also listed are the costs/ton for raw limestone delivery and ash disposal. Raw limestone is delivered to the plant in a size range up to 10 inches. This must be further processed by the plant to produce a median particle size of 150 micron. The raw limestone cost listed in Table 4-8 does not include this expense. However, the total cost for SO_2 removal reported in Section 4.2 includes raw limestone expenses, and costs for preparation and feed. Fly ash and bottom ash are removed from the plant site by trucks owned and operated by an outside contractor. The costs represent this charge for removal, haulage and disposal.

Table 4-8. Unit Costs for Coal, Limestone and Ash Disposal for the Nucla CFB Demonstration Project

• COAL	\$1.08/MMBtu (1987-1989)
	\$1.26/MMBtu (1990-1991)
• LIMESTONE (includes hauling)	\$21.46/ton delivered
• ASH DISPOSAL (calculated value, includes haulage)	\$3.25/ton wet

Total quantities of coal consumed and limestone delivered, and wet ash disposed of are shown for each month during the reporting period from 1988 through 1991 in Tables 4-9 through 4-12.

NUCLA STATION
1988

Month	Coal (tons)	Ash (%)	Limestone Delivered (tons)	Ash Loads (#)	Ash Loads x 25 (tons)
Jan	17,666	16.12	0.00	221	5,525
Feb	18,174	16.93	914.550	239	5,975
Mar	14,732	18.80	1,061.815	245	6,125
Apr	11,436	20.37	504.370	147	3,675
May	15,048	19.90	626.35	223	5,575
Jun	19,559	23.60	2,026.72	363	9,075
Jul	20,491	18.02	1,368.38	315	7,875
Aug	0	0	0	45	1,125
Sep	5,428	28.55	0	81	2,025
Oct	20,528	23.73	1,366.17	275	6,875
Nov	20,690	26.54	1,245.67	367	9,175
Dec	21,038	18.20	1,450.18	301	7,525
TOTAL	184,789		10,564.21	2,822	70,550

Table 4-9. 1988 Coal and Limestone Consumption and Ash Removal.

NUCLA STATION
1989

Month	Coal (tons)	Ash (%)	Limestone Delivered (tons)	Ash Loads (#)	Ash Loads x 25 (tons)
Jan	4,169	16.52	195.18	92	2,300
Feb	5,340	17.97	1,048.68	64	1,600
Mar	25,393	18.77	1,097.14	330	8,250
Apr	19,477	20.04	1,739.95	303	7,575
May	7,890	23.70	198.92	100	2,500
Jun	21,759	19.44	233.57	330	8,250
Jul	20,753	14.20	1,124.60	236	5,900
Aug	9,869	12.96	1,132.11	107	2,675
Sep	12,141	15.49	928.91	139	3,475
Oct	4,805	28.00	181.10	88	2,200
Nov	24,620	20.38	747.95	299	7,475
Dec	24,041	18.08	1,259.97	306	7,650
TOTAL	180,257		9,888.08	2,394	59,850

Table 4-10. 1989 Coal and Limestone Consumption and Ash Removal.

NUCLA STATION
1990

Month	Coal (tons)	Ash (%)	Limestone Delivered (tons)	Ash Loads (#)	Ash Loads x 25 (tons)
Jan	23,418	19.18	1,979.75	347	8,675
Feb	5,765	18.11	470.63	67	1,675
Mar	32,656	17.31	1875.31	351	8,775
Apr	33,576	17.21	2,239.13	431	10,775
May	11,226	17.82	1,115.00	139	3,475
Jun	22,302	16.64	2,003.85	345	8,625
Jul	9,415	17.03	1,037.87	110	2,750
Aug	5,041	16.56	335.28	70	1,750
Sep	7,450	15.91	442.37	75	1,875
Oct	14,209	18.21	750.97	153	3,825
Nov	34,283	17.07	1,799.30	408	10,200
Dec	30,420	15.59	1,931.47	348	8,700
TOTAL	229,761		15,980.93	2,844	71,100

Table 4-11. 1990 Coal and Limestone Consumption and Ash Removal.

NUCLA STATION
1991

Month	Coal (tons)	Ash (%)	Limestone Delivered (tons)	Ash Loads (#)	Ash Loads x 25 (tons)
Jan	26,039	17.65	2,418.96	340	8,500
Feb	1,693	25.43	156.28	34	850
Mar	2,202	17.76	160.15	27	675
Apr	26,104	16.58	1,068.62	274	6,850
May	21,103	16.77	1,011.81	237	5,925
Jun	23,481	17.75	785.84	236	5,900
Jul	20,817	19.51	558.29	251	6,275
Aug	25,115	19.49	860.89	291	7,275
Sep	21,370	21.21	980.58	280	7,000
Oct	27,695	22.54	993.93	399	9,975
Nov	12,780	18.28	237.25	191	4,775
Dec	0	0.00	0.0	0	0
TOTAL	208,398		9,232.60	2,560	64,000

Table 4-12. 1991 Coal and Limestone Consumption and Ash Removal.

