Tidd PFBC Demonstration Project
Final Report

Fourth Year of Operation:
March 1, 1994 Through March 30, 1995

Work Performed For:

Ohio Coal Development Office
Under Contract No. CDO/ D-86-28(B)

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Under Contract No. DE-FC21-87 MC-24132.000

BY:

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Forward

This Final Report on the Ohio Power Company's Tidd PFBC Demonstration Plant covers the fourth year of plant operations from March 1, 1994 through completion of the program on March 31, 1995. Details of the first three years of operation were previously reported in a report titled " Tidd PFBC Demonstration Plant Project Report - First Three Years of Operation: Initial Startup through February 28, 1994."

The Tidd Pressurized Fluidized Bed Combustion (PFBC) Demonstration Plant was the first utility-scale pressurized fluidized bed combustor to operate in combined-cycle mode in the United States. The plant is owned and operated by Ohio Power Company (OPCo) and is located on the banks of the Ohio River, approximately 75 miles downstream of Pittsburgh, Pennsylvania.

The 45-year old pulverized coal plant was repowered with PFBC components in order to demonstrate that PFBC combined-cycle technology is an economic, reliable, and environmentally superior alternative to conventional technology in using high-sulfur coal to generate electricity.

This project received cost sharing from the U.S. Department of Energy (DOE), administered by the Morgantown Energy Technology Center in accordance with DOE Cooperative Agreement No. DE-FC21-87 MC24132.000. The project also received cost sharing from the State of Ohio, under Ohio Coal Development Office agreement Nos. CDO/D-86-28 and CDO/D-86-28(B).

Detailed design work on the project began in May 1986, and site construction work started in April, 1988. Unit start-up was initiated in November 1990 and the first combined cycle operation was achieved on November 29, 1990. The three-year demonstration period was from February 28, 1991 through February 28, 1994. The fourth year of plant operations was begun on March 1, 1994 and continued through March 30, 1995 and is the subject of this report.

Section 1.0 of this report is an executive summary of the fourth year of operations of the Tidd PFBC Demonstration Plant. Section 2.0 is an introduction to the plant and a brief description of the plant systems and layout. Section 3.0 covers the project history, fourth year overview and operating statistics. Section 4.0 addresses unit testing that was accomplished during the fourth year. Section 5.0 reviews the significant process related findings and plant modifications required during the fourth year. Section 6.0 describes the individual PFBC system inspections completed after the plant was shut down on March 30, 1995. Appendix I is an operational narrative of each of the unit runs and major outages. Appendix II is a log of the operational hours and statistics of each run. Appendix III is a log of performance test results. This report is a companion report on this project. The history, modifications, and operating history of the first three years of operation is covered in a separate report issued by the Department of Energy titled "Tidd PFBC Demonstration Project - Final Report - First Three Years of Operation: Initial Startup Through February 28, 1994."

The report was prepared by the American Electric Power Service Corporation as agent for the Ohio Power Company. Assistance and input for this report was provided by the staff of the Tidd PFBC Demonstration Plant. The following individuals prepared this report:

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Acronyms and Abbreviations

AB	ASEA Babcock - A business partnership between a subsidiary of ABBC and the Babcock & Wilcox Company (USA)
AFBC	Atmospheric Fluidized Bed Combustion
AEP	American Electric Power Company, Inc.
AEPSC	American Electric Power Service Corporation, a subsidiary of AEP
ABB	Asea-Brown Boveri
ABBC	ABB Carbon - a subsidiary of ASEA-Brown Boveri (subcontractor)
ABB Stal	ABB Stal - a subsidiary of ASEA-Brown Boveri
Al_2O_3	Aluminum Oxide
APF	Advanced Particle Filter
B&W	The Babcock & Wilcox Company (subcontractor)
Btu	British Thermal Units
Btu/#	British Thermal Units per Pound
BWCC	The Babcock & Wilcox Construction Company (subcontractor)
BOP	Balance of Plant
CaO	Calcium Oxide
Cl	Chlorine
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CTF	Component Test Facility
CWP	Coal Water Paste
DOE	Department of Energy (United States)
EMP	Environmental Monitoring Plan
EPA	Environmental Protection Agency
ESP	Electrostatic Precipitator
Fe_2O_3	Iron Oxide
GT	Gas Turbine
HGCU	Hot Gas Clean-Up
HP	High Pressure
HPC	High Pressure Compressor
HPT	High Pressure Turbine
HVAC	Heating, Ventilating & Air Conditioning

Acronyms and Abbreviations

I&C	Instrumentation & Control
lbm	Pounds Mass
K_2O	Potassium Oxide
kva	Kilovolt Amperes
kW_e	Kilowatts Electrical
LP	Low Pressure
LPC	Low Pressure Compressor
LPT	Low Pressure Turbine
MgO	Magnesium Oxide
mm	Millimeters
MMBtu	Million Btu
MW_e	Megawatts Electrical
MW_t	Megawatts Thermal
MWg	Megawatts Gross
NCB	National Coal Board
NDE	Nondestructive Examination
NOVAA	Northern Ohio Valley Air Authority
NO_x	Nitrogen Oxides
NPDES	National Pollutant Discharge Elimination System
NSPS	New Source Performance Standards
OEPA	Ohio Environmental Protection Agency
OCDO	Ohio Coal Development Office - a part of Ohio Department of Development
OPCo	Ohio Power Company
pf	Power Factor
PFBC	Pressurized Fluidized Bed Combustion
POPS	Plant Operations and Performance System
ppb	Parts Per Billion
pph	Pounds Per Hour
rpm	Revolutions per Minute
SiO_2	Silicon Oxide
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide

1.0 Executive Summary

1.1 Introduction

The Tidd Pressurized Fluidized Bed Combustion (PFBC) Demonstration Plant was the first utility-scale pressurized fluidized bed combustor to operate in combined-cycle mode in the United States. The plant is owned and operated by Ohio Power Company (OPCo) and is located on the banks of the Ohio River, approximately 75 miles downstream of Pittsburgh, Pennsylvania.

The 45-year old pulverized coal plant was repowered with PFBC components in order to demonstrate that PFBC combined-cycle technology is an economic, reliable, and environmentally superior alternative to conventional technology in using high-sulfur coal to generate electricity.

The PFBC related equipment was supplied by ASEA Babcock, a partnership between ASEA Brown Boveri Carbon (ABB Carbon) and The Babcock & Wilcox Company (B&W). American Electric Power Service Corporation (AEPSC) engineered and designed the plant. Construction of the PFBC Island and modification of the existing facility were performed by Ohio Power Company.

This project received cost sharing from the U.S. Department of Energy (DOE), administered by the Morgantown Energy Technology Center in accordance with DOE Cooperative Agreement No. DE-FC21-87 MC24132.000. The project also received cost sharing from the State of Ohio, under Ohio Coal Development Office agreement Nos. CDO/D-86-28 and CDO/D-86-28(B).

Detailed design work on the project began in May 1986 and site construction work started in April 1988. Unit start-up was initiated in November 1990 and the first combined-cycle operation was achieved on November 29, 1990. The three-year demonstration period started on February 28, 1991 and terminated on February 28, 1994. The fourth year of testing started on March 1, 1994 and terminated on March 30, 1995.

This report reviews the experience of the 70-MW_e Tidd PFBC Demonstration Plant during the fourth year of operation. The experience of the first three years has been previously reported in a report titled "Tidd PFBC Demonstration Plant Project Report - First Three Years of Operation: Initial Start-up Through February 28, 1994".

1.2 Operating Overview

The Tidd PFBC Demonstration Plant accumulated approximately 11,500 hours of coal-fired operation during its four years of operation. The fourth year of operation accounted for approximately 5400 hours of operation. The achievements during that period were significant in establishing PFBC as a viable option for base-load, coal-fired generation. The highlights of the fourth year of operation are noted below:

First quarter 1994 - The unit continued to demonstrate improved operation. Unit availability and reliability were improving significantly and achieving an acceptable level for a demonstration plant utilizing "first-of-a-kind" technology. However, attempts at achieving design bed operating temperature (1580 F) at high unit loads remained unsuccessful. Excessive egg sinter formation continued to be an obstacle to achieving full bed temperature at higher loads. Sorbent utilization was still below expectations. Plumes of high SO_2 concentration continued to be measured above the fuel nozzles. The ash removal systems were now working effectively. However significant maintenance effort was still required to maintain primary cyclone ash system integrity. The unit operated for a total of 850 hours on coal during the period. 310 hours were recorded during March - the first month of the fourth year of operation.

Second quarter 1994 - This period proved to be the most productive of the entire test period. From April to June the unit fired coal for 1521 hours. Unit reliability had reached a point where efforts could be focused on unit testing. Thirteen performance tests were conducted during this period. The plant established a new record for its longest continuous run on coal of 1079 hours surpassing its previous record of 740 hours. Unit availability for the first half of 1994 was 54.7%. During this period the focus of investigation into excessive sintering was shifted from inadequate fuel distribution and fuel splitting to investigation of bed fluidization. Since superficial fluidizing velocity could not be increased to improve agitation and mixing, the bed dynamics were modified by altering the size consist of the sorbent feed to produce a finer bed. The finer bed showed considerably improved properties including improved heat transfer and more uniform bed and evaporator tube outlet leg temperature profiles. No signs of excessive sintering were observed in any runs using finer dolomite as the sorbent.

Third quarter 1994 - The unit continued to operate successfully. Fourteen performance tests were conducted. Unit availability for the first three quarters of the year remained at approximately 55%. Sintering, with dolomite as the sorbent, had been basically resolved. Notable improvements in sorbent utilization were being achieved. Ca/S molar ratios below the "design" and "goals" were being demonstrated with "off-site" prepared sorbents. The unit operated for a total of 1213 hours during this period.

Fourth quarter 1994 - The unit continued to operate well during this period, a total of 1194 hours of coal fired operation were logged. Unit availability remained acceptable at approximately 55% for the year. Six performance tests were conducted. The unit continued to operate without excessive sintering when utilizing dolomite feestock. Testing with limestone feedstock was attempted during this period. This resulted in a gradual deterioration of bed conditions. The test was aborted after about 36 hours.

First quarter 1995 -The unit continued to operate very effectively during this period. The unit operated on coal for a total of 1144 hours during the period. Twelve performance tests were conducted during the quarter, bringing the total to 95 for the four year test period. Various coals tested during this period included M&M Coal Company (Betsy Mine) Pittsburgh #8, Minnehaha, and Consol Mahoning Valley Pittsburgh #8. Sorbents tested included Plum Run Greenfield Dolomite, Mulzer Dolomite, and National Lime Delaware Limestone.

The final test of the program was completed on 3/28/95 while operating with Consol coal and National Lime Delaware limestone. The test was conducted at 115" bed level and 1580 F bed temperature. The unit operated for approximately 40 hours during which time the bed showed signs of deterioration (bed and evaporator temperature distributions were slowly deteriorating as bed density and steam production continued to drop). In spite of the noted deterioration of bed conditions, there were no signs of excessive egg sinters in the bed ash removal system. The fourth year test program was completed at the end of March 1995.

Over the final year of operation, which covered the period between March 1, 1994 and March 30, 1995, the unit fired coal for a total of 5,382 hours. Unit availability for this period of operation was 57.0%. The unit gross output factor was 68.8% and the gross unit capacity factor was 39.3%. Key operating statistics for the total demonstration are presented in Table 1.2.1.

Table 1.2.1 - Key Operating Statistics

Key Operating Statistics October 1990 through March 30, 1995						
Yearly Data	1990 3 Months	1991	1992	1993	1994	1995 3 Months
G. T. Operating Hours	457	1482	2914	2544	5035	1301
Coal Fire Hours	61	795	2367	2310	4767	1145
Unit Availability	4.1%	9.6%	28.7%	26.6%	54.7%	54.5%
Gross Capacity Factor @ 70 MWG	0.4%	3.6%	17%	15.5%	37%	38.9%
Number of Runs	9	43	29	16	18	10
Gross Unit Output Factor @ 70 MWG	10.7%	37.3%	59.2%	58.2%	67.6%	71.4%
Maximum Gross Unit Load Achieved	N/A	53 MW	71 MW	64 MW	68 MW	72 MW

1.3 Significant Findings

The significant findings for the Tidd test program are focused in four areas. These include: process/environmental performance, boiler performance, gas turbine performance, and ancillary systems performance.

1.3.1 Process/environmental

The unit successfully met or exceeded all of its guarantee conditions except gas turbine output. The process was able to meet its design sulfur retention (SR) of 90% and was able to demonstrate sulfur retention in excess of 95%. Testing using various finer crushed grades of dolomite, with a narrow size consist range, resolved sintering while concurrently demonstrating exceptional improvement in Ca/S molar ratio. The best results were achieved using Plum Run Greenfield (PRG) 12 mesh "designer" (off-site prepared) dolomite.

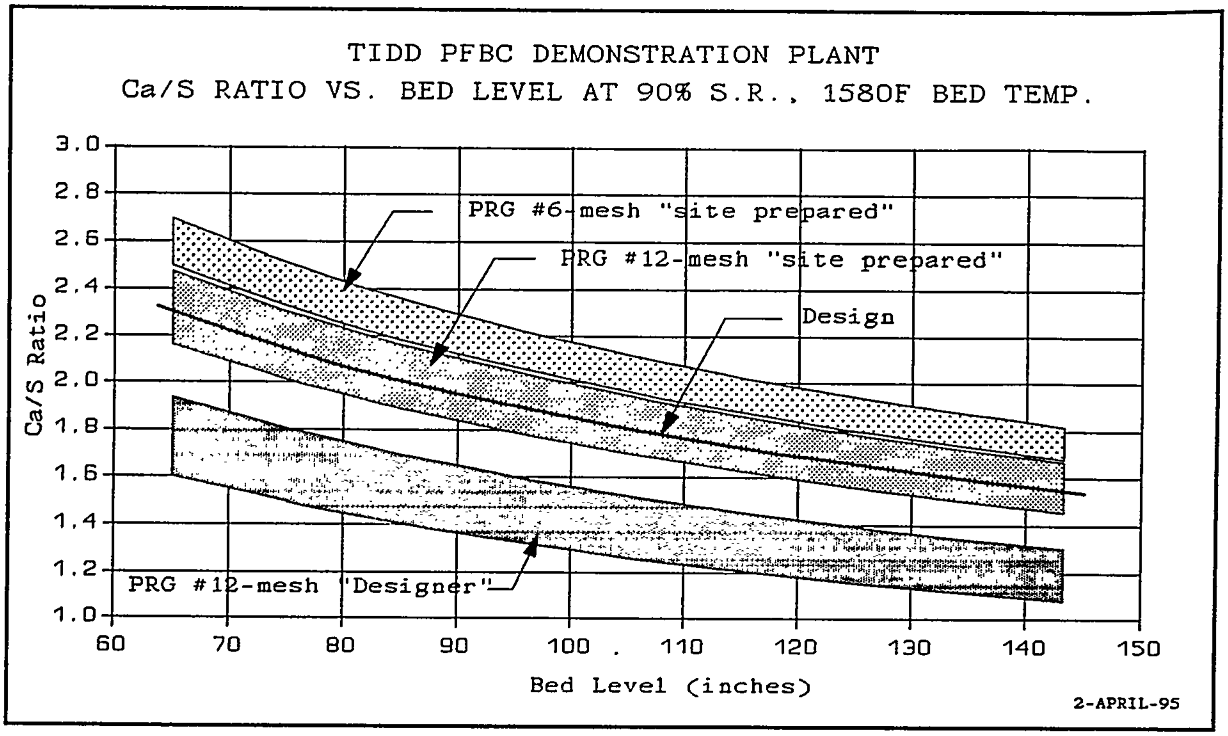


Figure 1.3.1 - Bed Height vs Ca/S Ratio, 90% Sulfur Capture

The use of this size gradation improved sorbent utilization by over 30% when compared to the same stone prepared "on-site" to approximately 6 mesh top size. Figures 1.3.1 and 1.3.2 show sorbent utilization (Ca/S) versus bed height for 90 and 95% sulfur capture for tests conducted with various sorbent size ranges.

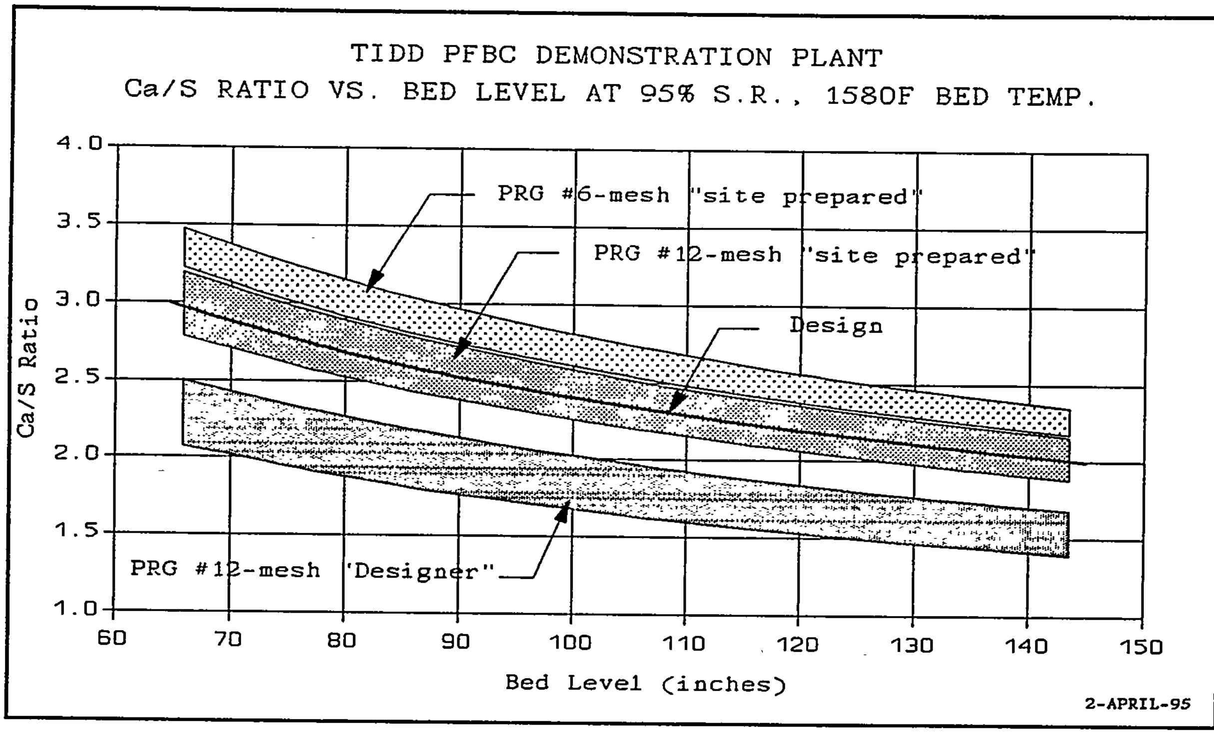


Figure 1.3.2 - Bed Height vs Ca/S Ratio, 95% Sulfur Capture

The process emitted lower NO_x emissions than design, typically below 0.25 lb/MMBTU. These low emissions were inherent to the process and did not require any enhancements such as ammonia injection in the boiler freeboard. Such enhancements could be expected to reduce NO_x emissions even further.

The combustion efficiency was better than predicted, combustion efficiencies above 99.6% were typical at full bed height.

Table 1.2.2 provides a summary of actual versus predicted performance for significant process parameters.

Table 1.2.2 - Summary of Actual Versus Expected Performance

Summary of Actual Versus Expected Performance			
Item	Goal or Expected Performance	Actual Performance	Reference
Total Plant Output - MWe	72.5	72	
Ca/S Molar Ratio @ 90% Sulfur Retention	1.6 - 2.0	1.1 - 1.2	Figures 1.3.1, 1.3.2, Section 4.3, 4.4
Ca/S Molar Ratio @ 95% Sulfur Retention	n/a	1.5 - 1.6	Same as 90 % Retention
NOx Emission - Lb/MMBtu	0.5 (permit limit)	0.15 - 0.33	Figure 4.7.1, Section 4.7
CO Emission - Lb/MMBtu	0.01	< 0.01	
Combustion Efficiency - %	99.0	99.6	Section 4.5
Particulate Emissions - Lb/MMBtu	0.03	<0.02	

1.3.2 Boiler

The in-bed tube bundle experienced no widespread erosion that would require significant maintenance. Minor localized erosion was detected and addressed during the early operation of the unit. There was one tube leak event in the in-bed tube bundle during the first three years of operation. This was attributed to localized erosion caused by a missing personnel access hatch seal. During the fourth year of operation a second tube leak event was experienced. A routine air pressure leak test of the superheater circuit, in the fall of 1994, indicated leaking tubes in the secondary superheater (SSH). Two leaking tubes were identified, one each on SSH circuit 15 and 16. Metallurgical examination determined the initiating failure mechanism to be I.D. initiated stress corrosion cracking of the #15 tube.

A significant amount of thinning was observed in certain areas of the water wall tubes. The thinned areas are generally located on each of the four walls of the boiler. They start approximately 5 feet above the air sparge ducts and terminate about three feet below the top of the tube bundle. No operational failures occurred during the test program, but it is clear that these areas would have failed in the near term. Thinning of these water wall tubes is not significant. The heat transfer in these tubes is minimal. Therefore, protective shielding with refractory would be possible to address this problem.

1.3.3 Gas turbine

The gas turbine was the leading cause of unit unavailability during the first three years of operation. The Low-Pressure Turbine blades were replaced once due to cracks, and once due to a catastrophic failure of a Low-Pressure Turbine blade. In addition, the Low-Pressure Compressor stationary blades were replaced due to cracks at the guide vane ring attachments. However, it is important to note that the above failures were all related to the design of the gas turbine rather than to its operation in a PFBC plant. Gas turbine performance was improved in the fourth year. No significant failures occurred. Downtime was limited to that required for routine inspection and maintenance of the gas turbine.

The erosion on the gas turbine blades continued to be relatively minor during the fourth year of operation. The most significant erosion was in the Low-Pressure Turbine variable-pitch inlet guide vanes and inlet guide vanes inner and outer rings. It should be noted that a design modification was available to mitigate this erosion; however, the modification was not implemented due to the relatively short life of the Tidd Project.

1.3.4 Ancillary systems

The early operation of Tidd was plagued by difficulties associated with the materials handling systems. However, design changes during the first three years were successful in addressing and resolving most of these issues. Some of the revisions carried over into the fourth year, but all ancillary system issues had been adequately addressed when the program was terminated. Section 6 provides a detailed discussion of the experience and performance of each system.

1.4 Significant Modifications

The various sections of this report detail the system modifications implemented during the fourth year of plant operation. Some of the significant modifications include:

Reinstallation of the dual stage fuel splitting air nozzle design to address the sintering issues which were pervasive at full bed temperature. The modification proved inadequate to address sintering.

Modifications to the sorbent injection system by increasing the number of sorbent feed lines and the continued installation of ceramic lined piping.

Modification of the sorbent preparation system to increase system capacity and to provide the flexibility to produce finer on-site prepared sorbent.

1.5 Unit Performance

A total of 95 unit performance tests were conducted during the four-year test program. The fourth year of operation contributed 48 performance tests. Performance goals and guarantees were verified by acceptance tests conducted during the first three-years of operation. Testing in the fourth year of operation focused on resolving the problem of sintering and on improving sorbent utilization. An additional goal was established to operate the unit extensively to establish the survivability of both the gas turbine and the "in-bed" tube bundle. During the fourth year, various coal and sorbent feedstocks were tested. The unit achieved its highest gross output of 72.1 MW_e while achieving a firing rate of 217 MW_t at a bed temperature of 1582 F. The sorbent utilization was found to be heavily dependent on the top size and size gradation of the sorbent feedstock. Operation at Tidd demonstrated that a Ca/S molar ratio of 1.1 is achievable at 90% sulfur capture and 142 inches bed level. The data also indicates that a Ca/S molar ratio of 1.5 is achievable at 95% sulfur retention. (Ca/S ratios are normalized to 90 and 95% sulfur retention at 1580 F bed temperature.) SO_2 and NO_x emissions were both better than design and well within the permit limitations. SO_2 emissions were 0.35 lbs/mmbtu while NO_x emissions were around 0.20 lbs/MMBtu during the test period. Combustion efficiencies of 99.4% were typical.

1.6 Conclusion

The Tidd PFBC Demonstration Plant successfully demonstrated the viability of PFBC technology, proving that the process could effectively control sulfur emissions from high-sulfur coal. The ability of a gas turbine to operate in a PFBC combined-cycle mode, utilizing exhaust gases from the PFBC process to drive a gas turbine, has been demonstrated. While some erosion was observed, the amount was acceptable. The ability of an in-bed tube bundle to perform acceptably in a bubbling bed environment was confirmed. The erosion of the in-bed tubes was negligible. The systems required to apply PFBC technology to electric power generation were demonstrated and, in many cases, refined at Tidd. The significant problems of sintering, post bed combustion and poor sorbent utilization were effectively addressed during the fourth year of operation. The process, which was demonstrated in early Tidd operation, has been refined and optimized to the point that first generation PFBC is ready for full-scale commercial deployment.

2.0 Introduction

The Tidd Pressurized Fluidized Bed Combined-Cycle (PFBC) Demonstration Plant was the first PFBC combustor to operate in combined-cycle mode in the United States. The plant is owned and operated by Ohio Power Company (OPCo) and is located on the banks of the Ohio River, approximately 75 miles downstream of Pittsburgh, Pennsylvania.

The 45-year old pulverized-coal power plant was repowered with PFBC components in order to demonstrate that pressurized fluidized bed combustion combined-cycle technology is an economic, reliable, and environmentally superior alternative to conventional technology in using high-sulfur coal for power generation.

The PFBC-related equipment was supplied by ASEA Babcock, a partnership between ASEA Brown Boveri Carbon (ABB Carbon) and the Babcock & Wilcox Company (B&W). American Electric Power Service Corporation (AEPSC) engineered and designed the plant. Construction and modification of the existing facility were performed by Ohio Power Company.

The project received cost sharing from the U.S. Department of Energy (DOE), administered by the Morgantown Energy Technology Center in accordance with DOE Cooperative Agreement No. DE-FC21-87 MC24132.000. The project also received cost sharing from the State of Ohio, under the Ohio Coal Development Office agreements No. CDO/D-86-28 and CDO/D-86-28(B).

Detailed design work on the project began in May 1986, and site construction work started in April 1988. Unit startup was initiated in October 1990. The first combined-cycle operation was achieved on November 29, 1990, and the three-year demonstration period began on February 28, 1991 and ended on February 28, 1994. The fourth-year of operation started on March 1, 1994 and was terminated on March 30, 1995. This report reviews the operating experience during the fourth year of operation.

2.1 Process Overview

A bubbling fluidized bed consists of a mass of granular particles with a gas stream flowing upward through the particles. At a minimum air velocity, that is dependent on particle size and shape, and on particle and gas densities, the particles achieve a highly turbulent suspended state. The bed in this state is said to be fluidized and behaves like a fluid. At higher fluidizing velocities, the particles become entrained in the flow stream, and the process acts like a transport reactor. That type of fluidized bed is called a circulating fluidized bed. The technology discussed in the report is limited to bubbling bed technology.

This fluidized motion permits excellent surface contact between the air and the particles. When a combustible material, such as coal, is introduced into the bed, this mixing permits almost isothermal conditions and efficient combustion. The operating temperature of the bed is determined by the fuel heat release in the bed, the excess air, and the rate of heat removal from the bed. The temperature range is established by the coal characteristics; for Eastern coals, the bed temperature range is 1350 F to 1700 F.

In a fluidized bed, the SO_2 generated during combustion is removed by adding a sorbent, such as dolomite or limestone, to the bed. Dolomite, composed primarily of calcium carbonate and magnesium carbonate ($CaCO_3 \bullet MgCO_3$), dissociates when heated to form the porous and reactive complex of magnesium oxide-calcium carbonate ($MgO \bullet CaCO_3$) to react with sulfur dioxide. At fluidized bed temperatures, the reaction of this complex with sulfur dioxide (SO_2) forms an inert magnesium oxide-calcium sulfate complex ($MgO \bullet CaSO_4$). This is expressed chemically as:

$$CaCO_3 \bullet MgCO_3 + \text{Heat} \rightarrow MgO \bullet CaCO_3 + CO_2$$

$$MgO \bullet CaCO_3 + SO_2 + 1/2\ O_2 \rightarrow MgO \bullet CaSO_4 + CO_2$$

Under pressurized conditions, calcination and sulfation do not necessarily occur as two separate reactions. Laboratory research has determined that a significant part of the sulfur capture occurs by direct diffusion of the SO_2 molecule into the calcium carbonate which replaces the CO_2 in the carbonate.