Table 4-13 shows a detail of the staffing requirements for the Nucla CFB Demonstration Project during the testing period covered in this report. On average, 43 people were required on-site to operate the plant. The various job functions along with personnel quantities are shown in the table. Note, the senior typist was required exclusively to complete tasks related to documentation of the demonstration test program. The three utility people were used approximately 50-75 percent for test program related activities. Adjusting for these quantities results in a staffing of 41 under normal conditions.

Table 4-13. Nucla Station Staffing Requirements.

POSITION	QTY
Plant Manager	1
Safety and Training Supervisor	1
Technical Supervisor	1
Chemist	1
Maintenance Superintendent	1
Assistant Maintenance Planner/Scheduler	1
Operations Superintendent	1
Shift Supervisor	5
Senior Typist	1
Certified Welder Mechanic	1
Control Room Operator	5
E & I Mechanic	2
General Mechanic	3
Heavy Equipment Operator	3
Laboratory Technician	1
Machinist Mechanic	1
Plant Operator	10
Record Clerk/Storekeeper	1
Utility Person	3

Section 5

PLANT RELIABILITY

This section summarizes some of the problems which affected plant availability during the course of the test program from October 1988 through January 1991. Note that the compilation of this data did not begin until after the completion of unit acceptance tests in early October 1988. This time period differs from the cost data presented in Section 4 and the Appendices by one month.

5.1 RELIABILITY ISSUES

Many of the operating problems which contributed to an average unit availability of 60.2% during the course of the test program can be attributed to "first-generation" CFB equipment and component design. However, the total quantity and duration of the outages were often affected by factors related to the demonstration nature of the project. For example, periodic boiler inspections were made as part of the test program's materials monitoring plan, which sometimes initiated or extended unit outages. The lack of power demand during certain periods also contributed to the low availability. In addition, capacity factors were affected by extensive part-load testing.

Despite these influences, operating data have been compiled and are plotted in Figures 5-1 and 5-2. Figure 5-1 shows a breakdown of the total period hours from October 1988 through the completion of the test program in January 1991. Figure 5-2 shows a breakdown of causes for the outage hours during the same period.

The largest CFB-related contributor to plant outage time has been from secondary superheater tube failures. This problem has been addressed temporarily through an operational change. Tube failures contributed to over 70 percent of the outage time between October 1989 and January 1991. Other CFB-related outages over the course of the test program have been required for refractory repairs, primary air fan upgrades, bubble cap replacement, bottom ash disposal system upgrade, and limestone feed system modifications. Note that the contribution from controls (1.1% of total), shown in Figure 5-2, results mainly from variable speed drive fan controls rather than boiler controls. Most of these problems have been addressed, and unit operating availabilities have shown marked improvements since the third quarter of 1990.

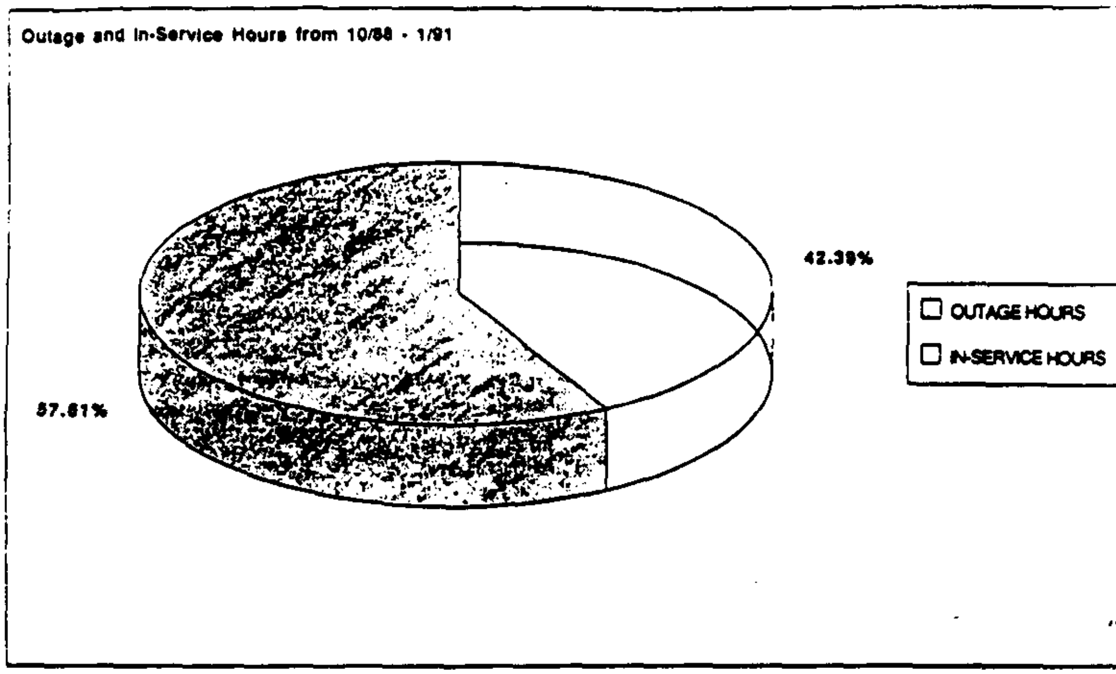


Figure 5-1. Summary of In-Service and Outage Hours from 10/88 - 1/91.

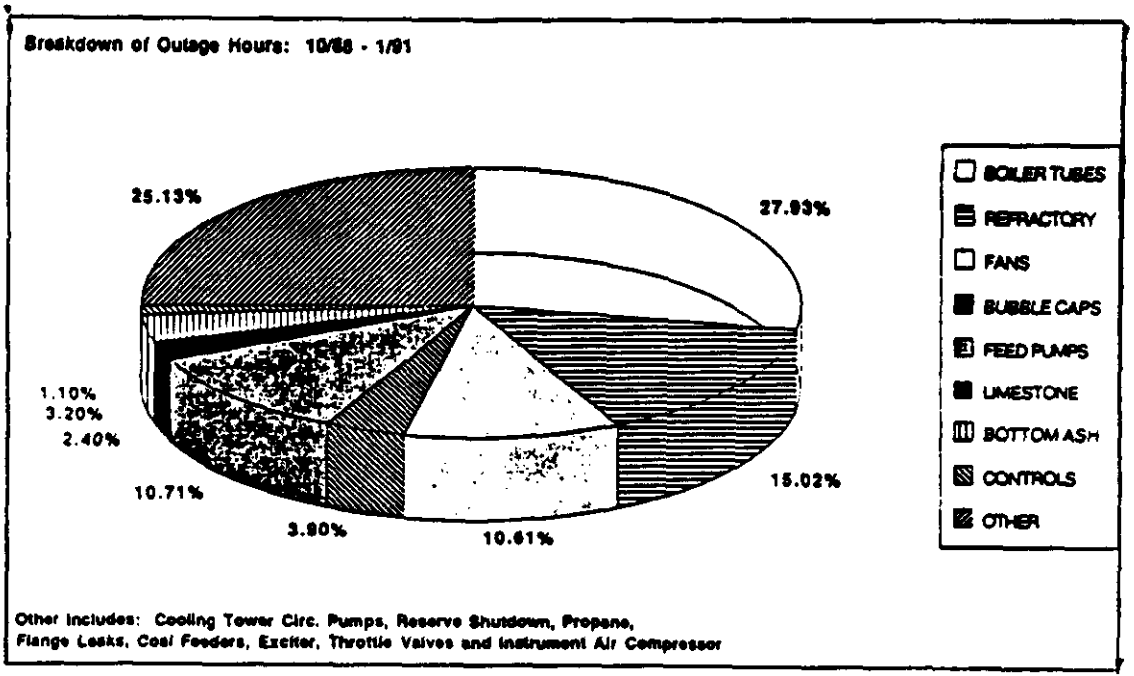


Figure 5-2. Breakdown of Unit Outage Hours from 10/88 - 1/91.

In order to demonstrate long-term reliability, operability, and reduced maintenance costs, several problems remain to be addressed at the conclusion of the test program. A more detailed discussion of each of these areas and those shown in Figure 5-2 is contained in the Final Technical Report and in the Annual Technical Reports covering the test program period. The principle problem areas, all of which are currently under review, include:

- Refractory condition in the lower combustion chambers, cyclone "bull nose" and impact areas, the cyclone conical sections and downcomers, and certain regions in the loop seals.

- Structural integrity of the cyclone vortex finders.

- Air distributor bubble cap erosion and retention.

- Adequate means for the collection and removal of backsifted bed material in the windboxes.

- Water-wall tube erosion at the lower combustion chamber refractory interface and on sections of the water walls that were warped during in the 1987 overheat incident.

- Secondary superheater erosion on out-of-plane tubes and on the back side of panels in regions conducive to solids flow channeling.

- Long-term overheat of secondary superheater tubes. This has been addressed temporarily through an operational change resulting in an increase in plant heat rate.

- Temperature matching between combustion chambers in order to optimize limestone consumption for SO_2 control.

- Reliability of variable speed drive controls on fans.

5.2 UNIT OUTAGE SUMMARY

Table 5-1 presents a summary of all unit outages from October 1988 through January 1991. The date, time, approximate outage duration and cause for the outage are listed. A more detailed discussion of this table is contained in the Final Technical Report.

Table 5-1. Outage Summary.