The magnesium oxide-calcium sulfate complex produced in these reactions is a dry granular by-product which can be easily managed.

In addition to reduced SO_2 emissions, NO_x emissions from a fluidized bed are lower than from a conventional pulverized coal boiler. The lower combustion temperature in a fluidized bed minimizes thermal NO_x generation.

During operation, the fluidized bed contains a relatively small percentage of combustible material (less than 1 percent with some coals). The balance consists of dolomite and inert material (reacted dolomite and ash). Because of this low percentage of combustibles and the low combustion temperature, the fluidized bed can burn a much wider range of fuels than conventional processes. Fuels with very low or high heating value, low or high ash content, low or high sulfur content, and moderate to high ash fusion temperatures can be burned in a fluidized bed.

Boiler tubes submerged in a fluidized bed are used to generate steam to drive a steam turbine-generator. Because of the turbulent nature of the bed particles, overall heat transfer rates 4 to 5 times greater than in a conventional furnace are achieved in these tubes. Therefore, the total amount of boiler surface is significantly reduced compared with a conventional boiler, resulting in capital-cost savings.

Fluidized beds can be operated under various conditions, the most distinguishing of which is pressure. Combustion in fluidized beds operating at pressures of about one atmosphere or less are referred to as Atmospheric Fluidized Bed Combustion (AFBC). Fluidized bed combustion at much higher pressures is referred to as Pressurized Fluidized Bed Combustion (PFBC). Tidd is a pressurized, bubbling-bed process.

Because of the higher pressure, the exhaust gases from a PFBC have sufficient energy to drive a gas turbine while the steam generated in the in-bed boiler tubes drives a steam turbine. This combined-cycle configuration allows a power plant design which is more economic and efficient than alternatives.

In PFBC, the higher operating pressure allows for the use of deep beds which result in a long residence time that yields high combustion efficiency and a high level of sulfur removal with lower sorbent requirements. A PFBC power plant permits burning a wide range of coals in an environmentally compatible manner. Intimate contact of the coal and dolomite enables a consistent, high degree of sulfur removal during combustion. Relatively low combustion temperatures and the deep bed result in low NO_x emissions. The waste products, both fly ash and bed ash, are dry, benign, and manageable. The high pressure and high in-bed heat transfer allow a reduction in plant size with corresponding material savings. The combined-cycle operation results in high generating efficiency.

2.2 Tidd Cycle

Figure 2.2.1 provides a composite cycle schematic which shows how PFBC was incorporated into the original Tidd Unit 1 conventional steam cycle. The Tidd Unit 1 steam cycle was a 1940's vintage cycle, with original steam conditions of 900,000 #/hr steam flow at 1300 psia and 925 F with no reheat. The plant produced an output of 110 MW_e at a cycle efficiency of 31%. As configured for PFBC operation, the plant was designed for a steam flow of 440,000 #/hr at 1300 psia and 925 F, to produce a gross electrical output of 56.7 MW_e from the steam turbine and 16.9 MW_e from the gas turbine with a net cycle efficiency of 34%. Table 2.2.1 provides the full load design values.

Table 2.2.1 - Full-Load Process Design Values

Feedwater / Steam Cycle	
Feedwater Flow	424,110 lb/hr
Final Feedwater Temperature/Pressure	478 F/1850 psig
Main Steam Flow	439,560 lb/hr
Main Steam Temperature/Pressure	925 F/1320 psig
Steam Turbine Output	56.7 MWG
Air/Gas Cycle	
LP Compressor Outlet Pressure/Temperature	71 psig/326 F
HP Compressor Outlet Pressure/Temperature	192 psig/572 F
Air Flow	646,000 lb/hr
Bed Temperature	1580 F
HP Turbine Inlet Pressure/Temperature	165 psig/1525 F
LP Turbine Inlet Pressure/Temperature	47 psig/986 F
Gas Flow	724,000 lb/hr
Excess Air	25%
Gas Turbine Output	16.9 MWG
Solids	
Coal Water Paste Flow	72,620 lb/hr
Sorbent Flow (1)	27,760 lb/hr
Bed Height (2)	126 in

NOTES:

(1) At calcium-to-sulfur molar ratio of 1.64 for 90% sulfur retention.

(2) Bed height was increased to 142 inches in December 1991.

The design full-load heat balances for the steam side and the gas side of the combined cycle are shown in Figures 2.2.2 and 2.2.3, respectively.

In the gas cycle, ambient air enters the low pressure compressor section of the gas turbine and is compressed to 71 psig. The compressed air is then cooled by the gas turbine intercooler. The air then enters the high pressure compressor where it is further compressed to 192 psig and 572 F.

The hot compressed air is then directed through the outer annulus of a coaxial air/gas pipe into the pressure vessel. Once inside the pressure vessel, the hot air is routed through a series of internal cyclone ash coolers where the air is further heated before it is directed into the fluidized bed via a system of sparge ducts.

The coal is fed to the bed as a coal-water paste (25% nominal water content by weight). The sorbent is injected into the bed by a pneumatic transport system.

After leaving the fluidized bed zone, the hot gases and entrained ash particles enter the freeboard zone above the bed. The hot gases and entrained ash then pass into seven parallel primary cyclones, and through six secondary cyclones and one hot-gas cleanup slip stream which operates in parallel to the other six secondary cyclones. The cyclones were designed to remove 98% of the entrained ash from the gas stream. The gas is cleaned sufficiently to pass through the gas turbine without deleterious erosion of the gas turbine components.

After exiting the cyclones and hot-gas cleanup slip stream, the gas is collected in a manifold and exits the pressure vessel. The gas is directed through the inner pipe of the coaxial pipe, past the hot gas intercept valves and into the high-pressure gas turbine at 1525 F and 165 psig where the hot gas is expanded. The gas then enters the low-pressure turbine where it is further expanded and then cooled to 350 F in the turbine exhaust gas economizer.

After the economizer, the gas enters the electrostatic precipitator where it is further cleaned to meet the New Source Performance Standards (NSPS) of 0.03 lbm/million BTU before being emitted to the atmosphere via the Cardinal Unit 1 flue gas stack.

The steam cycle is a Rankine cycle with a once-through Benson-type boiler. Condensate from the condenser is heated from 74 F to 259 F in three stages of low-pressure heaters and the gas turbine intercooler as it is pumped to the deaerator by the hotwell and condensate booster pumps. From the deaerator, the feedwater is pressurized by the tank pumps and further heated to 295 F by the single high-pressure heater before being fed to the suction of the feedwater pump. The flow is further pressurized by the feedwater pump and directed to the economizer where heat in the gas exiting the gas turbine further preheats the feedwater to 478 F. From there the subcooled feedwater is routed to the pressure vessel and enters the boiler at 478 F and 1850 psig.

The boiler is a subcritical once-through steam generator that employs a pump assisted circulation loop and a moisture separator for startup and shutdown. The boiler provides steam at 1350 psig and 925 F.

2.3 Plant Description

2.3.1 Site Description

The 70 MW_e Tidd PFBC Demonstration Plant is located at the Ohio Power Company Tidd Plant on the Ohio River in Brilliant, Ohio. The PFBC module repowered Tidd Unit 1, a 110 MW_e steam plant. The original Tidd Unit 1 was commissioned in September 1945, deactivated in 1976, and retired in 1979.

The Tidd Plant offered an ideal site for the PFBC Demonstration Plant for the following reasons:

Existing plant equipment such as coal handling systems, plant services, and high voltage connection to the existing 138,000-volt switchyard could be utilized.

The demonstration plant could be erected and placed in service in much less time than if a Greenfield site was selected.

Cost savings could be realized in developing the combined cycle aspect of PFBC by utilizing the Unit 1 existing steam turbine-generator, condenser, and feedwater system.

The open space adjacent to Unit 1 provided an unobstructed location for the PFBC plant.

The site is adjacent to the Ohio River which is conducive to barge shipment of large modular components to the site.

2.3.2 Plant Layout

The new PFBC power island, which included the combustor, gas turbine, and coal and sorbent systems, was installed in a new building constructed adjacent to the original Tidd Unit 1. The new economizer, electrostatic precipitator, ash silos, and electrical control building were located nearby. Much of the original Tidd balance of plant equipment was refurbished and reused. The steam cycle utilized many of the original components, including the steam turbine/generator, condensate and feedwater heaters, and pumps.

Many of the service buildings, control and piping systems were also reused. The original structures for storing and handling coal were used for both coal and dolomite, as was the 138,000 volt switchyard.

Major new equipment that was installed included the pressurized fluidized bed combustor and related components (including the boiler, bed ash reinjection system, and cyclones), the gas turbine, coal and sorbent preparation and injection systems, the economizer, the electrostatic precipitator, ash removal and disposal systems, and electrical components (including transformers and switchgear). It was also necessary to construct new foundations, buildings, and piping and electrical systems needed to integrate the PFBC system with the balance of the plant.

2.4 Plant Systems

2.4.1 Pressure Vessel

A single cylindrical pressure vessel contained the boiler, cyclones, cyclone ash coolers, and bed ash reinjection system. This arrangement allowed the components within the vessel to be designed for a relatively low differential pressure, even though the process pressure was relatively high.

The pressure vessel was externally insulated and was designed for internal operating conditions of 675 F and 185 psig. It consisted of a vertical cylindrical shell about 70 feet high and 44 feet in diameter, with elliptical heads.

The pressure vessel heads included removable service openings that allowed for the removal of internal components. In addition, internal and external service platforms, lifting devices, and access doors were provided to permit service and maintenance of both the internal and external systems.

2.4.2 Boiler

The PFBC boiler enclosure was designed with membrane water wall construction. At normal operating loads, the boiler was a subcritical, once-through unit. There were three major sections in the boiler: the boiler bottom, the bed zone, and the freeboard.

The boiler bottom consisted of fluidizing air ducts arranged on top of a pair of membrane water wall hoppers. The hoppers, which remained full of ash during operation, directed the spent bed material to the bed ash removal system.

The bed zone was an 11-feet 8-inch deep tapered, fluidized bed in which the superheater and evaporator sections were submerged. At full load, all of the evaporator and superheater surfaces were submerged within the bed. At reduced loads, the bed level was lower, and portions of the surface were exposed. The surface above the bed cooled the gases before they passed to the gas turbine.

The freeboard section above the bed was internally insulated to minimize heat loss from the gases which drove the gas turbine.

2.4.3 Bed Ash Reinjection System

Bed level was the main controlling parameter in the Tidd PFBC boiler. The bed ash reinjection system permitted rapid change in the unit load by transferring bed material to and from a pair of reinjection vessels located inside the combustor pressure vessel.

Air from the combustor pressure vessel transported the bed material to the reinjection vessels, and "L" valves transported the material from the reinjection vessels back to the bed. The transport air flow was separated from the ash and vented outside the combustor into the main combustion flue gas. The reinjection vessels were normally at the same pressure as the boiler; however, during load decreases, they were at a slightly lower pressure, accomplished through controlled venting.

2.4.4 Cyclones

To reduce particulate flowing to the gas turbine, the exhaust gases leaving the upper part of the boiler freeboard passed through a series of cyclones. At Tidd, there were originally seven parallel strings of cyclones, each with two stages of separation. However, one of the secondary cyclones was replaced with a hot-gas cleanup slip stream filter. The gas was conveyed from the boiler to the first stage cyclones through connecting flues. Gas flowed from the second stage cyclones to a manifold and then exited the pressure vessel, and was routed to the inner portion of a coaxial pipe and past the hot gas intercept valves on its way to the gas turbine.

2.4.5 Gas Turbine/ Generator

The gas turbine at the demonstration project was the ABB Stal GT-35P machine. The turbine was arranged in line on two shafts. The variable-speed, low-pressure compressor was mechanically coupled to its driving low-pressure turbine on one shaft. The high-pressure turbine drove both the constant-speed high-pressure compressor and the electric generator. An epicyclic gear reducer coupled the electric generator to the high-pressure shaft.

2.4.6 Steam Turbine/ Generator

The original steam turbine at the Tidd Plant was a 110 MW_e, 1800 rpm condensing turbine/ generator. It was contained in a single casing directly connected to a 0.9 pf, 111,111-kva, 3-phase, 60-cycle, 13,800-volt generator. The PFBC boiler produced less main steam flow than the original Tidd boilers; therefore, the steam turbine produced 57 MW_e at full load.

2.4.7 Economizer

The once-through turbine exhaust gas economizer at Tidd recovered heat from the gas turbine exhaust to preheat the feedwater. Tidd's economizer was a modular design, with the flue gas flowing horizontally across vertical, in-line, spirally-finned water tubes. It was installed in series with the condensate heaters and replaced the original high-pressure feedwater heaters.

2.4.8 Electrostatic Precipitator

After leaving the economizer, the gas entered the electrostatic precipitator. Here, the gas was further cleaned of particulate to the NSPS level of 0.03 lbm per million Btu. The gas was then released to the atmosphere via the flue gas stack.

2.4.9 Coal Handling, Preparation, and Injection Systems

The Tidd PFBC Demonstration Plant utilized coal-water-paste (CWP) fuel, with a water content of 25% by weight, which was injected into the fluidized bed. Coal was weighed and sampled prior to placement in the coal storage area. A 30-day supply of coal was maintained in the storage area which has adequate space for storage of two smaller piles of test coals, each with a seven-day supply. Mobile equipment was used to maintain the storage piles and to reclaim coal from storage.

Coal, from storage, was loaded into rotary car dumper hoppers and delivered by a system of belt conveyors and transfer stations to three bunkers located in the main plant building. The conveyors were totally enclosed and were provided with dust collection and fire protection systems. Weighing, crushing, screening, and magnetic separation equipment are provided in the system. The three bunkers had a total storage capacity of 1350 tons, and were filled by a conveyor equipped with a traveling tripper.

A new conveyor system was installed below the original Tidd bunkers to convey coal to the coal preparation system, which was located in the new combustor building. The coal, one inch or less in size and stored in a surge hopper with a storage capacity of 45 tons, was fed into a double-roll crusher by a vibratory feeder. Crushed coal, all of which was 6 mm (¼ inch) or less in size, was transported by a system of conveyors onto a triple-deck screen to eliminate undesirable oversized pieces over 10 mm (3/8 inch) and then through a weigh feeder into a pug mill type mixer. Subsequent to the startup of the unit, a system was installed to recirculate a portion of the crushed coal back to the crusher to increase the fines content of the coal. Water was added to the coal in the mixer at a rate proportional to the coal weight feeder indication. The water to coal ratio was periodically trimmed based upon manual slump testing of the paste.

Prepared CWP was continuously fed into a paste tank from which six parallel coal injection pumps draw the CWP and deliver it to the boiler. Each pump delivered the fuel flow into the boiler through a dedicated fuel nozzle. The nozzles penetrated the pressure vessel and boiler enclosure walls. High-pressure compressed air was used to break up the CWP at the discharge of the nozzles. The coal injection pumps were hydraulically operated piston pumps. The fuel flow rate was controlled by varying the speed of the pumps.

2.4.10 Sorbent Handling, Preparation, and Injection Systems

Sorbent (dolomite or limestone) was unloaded by a temporary conveying system to the storage area, separate from the coal piles. A 30-day supply of sorbent was maintained in the storage area which had adequate space for storage of two smaller piles of test sorbents, each with a seven-day supply. Mobile equipment was used to maintain the storage piles and to reclaim sorbent from storage. Reclaimed sorbent was loaded into the reclaim hopper and delivered to a bunker by the same belt conveyors that conveyed coal to the bunkers. The sorbent bunker had a total storage capacity of 650 tons. A new conveyor system was installed below the sorbent bunker to convey sorbent to the sorbent preparation system, which was located in the combustor building. The sorbent was stored in a 70-ton capacity surge hopper, from which it was fed into an impact dryer mill. The size of the sorbent was controlled by a vibrating screen and was heated by air flowing through the mill. The sized material was swept from the mill by the hot air and then sorted by a cyclone separator and a bag house. A vibrating screen, located at the outlet to the cyclone separator, diverted oversized material back to the mill. The final product was transported by conveyor into a 200-ton sorbent storage hopper. The hopper had two outlets to feed the sorbent injection system.

Lockhoppers received the prepared sorbent at atmospheric pressure. When full, the lockhoppers were isolated from the storage vessel and pressurized to a level slightly higher than the combustor. Variable speed rotary feeders metered the flow of sorbent to pneumatic conveying pipes. When the lockhoppers were empty, they were isolated from the combustor and were vented to the atmosphere through a bag filter. When completely depressurized, they were refilled.

Subsequent to the initial operation of the plant, a system was installed to receive and feed sorbent fines into the coal water paste system.

2.4.11 Ash Removal and Handling Systems

Fine ash, collected in the cyclones, was continuously removed by a pneumatic transport system. The ash was cooled and a portion of the heat was recovered in the combustion air. Depressurization required no lockhoppers or valves. The ash from the primary cyclones was conveyed to a cyclone and a bag filter separator located atop the cyclone ash storage silo. The ash from the secondary cyclones was transported by means of a pressurized pneumatic ash transport system to discharge in the flue gas exhaust duct upstream of the electrostatic precipitator.

Granular bed ash was continuously removed by gravity from the boiler bottom hoppers in order to maintain the desired bed level. Two parallel lockhoppers, each serving one of the bottom hoppers, were filled and emptied independently. When full, the lockhoppers were depressurized by venting and emptied by gravity into a common atmospheric pressure hopper. From there, the ash was fed onto an enclosed conveyor system and transported to the bed ash storage silo.

The fly ash collected in the electrostatic precipitator was pneumatically conveyed by means of a vacuum removal system to the cyclone ash silo.

The cyclone ash and fly ash silo was a 22-foot-diameter, flat-bottom, elevated storage silo with an active storage capacity of 260 tons. Conditioning equipment installed in the cyclone ash silo removed cyclone ash from the storage bin, wetted it to minimize fugitive dusting, and transferred it to open type dump trucks for disposal. Dry cyclone ash could also be loaded into dry bulk carrier trucks for sales or testing purposes.

The bed ash silo was a 22-foot-diameter, conical-bottom storage silo, adjacent to the cyclone ash silo. Active storage capacity was 220 tons. The bed ash was unloaded from the bin to open-type dump trucks for disposal. Because of the granular nature of bed ash, wetting of the ash was not necessary.

Both bed ash and cyclone ash were disposed in an Ohio EPA permitted area that had been used to dispose of over 8.5 million tons of fly ash from Cardinal Plant. From the storage silos located at the plant site, the ash was loaded into dump trucks that were covered and weighed prior to departure for the disposal site. Spray curtains and truck washes at the silos reduced dusting during loading operations and removed ash which adhered to the vehicles during loading. The dump trucks hauled the ash to the disposal site, where the ash was dumped from the trucks, spread, wetted to optimum moisture content, and finally compacted.

2.4.12 Control System

A distributed programmable logic system was used to collect signals and measurements. The control system, a Bailey Network 90, used twenty process control units divided into the following nodes: gas turbine, combustor, steam turbine, balance of plant, hot gas clean up, and safety. These units performed the control of individual plant items, and also most of the coordinating control, interlocking, and automatic function involving groups of related items.

2.5 Feedstocks

The Tidd Plant was designed to burn Pittsburgh # 8 coal, and Plum Run Dolomite. Tables 2.5.1 and 2.5.2 provide their analyses.

In addition to the design Pittsburgh #8 coal, tests were conducted using Ohio 6A, Peabody Anker, Minnehaha, and Consol Mahoning Valley coals. The Tidd Plant also conducted tests using Plum Run Greenfield and Peebles dolomites, National Lime Carey dolomite, and Mulzer dolomite, as well as National Lime Delaware and National Lime Bucyrus limestones.

Table 2.5.1 - Design Coal Analysis

Design Coal Analysis (Pittsburgh #8)		
	As Received	As Fired
Carbon %	66.45	52.43
Hydrogen %	4.58	3.62
Nitrogen %	1.36	1.07
Oxygen %	7.45	5.88
Sulfur %	3.36	2.65
Ash %	11.85	9.35
Moisture %	4.95	25.00
High Heating Value BTU/#	12,223	9651

Mineral Ash Analysis (Pittsburgh #8)	
	As Received
Silicon Dioxide (SiO_2) %	51.35
Iron Oxide (Fe_2O_3) %	22.80
Aluminum Oxide(Al_2O_3) %	19.09
Calcium Oxide (CaO) %	1.06
Magnesium Oxide (MgO) %	0.85
Sodium Oxide (Na_2O) %	0.31
Potassium (K_2O) %	2.13
Titanium Oxide (TiO_2) %	1.10
Sulfur Trioxide (SO_3) %	0.50
Phosphoric Oxide (P_2O_5) %	0.63
% Undetermined	0.18

Table 2.5.2 - Design Sorbent Analysis

Design Sorbent Analysis (Plum Run Greenfield)	
Moisture %	0.1
Carbon Dioxide-CO_2 %	46.0
Calcium Oxide-CaO %	29.3
Magnesium Oxide-MgO %	21.0
Silicon Dioxide-SiO_2 %	2.1
Aluminum Oxide-Al_2O_3 %	0.4
Iron Oxide-Fe_2O_3 %	0.54
Sodium Oxide-Na_2O %	0.06
Potassium Oxide-K_2O %	0.05
Sulfur Trioxide-SO_3 %	0.4
Chlorine-Cl %	0.05

Figure 2.2.1 - Typical PFBC Composite Cycle Diagram

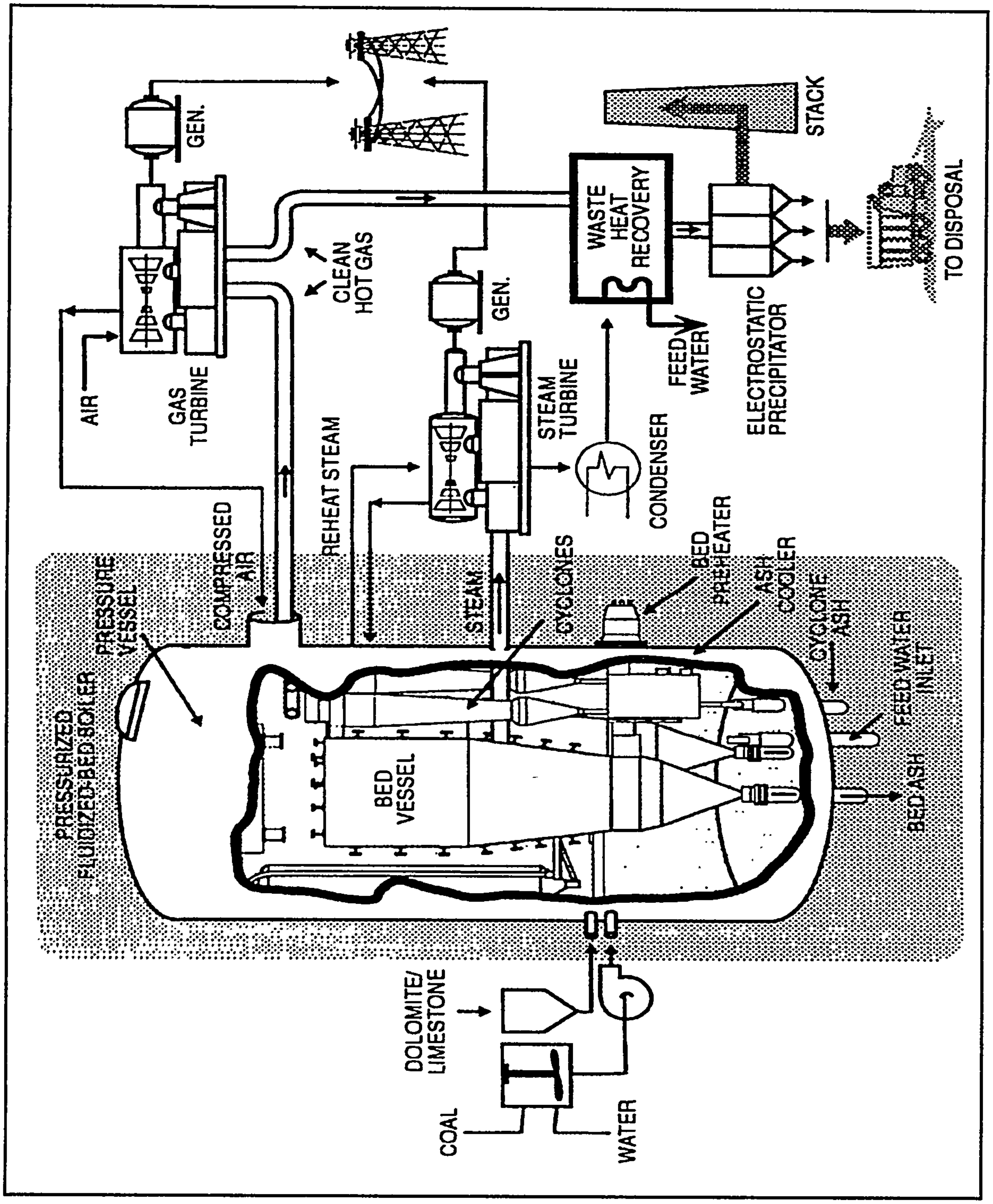


Figure 2.2.2 - Tidd Steam Side Heat Balance

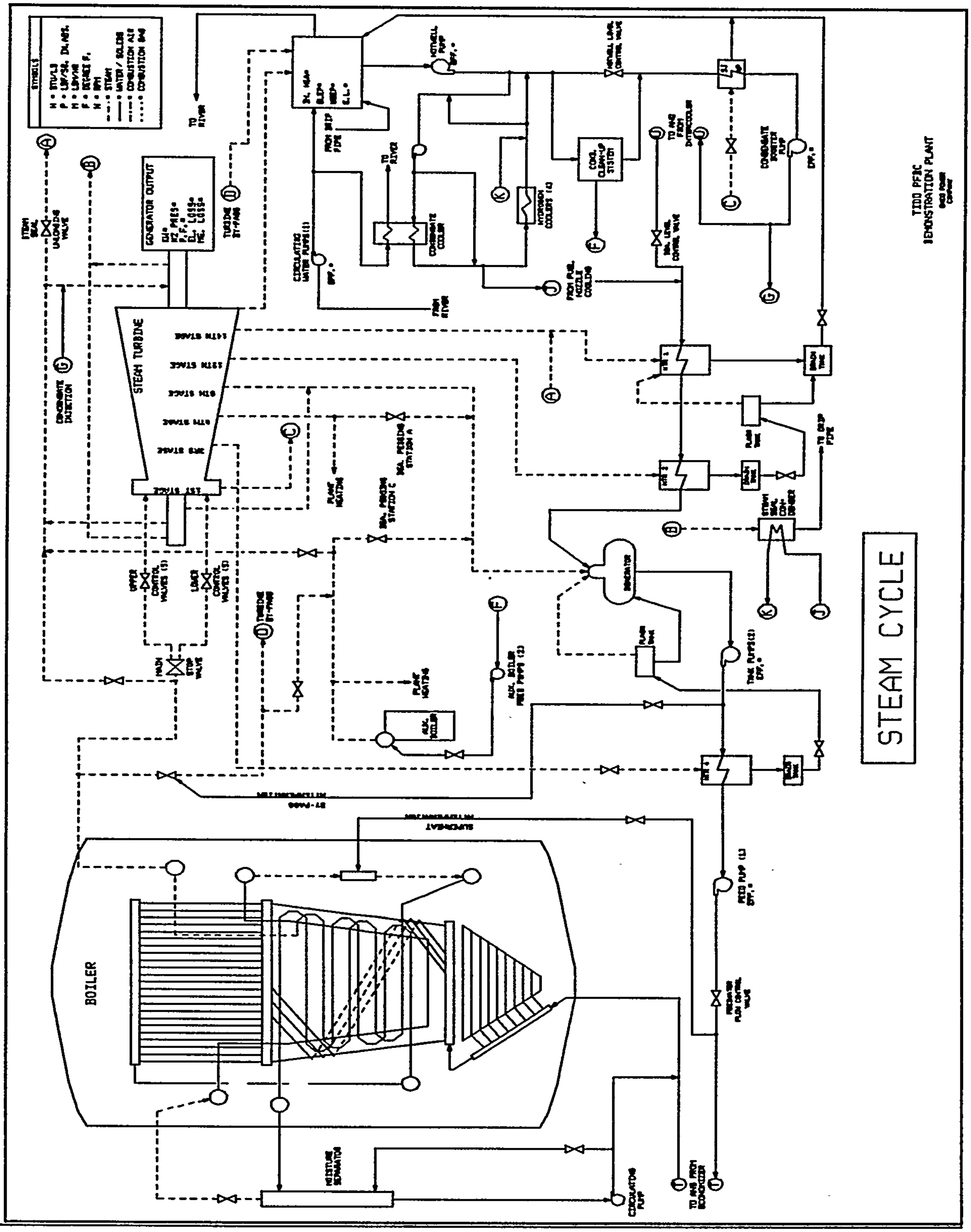
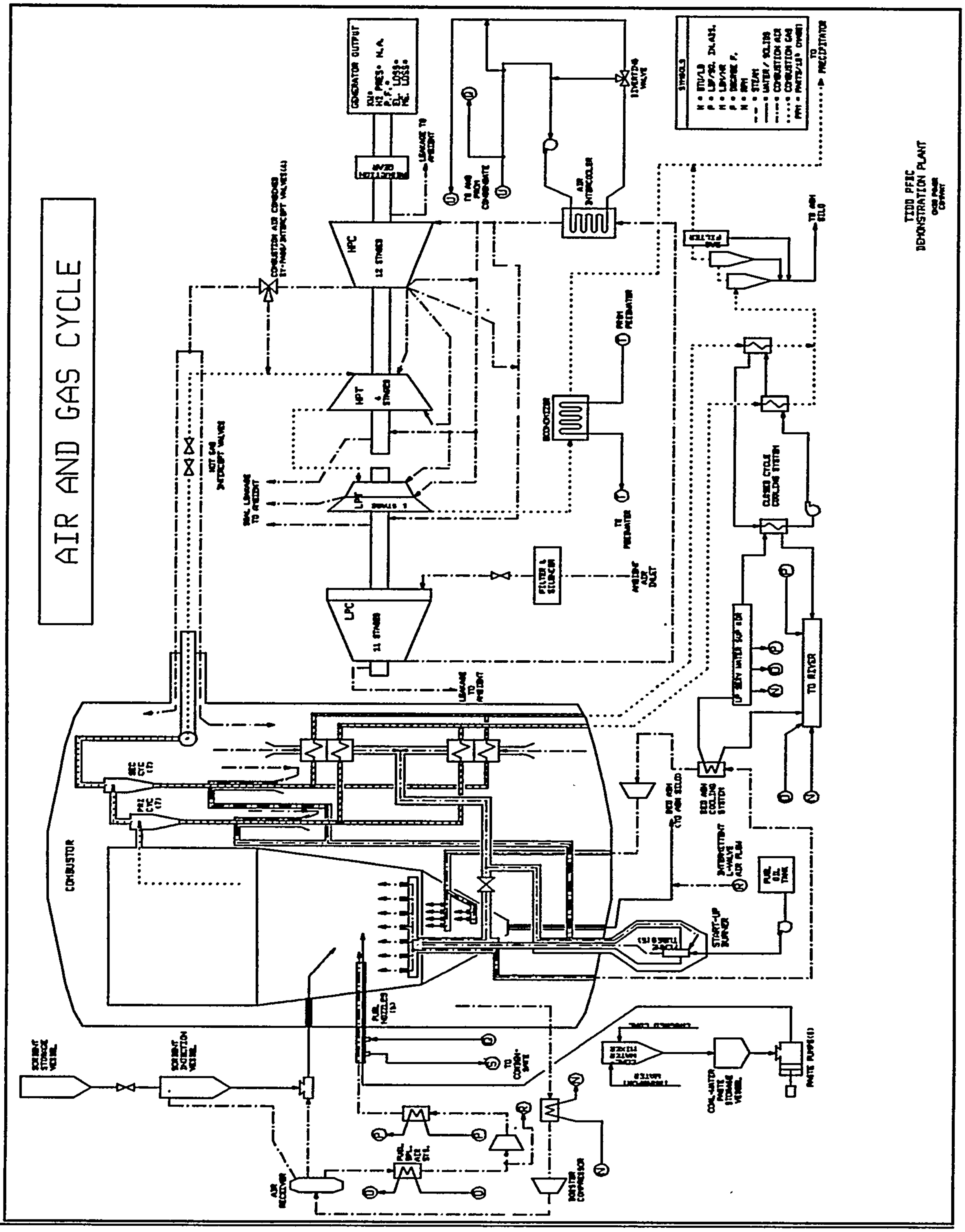