START OUTAGE DATE	TIME	STOP OUTAGE DATE	TIME	DURATION (APPROX.) HRS.	CAUSE
1-Oct-88	14:30	2-Oct-88	5:00	14.5	FAILURE OF AN INPUT/OUTPUT MODULE POWER SUPPLY ON THE DCS CAUSED MAIN FUEL TRIP (MFT).
2-Oct-88	12:00	3-Oct-88	15:00	27	CONTROLLED SHUTDOWN AS A RESULT OF LOW BED TEMPERATURES FROM HIGH ASH, LOW HHV COAL SUPPLY. UNIT HELD OFF LINE TO RESTORE PROPANE INVENTORY.
6-Oct-88	14:00	6-Oct-88	16:00	2	INDUCED DRAFT (ID) FAN TRIP FROM A SYSTEM GROUND FAULT DURING A LIGHTNING STORM
17-Oct-88	20:00	26-Oct-88	2:00	198	CONTROLLED SHUTDOWN RESULTING FROM UNIT BEING OUT OF SO2 COMPLIANCE ON HIGH SULFUR COAL TEST. WENT INTO EXTENDED OUTAGE TO REPLACE MISSING BUBBLE CAPS AND TO WORK ON LIMESTONE FEEDERS.
28-Oct-88	8:00	28-Oct-88	9:30	1.5	TWO OF THREE COAL FEEDERS OUT OF SERVICE ON FURNACE B. BOILER TRIPPED WHEN THIRD COAL FEEDER TRIPPED ON BELT MISALIGNMENT.
4-Nov-88	11:30	10-Nov-88	4:00	136.5	CONTROLLED SHUTDOWN TO INSPECT COMBUSTORS FOR SUSPECTED REFRACTORY BLOCKAGE IN LOOP SEALS AND ASH CLASSIFIERS.
19-Nov-88	12:00	19-Nov-88	22:30	10.5	CONTROLLED SHUTDOWN TO REPAIR PACKING LEAK ON STEAM DRUM BLOW DOWN VALVE.
20-Nov-88	12:00	20-Nov-88	12:30	0.5	ID FAN TRIP DURING DELTA/WYE SWITCH.
24-Nov-88	14:00	24-Nov-88	18:30	4.5	MFT FROM MALFUNCTION OF FURNACE 4A PRESSURE SWITCHES FOR DRAFT CONTROL.
3-Dec-88	9:00	3-Dec-88	11:30	2.5	MFT DUE TO HIGH PRIMARY AIR (PA) FAN AMPS.
11-Dec-88	21:00	20-Dec-88	10:30	205.5	FAILURE OF GENERATOR 4A EXCITOR COLLECTOR RING.
26-Dec-88	2:30	26-Dec-88	10:30	8	MFT FROM FAULTY PRESSURE SWITCH ON ID FAN INLET.
27-Dec-88	12:00	27-Dec-88	17:30	5.5	MFT FROM OVERHEAT OF VARIABLE SPEED DRIVE (VSD) CONTROL CARD ON SECONDARY AIR (SA) FAN DUE TO ROOM AIR CONDITIONING PROBLEMS.
5-Jan-89	10:45	13-Feb-89	7:41	933	CONTROLLED SHUTDOWN DUE TO HOT SPOT AT LOOP SEAL 4B WELDED JOINT. DECISION MADE TO START PPCO OUTAGE TO REPAIR DAMAGED REFRACTORY IN THE LOOP SEALS AND CONES OF THE CYCLONES.

Table 5-1. Outage Summary (continued).

START OUTAGE		STOP OUTAGE		DURATION (APPROX.)	CAUSE
DATE	TIME	DATE	TIME	HRS.	
13-Feb-89	16:36	16-Feb-89	2:33	58	UNIT TRIP ON FUEL/AIR RATIO MISMATCH. THE MFT RESULTED FROM SYSTEM SOFTWARE UPDATE PROBLEM. ALSO FOUND LEAKING FLANGE GASKET ON SH SAFETY VALVE.
16-Feb-89	2:33	16-Feb-89	3:44	1	UNIT TRIP IMMEDIATELY AFTER SYNCHCRONIZATION ON MFT DUE TO ID FAN UNDERVOLTAGE TRIP.
17-Feb-89	15:15	23-Feb-89	12:14	141	CONTROLLED SHUTDOWN TO REPAIR SEIZED 4B CIRCULATING WATER PUMP . INLET AND DISCH. VALVES LEAKING BY TOO MUCH TO ISOLATE PUMP AND REPAIR ON LINE.
3-Mar-89	12:24	3-Mar-89	19:40	7	UNIT TRIP ON MFT DUE TO LOW PA FLOW TO 'B' FURNACE. THE LOW PA FLOW WAS CAUSED BY A SUDDEN LOOP SEAL SURGE WHICH INCREASED BED PRESSURE TO APPROXIMATELY 60" WC.
24-Mar-89	23:23	29-Mar-89	22:46	119	SCHEDULED SHUTDOWN TO INSPECT COMBUSTORS AFTER COMPLETING TEST BURN WITH 'SALT CREEK' COAL. REPAIRED 4A BOILER FEED PUMP MECHANICAL SEAL DURING THIS OUTAGE
12-Apr-89	16:53	18-Apr-89	17:31	145	CONTROLLED SHUTDOWN DUE TO ASH REMOVAL PROBLEMS IN "A" FURNACE RESULTING FROM A BENT FLUIDIZING TUBE AT THE ENTRANCE TO EACH BOTTOM ASH COOLER.
21-Apr-89	17:02	21-Apr-89	21:17	4	UNIT TRIP ON MFT DUE TO LOSS OF THE ID FAN RESULTING FROM A TRANSMISSION SYSTEM DISTURBANCE.
27-Apr-89	22:00	10-May-89	7:06	297	CONTROLLED SHUTDOWN DUE TO MECHANICAL SEAL LEAKS ON BOTH 4A AND 4B FEEDWATER PUMPS. 4B FEED PUMP ALSO REQUIRED CASING REPAIRS WHICH WERE COMPLETED OFF SITE.
10-May-89	7:21	10-May-89	23:25	16	UNIT TRIP ON MFT DUE TO LOSS OF THE ID FAN RESULTING FROM LOOSE ELECTRICAL CONNECTION WHICH CAUSED THE COMMUTATOR TO SHORT OUT.
14-May-89	11:22	22-May-89	17:30	198	UNIT TRIP ON MFT DUE TO SA FAN TRIP. REPLACED BAD FAN CONTROL CARD. DURING OUTAGE REINSTALLED 4B FEEDWATER PUMP. UNIT ON RESERVE SHUTDOWN AT 20:50 ON 5/19.
22-May-89	20:00	23-May-89	6:31	11	CONTROLLED SHUTDOWN DUE TO LACK OF PROPANE

Table 5-1. Outage Summary (continued).

START OUTAGE		STOP OUTAGE		DURATION (APPROX.)	CAUSE
DATE	TIME	DATE	TIME	HRS.	
23-May-89	13:17	23-May-89	16:47	3	CONTROLLED SHUTDOWN DUE TO LACK OF PROPANE
30-May-89	9:17	30-May-89	10:33	1	UNIT TRIP ON MFT DUE TO "PHANTOM" SA FAN TRIP REASON UNDER INVESTIGATION.
9-Jun-89	13:57	9-Jun-89	18:12	4	CONTROLLED SHUTDOWN TO REMOVE "CLINKER" FROM 4C BOTTOM ASH COOLER. THREE BUBBLE CAPS WERE ALSO FOUND ADRIFT IN THIS COOLER AND REPLACED.
23-Jun-89	19:47	9-Jul-89	3:29	368	SCHEDULED SHUTDOWN AT THE COMPLETION OF ALTERNATE FUEL TESTING TO COMPLETE PA FAN INLET BOX AND LIMESTONE FEED SYSTEM MODIFICATIONS
28-Jul-89	14:47	28-Jul-89	16:49	2	UNIT TRIP ON MFT DUE TO LOSS OF ID FAN RESULTING FROM SYSTEM DISTURBANCE. 4A BFP SIEZED DURING THE UNIT ROLLDOWN WHEN ITS RECIRCULATION VALVE DID NOT PROPERLY OPERATE.
30-Jul-89	22:47	7-Aug-89	18.24	188	CONTROLLED SHUTDOWN TO ISOLATE 4A BFP FOR REMOVAL AND OFF-SITE REPAIR. UNIT STATUS CHANGED TO RESERVE SHUTDOWN FROM 12:00 HRS ON 8/2 TO 16:10 ON 8/4. THE INSTRUMENT AIR COMPRESSOR CHECK VALVE BETWEEN THE HIGH AND LOW PRESSURE STAGES FAILED AND WAS REPLACED
20-Aug-89	0 45	26-Aug-89	4:43	148	CONTROLLED SHUTDOWN TO REINSTALL 4A BFP. OUTAGE EXTENDED TO REPLACE 23 DISTRIBUTOR PLATE "BUBBLE CAPS" IN A COMBUSTOR AND TO COMPLETE ADDITIONAL INSTRUMENT AIR COMPRESSOR REPAIRS.
26-Aug-89	5:43	26-Aug-89	16:28	11	CONTROLLED SHUTDOWN DUE TO LACK OF PROPANE
28-Aug-89	11:35	11-Sep-89	13:25	338	CONTROLLED SHUTDOWN DUE TO WATERWALL TUBE LEAK AT WALL BOX CONNECTION ON OUTSIDE OF BOILER. THE UNIT MFT'd DURING RESTART DUE TO A TRIP ON EXCITER VOLTAGE CABINET FAN FAILURE. THE NO. 2 THROTTLE VALVE REMAINED 11 % OPEN AFTER THE UNIT TRIP. THE VALVE WAS DISASSEMBLED AND THE UPPER STEM GUIDE BUSHING WAS REMACHINED TO THE MANUFACTURER'S SPECIFICATIONS. TWO ADRIFT NOZZLE CAPS NEAR THE LOOP SEAL IN 4B COMBUSTOR WERE ALSO CAPPED FROM THE WINDBOX SIDE AS A TEMPORARY REPAIR.

Table 5-1. Outage Summary (continued).