Figure 2.2.3 - Tidd Gas Side Heat Balance



3.0 Project History and Overview

This section presents an overview of the project's fourth year of operation and presents the data for that period. More detailed information can be found in the individualized system Section 6.0 and the appendix. Appendix I includes a narrative of each operational run as well as a summary of each unit outage. Appendix II is a listing of each operational run including operating statistics for each run as well as summary statistics.

3.1 Project Schedules

3.1.1 Project Schedule Overview

The overall project schedule was based on a four-year engineering, design, and plant construction period followed by a three-year plant demonstration period. As with any ambitious demonstration program on an emerging technology, the actual three-year testing program was challenged by a series of technological hurdles. Each of these hurdles was met and overcome on an effective basis but did impact the detailed testing planned for the original three-year test program. Therefore, the project was extended to include an additional year of operation to permit optimization of sorbent utilization and resolution of the bed sintering problem, identified late in the original three year program.

3.1.2 Detailed Project Schedules

The schedules for construction, startup, and the first three years of the demonstration period were detailed in the prior report. Figures 3.1.1 and 3.1.2 provide the schedule for the fourth year of operation. The actual elapsed time for the fourth year of operation was 13 months.

Figure 3.1.1 - Tidd PFBC 1994 Schedule

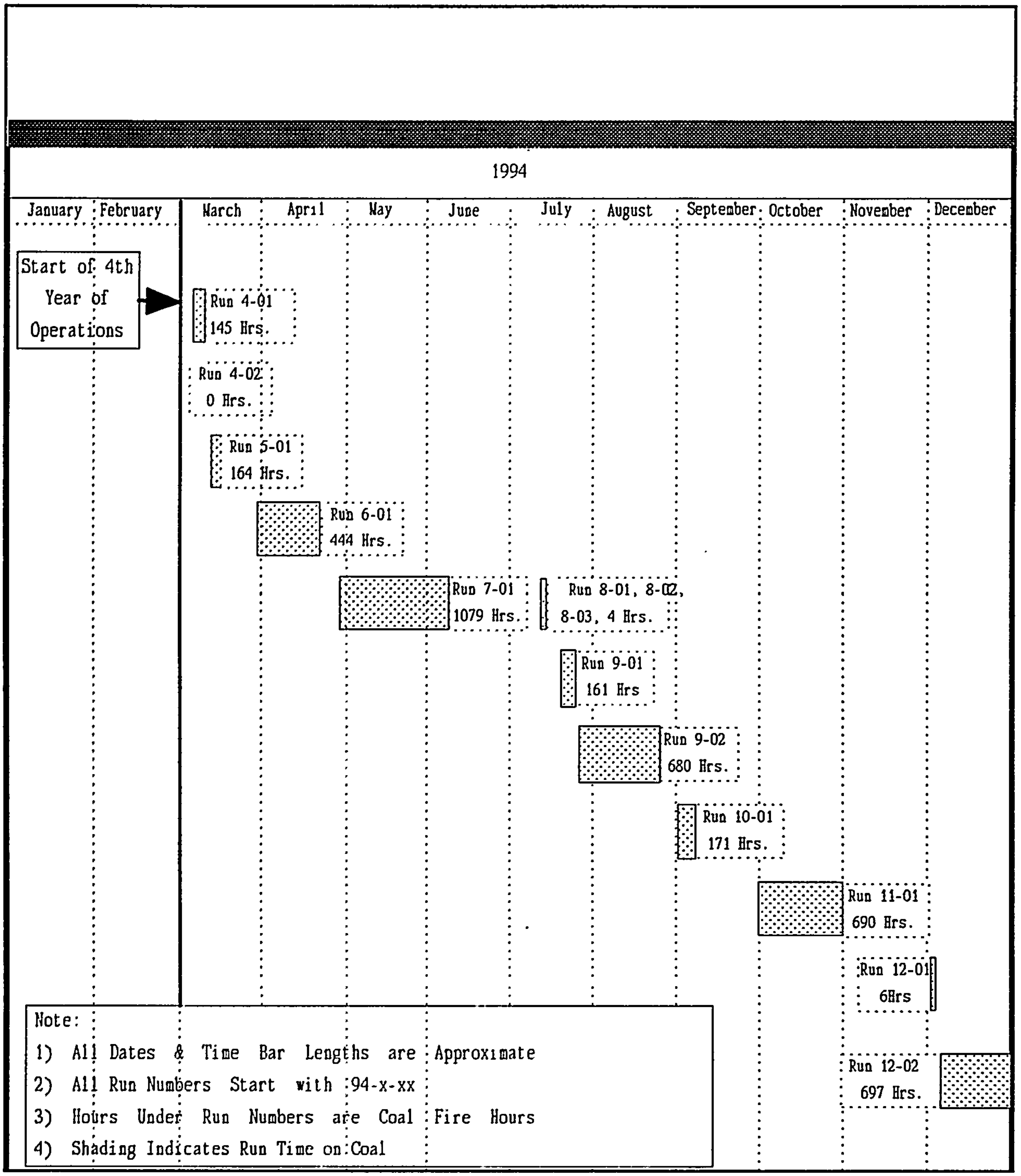
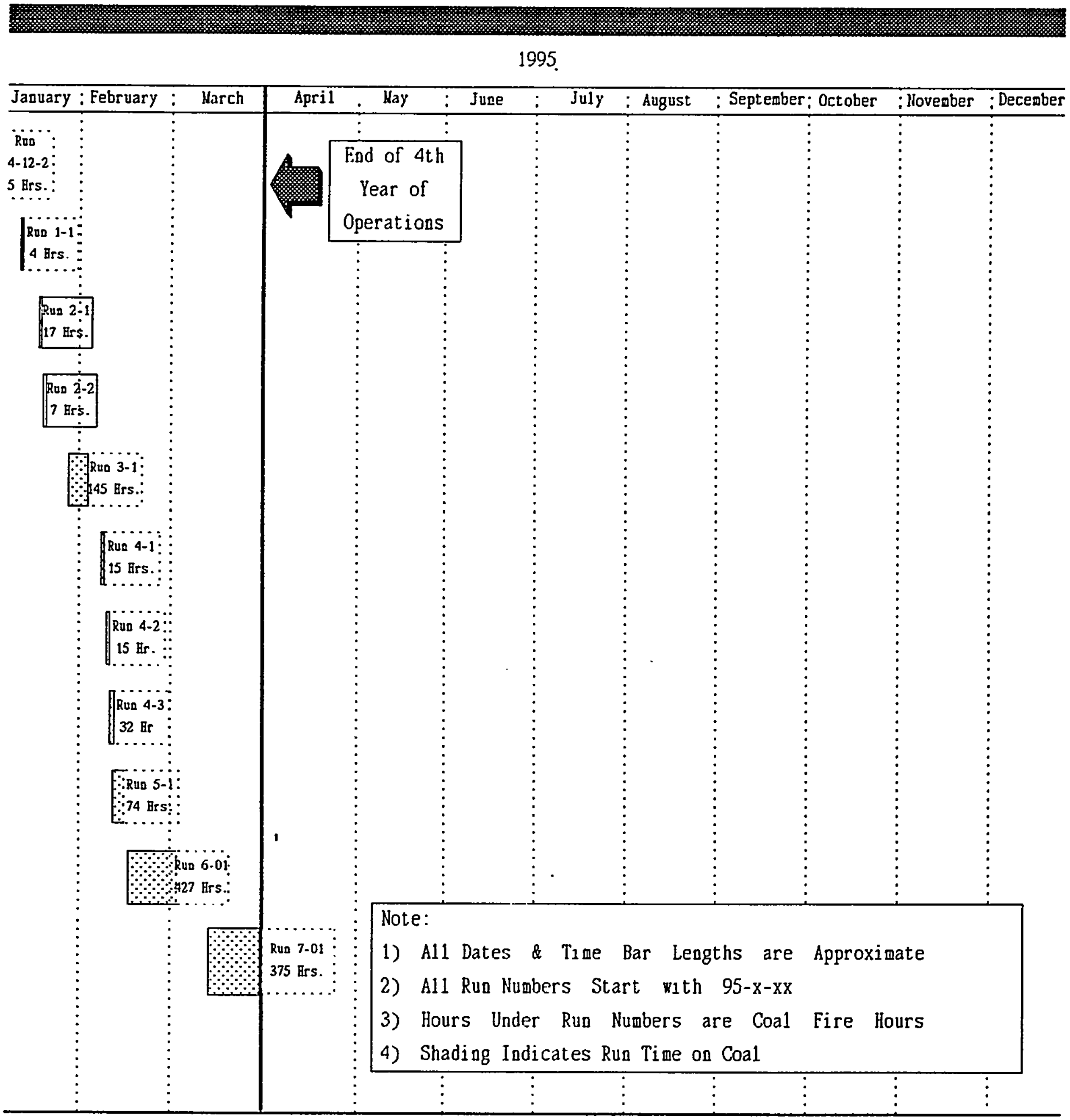


Figure 3.1.2 - Tidd PFBC 1995 Schedule



3.2 Fourth Year Overview

3.2.1 Operational Summary

The fourth year of unit operation proved to be significant in demonstrating both unit reliability and in improving process performance. This section summarizes unit operation during the last 13 months of the program covering the period from March 1, 1994 through March 30, 1995. During this period, the unit fired coal for a total of 5382 hours, with the longest continuous run of 1079 hours. A total of 48 unit performance tests were conducted. Testing was primarily focused on addressing the sintering, which was observed at high unit loads coupled with full bed temperatures (1580 F), as well as evaluating the sorbent utilization associated with variations in sorbent feedstock size and type. Additional testing utilizing various coal feedstocks was also performed during this period.

Operational problems were more varied and less frequent in the final thirteen months indicating that the unit was reaching a level of maturity. The average length of coal-fired operation was increasing significantly and the focus of attention shifted to process performance improvement.

3.2.2 Operational Details

First quarter 1994 - The fourth year of operation began on March 1, 1994 with the unit in the startup mode. Coal fire was initiated on March 3rd and the unit was subsequently operated at bed heights of 142-150 inches with a reduced bed temperature of 1520 F. Attempts to raise bed temperature continued to result in deteriorating bed conditions which were thought to be due to excessive "egg" sinter accumulation in the bed. Tests, conducted during runs at the end of the first three years of operation, showed that increased splitting air flow was of no significant benefit in resolving the bed deterioration at high bed heights with high bed temperatures. An attempt was made to produce a less cohesive coal paste by altering crusher operation to produce a lower quantity of -325 mesh fines. It was thought that less cohesive paste would split easier and thus reduce the tendency to form the sinters. During the morning of March 9, the coal paste with reduced fines proved to be difficult to pump, resulting in the loss of two paste lines and consequently a unit trip. The unit fired coal for a total of 145 hours during the run, and two performance tests were conducted. After cleaning the fuel nozzles, a subsequent attempt at a restart on March 10 was aborted due to plugged primary cyclone ash removal lines. The unit was returned to service on March 16 and fired coal for 164 hours before a faulty lube oil pressure switch initiated a gas turbine trip on March 23. During the run high bed height operation with high bed temperature was again attempted, but resulted in the same deteriorating bed conditions as experienced in the preceding runs. As the quarter came to an end, this problem remained an obstacle to achieving true full load operation. With the arrival of spring, the warmer ambient temperatures meant reduced air capacity from the gas turbine compressor, and thus additional high load testing would not be possible until the fall. The above noted runs contributed to a cumulative 850 hours of coal fired operation during the first quarter of 1994.

Second quarter 1994 - The first run of this quarter began on March 31 and lasted for 444 hours before a leak in the ceramic lined sorbent pipe inside the combustor vessel necessitated a shutdown during the evening of April 18. During the run attempts were made to determine the threshold temperature for sintering. This testing, performed at 125" bed level, seemed to show that deteriorating bed conditions occurred at bed temperatures above 1500 F. Two performance tests were conducted during the run. After an outage of approximately three weeks, the unit was returned to service on April 29 and ran continuously for 1079 hours before the unit was manually removed from service on June 12 due to a suspicious noise in the gas turbine exciter. This extended run not only set the record for continuous operation at Tidd, the tests accomplished during this period provided a breakthrough in operation and performance of the unit. Testing with finer sorbent gradations revealed improved fluidization conditions within the bed that resulted in more even bed and evaporator outlet leg temperature profiles as well as improved heat transfer and sorbent utilization. (Refer to Section 5 of this report). The improved bed conditions allowed testing for extended periods at the full bed design bed temperature of 1580 F with no signs of deteriorating bed conditions. While such testing was limited to a bed height of 115" due to gas turbine compressor air mass flow capacity limitations, the noted improvements in bed conditions gave promise that full load testing would be possible upon the return of cooler ambient conditions. During the run a total of 11 performance tests were conducted. The unit entered an extended outage in mid-June to repair the gas turbine, and was out of service as the quarter came to an end. Coal was fired for a total of 1521 hours during the quarter. This resulted in a unit availability of 54.7% for the first half of 1994.

Third quarter 1994 - Operation in the third quarter began uneasily in mid-July with a number of nuisance trips at start-up. This was followed in late July by a one week run during which load was severely limited due to high vibration on the gas turbine. The unit was returned to service at the end of July after a balance shot was installed on the gas turbine. During the 680 hour run that followed, a total of 11 performance tests were conducted. All but one of these tests was conducted with finer on-site prepared sorbent that was afforded by a new vibrating screen, which was installed in June. The run ended due to steam turbine relay problems. The next run began in early September, but lasted only one week when a leak in an unlined section of sorbent piping just upstream of one of the two combustor isolation valves forced an outage. One performance test was conducted during the run. The unit was returned to service during the third week of September and remained in service as the quarter came to an end. In spite of the erratic operation, unit availability for the first three quarters of the year remained at approximately 54.9%. The unit operated for a total of 1213 hours during this period.

Fourth quarter 1994 - The unit was in-service at the start of the quarter and remained so until the third week of October when a planned shutdown was taken. This ended a successful 690 hour run during which time 4 performance tests were conducted including a record 36 hour test with fine magnesian limestone as the sorbent. The unit then began a 5 week outage to repair the gas turbine. The unit was returned to service at the end of November, but a leaking instrument connection in the boiler circulation system forced an outage after just a few hours of coal fire. Repairs were made quickly and the unit was returned to service later that evening. The unit remained in service for the rest of the month before a drive bearing failure on the coal crusher forced an outage on January 2, 1995. During the 732 hour run a total of 5 performance tests were conducted. The unit fired coal for a total of 1194 hours during the quarter. Unit availability remained acceptable at approximately 54.7% for the year.

First Quarter 1995 - The unit began the new year with a number of nuisance trips at start-up. The unit finally made it through start-up in late January but ran for only 145 hours when a hot spot on a blind flange in the hot gas piping downstream of the APF forced an outage. One performance test was conducted during the run. During the second and third weeks of February, the unit experienced a number of nuisance problems during four separate start-up attempts. While these problems severely hampered unit testing, this experience proved that the unit could be hot restarted rapidly in successive attempts, without entering the combustor vessel. A successful start-up and run was finally achieved in mid-February. The run lasted 427 hours during which time a total of 8 performance tests were conducted. Due to low ambient temperatures and the associated availability of high compressor air mass flows, tests conducted during the run were performed at or near full bed height. Due to high heat transfer rates afforded by the finer sorbent being tested, record firing rates and unit outputs were achieved during the run. The run ended in early March as paste preparation problems were experienced with a new coal being tested. The unit was returned to service in mid-March and ran for 369 hours before it was shutdown manually for the last time on the morning of March 30. Two performance tests were conducted during this last run including a 40 hour test with magnesian limestone as the sorbent. The unit fired coal for a total of 1144 hours during the quarter, bringing the total hours for the thirteen month long fourth year of operation to 5382 hours. The availability for the fourth year of operation was 57.0%.

3.2.3 Unit Testing Accomplishments

During the final thirteen months of the Tidd test program, a total of 48 performance tests were conducted. The focus of testing continued to be the elimination of the sintering problem identified late in the third year of operation and optimization of sorbent utilization. Changes in the sorbent feedstock size consist initiated early in the fourth year of operation proved significant. The effects on the bed dynamics were immediately discernable. Sintering ceased to be an issue, when utilizing dolomite sorbent. The unit consistently operated at bed heights above 120 inches and at bed temperatures above 1540 F. Bed temperatures as high as 1585 F were achieved without significant sintering. Once the sintering issue had been addressed, testing was focused on sorbent utilization.

Unit Performance Tests 48 through 52 were conducted with MM Pittsburgh # 8 coal and #6 mesh site prepared Plum Run Greenfield dolomite. Bed mean temperature was generally maintained below 1520 F. Several attempts to operate at bed temperatures of 1540 F resulted in signs of excessive sintering. Performance tests 53 through 59 were conducted with MM Pittsburgh #8 coal and National Lime Carey (NL) dolomite. The dolomite size consist ranged from minus 6 mesh site prepared to minus 12 and 20 mesh off-site prepared material. This series of testing confirmed that sintering was minimized to an acceptable rate when utilizing the finer sorbent materials. Bed temperatures of 1580 F were achieved with the finer feedstock. Sorbent utilization also improved dramatically with the finer feedstock. Typically, sorbent utilization increased 30-40% above that measured when utilizing minus 6 mesh site prepared material.

Three subsequent tests (60-62) were conducted utilizing MM Pittsburgh # 8 coal and Plum Run Greenfield (PRG) minus 12 mesh, off-site prepared dolomite. These tests were conducted without unacceptable sintering and showed improvements in sorbent utilization.

The next series of tests (63-77) were conducted utilizing MM Pittsburgh #8 coal and either minus 10 or minus 12 site prepared Plum Run Greenfield dolomite. All of these tests confirmed previous findings with respect to sintering and sorbent utilization. A single test was conducted using minus 12 mesh off-site prepared material. It became apparent that the off-site prepared material with its lower content of minus 60 mesh fines was more effective in sulfur capture. It also became apparent that the more reactive PRG performed better than the less reactive NL dolomite.

The next test (78) utilized MM Pittsburgh #8 coal and Bucyrus minus 18 mesh, off-site prepared, limestone. Bed dynamics changed significantly with the introduction of limestone. Bed density started to decrease noticeably and both bed temperature distribution and evaporator tube temperatures became erratic. Bed conditions conducive to sintering, which had been eliminated when utilizing dolomite, reappeared when limestone sorbent was introduced.

The remainder of the test program (tests 79-94) was conducted utilizing primarily minus 12 mesh PRG or Mulzer dolomites. In addition, both Minnehaha and Consol Mahoning Valley coals were used. While results with respect to sorbent utilization varied, the absence of significant sintering was confirmed in all cases.

The final test of the program (test 95) utilized Consol MV coal and Delaware limestone. Once again, bed conditions showed signs of deterioration.

Detailed results of all testing are presented in Section 4.2.

3.2.4 Modification Summary

The need for system modifications had been significantly reduced during the last year of operation. However a number of modifications were made in an attempt to improve the performance and operating characteristics of the unit.

Reinstallation of the dual stage fuel splitting air nozzle design to address the sintering issues which were pervasive at full bed temperature. The modification proved inadequate to address sintering and was subsequently abandoned.

Modifications to the sorbent injection system by increasing the number of sorbent feed lines to improve sorbent utilization.

Modification of the sorbent preparation system to increase system capacity and to provide the flexibility to produce finer on site prepared sorbent.

3.3 Operating Statistics and Graphs

3.3.1 Operating Statistics

Table 3.3.1 contains a summary of the key operating statistics for the fourth-year demonstration period. Table 3.3.2 contains a summary of the key operating statistics for the full four-year demonstration period. Table 3.3.3 contains a summary of the average and maximum operating statistics for each year.

An explanation of some of the terms and calculations used in these tables is as follows:

Gas Turbine Operating Hours - Total number of operating hours on the gas turbine from the time the gas turbine is started by the frequency converter until the gas turbine breaker is tripped to shut the turbine down or disconnect it from the distribution grid.

Coal Fire Operating Hours - Total number of coal-fire operating hours from the time the coal injection system is ordered on by the unit operators via the control system until the time the combustor trips and also causes a stop of the coal feed.

Steam Turbine Operating Hours - Total number of steam-turbine operating hours from the time the steam turbine generator is paralleled to the time the combustor trips. For simplicity, the combustor trip time was used for the calculations. In fact, the steam turbine generator trips within minutes of a combustor trip.

Yearly Unit Availability - Total steam-turbine operating hours in a year divided by the number of hours in a year.

Yearly Gross Capacity Factor @ 70 MWG - Total gross generation from both the steam turbine and the gas turbine divided by the number of hours in a year times 70 MW. Does not deduct generation required to motor the gas turbine at startup since that power requirement is considered part of the plant's auxiliary power requirements for each run.

Yearly Gross Unit Output Factor @ 70 MWG - Total gross generation from the steam turbine and gas turbine divided by the total steam turbine operating hours in the year times 70 MW.

A complete listing of the operating times for each run is listed in Appendix - II.

Table 3.3.1 - Operating Statistics - March 1, 1994 through March 30, 1995

Operating Statistics - March 1, 1994 through March 30, 1995		
Number of Runs During Period	24	
Total Hours of Gas Turbine Operation	5750 hours	
Total Hours of Coal Fire Operation	5382 hours	
Unit Availability	57.0%	
Gross Unit Capacity Factor @ 70 MWG	39.2%	
Gross Output Factor @ 70 MWG	68.8%	
Statistics per Operating Run	Average	Maximum
Coal Fire Hours	225 hours	1079 hours
Gas Turbine Hours	239 hours	1095 hours
Outage Length	169 hours	996 hours
Maximum Gross Unit Load Achieved	N/A	72 MW
Gross Unit Generation	10853 MWHr.	51233 MWHr.
Gross Unit Output Factor @70 MWG	N/A	81.0%

Table 3.3.2 - Key Operating Statistics October 1, 1990 through March 30, 1995

Key Operating Statistics November 1, 1990 through March 30, 1995							
Operating Data	1990	1991	1992	1993	1994	1995	Project Totals
Number of Runs	9	43	29	16	18	10	125
Gas Turbine Operating Hours	457	1482	2914	2544	5035	1301	13733
Coal Fire Operating Hours	60	795	2367	2310	4768	1144	11444
Steam Turbine Operating Hours	71	846	2523	2327	4791	1155	11713
Yearly Unit Availability	4.1%	9.6%	28.7%	26.6%	54.7%	54.5%	30.1%
Yearly Gross Capacity Factor @ 70 MWG	0.4%	3.6%	17%	15.5%	37.0%	38.9%	18.6%
Yearly Gross Unit Output Factor @ 70 MWG	10.7%	37.3%	59.2%	58.2%	67.6%	71.4%	61.8%
Yearly Maximum Gross Unit Load Achieved	N/A	53 MW	71 MW	64 MW	68 MW	72 MW	N/A
Outage Hours	1674	7913	6261	6433	3969	966	27216
Gross Unit Generation MWHr.	537	22123	104508	94866	226720	57755	506509
Hours in the Period	1745	8760	8784	8760	8760	2120	38939

Table 3.3.3 - Avg. and Max. Run Operating Stats Oct. 1, 1990 through March 30, 1995

Average and Maximum Run Data	1990	1991	1992	1993	1994	1995
Average Gas Turbine Operating Hours	21.8 Hrs	29.1 Hrs.	88.3 Hrs.	159 Hrs.	280 Hrs.	130 Hrs.
Average Steam Turbine Operating Hours	5.1 Hrs.	16.6 Hrs.	76.5 Hrs.	145 Hrs.	266 Hrs.	116 Hrs.
Average Coal Fire Operating Hours	4.3 Hrs.	15.6 Hrs.	71.7 Hrs.	144 Hrs.	265 Hrs.	115 Hrs.
Maximum Coal Fire Operating Hours	14.7 Hrs.	110 Hrs.	740 Hrs.	597 Hrs.	1080 Hrs.	427 Hrs.
Average Outage Time Between Runs	100 Hrs.	149 Hrs.	189 Hrs. See Note 1	363 Hrs See Note 2	221 Hrs.	97 Hrs.
Average Gross Unit Output Factor @ 70 MWG	5.5%	17.8%	26.5%	35.1%	67.6%	71.4%

Table Note 1 - Average Outage Hours in 1992 would have been 141 hours if the 1574-hour gas turbine overhaul outage is not included in the average.

Table Note 2 - Average Outage Hours in 1993 would have been 152 hours if the 3385-hour gas turbine overhaul outage is not included in the average.

3.3.2 Operating Statistical Graphs

The following graphs present key operating data on a yearly basis for October 1990 through March 1995:

Figure 3.3.1 - Yearly and Project Unit Availability Factors

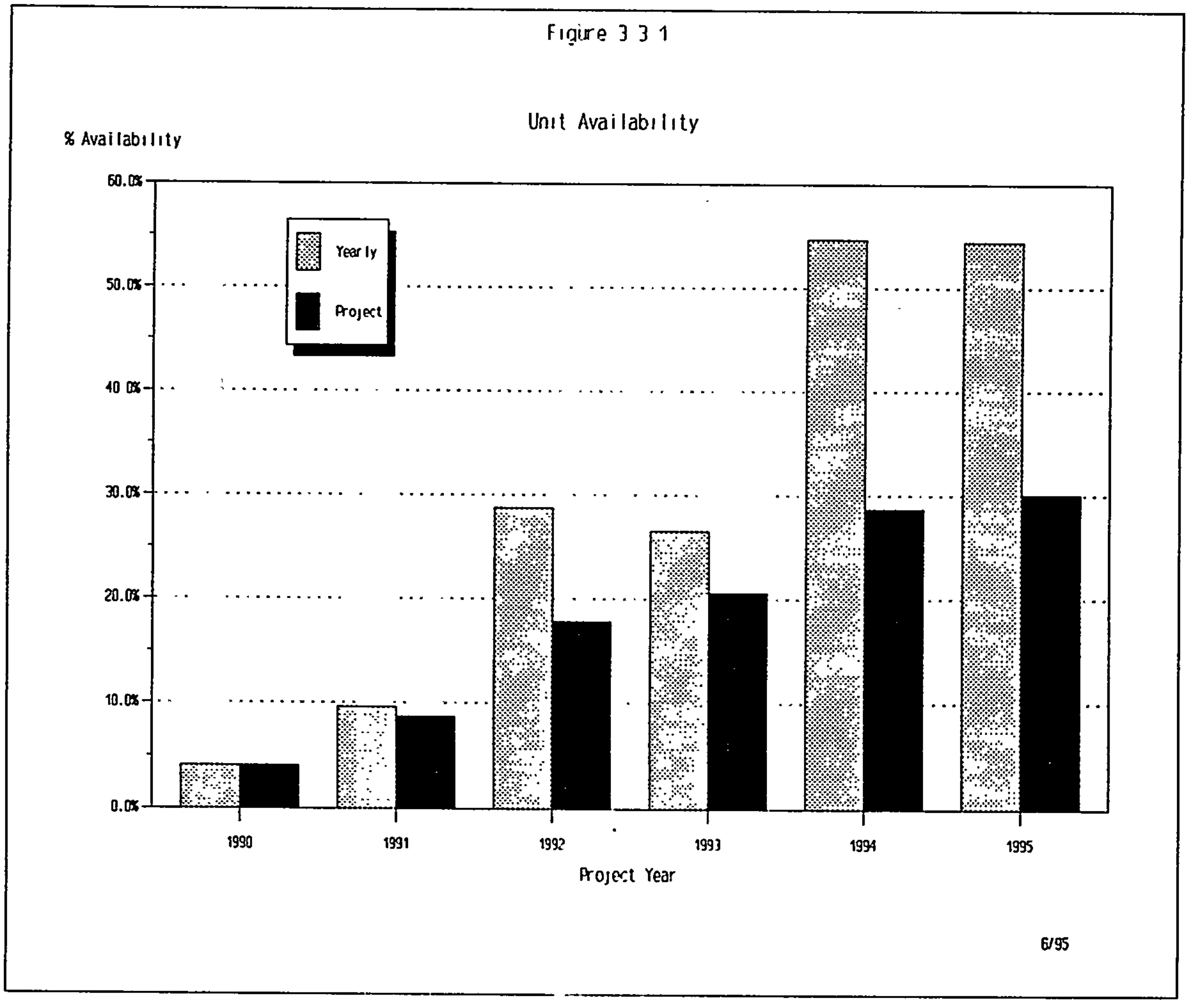


Figure 3.3.2 - Yearly and Project Capacity Factors

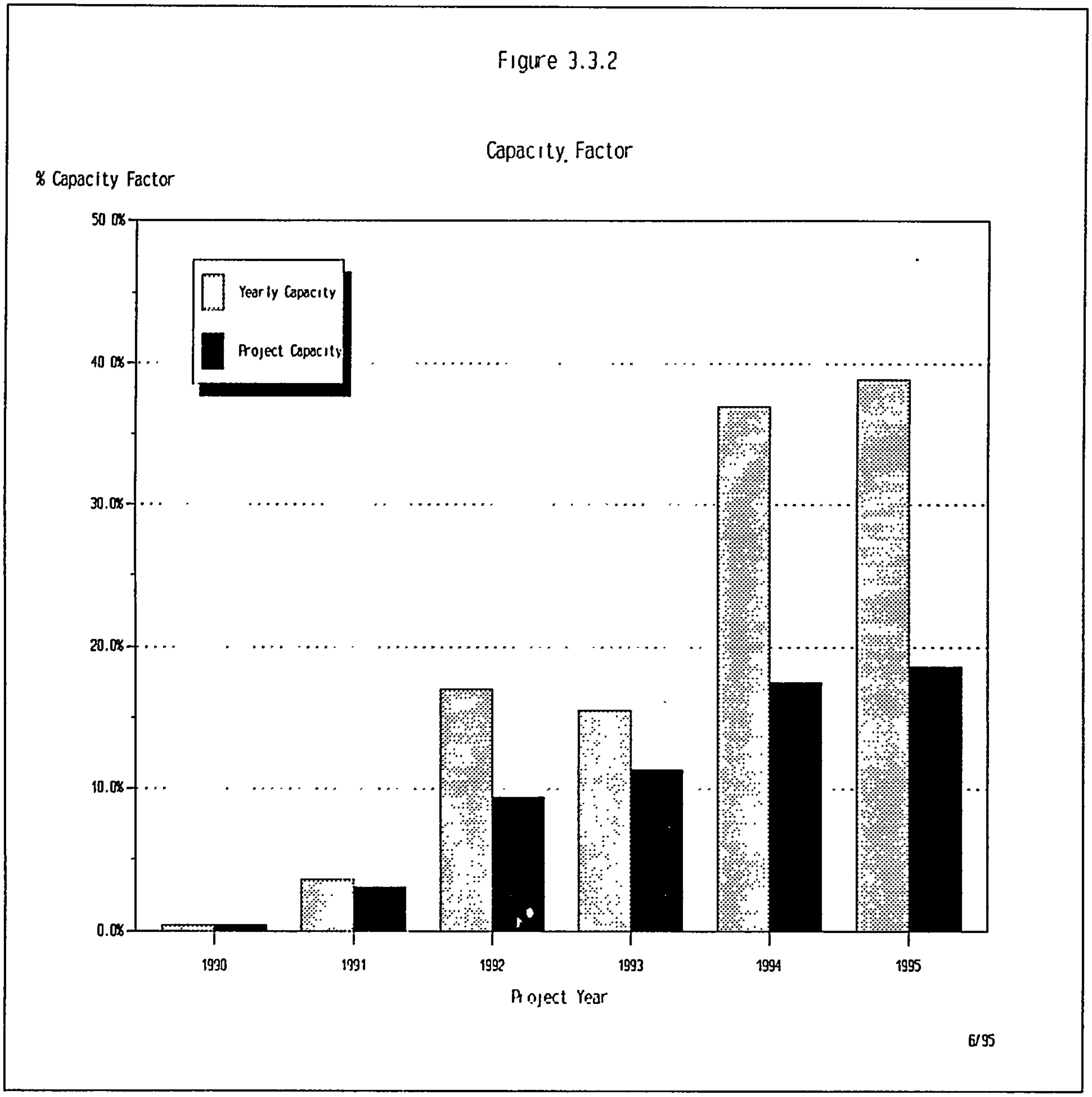


Figure 3.3.3 - Yearly and Project Gross Output Factors

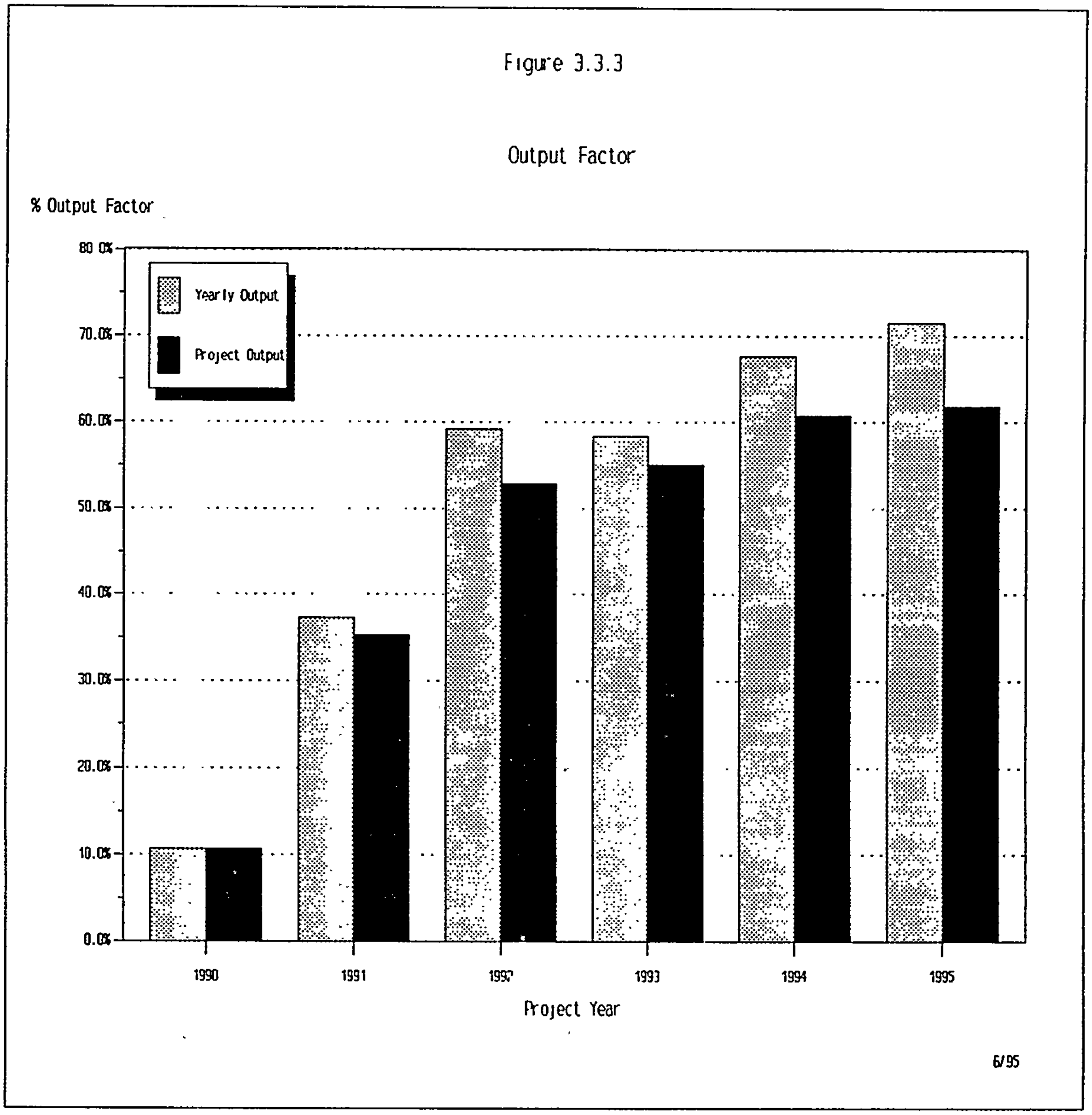


Figure 3.3.4 - Yearly and Project Gas Turbine Operating Hours

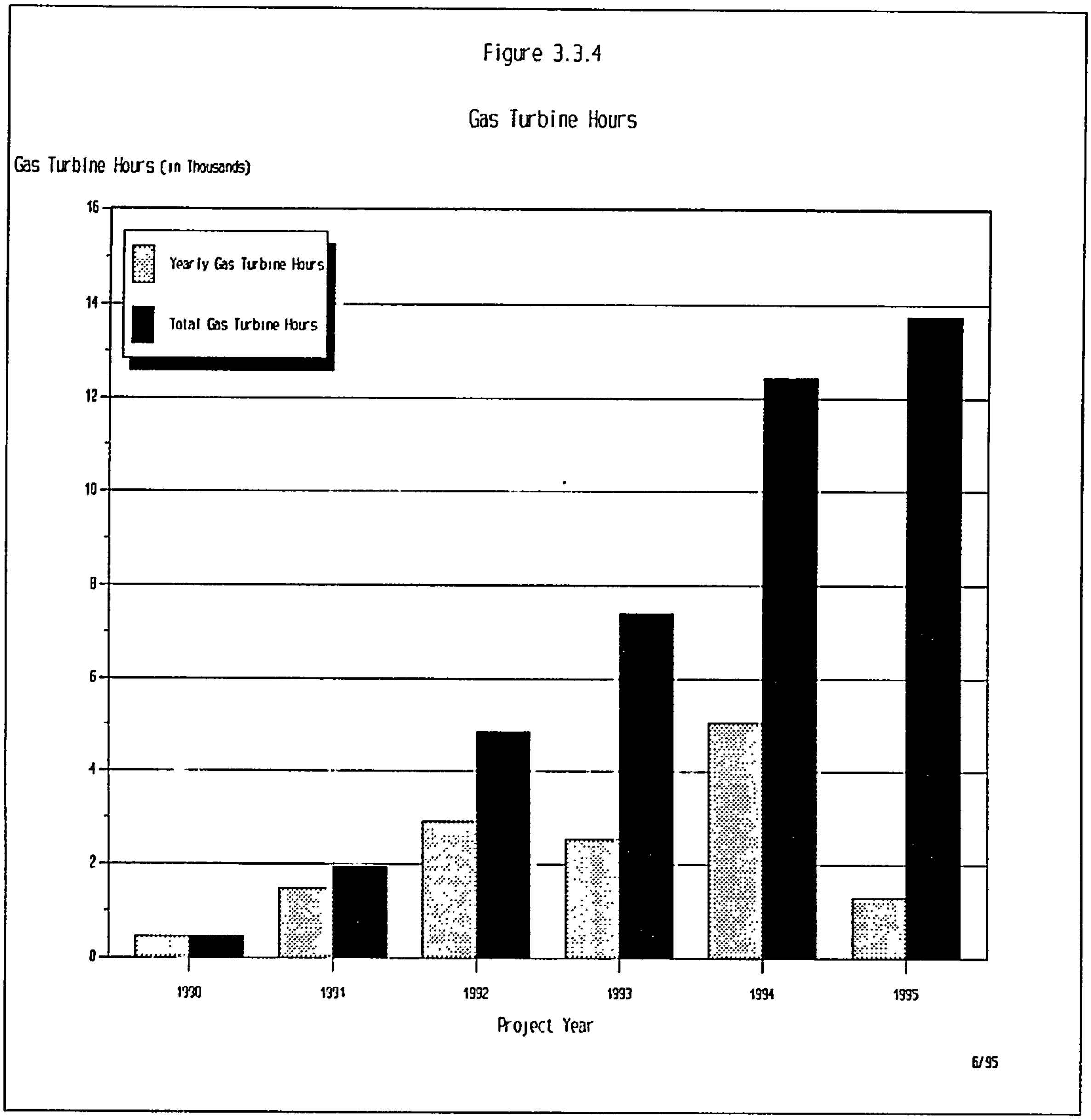


Figure 3.3.5 - Yearly and Project Coal Fire Operating Hours

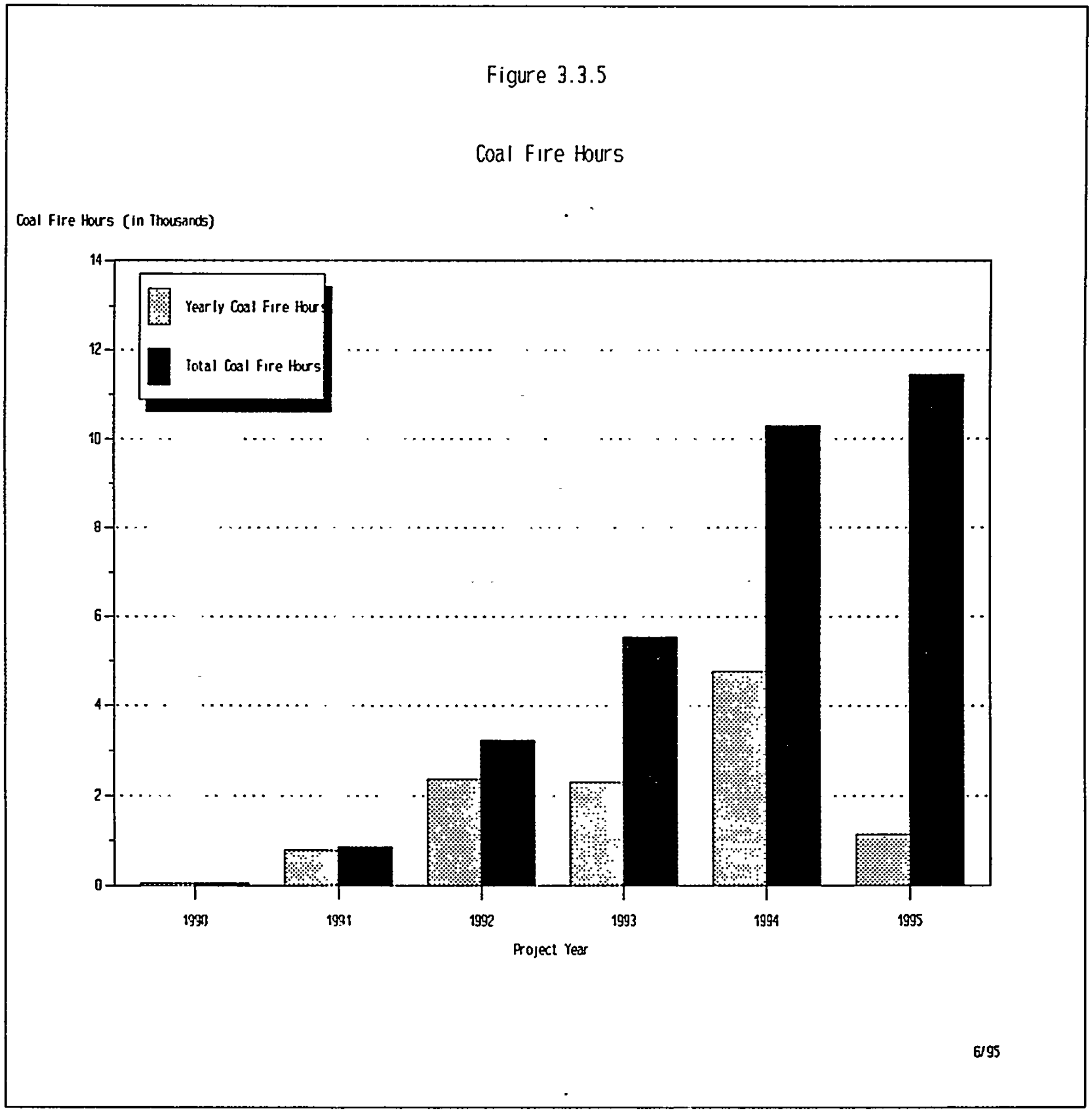
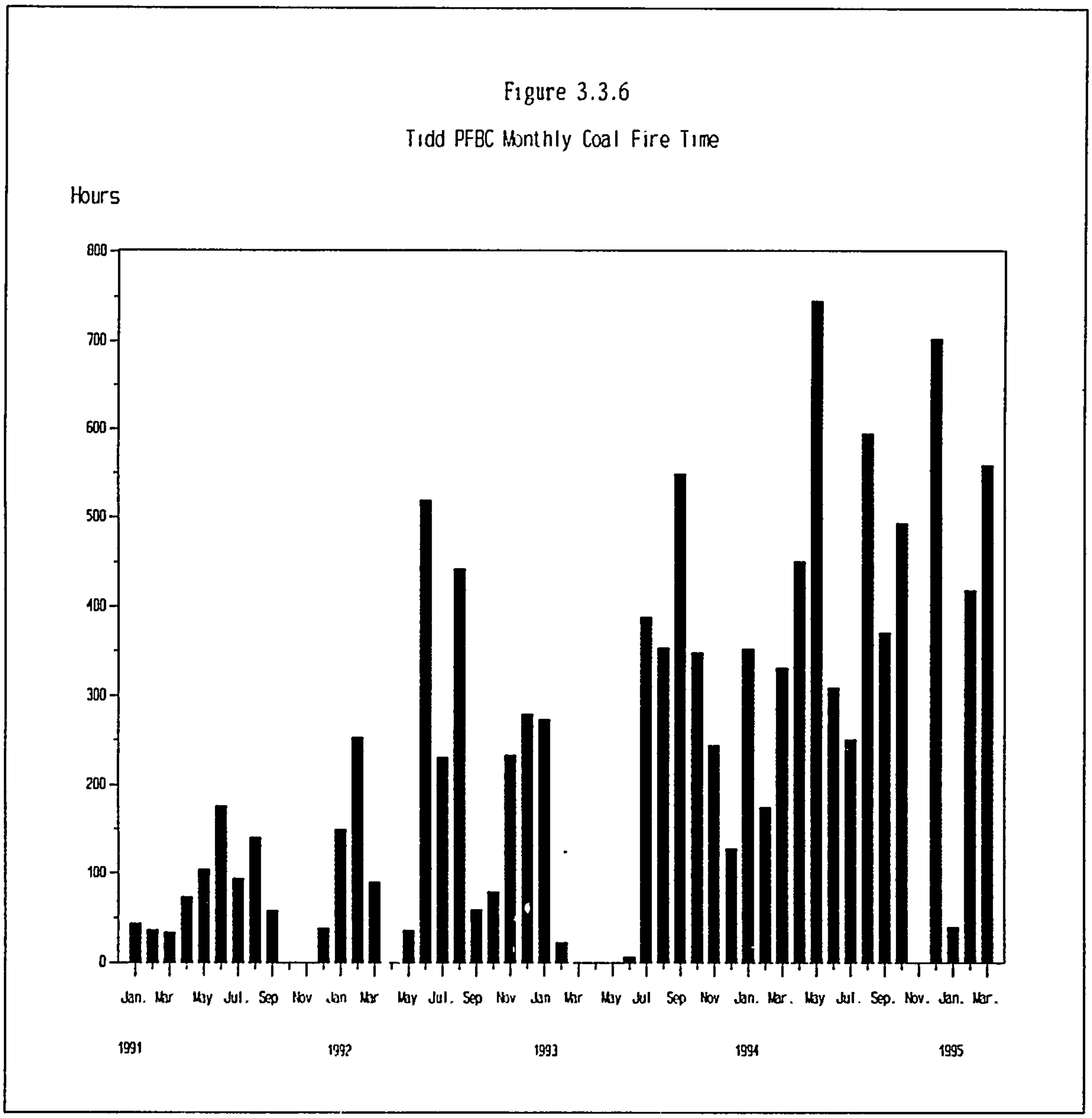


Figure 3.3.6 - Coal Fire Hours on a Monthly Basis for 1991 through 1994



3.4 Reliability and Availability of Key Operating Components

3.4.1 Availability Background and Data Collection

This section addresses the availability of components within the plant cycle. Data was collected using the AEP System Generating Availability Data System (AEP-GADS) which is an on-line component tracking system for unit availability within the AEP System. This system is used by the AEP System to report generating unit statistics to the North American Electric Reliability Council (NERC-GADS). This data is in accordance with NERC-GADS and IEEE Standard 762 requirements for standard definitions for use in reporting electric generating unit reliability, availability, and productivity.

Due to the nature of the Tidd PFBC Demonstration Project, component availability reporting requirements were adjusted to reflect the anticipated operation of the plant and its testing program. Tidd PFBC was designed and operated as a demonstration test facility. As such, sufficient component redundancy, high availability, electrical generation output requirements were considered of secondary importance to the Tidd PFBC mission. It should also be noted that the following data must be viewed in light of the fact that the systems were designed intentionally without commercial plant redundancy, that startup and shakedown of the plant were affected by the first-of-a-kind nature of the project, and that the unit was not load dispatched resulting in operation and outage durations that did not always have the urgency of a commercial plant. The intent of this data is to provide a means to assess the readiness of the technology and systems for commercial operation, not to represent Tidd PFBC as a commercially operated plant. The mission of unit testing and shakedown of the plant was the most urgent issue, and that drove all other decisions, modifications, and operating plans. In addition, due to the extended startup and commissioning program encountered at Tidd, data was not recorded during 1991. Component data was recorded starting January 1, 1992 through March 30, 1995. In addition, the following constraints were also imposed on the data collection process.

All lost MWHr outages and curtailments were recorded for both the PFBC Island (including the HGCU system) and the balance of plant components.

For the PFBC Island, data entries were also made for component failures even if those failures did not result in a loss of megawatt generation. This was done to track failures of PFBC Island components and how they may impact unit operation and availability. These non-MWHr loss curtailments are discussed in detail in Section 3.4.3.

Unit load curtailments were not recorded in AEP-GADS for reduced unit load due to unit testing requirements or ambient weather conditions that impacted unit operations. Therefore, if a specific performance test was conducted at 115" and approximately 57 MW, no load curtailment was recorded. Likewise, if ambient weather conditions prevented the gas turbine air flow from reaching full load during the summer, no load curtailment was recorded.

The gross maximum unit load achievable at Tidd as used in the AEP-GADS calculations is 70 MWG.

Due to the nature of the Tidd PFBC Demonstration program, unit events that impacted availability were not broken down into scheduled, planned, or forced outages or curtailments. During the demonstration period, Tidd had few annual or planned outages. Instead, repairs and/ or modifications were worked into unit outages as appropriate or required to support the test program. For example, once the length of the gas turbine blade failure outage was known in early 1993, programs were initiated to replace the secondary cyclone ash removal system and the boiler sparge ducts within the time the unit was out of service for the gas turbine outage. When known modifications were developed for the unit, the designs were completed and the material procured and shipped to the plant. At the next appropriate outage, the outage length was adjusted to permit the installation of that component or system modification. Outage times were also adjusted to support the next series of performance testing as required.

For unit availability, the unit was reported to be in service from the time the steam turbine generator breaker was closed, paralleling the unit to the system grid, until the time the combustor tripped. The steam turbine generator breaker would always open within minutes or sooner after a combustor trip. For official GADS reporting, a conventional coal-fired unit is in service for the entire time the steam turbine generator is connected to the electrical grid. Currently, AEP-GADS reporting procedures do not take into consideration a PFBC Combined-Cycle type of unit where there is a gas turbine, steam turbine, and combustor. Therefore, in order to meet the intent of AEP-GADS as closely as possible, the steam turbine generator breaker closure to combustor trip reporting method was used at Tidd.

3.4.2 Component Redundancy

During the design phase of the PFBC Island, a decision was made to limit redundancy of components in the plant, due to the relatively short life of the demonstration period. Therefore, there were no spare components installed on any of the PFBC Island systems. Where there was more than one component installed, i.e. paste pumps, all were required to be in service to achieve full-load operation.

The Tidd spare parts inventory was maintained at a minimum level. Any part which could be procured from a vendor in less than 24 hours was not stocked at the plant. The maintenance history shows that this type of stocking arrangement did not adversely impact operations. In fact, there were only one or two incidents when this impacted operations.

In the case of larger spare parts, there were very few capitalized spare parts, such as spare valve assemblies, etc., stored at Tidd. This did impact outages on a frequent basis, especially in the case of large valves in solids material transport systems. In many instances, the valves were shipped to a vendor's repair facility. A typical example would be the sorbent transport system isolation valves at the combustor vessel wall. These valves would require rebuilding approximately every three months. During an outage, the valves would be removed from the line at the beginning of the outage, sent out for seven days to be rebuilt, and then reinstalled in the transport line near the end of the outage.

3.4.3 Non-MWHr Lost Curtailments

In order to track PFBC equipment outages that could have an impact on unit operations, an entry was made into the AEP-GADS system for each PFBC component that failed while the unit was in service. If the failure resulted in a lost-MWHr curtailment, the lost generation period was entered into AEP-GADS. However, other component failures also occurred and could have impacted unit load, but did not. These were also entered into AEP-GADS but with no loss in generation. Those events are summarized in Table 3.4.1 for 1994/1995 (January 1,1994 through March 30, 1995). Instead of lost MWHrs, they are summarized by the total and average number of hours that those failures lasted. Percentages are also calculated for the percent of time the failures occurred during both a calendar year basis and the amount of time the unit was actually in service. The hours used in the calculations are as follows:

YEAR	Calendar Hours	Unit Operating Hours
1994	8760	4791
1995	2120	1155

1994/1995 Non-MWHR Lost Curtailments

The most significant non-MWhr lost curtailments are discussed below. The remaining events for 1994/1995 represented a low percentage and are not discussed further but are included in Table 3.4.1.