START OUTAGE		STOP OUTAGE		DURATION (APPROX.)	CAUSE
DATE	TIME	DATE	TIME	HRS.	
13-Sep-89	3:03	13-Sep-89	11:50	9	UNIT TRIP ON MFT DUE TO LOSS OF THE SA FAN ON "PHANTOM" TRIP. AFTER SEVERAL UNSUCCESSFUL ATTEMPTS TO RESART THE FAN IN A NORMAL FASHION, THE FAN WAS RESTARTED "ACROSS THE LINE". A CONDENSER TUBE LEAK WAS ISOLATED AND REPAIRED BEFORE UNIT 1 WAS RETURNED TO SERVICE.
17-Sep-89	14:01	17-Sep-89	14:46	1	UNIT MFT ON LOW DRUM LEVEL DUE TO IMPROPER OPERATION OF THE MAIN FEEDWATER CONTROL VALVE.
23-Sep-89	22:21	9-Oct-89	22:29	384	UNIT MFT DUE TO LOSS OF THE PA FAN ON "PHANTOM" TRIP. STARTED SCHEDULED OUTAGE FOR PYROPOWER TO REPLACE THE PA FAN WHEEL.
13-Oct-89	19:41	11-Nov-89	18:08	694	UNIT MFT ON HIGH FURNACE DRAFT PRESSURE DUE TO A BOILER TUBE LEAK IN 4B FURNACE. WATER FROM THE TUBE CAUSED AGGLOMERATION OF THE BED MATERIAL IN 4B COMBUSTOR, 4B WINDBOX, AND 4D BOTTOM ASH COOLER. SUBSEQUENT INSPECTION OF THE SUPERHEATER II PLATENS IN BOTH COMBUSTORS REVEALED MANY AREAS OF LOCALIZED EROSION WHICH WERE REPAIRED
12-Nov 89	18 27	12-Nov-89	20.27	2	UNIT MFT ON LOW AIR/FUEL RATIO DUE TO AN IMPROPER BTU BIAS SETTING.
4-Dec-89	10.33	4-Dec-89	11:36	1	UNIT MFT ON LOW ELECTRO-HYDRAULIC CONTROL (EHC) SYSTEM PRESSURE. PROBLEM OCCURRED WHILE I&C TECHNICIAN WAS VALVING AN EHC ACCUMULATOR BACK IN-SERVICE AFTER BEING RECHARGED.
8-Dec-89	4:37	15-Dec-89	14:00	177	CONTROLLED SHUTDOWN DUE TO HIGH BED PRESSURE IN 4A COMBUSTOR DURING TYPE "B" COAL ACCEPTANCE TESTING USING A HIGH SULFUR COAL (1.8% S). SUBSEQUENT INSPECTIONS REVEALED A TOTAL OF TWENTY SEVEN BUBBLE CAPS ADRIFT IN 4A COMBUSTOR (25), 4B COMBUSTOR (1), AND 4B LOOP SEAL (1).
17-Dec-89	23:26	18-Dec-89	5:27	6	UNIT MFT DUE TO UNIT 4 EXCITER FIRING CIRCUIT CARD FAILURE.
18-Dec-89	6:42	20-Dec-89	17:27	59	UNIT MFT DUE TO UNIT 4 EXCITER AFTER AN UNSUCCESSFUL ATTEMPT TO RESTART THE UNIT. CUEA OBTAINED ENOUGH GOOD CARDS BETWEEN THE TWO REDUNDENT FIRING CIRCUITS TO RETURN THE UNIT TO SERVICE.

Table 5-1. Outage Summary (continued).

START OUTAGE		STOP OUTAGE		DURATION (APPROX.)	CAUSE
DATE	TIME	DATE	TIME	HRS.	
30-Dec-89	5:08	30-Dec-89	8:56	4	UNIT MFT ON LOW DRUM LEVEL DUE TO A UNIT 4 TURBINE UPSET. THE UPSET WAS THE RESULT OF A TURBINE CONTROL PROBLEM CAUSED BY AN IMPROPERLY CALIBRATED MW TRANSDUCER.
30-Dec-89	9:11	30-Dec-89	18:34	9	CONTROLLED SHUTDOWN DUE TO LEAK IN UNIT 4 GOVERNOR OIL CIRCUIT.
7-Jan-90	18:14	9-Jan-90	20:40	50	CONTROLLED SHUTDOWN DUE TO LOSS OF THE COAL PREP SYSTEM FROM A 4A COAL CRUSHER MOTOR BEARING FAILURE. THE OUTAGE WAS EXTENDED BECAUSE OF A STEAM LEAK ON THE WEST STEAM LEAD FLANGE BETWEEN THE WEST THROTTLE VALVE AND THE GOVERNOR VALVE WHICH DEVELOPED DURING RESTART.
18-Jan-90	14:10	19-Jan-90	18:51	29	UNIT MFT ON GENERATOR LOW FREQUENCY RESULTING FROM A RELAY WIRING ERROR. DURING RESTART A SH SAFETY VALVE FLANGE LEAK WAS DISCOVERED AND REPAIRED AFTER THE BOILER WAS COOLED DOWN.
26-Jan-90	18:37	6-Feb-90	21:16	267	CONTROLLED SHUTDOWN TO REPAIR THE "VORTEX FINDER" IN 4B COMBUSTOR CYCLONE AND TO CLEAN OUT BACKSIFTED MATERIAL FROM 4A AND 4B COMBUSTOR WINDBOXES.
9-Feb-90	4:18	9-Feb-90	21:36	17	CONTROLLED SHUTDOWN DUE TO VIBRATION IN THE SA FAN INLET DUCT. TWO STIFFENERS WERE ADDED TO A FAN INLET TURNING VANE TO RESOLVE THE PROBLEM.
9-Feb-90	22:36	10-Feb-90	2:36	4	UNIT MFT DUE TO LOW VACUUM ON UNIT 4 CONDENSER.
10-Feb-90	17:23	21-Feb-90	6:55	254	UNIT MFT ON HIGH FURNACE DRAFT PRESSURE DUE TO A BOILER TUBE LEAK IN 4A FURNACE. WATER FROM THE TUBE CAUSED AGGLOMERATION OF THE BED MATERIAL IN 4A COMBUSTOR AND WINDBOX. 4A BFP WAS FOUND SEIZED WHILE ATTEMPTING BOILER HYDROSTATIC TEST AFTER COMPLETING TUBE REPAIRS.
26-Feb-90	0:08	3-Mar-90	9:41	130	CONTROLLED SHUTDOWN DUE TO WATERWALL TUBE LEAK OUTSIDE THE BOILER. THE LEAK WAS LOCATED IN A FLOOR TUBE WHERE THE WINDBOX TIES INTO THE FLOOR TUBES. THE OUTAGE WAS EXTENDED TO REPAIR A SECTION OF ABRASION RESISTANT REFRACTORY IN 4B CYCLONE CONE SECTION.
22-Mar-90	13:36	22-Mar-90	15:23	2	UNIT TRIP ON MFT DUE TO LOSS OF ID FAN RESULTING FROM SYSTEM DISTURBANCE.