Bed ash reinjection vessel - (19.28% of operating time) - One of the two bed ash reinjection vessel "L" valves became plugged during a single extended run. The plugged valve prevented bed material from being fed from one of the reinjection tanks to the bed. The inability to operate one of the two reinjection vessels presented no significant problem to Tidd. However, such an incident does impact the ability of the unit to respond to rapid load changes and could have an impact on a commercial unit.

Miscellaneous balance of plant - (14.59% of operating time) - The most significant single problem was the freezing of coal during extremely cold periods. This type of problem is not unique to PFBC and is included in the interest of accuracy. Other difficulties were varied and consistent with the expectations of a 45 year old balance of plant.

Bed Ash Removal - (6.64% of operating time) - The major difficulty encountered in the bed ash removal system proved to be its inability to adequately cool the bed material being removed to maintain bed level. The problem was not identified until the unit was successfully operated at high loads and design bed operating temperatures of 1580F, particularly with finer beds. In addition a number of more typical incidents associated with conveyer belt maintenance were observed.

Hot Gas Cleanup - (3.66% of operating time) - The problems associated with HGCU dealt primarily with leaking or plugged ash removal lines, some of which remained isolated for extended periods of time either by necessity or on occasion by design.

Table 3.4.1 - Listing of Non-MWHr Lost Curtailments

Listing of Non-MWHr Lost Curtailments						
System Number	Description	Number of Occurrences	Total Hours	Average Hours	Percent of Total Year	Percent of Operating
1994						
274	Bed reinjection vessels	1	924.0	924.0	10.54%	19.28%
999	Miscellaneous balance of plant	2	698.8	349.4	7.98%	14.59%
272	Bed ash removal	4	318.1	79.5	3.63%	6.64%
333	HGCU	7	175.2	25.0	2.00%	3.66%
510	Instruments	2	41.2	20.6	0.47%	0.86%
266	Coal injection	10	26.1	2.6	0.30%	0.54%
262	Coal preparation	1	1.8	1.8	0.02%	0.03%
268	Sorbent injection	1	2.4	2.4	0.03%	0.05%
264	Sorbent preparation	4	8.2	2.1	0.09%	0.17%
All	No occurrences in 1995	0	0	0	0	0

3.4.4 1994 Availability Data

This section addresses the outages and load curtailments that occurred during 1994. The major events are discussed below and all of the outages or load curtailments are listed in Table 3.4.2. For each type of event, the total lost MWHr for outages and curtailments is divided by the total possible generation to calculate the Effective Forced Outage Rate (EFOR).

General - The longest outage during the fourth year of operation (41 days) was scheduled from October 21, 1994 to December 1, 1994. The primary purpose was to refurbish all systems in preparation for full load operation during the winter of 1994/1995. A detailed review of outage report TD-OT-94-11-01, contained in Appendix I, will show those areas which received attention. This outage was not allocated to any specific component. The designation of general is used to indicate that this outage is typical of what would be considered a scheduled maintenance outage on a commercial unit.

Gas Turbine - (EFOR = 19.30%) - On June 13, 1994, the unit was removed from service to investigate a noise in the gas turbine generator exciter. Inspection showed that the diode heat sink bolts were hitting the end shield horizontal joint bolts. Wear in the reduction gear thrust bearing likely allowed the generator to shift axially causing the contact. The HPT was suspected to be heavily fouled, prior to the outage. A borescope inspection confirmed a heavy build up on the blading. The turbine was cleaned and removed from service for a planned inspection of the LPT blade roots, LPT inlet guide vanes, and LPC first and second stage stationary guide vanes. The LPT inlet guide vane rings were found to be heavily eroded. A new outer ring was installed. The existing inner ring was refurbished and reinstalled. The gas turbine work was completed on July 14, 1994. Two additional lengthy outages were required to repair cracks in the GT low pressure compressor and to repair leaks in the GT intercooler. In addition, numerous outages were sustained to address various difficulties such as a faulty oil pressure switch, a failed "O" ring in the hydraulic system, gas turbine vibration, and other miscellaneous problems.

Boiler Water/Steam - (EFOR = 6.46%) - There were five occurrences of unit trip due to this system. The most significant incidents involved leaks in the boiler evaporator and secondary superheater sections. The failure of a one inch line at the boiler injection tank also contributed to the downtime.

Sorbent Injection System - (EFOR = 5.13%) - There were two outages caused by erosion failure of sorbent injection piping. One of the failures occurred in a ceramic lined pipe and was attributed to poor ceramic liner installation. The other occurred in an unlined pipe. There was one failure associated with a surging problem in the single sorbent booster compressor.

Primary Cyclone Ash Removal - (EFOR = 4.29%) - The unit experienced three unit shutdowns due to primary cyclone pluggage.

Controls - (EFOR = 2.56%) - There were two instances of control failure resulting in a unit trip. One was associated with the gas turbine, the other with the steam turbine.

Steam Turbine -(EFOR = 2.09%) - There were two outages attributed to the steam turbine. One was the result of a stuck underfrequency/overcurrent relay, the other a mechanical problem.

The remaining events for the fourth year represent a small percentage and are not discussed further, but are shown in Table 3.4.2.

Table 3.4.2 - Listing of 1994 Lost MWHr Curtailments and Outages

Listing of 1994 Lost MWHr Curtailments and Outages							
System No.	Description	Unit Outages			Curtailments		Total MWHr EFOR
		Outages # Times	Lost MWH	Calc Hours	Curtail. # Times	Lost MWH	
310	Gas Turbine	9	98,350	1405.0	2	9787	19.30%
225	Boiler Water/Steam	5	36,176	516.8	0	0	6.46%
268	Sorbent Injection	3	28,707	410.1	0	0	5.13%
231	Cyclone Ash Removal	3	24,031	343.3	0	0	4.29%
510	Controls - Net-90	2	14,315	204.5	1	1	2.56%
999	Balance of Plant - Steam Turbine	2	11,676	166.8	0	0	2.09%
333	Hot Gas Clean Up Filter	2	5,131	73.3	1	258	0.96%
262	Coal Preparation	1	1,344	19.2	6	2449	0.68%
266	Coal Injection	3	2,537	36.1	2	111	0.54%
222	Bed Dynamics	0	0	.0	3	1781	0.21%
252	Bed Preheating	1	210	3.0	0	0	0.04%
1000	1994 subtotals	31	222,477	3178.1	15	14387	42.28%

3.4.5 1995 Availability Data

This section addresses the outages and load curtailments during 1995. The major events are discussed below and all events are listed in Table 3.4.3.

Coal Injection - (EFOR = 10.15%) - The most significant difficulty, during this period of testing alternate feedstocks, dealt with the quality of the paste being produced. Variation in paste quality caused pluggages in both the paste pumps and the paste lines.

Hot Gas Clean Up - (EFOR = 9.58%) - Failure of an internal insulation restraining system on a blind flange in the HGCU system, downstream of the back-up cyclone, resulted in the insulation and the metal restraining devices passing through the gas turbine. This necessitated a thorough inspection of the gas turbine. However no repairs were made due to the short remaining unit life.

Bed Dynamics - (EFOR = 7.29%) - A significant shutdown was required due to the inability to properly fluidize the bed after a high-load gas-turbine trip. This was found to be the result of significant ash build-up in the fluidizing air sparge ducts. This was attributed to a transient during the gas turbine trip, which caused the sparge duct pressure to be lower than the boiler freeboard pressure, which resulted in ash flow from the bed into the ducts.

Cyclone Ash Removal - (EFOR =6.01%) - There was a single incident of primary cyclone pluggage during this period.

Table 3.4.3 - Listing of 1995 Lost MWHr Curtailments and Outages

Listing of 1995 Lost MWHr Curtailments and Outages							
System No.	Description	Unit Outages			Curtailments		Total MWHr EFOR
		Outages # Times	Lost MWH	Calc Hours	Curtail. # Times	Lost MWH	
266	Coal Injection	2	13,895	198.5	0	0	10.15%
333	Hot Gas Clean Up	2	12,663	180.9	1	446	9.58%
222	Bed Dynamics	1	9,982	142.6	0	0	7.29%
231	Cyclone Ash Removal	1	8,225	117.5	0	0	6.01%
310	Gas Turbine	1	2,205	31.5	1	245	1.79%
262	Coal Preparation	1	4,270	61.0	1	77	3.18%
225	Boiler Water/Steam	1	861	12.3	0	0	0.63%
1000	1995 subtotals	9	51,101	744.3	3	768	38.63%

3.4.6 General Conclusions and Recommendations

This section addresses the general issues identified for various systems and components and the need for improvement and optimization to achieve commercial viability. Below is a listing of the major systems in the plant and some suggested redundancy considerations for a commercial 70-MW unit. These recommendations are based on the final configuration of the plant and do not address previous modifications made to the original plant and system designs.

Combustor Vessel:

The design of the combustor vessel was found to be satisfactory. The vessel performed its intended function and presented no challenge to system availability. However, the amount of time required to gain access into the combustor vessel would be considered unacceptable for a commercial unit. A forced cooling system designed to minimize the cooldown time between shutdown and access into the combustor should be given serious consideration. Installation of maintenance aids such as a vacuum header system, a compressed air header, and permanent lighting should also be considered to expedite routine maintenance. In addition, a proper ventilation system is required to insure efficient performance of maintenance activities. Also, a conventional lagging system for all insulated surfaces within the pressure vessel should be considered to minimize cleanup efforts.

Boiler Systems:

This section includes the boiler, boiler bottom, freeboard, tube bundle, and auxiliary equipment, such as the O_2 analyzer system, freeboard injection, etc.

The performance of the boiler, boiler freeboard, and "in-bed" tube bundle were all judged to be acceptable. Some localized erosion was observed in the "in-bed" bundle, therefore care should be taken to identify these areas early in the life of the plant so that appropriate shielding can be installed to preclude failure. Some improvements in the tube bundle support structure are also indicated to minimize deformation of the bundle. The boiler wall liners must be improved for longer life. Significant erosion was noted on the boiler water walls. Unlike the localized erosion observed on the "in-bed" tubes, the water wall erosion was more widespread. The most efficient solution for this problem will likely include shielding of the water walls, since the loss in heat absorption is considered minimal. The oxygen analyzer system must be improved to reduce excessive maintenance requirements. Consideration should be given for spare analyzers to permit on-line maintenance of them without impacting unit operations. The boiler bottom hopper must be redesigned to insure proper ash draining/cooling with finer bed material. The boiler circulation pump operation was acceptable after bearing material improvements were implemented, and the system was adequately cleaned. A complete spare pump rotor should be considered for this critical piece of hardware.

Turbine Exhaust Gas Economizer:

The finned tube exhaust gas economizer exhibited significantly heavier fouling than anticipated, resulting in higher gas side velocities and lower heat transfer. The installation of eight soot blowers helped to mitigate the problem, but heavy fouling continued to be observed in regions of the economizer that the soot blowers could not reach. The economizer must be designed to permit adequate sootblowing of finned tube surfaces and to ease in cleaning of ash buildup along the floor and ductwork bottom.

Ductwork casing must address the corrosive nature of the ash buildup and high SO_3 levels, given the environment of an exterior ductwork economizer module.

Gas Turbine Systems:

This section covers the gas-turbine compressor, turbine, and generator, along with auxiliary systems such as control fluid, lube oil, and gas-turbine cleaning.

The gas turbine unit was the most significant cause of downtime during the four years of operation of the Tidd PFBC Demonstration Plant. Major impacts in availability occurred as the result of LPT blade cracks discovered during Spring 1992, LPT blade failures that occurred in Spring 1993, LPC guide vane blade attachment brazing cracks found late in 1993, LP compressor cracks found in early 1994, and continuing difficulties associated with erosion damage at the LP turbine inlet guide vane rings. In addition, excessive air leakage from the HPC to the HPT resulted in reduced air availability to the combustor. All of these problems and the associated downtime and reduced unit output are mainly attributable to design deficiencies associated with the initial production run of ABB Stal GT-35P machines. Second- and later-generation machines will undoubtedly experience improved availability and performance from design changes that were implemented as a result of the experiences at Tidd and its sister units in Europe. However, outages induced by GT problems will likely remain as the main cause of unit outages and downtime in future generation PFBC commercial plants. For this reason, as well as the need for periodic overhauls, future commercial units would benefit from having spare GT compressor and turbine modules. It is expected that the most cost effective and expeditious method to improve availability would be a scheduled maintenance program under which the GT compressor and turbine modules would undergo periodic overhauls on a three year cycle. Availability of the spares would minimize the length of outage needed to effect the overhaul.

The availability of the rest of the gas turbine auxiliary equipment, the generator, and associated components performed acceptably during the demonstration period. No installed redundant equipment is indicated. However, two of three instrumentation trip logic arrangements should be included for vibration, control fluid pressure, lube oil tank levels, and other critical pressures and temperatures to preclude spurious trips.

Coal Preparation and Injection:

This section includes the coal paste preparation and paste injection systems and the fuel nozzles in the fluidized bed. The coal yard-to-plant bunker systems are not addressed. Tidd utilized the original plant systems, which were designed for 800 tons/hour and which do not represent the true requirements for a 70-MW PFBC plant.

The double-roll coal crusher installed in the coal preparation system was found to be a highly power-efficient device with low operating cost for crushing coal to the size consist required for the PFBC technology. The major issue with the crusher was product consistency, which varied considerably depending on the coal source, and the physical properties of the coal. Experience showed that this crusher, in its recycle mode of operation, was capable of crushing Pittsburgh #8 coal from a specific mine. However, before any other coal was tested at the plant, a test crushing was required to see if the coal could be prepared at the capacities required. In most cases, the alternate coal source could not be used due to poor crusher product quality. It is anticipated that this issue could be overcome with installation of a second 100% redundant coal preparation system and crusher of the same design as Tidd. The availability and flexibility could be further enhanced by the installation of a slipstream vertical wet ball mill similar to those used in the limestone industry. This mill would provide the ability to produce additional paste fines to complement the roller mills and produce a more consistent product.

It is expected that the installation of two 100% or three 50% redundant coal preparation systems, which would be typical of a commercial plant would address all of the issues of availability which were identified during the demonstration period.

The coal paste injection system functioned effectively during the demonstration period. However the lack of installed redundancy in the system caused significant downtime, especially when coupled with early crusher problems. Proper operation of the coal water paste pumps is heavily reliant on the quality of the paste produced which is obviously impacted by the consistency of the crushed coal. Addition of spare capacity in the form of a spare paste pump would be beneficial.

The location and number of fuel injection points in the bed was an issue of ongoing debate. Due to the complexity of the nozzles and vessel penetrations, additional fuel feed points were not added at the Tidd Plant. However, the installation of additional fuel feed points, would reduce fuel concentration and should be considered as a means of addressing both unit availability and bed stability.

Sorbent Preparation and Injection:

This section includes the sorbent preparation and injection systems. The sorbent handling system from the Tidd yard utilized the existing Tidd plant coal handling system. Like the coal handling system, it was significantly oversized, and is not addressed here.

The sorbent preparation system was a significant maintenance issue throughout the Tidd project life. Modifications were continuously being made in an effort to improve both its longevity and the size consist of the prepared sorbent. The sorbent preparation system was typically capable of 30 continuous days of operation before major overhaul on the crusher, cyclone, screens, and ductwork/chutes was necessary. A commercial application would dictate 100% redundancy in this system. In addition, significant improvements of wear rates and product flexibility (size distribution) need to be achieved. Further investigation aimed at finding a crusher that can withstand the abrasive nature of the dolomite and remain in service for longer than 30 to 45 days is indicated. Improvements are also required on the system's ability to produce the desired product size distribution.

The sorbent injection system utilized at Tidd was comprised of two parallel strings feeding sorbent in a batch mode resulting in a pause in flow when switching between lockhoppers. This method of feeding sorbent proved effective. However, a continuous flow system may prove desirable. Ceramic lining of all components in the injection piping system is highly desirable to prevent erosion. Special coating of all transport line valves as well as excellent alignment of components is also critical to longevity.

Cyclone Ash Removal:

This section addresses both the primary and secondary ash removal systems and their associated cyclones.

The primary ash removal system presented a major maintenance issue. For economic reasons, the primary ash system internal ash coolers and piping tee bends were not replaced during the demonstration period with a more reliable design. Instead, system integrity was maintained by an extensive gasket replacement program. However, at high loads and temperatures, excessive numbers of gaskets burned out, impacting system availability. For a commercial unit, the use of flange connections in the primary ash removal system should be minimized. In addition, it would be desirable for each ash removal line to independently exit the combustor vessel so that, if pluggage occurred, the line could be blown down and possibly cleared in service. In addition, it would be desirable to design the primary cyclones to permit access to the dip legs without the need to enter the combustor vessel.

A properly designed system which incorporates the lessons learned from the demonstration units should be able to achieve commercial reliability.

Secondary ash lines and cyclones as modified at Tidd are considered adequate for a commercial plant design, provided a routine maintenance program is instituted to replace worn bends periodically.

Bed Ash Removal:

This section covers the bed ash removal system from the boiler bottom to the ash silos.

This system has been problem-free after several modifications early in the project. Isolation and venting valves continue to be maintenance issues, and should be considered for redundant valves. A complete redundant lockhopper train would enhance operations capabilities and flexibility if a valve failed in service. In addition, ash flow control and ash cooling problems were experienced when tests were conducted with very fine sorbents.

Several failures of the transport conveyor belts occurred but did not impact unit operations, since a vacuum truck was used to remove bed ash while the belts were being repaired.

Valves in Solid Transport Systems:

An extensive and routine amount of maintenance was required in valves located in lines that transported solid materials such as sorbent injection, bed ash removal, HGCU, and cyclone ash removal. Generally, it was found through experience that the right combination of valve materials would survive in these harsh operating conditions. This included body and ball materials, coatings, seats, and clearances. However, experience has also shown that valves installed in material transport lines need to have complete spares stored at the plant so that the valves can be changed during a short outage and the old valves can be shipped out for repair/rebuild.

3.5 PFBC Technology Assessment

The first three-years of operation at the Tidd PFBC facility clearly demonstrated the ability of the technology to meet and exceed the expectations of the demonstration. The Tidd PFBC Demonstration Plant accumulated 6057 hours of coal-fired operation during its first three years of service. Forty-seven performance tests were conducted to confirm unit performance. The achievements during that period were significant in confirming the viability of PFBC technology. The unit met or exceeded all of its design (guarantee) conditions except gas turbine output. Sulfur retention of 90% at a guaranteed Ca/S molar ratio of less than 2.0 was demonstrated. Sulfur retention of 95% was also achieved. Process NOx emissions were lower than the guaranteed 0.5 lbm per million BTU. Overall process performance clearly showed that PFBC was capable of meeting current and future environmental standards for base load, coal-fired power generation.

Testing during the fourth year of operation advanced the basic understanding of PFBC and provided additional evidence that a PFBC combined cycle would compete with both existing and proposed solid fuels technologies. Improved unit availability provided the opportunity to operate for an additional 5382 hours and to perform an additional forty-eight performance tests. The results achieved in the last year of testing were significant to the commercialization of PFBC technology. Sintering was controlled, process performance was optimized, and both the gas turbine and the "in-bed" tube bundle continued to perform acceptably.

Testing in the fourth year clearly showed that both bed sintering and sorbent utilization were affected by the fluidization characteristics of the bed. The reduction in bed size consist, effected by reduction in sorbent feedstock size consist, proved pivotal in improving bed fluidization. The better fluidized bed provided sufficient mixing to preclude uncontrollable sintering with dolomite as the sorbent. Sintering in the bed was effectively controlled in the normal bed operating temperature range up to 1585 F.

Reduced sorbent feed size and the associated improved fluidization also provided the opportunity to enhance sorbent utilization beyond what had previously been considered acceptable. The first three years of testing demonstrated sulfur capture of 90% at a Ca/S molar ratio of around 2.0. The fourth year of testing showed that, by using carefully controlled sorbent size consist, a sulfur retention of 90% was demonstrated at a Ca/S molar ratio of 1.27 when operating at 107 inches bed level and 1580 F bed temperature. This correlates to a 1.1 Ca/S at full bed height. This further correlates to a Ca/S ratio of 1.5 at 95% sulfur retention. Such improvements in sorbent utilization are significant in reducing the operating cost of the PFBC option.

NOx emissions have continued to be well below anticipated levels. The Tidd plant typically emitted 0.25 lbm of NOx per million BTU, at full load. No extraordinary measures were taken to reduce NOx. The demonstration at Tidd coupled with experience at other PFBC units has shown that NOx emissions levels of less than 0.1 lbm/MMBtu are achievable with minor system enhancements.

The first three years of operation confirmed the expectations of PFBC technology and clearly defined avenues for further testing in the fourth year. The fourth-year of operation pursued those avenues and resolved the single most significant operating problem - sintering, while enhancing process performance to levels beyond the most optimistic projections. In addition, PFBC systems have been tested, modified, and refined to the point where the design and construction of a base-load commercial size unit is immediately feasible. The process has been demonstrated to be environmentally sound and capable of achieving the reliability and availability required in a power generating unit. Commercial deployment remains the only significant hurdle.

3.6 PFBC Commercialization

Clean Coal Technologies in general, and PFBC technology in particular, offer an important opportunity for sustained economic development, both domestically and internationally. However, as with most technologies in the capital intensive power industry, these new technologies require 20 to 25 years from their initial development stages to the point where the technology risk has been sufficiently reduced for power generation companies to assume the risk of commercial deployment.

Most of the development work required for PFBC technology to reach this phase has been completed. The successful operation of the Tidd PFBC Demonstration Project has established the viability of the process, while developing and optimizing plant systems. Successful continued operation of PFBC plants throughout the world; at places such as Vartan in Sweden, Escatron in Spain, and Wakamatsu in Japan; continue to demonstrate the viability of PFBC technology.

Power Generation companies are concerned about future competition as well as the availability of primary energy sources for power generation. Virtually all integrated resource plans for the next ten to fifteen years rely on the addition of simple cycle or combined cycle natural gas-fired combustion turbine systems to meet their near-term growth needs, satisfy peaking demands, and achieve environmental compliance at the least cost. One key reason for this reliance on natural gas fired combustion turbines is the present historically low price of natural gas. However concerns remain about the future escalation and the reliability of supply of natural gas. The expected real escalation of natural gas in the next decade should re-establish coal as the fuel of choice for future additions of base load power generation.

Most Clean Coal Technologies, including PFBC, are well suited for base load power generation. The cost of electricity comparison of various mature technologies clearly show that PFBC is the lowest-cost option for coal firing. Furthermore, PFBC technology has reached a stage where full-size commercial demonstration is a viable option. However, as with all emerging technologies, PFBC is on the upward side of the cost maturation curve, which results in higher first-of-a-kind costs for the first several units built.

Continued support of the Federal Government and the willingness of regulators is required to promote PFBC and other clean coal technologies based on their merit for sustainable development. American Electric Power's Philip Sporn Project was conceived as a 330 MWe repowering of the existing Sporn Plant Units 3 and 4. The project was proposed to the U. S. Department of Energy in 1988 and was accepted for funding as part of the Clean Coal Technology II initiative. A cooperative agreement was signed in April 1990 for the project. The availability of U.S. DOE cost sharing for this commercial demonstration project has provided the opportunity to proceed with the first full scale demonstration. While repowering of the Sporn facility was subsequently deemed not viable, the program's main objective of achieving commercial demonstration of the PFBC process on a utility scale remains desirable and viable for deployment early in the next decade.

Deployment of such a unit coupled with potential deployment of a similar unit in Japan will provide the operating experience necessary to address the risks associated with wholesale deployment of this technology.

It is widely predicted that some time after the year 2000, electric demand in our nation will catch up to available generating capacity and as a result, new power plant construction will have to increase. In addition, a large portion of existing generating capacity will be reaching the end of useful life and will need to be replaced. Taken together, these factors should result in a significant market for new or repowered generation facilities.

With a broad selection of coal-based technologies being developed, tested and readied for commercial deployment and a large market looming on the horizon, the stage appears to be set for a whole new generation of electric power generation.

The low cost of PFBC technology, when compared to other available CCT options, should place it in a strong position to capture a significant share of the developing market.

3.7 Environmental Monitoring Plan Overview

In support of the PFBC project and in conjunction with the Cooperative Agreement with DOE, an Environmental Monitoring Plan (EMP) was written and implemented. The purpose of the EMP was to produce an environmental, health, and safety data base relative to operation of the Tidd PFBC Demonstration Plant and for application to future replication of the PFBC technology.

The EMP consisted of compliance monitoring and supplemental monitoring. Compliance monitoring is that monitoring required by permits and regulations. Supplemental monitoring covers other sources and parameters not required under compliance monitoring. The environmental monitoring is performed on a quarterly basis. Quarterly reports, detailing results of the environmental monitoring, were forwarded to DOE within 60 days of the quarter's end. An annual report, summarizing the four quarters of environmental monitoring during the previous year, is submitted to DOE by the end of March of the following year. The annual report also covers the previous year's health and safety monitoring, which is reported only on an annual basis.

Environmental monitoring consisted of sampling and analyzing wastewater, solid waste, and air-related wastestreams. Sources for wastewater sampling include the condenser pit sump, combustor building sump, wastewater collection sump, the PFBC ash disposal area groundwater monitoring wells, coal pile runoff, dolomite pile runoff, once-through cooling water discharge, and, for background information, the Ohio River intake water. For solid waste, the PFBC bed ash, PFBC fly ash, and any chemical metal cleaning wastes were sampled and analyzed. Also for supplemental information, the coal and sorbent were analyzed. Air-related wastestreams that were sampled include the flue gas from the PFBC combustor and the gas turbine exhaust gas. Other miscellaneous wastestreams were sampled as the need arose.

Health and safety monitoring consists of three components - industrial hygiene, medical surveillance, and safety. Airborne contaminants were analyzed for exposure assessments, medical surveillance of employees was conducted through physicals, and safety training was performed regularly.

EMP reports on the operations phase of the PFBC project have been filed with DOE, beginning with the first quarter of 1991 and continuing through the present. Details on the wastestreams and parameters analyzed and the results of monitoring are contained in the EMP reports.

4.0 PFBC Testing

4.1 Fourth Year Test Program Goals and Objectives

One key objective for the fourth year of the Tidd test program was to optimize sorbent utilization by adjusting the critical parameters which have been identified to affect sorbent utilization. The key parameters investigated were sorbent particle size distribution and sorbent selection. Various sorbent size distributions were tested ranging from 6-mesh top size to 20-mesh top size. The various sorbents tested were Plum Run Greenfield dolomite, National Lime Carey dolomite, Mulzer Laurel dolomite, and National Lime Bucyrus and Delaware limestones.

Other major goals and objectives of the test program were:

- Evaluate the unit for the causes of bed sintering with the goal of resolving the sintering problems that were occurring at high loads with dolomite and all loads with limestone.

- Minimize the risks of commercial deployment by demonstrating a minimum unit availability of 40%.

- Demonstrate extended operation and availability of the gas turbine. Inspect the gas turbine for erosion and corrosion after extended hours of operation.

- Evaluate the impact of extended operation on the in-bed tube bundle for erosion.

- Complete testing for hazardous air pollutants upstream and downstream of the HGCU Advanced Particle Filter and Electrostatic Precipitator.

- Demonstrate acceptable HGCU filter performance at PFBC operating conditions. Evaluate the HGCU candle elements for reduction of strength due to extended hours of operation.

These goals were achieved during the fourth year of unit operation through data collection, performance tests, equipment inspections, reports, and studies. This section of the report details the unit performance testing completed during the final year of operation.

The problems of bed sintering were resolved by operating with a finer dolomite size which reduced the mean bed particle size, thereby enhancing bed fluidization. Background information and details of testing with finer sorbent sizes are included in Section 5.1.

The availability goal was achieved by operating a total of 5382 hours from March 1, 1994 through March 30, 1995 resulting in 57.0% unit availability for the fourth year of operation.

The gas turbine was operated in excess of 5750 hours during the extended fourth year. A significant increase in gas turbine blade erosion was noted during the October 1994 outage following a run when the P11 cyclone upstream of the HGCU filter was completely spoiled and the filter was operated with a number of broken candles. Details of the gas turbine inspections are presented in Section 6.13.

Details of the in-bed tube bundle inspections are presented in Section 6.2.

Hazardous air pollutant testing was completed during the week of April 11, 1994 by Radian Corporation. Details of that testing are contained in report DCN 94-633-021-03 dated October 27, 1994 entitled "A Study of Hazardous Air Pollutants at the Tidd PFBC Demonstration Plant". This report was prepared by Radian Corporation for American Electric Power Service Corporation.

4.2 Fourth Year Test Program Description

A total of 48 performance tests (Tests 48 through 95) were conducted during the fourth year of Tidd operation in order to evaluate and optimize process performance while burning various coals and sorbents at various load conditions. The emphasis of the fourth year test program was to optimize sorbent utilization. This was done by evaluating unit performance with various types and size distributions of sorbents. Sorbent utilization is discussed in Sections 4.3 and 5.2.

This report discusses only the tests conducted during the fourth year of operation, however, a copy of the "Test Results Summary" for all 95 tests completed during the project is contained in Appendix III. Discussions on results for the first 47 tests, including the acceptance tests, are contained in the Tidd three year report.

Tests were conducted with MM Pittsburgh #8 coal, Minnehaha coal, and Consol Mahoning Valley Pittsburgh #8 coal. The sorbents tested during the fourth year included Plum Run Greenfield dolomite, National Lime Carey dolomite, Mulzer Laurel dolomite, and National Lime Bucyrus and Delaware limestones. Typical analyses of the coals and sorbents tested are contained in Tables 4.2.1 and 4.2.2.

Table 4.2.1 - Typical Coal Analyses

Typical Coal Analyses			
Coal Company Mine and Seam	MM Coal Company Betsy Mine Pittsburgh #8	Cyprus Amax Coal Minnehaha Mine Indiana #6	Consolidation Coal Mahoning Valley Mine Pittsburgh #8
Sample Number	C-410419 (13318A)	C-503055 (13600A)	C-503648 (13694A)
Sample Date	October 13, 1994	March 2, 1995	March 28, 1995
Proximate Analyses			
% Total Moisture	4.52	16.24	7.23
% Ash (D/B)	11.64	10.88	16.95
% Sulfur (D/B)	3.20	1.61	2.05
HHV, Btu/lbm (D/B)	13,048	12,900	12,129
SO_2, lbm/MMBtu (D/B)	4.91	2.50	3.38
Ultimate Analyses			
% Carbon (D/B)	70.91	70.00	66.50
% Hydrogen (D/B)	4.40	4.71	4.54
% Nitrogen (D/B)	1.39	1.53	1.29
% Chlorine (D/B)	0.02	0.03	0.10
% Oxygen (D/B)	8.26	11.24	8.57
Ash Fusion Temperature - Reducing Atmosphere			
Initial Deformation (F)	n/a	n/a	2108
Softening (F)	n/a	n/a	2165
Hemispherical (F)	n/a	n/a	2197
Fluid (F)	n/a	n/a	2284

Table 4.2.2 - Typical Sorbent Analyses

Typical Sorbent Analyses					
Company Name	Davon Inc. Plum Run Division	National Lime & Stone Co.	National Lime & Stone Co.	National Lime & Stone Co.	Mulzer Crushed Stone
Geological Formation	Greenfield	Carey	Bucyrus	Delaware	Laurel
Sorbent Type	dolomite	dolomite	limestone	limestone	dolomite
Sample Number	4845A	4710A	4811A	4865A	4837A
Sample Date	3/07/95	5/13/94	10/13/94	3/28/95	2/27/95
Constituent Analyses					
% Total Moisture	0.04	0.06	<0.01	0.18	0.12
% $CaCO_3$ (D/B)	52.44	51.06	73.43	81.97	50.33
% $MgCO_3$ (D/B)	43.95	43.56	20.08	12.80	38.54

All tests during the fourth year of operation were conducted with four sorbent feed points which were found to be more effective in sorbent utilization than the original two feed points. Variations in sorbent distribution and feed points were investigated during the initial three years of operation. Details of that testing and the physical modifications to the sorbent distribution piping can be found in the three year report. Since improvements were noted with the four sorbent feed points, the unit remained in this configuration for the remainder of the test program.

Tests were conducted at various bed levels, bed temperatures, and sulfur retention levels in order to verify the Grimethorpe correlation at unit operating conditions not investigated previously. In May 1994 the first test at 1580 F bed temperature was successfully completed using a finer size grade of National Lime Carey dolomite. Earlier attempts at reaching the design bed temperature were unsuccessful due to sintering. Tests were conducted at bed levels up to 150 inches and sulfur retention levels up to 95%.

Additionally, tests were conducted to investigate the effect of excess O_2 on sorbent utilization. Discussions on the Grimethorpe correlation and related tests are presented in Section 4.4.

Each performance test was generally conducted by bringing the unit up to the desired load (i.e., bed level, bed temperature, and air flow) which set the firing rate. The outlet SO_2 emissions were set to the desired level by controlling the sorbent flow. After the unit reached steady state operating conditions, data collection and materials sampling were initiated.

Typical data collection and materials sampling lasted for a period of 8 to 24 hours. The steadiest operating interval in the data collection period was selected for evaluation. The evaluation period was usually 4 to 12 hours in length.

Process data collection consisted of downloading on-line Plant Operation Performance System (POPS) data points to an ASCII data file. Each data point was then averaged over the evaluation time period and used as an input to a FORTRAN program developed to calculate plant performance parameters.

Materials sampling typically consisted of collecting coal, coal water paste, sorbent, bed ash, and cyclone ash samples over the data collection period for chemical analysis. The results of the chemical analyses were used as additional inputs to the calculation program. Due to the lead and lag times of the materials handling systems, the coal sampling was conducted two hours ahead of the data collection period, and bed ash sampling was conducted 12 hours after the data collection period. All other materials sampling periods were at the same time intervals as data collection.

The calculation program used the process and chemical analysis data as inputs to calculate performance values. Key performance values included coal water paste flow, flue gas flow to the high pressure turbine, excess air, sulfur retention, calcium to sulfur molar ratio, NO_x emissions, and combustion efficiency. To determine the values for coal water paste flow, the calculations were iterated until an energy balance on the pressure vessel was achieved. The air flow bypassing the bed was calculated based on oxygen levels in the freeboard and downstream of the gas turbine. (Oxygen in the freeboard was determined by averaging the oxygen levels measured downstream of each of the seven primary cyclones.) Mass and heat balance closures were calculated and used to determine the accuracy of the performance tests.

In addition to the unit performance tests, environmental compliance tests were conducted on September 30, 1994 to determine the relative accuracy of the Continuous Emissions Monitoring Systems (CEMS). These test results are presented in Section 4.8.

4.3 Sorbent Utilization Testing

During the fourth year of operation, a total of 48 performance tests were conducted at bed levels from 85 to 150 inches with bed temperatures from 1475 F to 1580 F while sulfur retention levels were tested in the range of 86% to 95%. For each test, the Ca/S molar ratio was calculated then normalized to conditions of 1580 F bed temperature and 90% or 95% sulfur retention using the Grimethorpe correlation. (See Section 4.4 for discussion on the Grimethorpe correlation.) Various coals and sorbents were tested in order to evaluate the impact on sorbent utilization. Results for all tests conducted in the four years of Tidd operation are contained in Appendix III. Details of sorbent utilization testing for the fourth year of operation are contained in Section 5.2.

Optimization of sorbent utilization consisted of testing the unit under various conditions that were expected to affect sulfur capture. The greatest impact on sorbent utilization was found to be changes in sorbent size. Tests were conducted using finer sorbent sizes prepared both on-site and off-site. The off-site (designer) sorbents exhibited a narrow range of sorbent particle sizes and contained fewer minus 60-mesh fines than the site prepared sorbents. The best sorbent utilization was obtained by operating with Plum Run Greenfield 12-mesh designer dolomite and MM Pittsburgh #8 coal where an average Ca/S ratio, adjusted to 1580 F bed temperature and 90% sulfur retention, of 1.26 was obtained at 115 inches bed level. This represents an improvement of approximately 35% over the results obtained with Plum Run Greenfield 6-mesh site prepared dolomite and MM Pittsburgh #8 coal. It is believed that the improvements in sorbent utilization are due to several factors all resulting from the changes in sorbent size. The finer sorbent particles allow a greater surface area for reaction with the combustion gases and also result in improved bed fluidization and mixing. In addition, the designer sorbent sizes contain fewer fines which are typically poorly utilized due to their relatively short residence times within the bed. Details of these tests are presented in Section 5.2.2 while graphical results and sorbent particle size distributions are presented in Figures 5.2.1 through 5.2.5.

During the fourth year of testing, three dolomites (Plum Run Greenfield, National Lime Carey, and Mulzer Laurel) and three coals (MM Pittsburgh #8, Minnehaha Indiana #6, and Consol Mahoning Valley Pittsburgh #8) were evaluated for sorbent utilization. Typical coal and sorbent analyses are presented in Tables 4.2.1 and 4.2.2. Of the various dolomites tested, the Plum Run Greenfield and Mulzer Laurel both performed equally well and better than the National Lime Carey. Of the coals tested, both of the Pittsburgh #8 coals performed equally well and better than the Minnehaha coal. Details of these tests are presented in Section 5.2.3.

Tests were conducted with Bucyrus limestone in October 1994 and with Delaware limestone in March 1995 both from National Lime & Stone Co. During both tests the bed showed signs of gradual deterioration exhibited by the decline of bed density and heat transfer as bed and evaporator temperature distributions became less uniform. In both cases the tests had to be ended early and sorbent was switched back to dolomite in order to stabilize bed conditions. Although not completely successful, these tests were far more successful than previous attempts during 1992-1993 when operation with limestone resulted in unit shutdowns due to deteriorating bed conditions. It is believed that the improved operation with limestone during the latest two tests is due to the finer sorbent sizes that were being tested which would tend to enhance bed fluidization. With respect to sorbent utilization, the limestone performed roughly equal on a mass basis as dolomite for a given sorbent particle size. Complete details on limestone operation and testing are contained in Sections 5.1 and 5.2.

4.4 Grimethorpe Correlation

In order to allow direct comparison of test results, even though actual test conditions may have varied between tests, the calcium-to-sulfur molar ratios presented in this report are usually normalized to specific test conditions for sulfur retention (typically 90%), bed temperature (1580 F), and sometimes bed level using the following correlation developed at Grimethorpe:

$$\ln(1-R) = -A \cdot C \cdot t^{1/2} \cdot \exp(-4650/T)$$

where:

R = sulfur retention, dimensionless
C = calcium-to-sulfur molar ratio, dimensionless
t = in-bed gas residence time, seconds
T = bed temperature, degrees Kelvin
A = constant, sorbent reactivity index

The sorbent reactivity index, A, is a constant for a given test and is a measure of the sorbent's reactivity at a given test configuration. Sorbent type, size, feed method, and distribution within the bed are all variables that may affect the sorbent's reactivity. After conducting a performance test, the sorbent reactivity index is calculated using the Grimethorpe equation solved for A:

$$A=-\frac{\ln(1-R)}{C\cdot t^{1/2}\cdot \exp(-4650/T)}$$

The performance data can now be normalized to any reference sulfur retention value, Ca/S ratio, or bed temperature by substituting the desired reference value into any one or two of the above variables and solving the Grimethorpe equation for the variable of interest. By substituting the calculated sorbent reactivity index value for A, 0.90 for R, and 1133 K (1580 F) for T, and solving the Grimethorpe equation for C, the calcium-to-sulfur molar ratio is predicted for 90% retention at 1580 F bed temperature. Note that when correlating test data for bed height, the actual variable in the Grimethorpe equation being tested is "t" (in-bed gas residence time) which is equal to bed level divided by the superficial fluidizing velocity.

During the initial three years of testing, the Grimethorpe correlation was verified to be reasonably accurate for bed levels from 80" to 142", bed temperatures from 1480 F to 1540 F, and sulfur retention levels from 85% to 95%. The Grimethorpe correlation was not initially validated for bed temperatures above 1540 F due to the inability to test at higher temperatures because of bed sintering problems. However, in the fourth year of operation the sintering problem was resolved and the majority of the tests conducted after May 1994 were conducted at 1580 F bed temperature. During the final year of operation, the Grimethorpe correlation was shown to be reasonably accurate for bed temperatures up to 1580 F, and also the Grimethorpe correlation was reconfirmed to be valid for bed level and sulfur retention.

In order to verify the accuracy of the Grimethorpe correlation, test series, each consisting of two performance tests, were conducted (in the same run with the same coal and sorbent) where all test variables except one is held constant. The Grimethorpe correlation is determined to be accurate for the variable of interest if the normalized Ca/S ratio is the same (or reasonably close) for both tests. The following Table 4.4.1 shows selected tests conducted in the fourth year of operation used to verify the Grimethorpe equation for bed height, bed temperature, and sulfur retention.

Results from these tests show that the normalized Ca/S ratio varies by less than 2.2% for each of the test series. This is within the normal scatter of results for tests of similar conditions. Hence, the Grimethorpe correlation appears to be reasonably accurate.

Table 4.4.1 - Test Series for Verification of Grimethorpe Equation

Test Series for Verification of Grimethorpe Equation					
Test Number	Bed Height (inches)	Bed Temperature (F)	Sulfur Retention (%)	Ca/S Ratio (actual)	Ca/S Ratio (@ 142" bed hgt, 1580 F, 90% SR)
Tests For Changes in Bed Height					
90	141.3	1563	89.4	1.65	1.63
92	90.6	1580	90.9	2.09	1.61
					1.1% Difference
Tests For Changes in Bed Temperature					
56	114.1	1498	89.9	2.55	1.93
57	115.0	1575	91.4	2.34	1.95
					1.2% Difference
68	110.6	1576	91.5	1.77	1.45
69	110.7	1497	89.9	1.97	1.47
					1.3% Difference
Tests For Changes in Sulfur Retention					
81	125.9	1574	93.9	2.01	1.54
82	125.7	1574	90.6	1.74	1.57
					2.2% Difference

Other variables not included in the Grimethorpe equation, may also have an impact on sorbent utilization. Since O_2 is required in the sulfation reaction of $CaCO_3$ it is quite possible that reduced levels of O_2 may have a negative impact on sulfur capture. In order to investigate this theory, several tests were conducted where all variables in the Grimethorpe equation are held constant while excess O_2 is varied by adjusting the air flow to the combustor. As presented in the following Table 4.4.2, the results from Tests 61 and 62 show a 0.4% increase in normalized Ca/S ratio as O_2 is reduced from 4.5% to 3.8%, and the results from Tests 65 and 66 show an increase of 1.8% in Ca/S ratio as O_2 is reduced from 7.3% to 4.0%. Since the changes noted in Ca/S ratio are smaller than the typical scatter of results from tests conducted under the similar conditions, this theory cannot be confirmed nor disproved. In any case, it appears that if excess O_2 does have an impact on sorbent utilization, the effect is relatively minor at the O_2 levels tested.

Table 4.4.2 - Test Series for Evaluation of the Impact of Excess O_2

Test Series for Evaluation of the Impact on Excess O_2						
Test Number	Excess O_2 (%)	Bed Height (inches)	Bed Temp. (F)	Sulfur Retention (%)	Ca/S Ratio (actual)	Ca/S Ratio (@ 142" bed hgt, 1580 F, 90% SR)
61	4.5	114.6	1499	88.3	1.34	1.09
62	3.8	114.6	1498	88.4	1.36	1.10
						0.4% Difference
65	7.3	86.8	1581	87.8	1.90	1.63
66	4.0	85.0	1584	90.6	2.18	1.66
						1.8% Difference

4.5 Combustor Performance

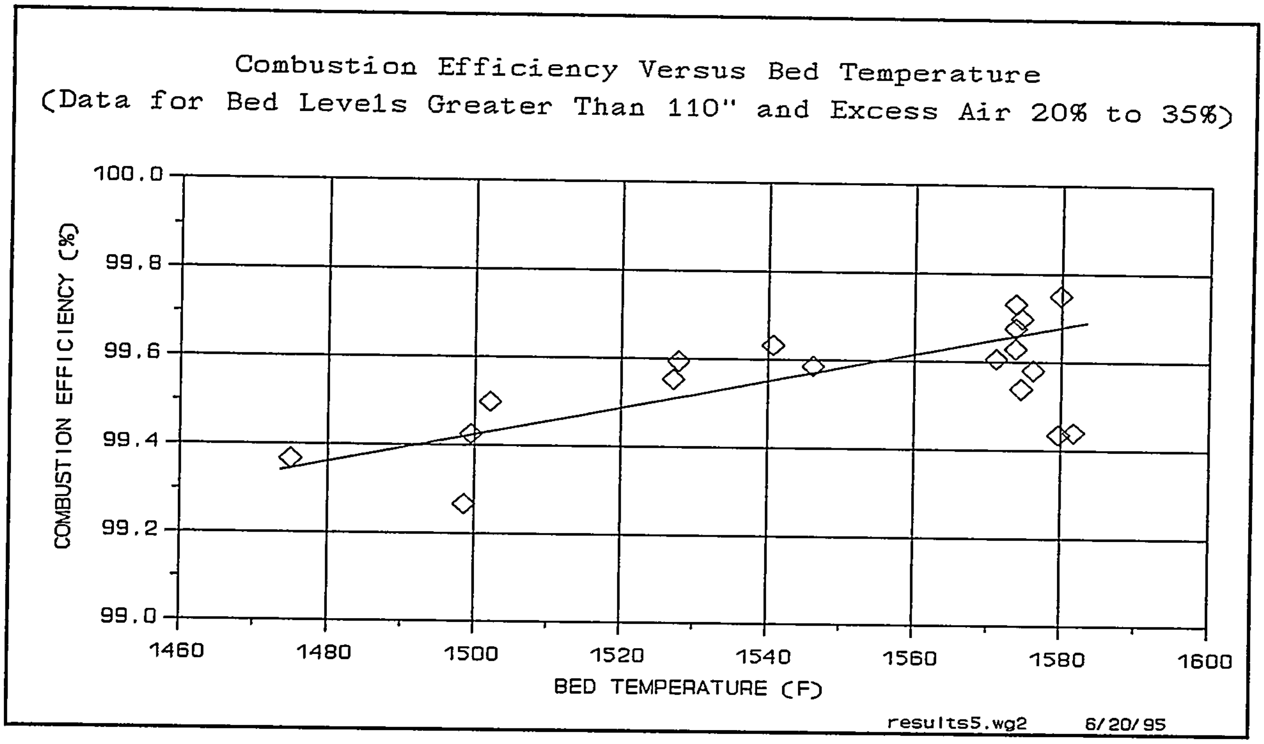
Combustion efficiency is calculated based on the measured unburned carbon in the cyclone ash and bed ash and carbon monoxide in the flue gas.

The design combustion efficiency of 99.0%, at full bed height and temperature and 25% excess air, was surpassed in all tests conducted in the fourth year of operation. The best combustion efficiencies achieved during the fourth year of operation were 99.65% to 99.75% which occurred at bed levels greater than 110 inches, full bed temperature (1580 F), and excess air levels greater than 20%. Other tests at similar bed levels and temperatures, but with excess air levels between 15% and 20%, had combustion efficiencies in the range of 99.40% to 99.65%. The average combustion efficiency for all tests greater than 110 inches was 99.5% while an average of 99.3% was achieved for tests at bed levels below 110 inches.

Combustion efficiencies were slightly improved from tests conducted during the initial three years when an average combustion efficiency of 99.4% was achieved for tests at bed levels greater than 110 inches. The reasons for improved combustor performance are most likely due to the improved bed fluidization by operating with finer sorbent and also by operating at higher bed temperatures which was not possible during the initial three years due to bed sintering problems.

Tests conducted at Grimethorpe show that combustion efficiency is a function of in-bed gas residence time, excess air, bed temperature, and volatile matter in coal. The in-bed gas residence time is a function of bed level and superficial fluidizing velocity. Figure 4.5.1 shows combustion efficiency versus bed temperature for tests conducted during the fourth year at bed levels greater than 110 inches and excess air levels between 20% and 35%. A general improvement in combustion efficiency is seen as the bed temperature is increased from 1475 F to 1580 F. Although not as apparent, trends of improved combustion efficiency were also noted with increased bed levels and/or excess air. The impact of volatile matter in coal versus combustion efficiency was not investigated at Tidd.

Figure 4.5.1 - Combustion Efficiency Versus Bed Temperature



4.6 Gas Turbine/ Compressor Performance

The gas-turbine compressor air mass flow limitations continued to impose limits on unit firing rate in all but the winter months. The increased firing rates possible as a result of better fluidization and increased heat transfer exacerbated the problem. The administrative maximum indicated compressor air flow limit, which was reasonable at previously attainable firing rates, was found to be a major impediment to operation at full bed height with the bed conditions achieved in the fourth year. Therefore, the administrative limit of 710,000 lbs/hr output from the GT compressor was re-evaluated and a revised limit of 760,000 lbs/hr was established. This revised limit allowed for full load, full temperature operation at ambient temperatures below 35 F. The higher air flow allowed the unit to be operated at or above its full load design firing rate of 206 MW_t which resulted in a higher gas turbine output than was previously possible. The gas turbine/ compressor performance data for these tests is presented in Table 4.6.1.

The gas turbine air leakage presented in this table includes the HPC air leakage to ambient, the HPC to HPT cooling air bypass flow, and the intercept valve internal leakage, and is presented as a percentage of the HPC indicated inlet air flow. The total leakage rate was determined by comparing measured oxygen levels in the gas stream at the freeboard to oxygen levels downstream of the gas turbine. The individual leakage rates were estimated by apportioning the overall measured leakage based upon shop test leakage data.

During the first three years of operation the highest gas turbine output achieved was 13.2 MW_e. The noted causes for below-design gas turbine performance were lower-than-design air flow capacity of the LPC, lower-than-design efficiency of the LPC, and higher-than-design internal air leakages in the gas turbine. These inefficiencies were never corrected during the fourth year of the project and thus the higher gas turbine output achieved during the fourth year is strictly a result of the higher allowed air flows and resulting firing rates obtained during these tests.

The inefficiencies of the gas turbine have been attributed primarily to poor tolerances achieved during fabrication of this first-of-a-kind machine. The experience gained at Tidd coupled with other PFBC operating experience should provide a sound basis for enhancement of gas turbine performance. The problems identified at Tidd should be fully resolvable on a commercial unit.

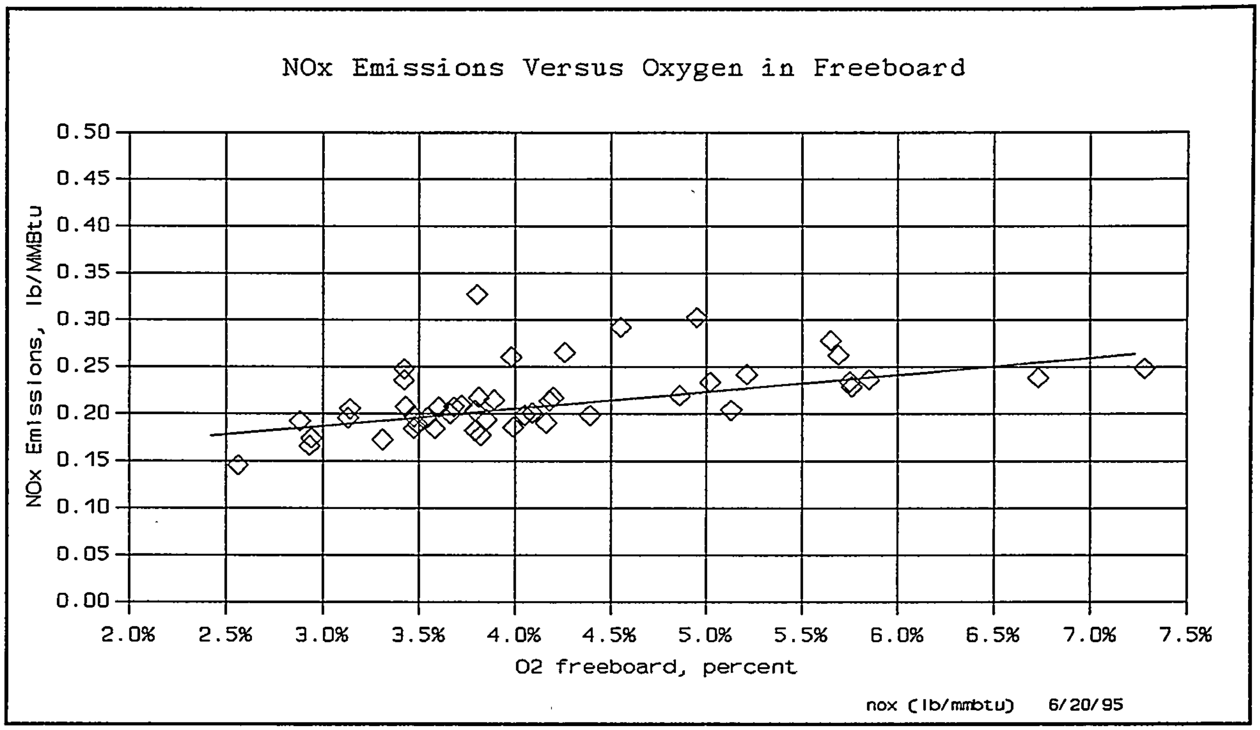
Table 4.6.1 - Gas Turbine Performance

Gas Turbine Performance					
Test Number	85	86	89	90	Expected Values
Test Date	2/22/95	2/24/95	3/2/95	3/4/95	
Gas Turbine Output (MW_e)	15.0	15.2	15.0	15.1	15.4
Air Leakage (%)	12.1	12.7	12.8	12.4	4.4
LPC Inlet Temperature (F)	30	32	31	38	59
LPC Outlet Temperature (F)	338	339	327	332	345
LPC Outlet Pressure (psia)	63	63	62	62	59
LP Shaft Speed (rpm)	5633	5628	5554	5558	5364
HPC Outlet Temperature (F)	571	572	572	572	572
HPC Outlet Pressure (psia)	186	187	186	184	174
HPC Inlet Air Flow (kpph) *indicated*	735	735	730	721	679
HPC Inlet Air Flow (kpph) *calculated*	715	726	694	700	679
Air Flow to Pressure Vessel (kpph)	626	633	605	610	649
Int. Valve Inlet Temperature (F)	1542	1552	1505	1558	1535
HPT Inlet Pressure (psia)	161	161	162	159	146
LPT Outlet Temperature (F)	737	746	714	751	782
LPT Outlet Pressure (psia)	15.6	15.6	15.7	15.6	14.8
Intercooler Heat Duty (kw)	3661	3764	3189	3505	4200

4.7 NO_x Emissions

The NO_x emissions levels at Tidd were in the range of 0.15 to 0.33 lb/mmbtu. Based on research conducted at Grimethorpe, NO_x emissions are known to be dependant on excess air and on the nitrogen content of coal. Figure 4.7.1 shows NO_x emissions (pounds per million Btu) plotted against percent oxygen in the freeboard for all performance tests conducted during the fourth year. As expected, an increase in excess air resulted in an increase in NO_x emissions. The impact of nitrogen in the coal on NO_x emissions was not investigated at Tidd since there was not a significant variation in the levels of nitrogen in the coals tested. The Tidd operating permit limit for NO_x emissions of 0.50 lb/MMBtu was met during all operating conditions.

Figure 4.7.1 - NO_x Emissions Versus Oxygen in Freeboard



4.8 Environmental Compliance Tests

The Tidd environmental permits required continuous monitoring and reporting of SO_2 and NO_x emissions and an annual Relative Accuracy Test Audit (RATA) of the SO_2 and NO_x monitors. A RATA test was conducted on August 1, 1994 during which the SO_2 monitor did not meet required relative accuracy; a successful repeat RATA test was conducted on September 30, 1994. No cause of failure of the first RATA test was ever identified. Testing was conducted by Environmental Source Samplers, Inc.

During the tests, CO_2 was measured as the diluent, while SO_2 and NO_x were the pollutants of interest. CO_2 monitoring was performed by EPA Method 3A, while EPA Method 6C was used for SO_2 sampling, and EPA Method 7E for NO_x sampling. Performance Specification 2 was followed for determining the monitors relative accuracy. A summary of the September 30, 1994 test results is presented in Table 4.8.1.