Table 5-1. Outage Summary (continued).

START OUTAGE		STOP OUTAGE		DURATION (APPROX.)	CAUSE
DATE	TIME	DATE	TIME	HRS.	
3-Apr-90	18:02	3-Apr-90	20:20	2	UNIT TRIP ON MFT DUE TO LOSS OF ID FAN RESULTING FROM SYSTEM DISTURBANCE.
18-Apr-90	19:00	22-Apr-90	10:30	88	UNIT TRIP ON MFT DUE TO LOSS OF EXCITATION DUE TO EXCITER TRANSFORMER FAILURE.
2-May-90	6:29	20-May-90	6:16	432	UNIT MFT ON LOW DRUM LEVEL. AT THE TIME OF THE TRIP,OPERATIONS PERSONNEL WERE REDUCING LOAD TO REMOVE THE BOILER FROM SERVICE VIA A CONTROLLED SHUTDOWN SEQUENCE AFTER AN INDICATION OF A TUBE LEAK IN 4A COMBUSTOR.
20-May-90	6:29	20-May-90	15:33	9	UNIT TRIP ON MFT DUE TO LOSS OF SA FAN RESULTING FROM A 4 KV LINE VOLTAGE. THE GENERATOR BREAKER HAD TO BE OPENED MANUALLY.
20-May-90	15:59	22-May-90	6:19	38	UNIT TRIP ON MFT DUE TO LOSS OF SA FAN RESULTING FROM A 4 KV VOLLTAGE LINE SURGE. THE GENERATOR REVERSE CURRENT RELAY HAD TO BE MANUALLY TRIPPED. THE BOILER WAS BOTTLED UP WHILE A RELAY WIRING FAULT WAS IDENTIFIED AND CORRECTED.
28-May-90	14.24	28-May-90	15:31	1	DURING A CONTROLLED SHUTDOWN DUE TO HIGH VIBRATION READINGS ON NO. 3 TURBINE BEARING, SWITCHYARD BREAKER N-521 TRIPPED. THE HIHG VIBRATION SOURCE WAS DETERMINED TO BE TRANSIENT AND A HOT RESTART FOLLOWED.
31-May-90	9:16	7-Jun-90	1:38	160	UNIT MFT ON LOW DRUM LEVEL DUE TO A BOILER WW TUBE LEAK IN 4A COMBUSTOR.
7-Jun-90	8:11	7-Jun-90	20:21	12	CONTROLLED SHUTDOWN - PROPANE SUPPLY < 22%
7-Jun-90	22:21	7-Jun-90	23:37	1	PROPANE VAPORIZER TRIP
27-Jun-90	20:14	28-Jun-90	0:47	5	SA INVERTER FAULT
28-Jun-90	14:27	10-Jul-90	4:48	278	SHII 4A COMBUSTOR TUBE LEAK
17-Jul-90	18:25	28-Jul-90	8:56	255	UNIT MFT ON HIGH FURNACE DRAFT DUE TO A BOILER TUBE LEAK IN 4A COMBUSTOR. AT THE TIME OF THE TRIP,OPERATIONS PERSONNEL WERE REDUCING LOAD TO REMOVE THE BOILER FROM SERVICE VIA A CONTROLLED SHUTDOWN SEQUENCE.

Table 5-1. Outage Summary (continued).

START OUTAGE		STOP OUTAGE		DURATION (APPROX.)	CAUSE
DATE	TIME	DATE	TIME	HRS.	
1-Aug-90	18:08	19-Aug-90	17:06	431	CONTROLLED SHUTDOWN DUE TO WATERWALL TUBE LEAK IN 4A COMBUSTOR. REPAIRS WERE COMPLETED AND THE UNIT WAS AVAILABLE FOR SERVICE AT 15:00 ON 8/16. HOWEVER, THE UNIT WAS PLACED ON RESERVE SHUTDOWN UNTIL 8/19
25-Aug-90	0:12	7-Sep-90	12:09	324	CONTROLLED SHUTDOWN FOR RESERVE SHUTDOWN
8-Sep-90	1:43	8-Sep-90	6:32	5	UNIT MFT ON PHANTOM PA FAN TRIP. A BLOWN FUSE IN THE FAN Y SIDE CONTROLLER WAS REPLACED.
12-Sep-90	0:12	13-Sep-90	4:05	28	CONTROLLED SHUTDOWN DUE TO A WATERWALL TUBE LEAK IN 4B COMBUSTOR. THE LEAK WAS EXTERNAL TO THE BOILER AT THE LOOPSEAL WALLBOX CONNECTION.
13-Sep-90	21:27	13-Sep-90	23:46	2	UNIT MFT ON PHANTOM PA FAN TRIP.
14-Sep-90	0:34	14-Sep-90	1:53	1	UNIT MFT ON HIGH DRUM LEVEL DURING START-UP SHORTLY AFTER SYNCHRONIZATION.
16-Sep-90	5:52	6-Oct-90	15:47	490	UNIT MFT ON HIGH FURNACE DRAFT PRESSURE DUE TO A BOILER TUBE LEAK IN 4A COMBUSTOR. DURING THE REPAIR OUTAGE B&W CONDUCTED A REMAINING USE-FUL LIFE ANALYSES ON THE RADIANT SUPERHEATER TUBES (SH II) AN TUBE METAL TEMPERATURE THERMO-COUPLES WERE INSTALLED.
6-Oct-90	17:06	7-Oct-90	0:36	8	CONTROLLED SHUTDOWN DUE TO A FLANGE LEAK BETWEEN THE THROTTLE AND CONTROL VALVES. DUR-ING START-UP.
19-Oct-90	2:04	19-Oct-90	5:45	4	UNIT MFT ON PHANTOM ID FAN TRIP. TWO CONTROL FUSES IN THE FAN DELTA SIDE CONTACTOR WERE REPLACED PRIOR TO RESTART.
23-Oct-90	13:00	23-Oct-90	14:16	1	UNIT MFT ON LOW AIR FUEL RATIO DUE TO A STUCK 4B UNDERBED DAMPER. DESSICANT DUST FROM THE CONTROL AIR DRYER CAUSED THE DAMPER TO STICK.
26-Oct-90	17:13	1-Nov-90	20:05	147	CONTROLLED SHUTDOWN FOR PYROPOWER TO INSPECT 4A AND 4B COMBUSTOR REFRACTORY AS PART OF THE CONTRACT CLOSEOUT. CUEA HIRED UNITED ENGINEERS AND CONSTRUCTORS TO PERFORM AN INDEPENDENT EVALUATION OF THE BOILER REFRACTORY.
14-Dec-90	5:01	14-Dec-90	12:27	7	UNIT TRIP ON MFT DUE TO LOSS OF ID FAN RESULTING FROM SYSTEM DISTURBANCE. THE FAN TRIP OCCURRED DURING A RECLOSURE ON 69KV BREAKER N-931.

Table 5-1. Outage Summary (continued).

START OUTAGE		STOP OUTAGE		DURATION (APPROX.)	CAUSE
DATE	TIME	DATE	TIME	HRS.	
17-Dec-90	10:29	17-Dec-90	12:24	2	UNIT TRIP ON MFT DUE TO MYSTERY TRIP OF ID FAN
20-Dec-90	17:19	20-Dec-90	19:59	3	UNIT MFT ON LOW DRUM LEVEL DURING DYNAMIC LOAD RAMP TESTING AS PART OF THE DOE TEST PROGRAM
22-Dec-90	16:19	22-Dec-90	20:08	4	UNIT MFT ON SA FAN TRIP DUE TO LOSS OF WDPF DROP 2. THE DROP WAS LOST DUE TO PROBLEMS WITH THE WDPF LOGIC ROOM HVAC SYSTEM.
2-Jan-91	15:05	2-Jan-91	18:32	3	CONTROLLED SHUTDOWN TO INSPECT A SWITCH ON THE #4 GENERATOR TRANSFORMER RAPID PRESSURE RELAY ALARM WHICH HAD ANNUNCIATED ON 12/31/90 AND DID NOT CLEAR. THE SWITCH WAS FOUND TO BE DEFECTIVE AND REPAIRED.
8-Jan-91	12:04	8-Jan-91	13:48	2	UNIT MFT ON HIGH ID FAN INLET PRESSURE DUE TO AN OUT-OF-CALIBRATION PRESSURE TRANSMITTER.
13-Jan-91	1:36	13-Jan-91	3:00	1	UNIT MFT ON LOSS OF COAL FEED TO 4A COMBUSTOR THE MFT WAS DETERMINED TO BE THE RESULT OF COAL FEEDER ROTARY VALVE PLUGGAGE RESULTING FROM THE USE OF "DORCHESTER" COAL
13-Jan-91	3:38	13-Jan-91	12:12	9	CONTROLLED SHUTDOWN, AFTER AND MFT ON LOW DRUM LEVEL, DUE TO A SUSPECTED TUBE LEAK IN 4A COMBUSTOR. UPON FURTHER INVESTIGATION, THE INDICATIONS OF A TUBE LEAK WERE FOUND TO BE FALSE AND UNIT START-UP WAS RE-INITIATED
16-Jan-91	12:18	17-Jan-91	2:30	14	UNIT MFT ON LOW-LOW UNDERBED PA AIR FLOW TO 4B COMBUSTOR DUE TO A STUCK CONTROL DAMPER DESSICANT DUST FROM THE CONTROL AIR SYSTEM DRYER CAUSED THE DAMPER TO STICK. REPAIRS WERE MADE TO THE WARM UP LINE FOR 4B BOILER FEED PUMP DURING THE SHUTDOWN.
18-Jan-91	11:44	18-Jan-91	12:35	1	UNIT MFT ON PHANTOM SA FAN TRIP.