Table 4.8.1 - Environmental Compliance Tests

Test Date	September 30, 1994
Unit Conditions	
Unit Gross Output (MW_e)	58.6
Stack CO_2 (percent, D/B)	14.27
Test Results	
Test SO_2 (lb/mmbtu)	0.4911
Monitor SO_2 (lb/mmbtu)	0.4662
SO_2 Monitor Relative Accuracy (%)	7.09
Test NO_x (lb/mmbtu)	0.2204
Monitor NO_x (lb/mmbtu)	0.1969
NO_x Monitor Relative Accuracy (%)	13.60

5.0 Significant Findings

5.1 Bed Sintering

5.1.1 Background

Given the relatively low design mean bed temperature of 1580 F and the fact that the burning coal particles are within 300 - 500 F of the bed temperature, the bubbling bed PFBC process should theoretically avoid problems associated with melting of the coal ash constituents. In practice; however, the calcium from the sorbent/bed material can flux the ash constituents resulting in a lower melting point eutectic which can cause agglomerations that can severely upset the bed.

5.1.2 Experience During the First Three Years of Operation

The following summarizes the problems experienced with excessive sinter formation during the first three years of operation of the Tidd PFBC unit. Section 5.2 of the report titled "First Three Years of Operation ..." contains more details on the past experiences with sintering.

Operating problems due to the formation of bed agglomerations in the form of hollow egg shaped sinters (1/2 to 2 inches in size) were experienced during the first three years of operation. Under normal conditions, egg sinters formed at a low enough rate that they did not accumulate due to removal via the bed drains. However, under certain operating conditions, the sinter formation rates were so high that they accumulated in the bed. When this occurred, the heat transfer to the submerged tubes would become uneven and gradually decrease and the bed temperatures would become excessively uneven. In a few instances bed conditions deteriorated to the point that unit trips occurred.

During the second and third years of unit operation, three attempts were made at using limestone as the sorbent. The limestone tested was National Lime Delaware limestone which had a much higher percentage of calcium carbonate (80% $CaCO_3$) and much lower percentage of magnesium carbonate (12% $MgCO_3$) than the typical Plum Run dolomite (52% $CaCO_3$/44% $MgCO_3$). In all three attempts with this material, the sinter formation rates were so excessive that bed conditions deteriorated rapidly (within 12 hours) and to such an extent that unit trips either occurred automatically or had to be initiated by the operator. The excessive sintering problem with limestone was not load dependent. This greater tendency to sinter with limestone as compared to dolomite was attributed to the lower magnesium carbonate content in the limestone. The presence of magnesium reduces the fluxing effect that the calcium has on the coal ash particles.

During the winter of 1993/ 1994, the first attempts to operate the unit for extended periods at high unit load with dolomite presented repeatable problems with deteriorating bed conditions. At high bed heights, operation was limited to bed temperatures below approximately 1520 F. At higher temperatures, bed conditions would deteriorate in a manner representative of what was seen when excessive egg sinter formation occurred. However, in these instances the quantity of egg sinters found in the bed drains was not excessive. Since the symptoms were the same, it was generally assumed that excessive egg sinter accumulation in the bed was the cause of the problem, but the sinters somehow did not drain from the bed.

5.1.3 Impact of Finer Size Consist of Dolomite

Testing at the NCB (CURL) PFBC pilot facility in the early 1980s had also revealed egg sinter formation in the bed when feeding Pittsburgh No. 8 coal as a paste and using limestone as the sorbent. The sinter formation problem was resolved at that facility by increasing the superficial fluidization velocity from 3 to 4 ft/ sec.

Since the Tidd fluidization velocity was fixed due to the gas turbine characteristics and bed geometry, the only way to improve the fluidization conditions in the bed was to reduce the size of the bed particles. The bed material at Tidd is made up mostly of spent sorbent, and excepting agglomerations, its size consist closely follows that of the raw sorbent feed. Thus the way to change the bed particle size consist was to change the raw sorbent feed size consist. It was decided early in the fourth year of operation that testing with finer sorbent feed was the first step in attempting to resolve the sintering problem.

The sorbent size consist at Tidd had essentially been constant throughout the first three years of operation with a top size of 6 mesh with approximately 35% of the material below the directly elutriable size of 60 mesh. Pluggage of the sorbent screens along with output capacity problems in the sorbent preparation system precluded the ability to produce a significantly finer sorbent size consist. To overcome this problem, finer size consist sorbent was purchased and delivered by bulk trucks in an already prepared form. Since it was not known how much attrition occurred in the bed, finer sorbent feed presented a concern that such finer bed material might break up too quickly potentially making it difficult to maintain a bed while also running the risk of overloading the cyclone ash removal systems. For this reason, the off-site prepared sorbent was specified with a lower -60 mesh fines concentration than the site prepared material. The first reduced sorbent size consist test was performed in the second quarter of 1994 using National Lime Carey dolomite with a top size of 12 mesh and a -60 mesh concentration of only 13%. Testing with this reduced sorbent size consist revealed dramatic improvements in the bed fluidization conditions. Heat transfer increased, bed temperature variations decreased and the evaporator outlet temperature variations decreased dramatically. In addition, sorbent utilization was noticeably improved. While full bed height testing was not immediately possible due to firing rate limitations imposed by the reduced gas turbine compressor air mass flow capacity in warm weather, these positive results gave strong indication that the finer bed material was the right course of action for minimizing the sintering problem.

Numerous tests were conducted with finer off-site prepared dolomite from both National Lime & Stone Co. as well as the normal Tidd sorbent supply of Greenfield dolomite from Plum Run Stone, Inc. These repeated tests confirmed that finer bed material results in dramatically improved bed fluidization conditions. Testing with even finer sorbent revealed that a bed could be maintained with material as fine as 20 mesh top size.

With the original minus 6 mesh material, bed temperatures above 1540 F were avoided even at reduced bed heights where excessive sintering had not been a recurring problem. This was due mainly to operator concerns that higher bed temperatures would further accentuate the uneven conditions in the bed, thus posing the risk of sintering even at the lower loads. The improved fluidization conditions with the finer sorbent feed material, allowed operation at the full design bed temperature of 1580 F without problem.

Since the finer sorbent made such a notable improvement in bed conditions and since the purchase of off-site prepared sorbent entailed high costs and handling burdens, it was decided to modify the in plant sorbent preparation system to be able to produce finer sorbent material on site. In the early summer of 1994, the system vibratory screen was replaced and other system changes were made (Refer to Section 5.2 for details). With the modified system, the on-site sorbent preparation system operation evolved to where minus 12 mesh material could be produced with sufficient capacity. Interestingly, this on-site prepared minus 12 mesh material had a directly elutriable minus 60 mesh fines content of approximately 48%, which was not that much higher than with the original minus 6 mesh material. This material showed nearly the same bed improvements as the off-site prepared fine materials, and therefore became the normal sorbent size consist for the remainder of the test program at Tidd.

With the return of cold weather in the winter of 1994/1995, increased air mass flow capability of the GT compressor permitted testing at higher bed levels. This testing revealed that the finer sorbent and the correspondingly finer bed permitted full bed temperature (1580 F) operation at full bed height with no sintering problems when using dolomite. Thus the sintering problem was fully resolved with regard to the use of dolomite by using finer size feed material to improve the bed fluidization conditions.

5.1.4 Impact of Using Finer Limestone

Limestone was tested during the third quarter of 1994. To insure the best possible fluidization conditions, it was decided to test an off site prepared material of finer gradation than could be prepared on-site. The limestone selected was minus 18 mesh National Lime Bucyrus magnesian limestone (73% $CaCO_3$/20% $MgCO_3$). An initial 12 hour test with this material revealed no obvious operating difficulties, so a longer 3 day test was planned. The longer test was performed at the full design bed temperature of 1580 F. After approximately 36 hours, The test was aborted by switching back to dolomite due to signs of deteriorating bed conditions. These signs included a gradual increase in temperature variations among bed thermocouples as well as the evaporator outlet leg thermocouples. While not completely successful, this test differed significantly from the previous attempts with -6 mesh magnesian limestone in that the test lasted much longer and normal bed conditions were recovered by switching back to dolomite. It is considered that the improved bed fluidization associated with the finer material feed was mainly responsible for this improved operation with limestone. However, it must also be recognized that the Bucyrus stone had a significantly higher percentage of $MgCO_3$ than the Delaware limestone that was tested in 1992 and 1993, and this factor probably contributed to the improved performance. It is interesting to note that while bed conditions did deteriorate with the -18 mesh limestone, no significant quantities of egg sinters were found in the bed drains.

The final performance test in late March, 1995 was conducted with minus 12 mesh National Lime Delaware limestone as the sorbent. This test was run at a reduced bed temperature of 1500 F. Similar to the -18 mesh test discussed above, it lasted approximately 40 hours before switching back to dolomite due to deteriorating bed conditions. As above, although the bed conditions deteriorated, there were no signs of excessive egg sinter formation in the bed drains. The coal used in this test was different than in the previous limestone tests. The test was run with Consol Mahoning Valley Pittsburgh #8 coal instead of the MM Betsy Pittsburgh #8 coal, which was burned throughout the majority of the Tidd test program. The Consol coal is somewhat lower in sulfur content compared to the M&M coal; however, it had similar ash fusion characteristics.

While not as positive a result as with dolomite, both of the above tests indicate that the use of a finer size gradation is a step in the right direction for resolving the problem of deteriorating bed conditions with limestone. Similar to the high load problem experienced with the relatively coarse -6 mesh dolomite in the winter of 1993/ 1994, the problems experienced with the finer size gradation limestones presented deteriorating bed conditions similar to those seen with excessive sinter formation without the hard evidence of such sinters in the bed drains. One possible conclusion from these collective results is that the excessive egg sinter formation is actually the consequence of deteriorating bed conditions instead of the cause. This would leave open the question as to what is actually going on when the bed conditions deteriorate, and why the problem is worse with limestone as compared to dolomite. While the testing from the Tidd PFBC Demonstration program has not provided a definitive answer to the cause of this phenomenon, the dramatic effects noted with finer size sorbent feed have clearly shown that fluidization is a critical factor in this matter. Density differences between reacted limestone and reacted dolomite may play a role in this phenomenon. Dolomite contains more Magnesium Carbonate which half calcines to Magnesium Oxide in the bed, thus it likely has a lower density making it easier to fluidize. Additionally, different attrition characteristics between limestone and dolomite may be a factor.

5.2 Sorbent Utilization

The primary objective for the fourth year of the Tidd test program was to optimize sorbent utilization by adjusting the critical parameters which have been known to affect sorbent utilization. A total of 48 performance tests were conducted during the fourth year, while 47 performance tests were conducted in the first three years of Tidd operation. Results for all 95 tests are included in the "Test Results Summary" contained in Appendix III. Section 5.2.1 provides background information and a brief description of the experience gained in the first three years of the Tidd test program. Sections 5.2.2 through 5.2.5 provide details and conclusions for testing conducted during the fourth year.

5.2.1 Experience from First Three Years

In the first three years of operation, baseline tests were conducted while operating with MM Pittsburgh #8 coal and Plum Run Greenfield dolomite (6-mesh top particle size) using the original two pneumatic sorbent feed points. Test results were normalized using the Grimethorpe correlation to conditions of 1580 F bed temperature and 90% sulfur retention. Numerous baseline tests were conducted at 115 inches bed level resulting in an average normalized Ca/S ratio of approximately 2.2 which is 30% above the original goal value for that bed level. At 142 inches bed level, two baseline performance tests were conducted resulting in an average normalized Ca/S ratio of 1.74 which is 12% above the original goal value for that bed level. Variations to the baseline; such as tests with sorbent fines in paste, improved sorbent distribution, finer sorbent sizing, and alternate sorbent types; were conducted in order to evaluate the impact on sorbent utilization. Several of these tests did show improvements in sorbent utilization, however, the gains were usually marginal and the original Ca/S goal was never achieved.

Tests were conducted with three Ohio dolomites (Plum Run Greenfield, Plum Run Peebles, and National Lime Carey) in order to rank the sorbent's reactivity. Plum Run Greenfield was found to be the most reactive by approximately 10 to 15%. Three attempts were made at testing the unit with limestone all resulting in unit trips due to unstable bed conditions thought to be due to a deterioration of bed fluidization caused by bed sintering. It is now believed that the bed sintering was a result, not a cause, of the deterioration of fluidization somehow caused by the presence of limestone.

Improvements of 5 to 15% over the baseline test results were achieved by operating with either sorbent fines in the paste, with the four-point sorbent injection system, or with finer sorbent sizes. However, with the exception of a single full-load test conducted with fines in the paste and four sorbent injection points, no other tests were conducted to evaluate the additive effects of each of the variables tested.

During the initial three years, several tests were conducted with sorbent fines in the paste. Some of these tests showed marginal improvements in sorbent utilization, however, the reasons were never fully explained. In these tests the sorbent fines used were ground to minus 325-mesh which is finer than the size of sorbent fines normally produced. Also in several tests, the sorbent fines were from a different dolomite formation than the dry sorbent feed. One test, conducted at full load with four sorbent injection points and sorbent fines in the paste, showed no improvement in sorbent utilization. No accurate conclusion can be drawn from the test with sorbent fines in the paste.

Late in 1993, tests were being conducted to evaluate the impact of sorbent distribution and the number of sorbent feed points. Several tests were conducted with a four-point sorbent distribution system which demonstrated improvements in sorbent utilization of approximately 10% over baseline tests at 115 inches bed level. Improvements were not noted at full bed level and it was postulated that as bed level is increased (and thus residence time is increased), sorbent distribution may have less impact on sulfur capture. Since the four-point sorbent injection system appeared to help (at least at reduced bed levels), it was decided to install a permanent ceramic-lined four-point sorbent injection system which would be the baseline configuration for all tests in the fourth year of operation. Details on the physical piping and testing of the four-point sorbent injection system are contained in the Tidd three year report.

In January 1994, three tests were conducted at 115 inches bed level with a slightly finer sorbent size using two sorbent feed points and MM Pittsburgh #8 coal and PRG dolomite. The finer sorbent testing was expected to improve fluidization which would minimize the potential for egg sinter formation as well as enhance sulfur capture. The potential for improved sorbent utilization was supported by lab tests conducted in 1993 by the University of North Dakota Energy and Environmental Research Center which showed that the larger sorbent particles were not being utilized to the extent of the smaller particles. Although no definitive conclusions were drawn on the reduced potential for sintering, the finer sorbent tests did demonstrate an improvement in sorbent utilization of 12% over baseline test results. During these tests, sorbent size consisted of less than 1% over 8-mesh and approximately 41% less than 60-mesh. Typical baseline sorbent sizes for the first three years were approximately 4 to 8% over #8-mesh and 30 to 35% less than 60-mesh. The improvements made in sorbent utilization appeared to be fairly significant for the slight change in sorbent size. By the end of the three year test program, plans were underway to conduct tests with even finer sorbent with the goal of resolving the sintering problem and the added potential of further improving sorbent utilization.

5.2.2 Finer Sorbent Testing

Based on the results of the finer sorbent tests conducted in January 1994, optimization of sorbent particle size seemed to have the greatest potential for improving sorbent utilization. The finer sorbent was expected to minimize the risks of sinter formation, by improving bed fluidization, as well as improve sorbent utilization.

A significant reduction in bed particle size was required to gain a meaningful increase in fluidization. This could be obtained by reducing the sorbent top particle size. However, attempts to produce a finer sorbent by using a finer mesh size on the vibrating screen in the sorbent preparation system resulted in blinding problems. Hence it was decided to purchase an off-site prepared sorbent with finer top particle size as an initial test to investigate the impact on bed sintering and sorbent utilization. Due to concerns that a finer sorbent would rapidly elutriate, the desired off-site prepared sorbent would require a low concentration of minus 60-mesh fines. National Lime & Stone Company was selected to provide the initial test dolomite due to the availability of a product already being produced. The dolomite was from the Carey geological formation near Carey, Ohio and was being sized to 12-mesh top size with approximately 12% passing 60-mesh. The actual sorbent size tested would vary slightly due to breaking up during transport and handling. This sorbent was designated as National Lime Carey (NLC) 12-mesh designer dolomite.

National Lime Carey Dolomite

Results from the initial three-year test program showed that Carey dolomite was less reactive than Plum Run Greenfield dolomite. Since many changes were made to the unit since the initial tests with Carey dolomite, it was decided to conduct several baseline tests with site-prepared 6-mesh Carey dolomite following the initial 12-mesh designer tests. In May 1994, Tests 53 through 55 were conducted with NLC 12-mesh designer" dolomite while Tests 56 and 57 were conducted with NLC #6-mesh site prepared dolomite. Test results with the designer dolomite showed an improvement of 15 to 25% over the results with the site prepared dolomite. In addition, in-bed heat transfer was dramatically improved due to the increase in bed fluidization and mixing. The improved fluidization also allowed testing for the first time at 1580 F bed temperature without sinter formation. The success of these tests led to additional tests conducted with even finer sorbent. In June 1994 Tests 58 and 59 were conducted with National Lime Carey 20-mesh designer dolomite. The results of these tests were even better than the results obtained with the NLC 12-mesh designer dolomite. An improvement of 30 to 40% over the results with the 6-mesh site-prepared dolomite was noted for these tests. During Test 58, which was conducted at 1580 F bed temperature and 113 inches bed level, a Ca/S ratio adjusted to 90% sulfur retention of 1.45 was achieved. Results comparing the various National Lime Carey sorbent sizes are presented in Figure 5.2.1. Results comparing the Ca/S ratio versus bed height for the various sorbent sizes of National Lime Carey dolomites and MM Pittsburgh #8 coal are presented in Figure 5.2.2.

Figure 5.2.1 - National Lime Carey Dolomite Size Distribution

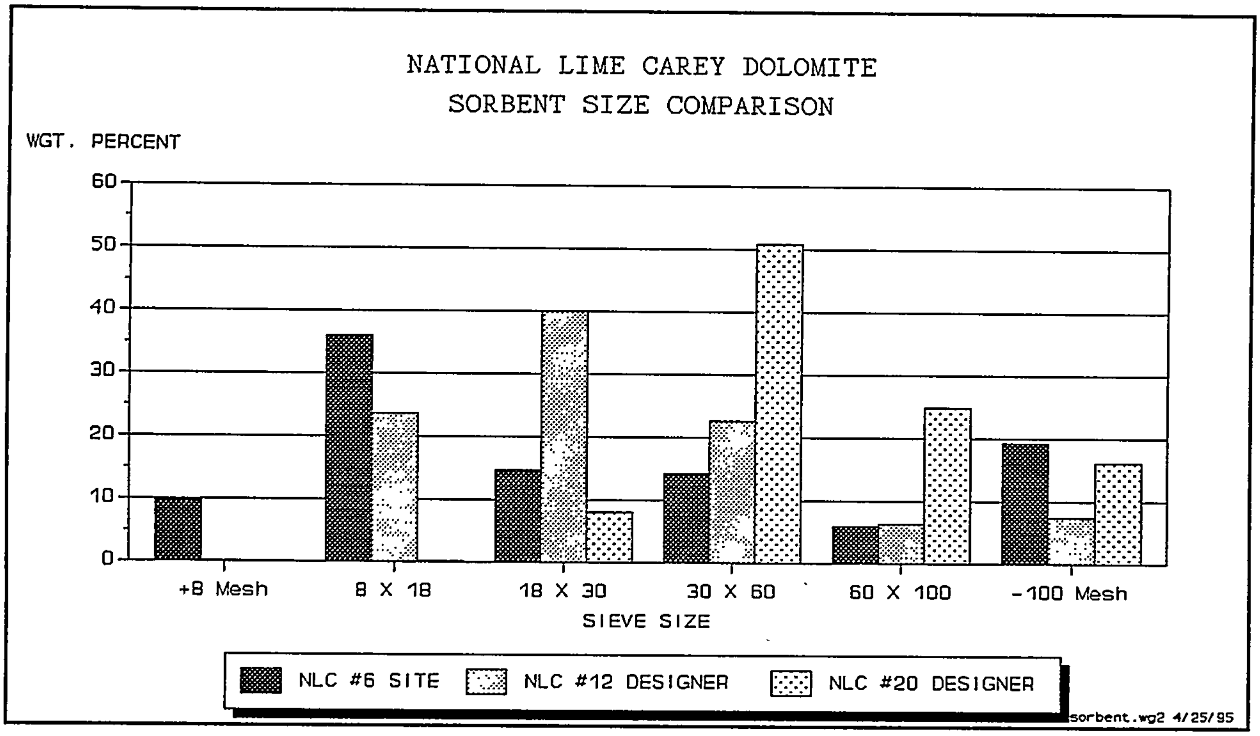
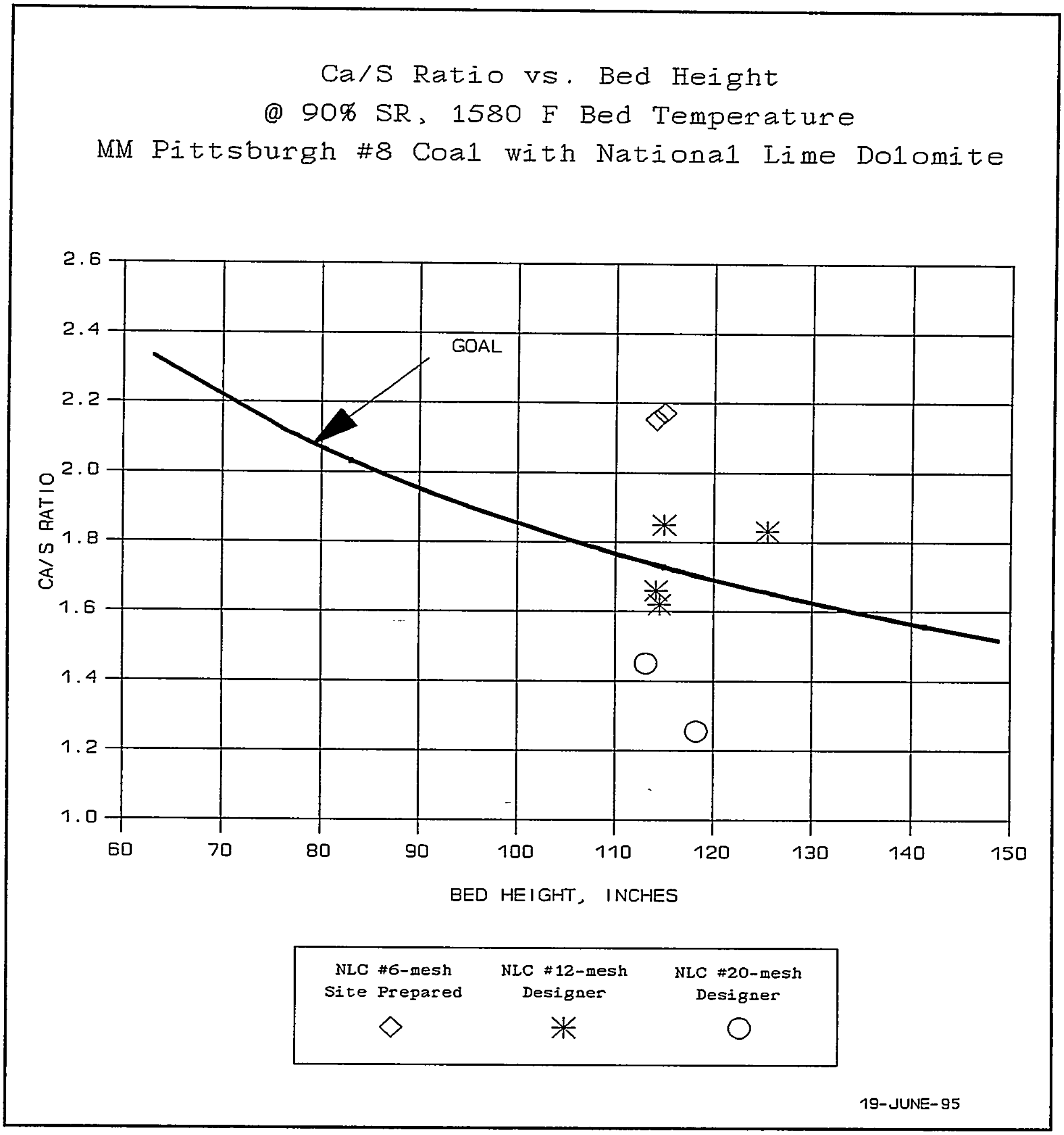


Figure 5.2.2 - Ca/S Molar Ratio Versus Bed Height



Plum Run Greenfield Designer Dolomite

Since Plum Run Greenfield dolomite was known to have a better reactivity than National Lime Carey dolomite, a desire to test a designer grade of PRG dolomite existed. Plum Run Division of Davon Inc. was contacted about producing a product of Greenfield dolomite with the size consistency similar to the National Lime Carey 12-mesh product. Although production and transportation logistics became a critical issue in test planning, Plum Run was able to support our testing. In June 1994 Tests 60 through 62 were conducted with PRG 12-mesh designer dolomite which actually had a sorbent size slightly finer than the NLC 12-mesh product. Later in the test program three additional tests (Nos. 72, 76, and 85) were conducted with the PRG 12-mesh designer dolomite for verification of performance and testing at higher bed levels.

Figure 5.2.3 shows Ca/S ratios for all tests with MM Pittsburgh #8 coal and PRG dolomite. The tests with PRG 12-mesh designer dolomite resulted in the best sorbent utilization obtained at Tidd. At 115 inches bed level an average Ca/S ratio, adjusted to 1580 F bed temperature and 90% sulfur retention, of 1.26 was obtained. However during Test 85, which was conducted in February 1995 at 132 inches bed level and a firing rate of 217 MW_t (the highest firing rate attained at Tidd), an adjusted Ca/S ratio of only 1.44 was achieved. Although sorbent utilization was better than tests with site prepared sorbent at this bed level, it was not as good as was expected for the designer sorbent being tested. One reason for the higher than expected Ca/S ratio may have been the relatively short time in allowing the bed to mature prior to conducting this test. Normally the bed is allowed 36 hours to mature after switching sorbents, however, due to delivery constraints and a limited window of cold weather opportunity to test the unit at full load, the sorbent hit the bed only 18 hours prior to the beginning of the test period. Another factor which may have contributed to the lower than expected sorbent utilization of Test 85 is that the sorbent sizing for this test (as well as for Test 76 which also did not perform as well as the earlier tests) was slightly more coarse than for the first three tests using PRG 12-mesh designer dolomite. The sorbent surface mean diameter (SMD) for Tests 76 and 85 was 417 microns while the average SMD for the first three tests using PRG 12 designer dolomite was 360 microns. Figure 5.2.4 shows the variation in sorbent sizing between the six tests conducted with PRG 12 designer dolomite.

Figure 5.2.3 - Ca/S Ratio Versus Bed Height

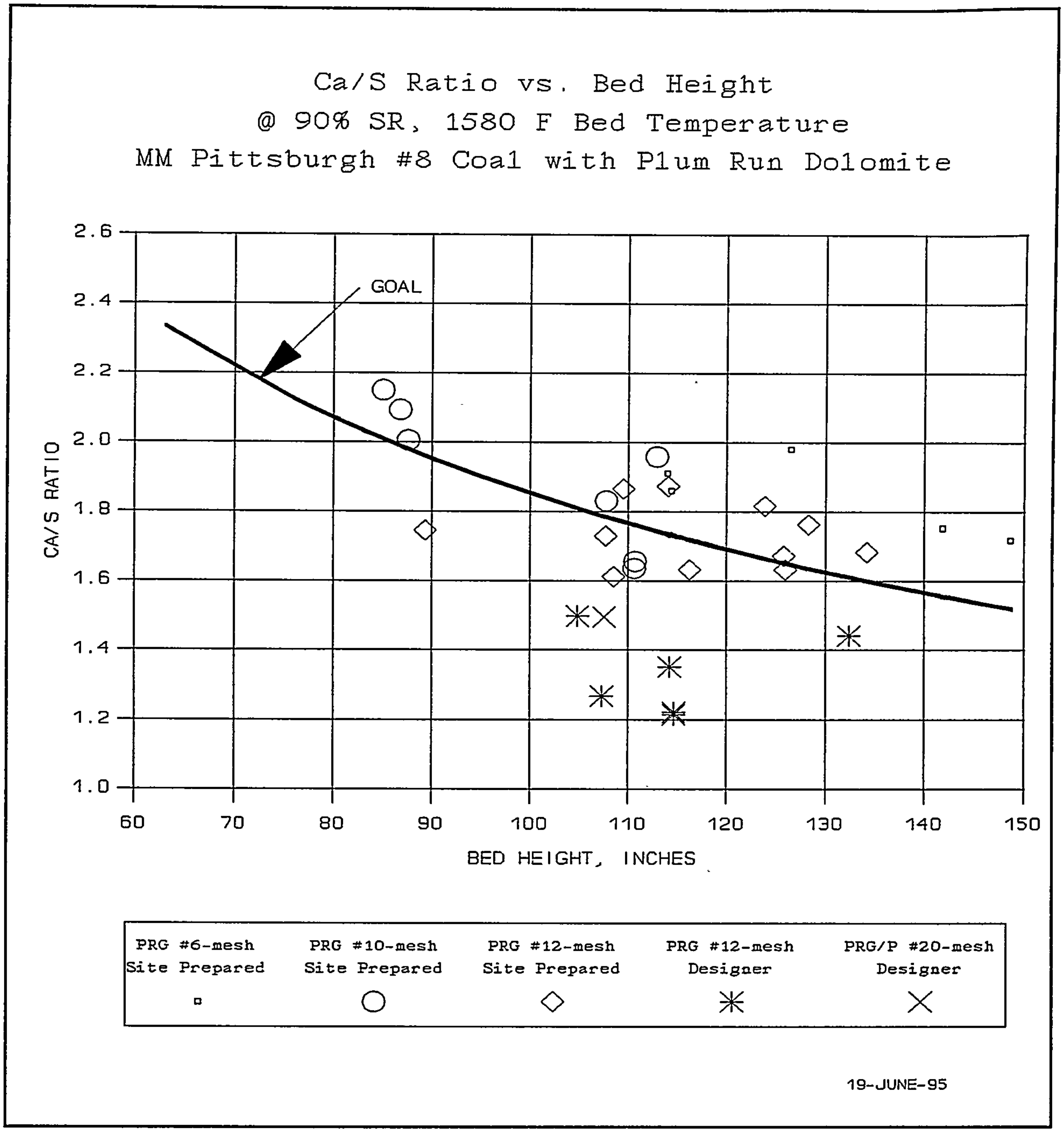
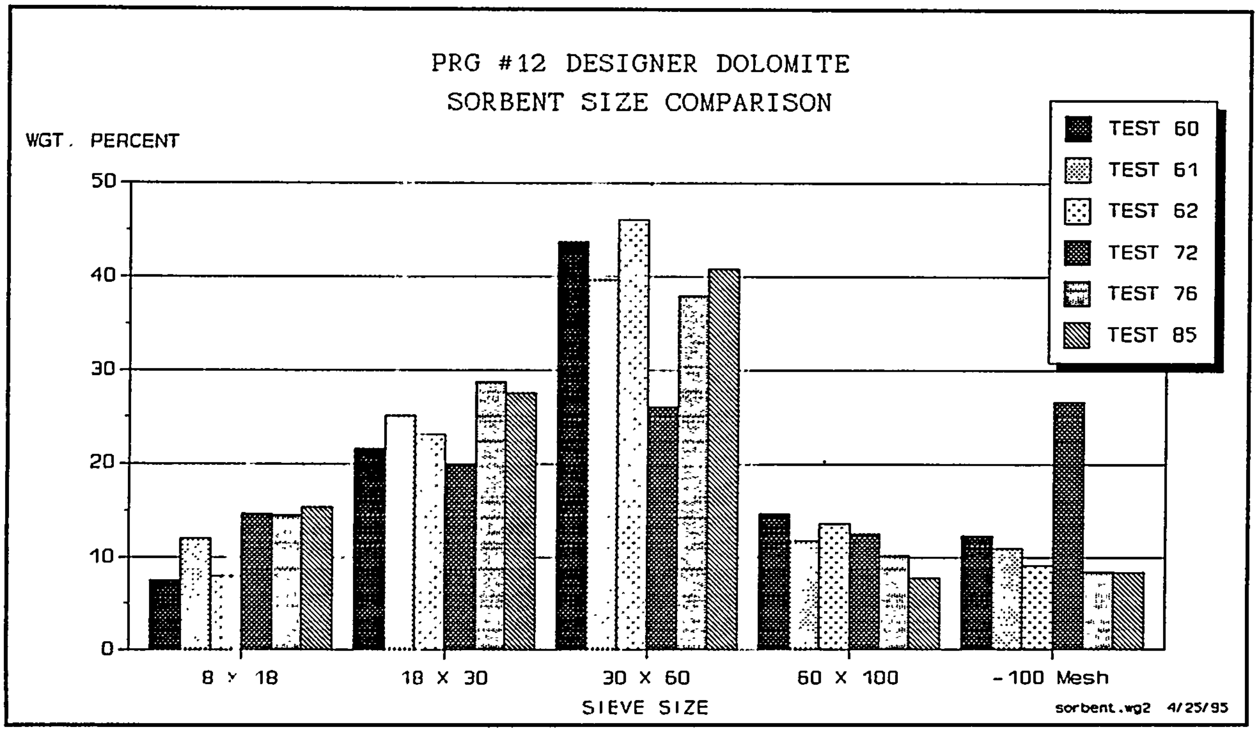


Figure 5.2.4 - Plum Run Greenfield Dolomite Size Distribution

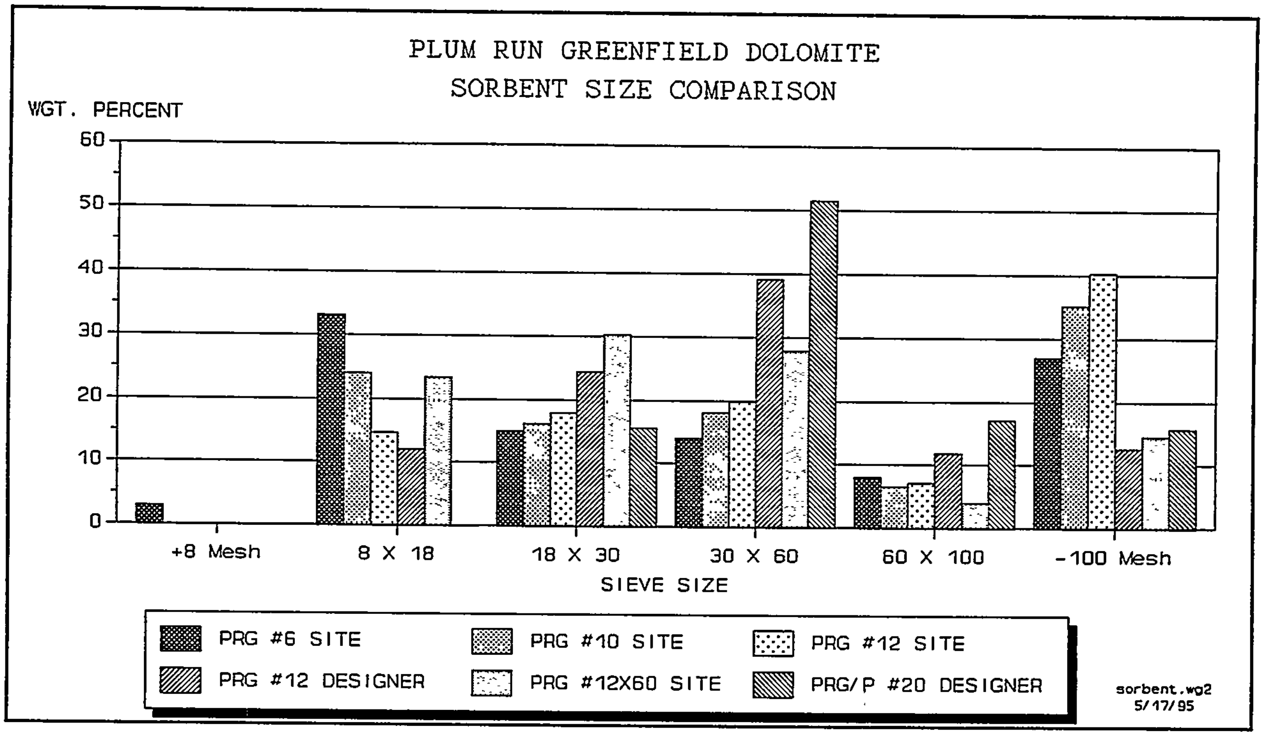


Plum Run Greenfield Site Prepared Dolomite

After successfully demonstrating improvements in sorbent utilization by operating with finer designer sorbents during May and June 1994, it was decided to improve the site sorbent preparation system so that finer sorbent could be prepared on site. A larger capacity vibrating screen was purchased to allow the required sorbent throughput for full load operation using 10 and 12-mesh screens. The screen was a double deck screen operating in parallel with all oversized material being recirculated to the sorbent crusher/dryer. In July and August 1994 a series of tests was conducted with PRG 10 and 12-mesh dolomites using MM Pittsburgh #8 coal. From this point until the end of the test program, the PRG 12-mesh dolomite was the standard sorbent being used at Tidd. Performance results were as expected. Although sorbent utilization was not as good as with the designer sorbents, the normalized Ca/S ratios were approximately 10% better than results obtained with the PRG 6-mesh site prepared sorbent. Little change in sorbent utilization was noted between the 10 and 12-mesh site prepared sorbents.

The difference in results obtained between the 12-mesh "site prepared" and designer dolomites can be explained by the difference in the sorbent size distribution. Although both of these sorbents have a top size of 12 mesh, the designer product has a narrower size distribution (63% of the product is between 18 and 60-mesh) and fewer fines (25% is less than 60-mesh). The "site prepared" product has 38% between 18 and 60-mesh, and 48% is less than 60-mesh. Figure 5.2.5 shows the sorbent size distributions for the various sizes of Plum Run Greenfield dolomites tested.

Figure 5.2.5 - Plum Run Greenfield Dolomite Size Comparison



The optimum sorbent particle size is believed to be those particles just over the elutriable size, i.e. just over 60-mesh. The resulting smaller bed ash particles have a larger relative surface area required for enhanced reaction with the combustion gases and since they are over the elutriable size they have longer in-bed residence times than the smaller particles. This theory is supported by evaluation of the degree of sulfation for the bed ash and cyclone ash for the various tests. The finer bed ash exhibits a greater degree of sulfation (moles of SO_3 per mole of CaO) than the more coarse bed ash while cyclone ash typically has a much lower degree of sulfation. In order to investigate this theory in more detail, a fractional analysis was performed on selected bed ash and cyclone ash samples and the degree of sulfation was determined for each of the different size fractions. The results of this fractional analysis for samples collected during Test 82 (while operating with MM Pittsburgh #8 coal and PRG 12-mesh site prepared dolomite) are presented in Table 5.2.1. As can be seen from these results, the most highly sulfated bed ash particles are those in the ranges between 20 and 60-mesh. The cyclone ash appears to be more highly sulfated in the size ranges of plus 100-mesh and minus 500-mesh, while the size ranges between 100 and 500-mesh are poorly utilized. This can be explained by theorizing that the larger cyclone ash particles remain in the bed for a longer period of time and are more highly reacted, while the finer cyclone ash particles have a very large surface to mass ratio and thus are also highly reacted. The mid-size range of cyclone ash particles do not have the long residence times or large surface areas for optimum performance.

Table 5.2.1 - Bed Ash and Cyclone Ash Fractional Analysis

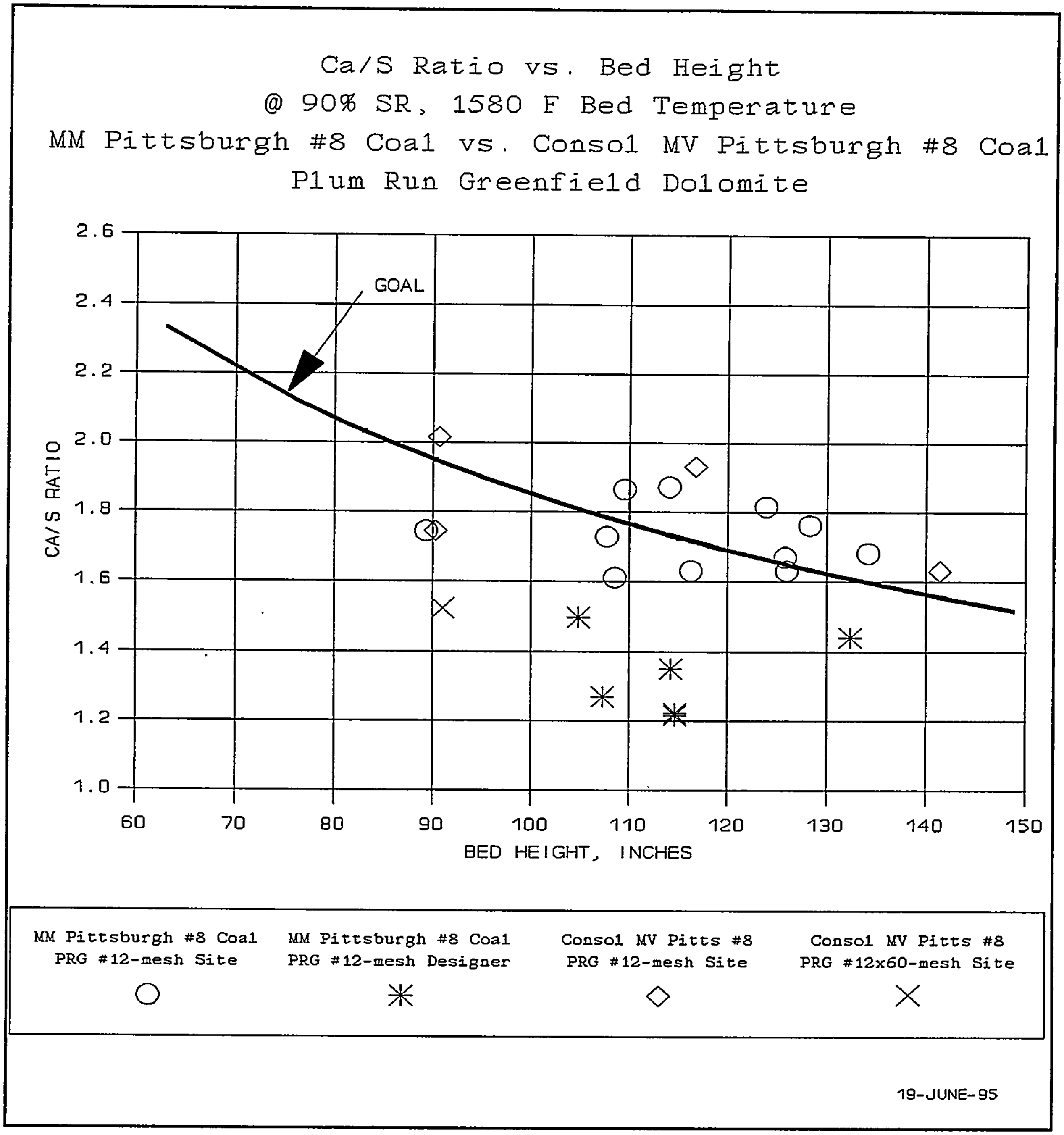
Bed Ash and Cyclone Ash Fractional Analysis				
Bed Ash Sample (No. 15138A) Collected 12/21/94 1000-1200 hrs.				
Size Fraction	Percent by Weight	Percent CaO (D/B)	Percent SO_3 (D/B)	Percent Sulfation
Plus 10-mesh	0.87	19.34	9.02	32.7
10x16-mesh	16.17	12.90	8.86	48.1
16x20-mesh	31.93	32.59	26.13	56.2
20x30-mesh	25.84	32.12	28.77	62.7
30x60-mesh	25.06	32.26	28.28	61.4
Minus 60-mesh	0.13	31.46	24.34	54.2
Total Bed Ash	100.00	29.09	24.41	58.8
Cyclone Ash Sample (No. 6572A) Collected 12/21/94 0600-0800 hrs.				
Plus 100-mesh	9.93	28.66	15.42	37.7
100x150-mesh	3.46	23.57	9.49	28.2
150x200-mesh	4.79	23.67	7.90	23.4
200x325-mesh	10.11	24.43	6.90	19.8
325x500-mesh	1.66	24.82	6.83	19.3
Minus 500-mesh	70.05	22.14	11.48	36.3
Total Cyclone Ash	100.00	23.19	11.09	33.5

Due to production limitations at the quarry, no tests were conducted using PRG 20-mesh designer dolomite, however Test 77 was conducted with a blend of Plum Run Greenfield and Peebles dolomites with a sorbent size slightly more coarse than the NLC 20-mesh designer dolomite. The sorbent used for this test is designated PRG/P 20-mesh designer dolomite. This test was conducted at 107 inches bed level and 1580 F bed temperature while burning MM Pittsburgh #8 coal. A Ca/S ratio adjusted to 90% sulfur retention of 1.50 was obtained for this test which is not as good as the PRG 12 designer tests. The lower reactivity of the Pebbles stone is the most likely reason that performance was not as good as the PRG 12 designer tests. It should also be noted that the 20-mesh designer sorbent sizes were the finest that the unit could acceptably operate with. The smaller bed ash particle sizes resulting from these sorbents caused problems with overheating of the bed ash lockhoppers and sparge ducts due to bed ash rat holing causing uneven cooling as the bed material was removed.

Scalping/Dedusting Test

On March 23, 1995 Test 94 was completed using Consol Mahoning Valley Pittsburgh #8 coal and Plum Run Greenfield dolomite while the sorbent preparation system was operating in the scalping/dedusting mode. In this mode of operation the sorbent fines (less than 60-mesh) are separated from the process and discarded. The sorbent being tested was 12x60 mesh (although approximately 18% of the product is less than 60-mesh). Due to the reduced capacity of the sorbent preparation system in this mode, the test was conducted at 90 inches bed level. A Ca/S ratio (adjusted to 90% sulfur retention and 1580 F bed temperature) of 1.54 was achieved during this test, this is an improvement of approximately 20% compared to the results obtained with the 12-mesh site prepared dolomite at the same bed level and using the same coal (see Figure 5.2.6). These results, when normalized to an equivalent bed level, represent sorbent utilization performance levels within the range of the tests with PRG 12-mesh designer dolomite and MM Pittsburgh #8 coal. This test supports the theory that optimum sorbent utilization occurs with sorbent size consists just over the directly elutriable size of 60-mesh. The cyclone ash/bed ash split for this test was 65%/35% compared to a typical ash split of 75/25 for the 12-mesh site prepared sorbent and 55/45 for the 12-mesh designer sorbent. The sorbent particle sizing for this test (designated PRG 12x60-mesh site) is shown in Figure 5.2.5 while the performance results are plotted in Figure 5.2.6.

Figure 5.2.6 - Ca/S Versus Bed Height



5.2.3 Tests with Alternate Sorbents and Coals

During the fourth year of operation three dolomites (Plum Run Greenfield, National Lime Carey, and Mulzer Laurel), two limestones (National Lime Bucyrus and Delaware), and three coals (MM Pittsburgh #8, Minnehaha, and Consol Mahoning Valley Pittsburgh #8) were tested. Typical coal and sorbent analyses are presented in Tables 4.2.1 and 4.2.2. This section details the testing with alternate dolomites and coals while Section 5.2.4 details the limestone tests.

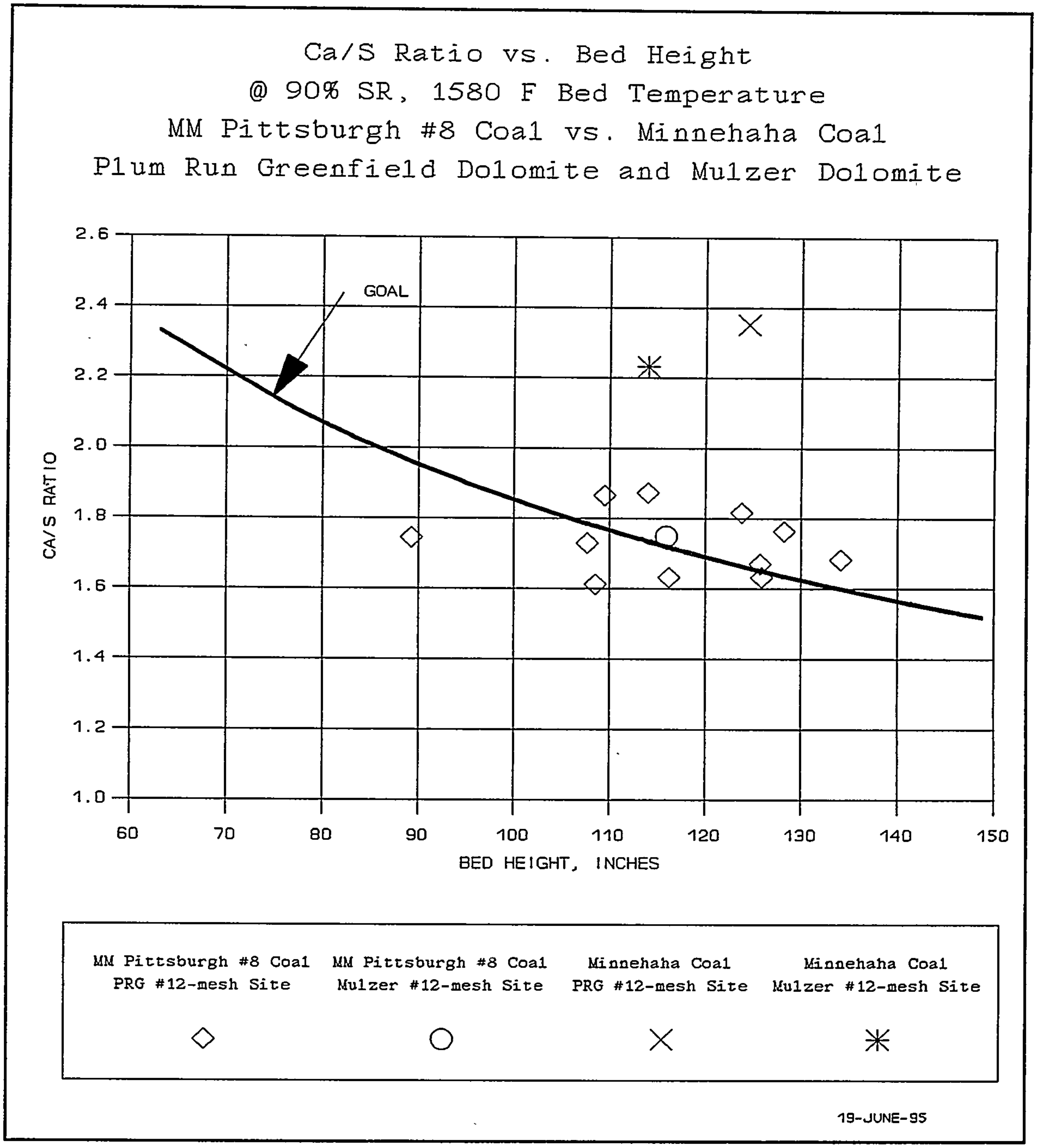
The dolomites used most predominantly during the fourth year of operation were Plum Run Greenfield and National Lime Carey. The normalized Ca/S ratio versus bed height for all tests with these dolomites while burning Pittsburgh #8 coal are shown on Figures 5.2.2 and 5.2.3. Sorbent sizes for these tests are shown on Figures 5.2.1 and 5.2.5. Although there are variations in sizing between the two sorbents, it appears that the Plum Run Greenfield is more reactive than the National Lime Carey dolomite. At 115 inches bed level, test results for PRG 6-mesh site prepared dolomite indicate sorbent utilization 15% better than for NLC 6-mesh site prepared dolomite. (However, note that the NLC is slightly more coarse than the PRG.) This is consistent with the findings for the first three years of Tidd operation.

Test 87 was conducted in February 1995 with MM Pittsburgh #8 coal and Mulzer 12-mesh site prepared dolomite at 116 inches bed level. A Ca/S ratio, adjusted to 90% sulfur retention and 1580 F bed temperature, of 1.75 was achieved. This is within the range of results obtained with MM Pittsburgh #8 coal and PRG 12-mesh site prepared dolomite at the same bed level indicating that both sorbents have similar reactivities.

In February 1995, Tests 88 and 89 were also conducted with Minnehaha coal which has approximately half the sulfur content of MM Pittsburgh #8 coal. Mulzer 12-mesh site prepared dolomite was used for Test 88 and PRG 12-mesh site prepared dolomite was used for Test 89. The Ca/S ratios calculated for these tests are 25 to 35% higher than with MM Pittsburgh #8 coal. The decline in sorbent utilization is likely due to the lower sulfur content of Minnehaha coal (The Ca/S normally increases with lower coal sulfur contents). It should also be mentioned that a much higher content of water was required to produce an acceptable coal water paste. The Minnehaha coal required 35% to 40% water content in the paste where typically 25% to 28% water content is used.

The results for Tests 87 through 89 along with results for tests with MM Pittsburgh #8 coal and PRG 12-mesh site prepared dolomite are presented in Figure 5.2.7.

Figure 5.2.7 - Ca/S Ratio Versus Bed Height



Early in March 1995 coal was switched to Consol Mahoning Valley Pittsburgh #8 coal for the remainder of the test program. Tests 90 through 93 were conducted using Plum Run Greenfield 12-mesh site prepared dolomite at various bed levels in order to develop a new baseline curve with the Consol coal. Although the sulfur content of the Consol coal is approximately 30% lower than that of the MM coal, the Ca/S ratios obtained during the Consol coal tests are closely in line with those of the MM Pittsburgh #8 coal tests. Test 90 was conducted at full bed level (141 inches) and 1560 F bed temperature; a Ca/S ratio, adjusted to 90% sulfur retention and 1580 F bed temperature, of 1.63 was achieved. Although at a slightly reduced bed temperature, this is the only full bed level test completed using a finer dolomite. Results for tests with Consol coal and PRG dolomite, including the scalping/dedusting test mentioned in the preceding section, are shown in Figure 5.2.6 along with the results for comparable tests with MM Pittsburgh #8 coal.

5.2.4 Limestone Testing

Two limestone tests were conducted during the fourth year. In October 1994 a test was conducted using National Lime Bucyrus 18-mesh designer limestone with MM Pittsburgh #8 coal at 117 inches bed level and 1580 F bed temperature. The limestone size consist was (on a mass basis) approximately 3% over 18-mesh, 64% between 18 and 30-mesh, and 33% less than 60-mesh. Typical analysis of this limestone is contained in Table 4.2.2. The unit was operated on this limestone for approximately 36 hours during which time the bed showed signs of gradual deterioration exhibited by the gradual decline of bed density and heat transfer as bed and evaporator temperature distributions became less uniform. A small amount of sinters, as is sometimes generated under normal operating conditions, was noted in the bed ash drains. The test was ended prematurely by switching back to dolomite. Sorbent utilization was good; the Ca/S ratio, adjusted to 90% sulfur retention and 1580 F bed temperature was 1.92 at 117 inches bed level. On a mass basis this is equivalent to the results obtained with the PRG 12-mesh designer dolomite. Although unable to demonstrate an extended period of stable operation, this test was far more successful compared to the three previous attempts of 1992-1993 (when operation with limestone resulted in unit trips). It is believed that the improved performance with limestone is a result of the finer more uniformly sized particles, resulting in a better fluidized bed, and the slightly higher magnesium content of the Bucyrus limestone compared to the Delaware limestone. It is also believed that the good sorbent utilization is a result of the finer sorbent particle size.

The final test of the program was also conducted with limestone. On March 28, 1995, Test 95 was completed while operating with National Lime Delaware #12-mesh site prepared limestone and Consol coal, which has similar ash fusion characteristics as the MM Pittsburgh #8 coal. Typical limestone and coal analyses are presented in Tables 4.2.1 and 4.2.2. This test was conducted at 118 inches bed level and a reduced bed temperature of 1500 F. The unit was operated for approximately 40 hours on limestone during which time the bed showed signs of deterioration similar to the limestone test of October 1994. However, there were no signs of excessive egg sinter formation in the bed drains. At the conclusion of this test, sorbent was switched back to PRG dolomite in order to stabilize bed conditions. A Ca/S ratio, adjusted to 1580F bed temperature and 90% sulfur retention, of 2.62 was achieved for this test. On a mass basis this is slightly better than the results obtained with the PRG 12-mesh site prepared dolomite which is within the range of what was expected for this size consist of limestone. The operating experiences gained from this test are similar to the experiences gained from the limestone testing of October 1994. The difference in the last two limestone tests from the earlier attempts of 1992-1993 (which resulted in unit shutdowns due to bed deterioration) is that the more recent tests used a finer size grade of limestone. The fact that excessive egg sinters were not observed during these latest two tests would suggest that the presence of limestone somehow causes a deterioration of bed fluidization which leads to conditions favorable for sinter formation as opposed to our previous belief that limestone operation causes egg sinter formation which leads to deterioration of the bed. Although testing at the Tidd Plant has not provided a clear understanding of the phenomenon that is taking place in the bed while operating with limestone, it does appear that fluidization of the bed is adversely affected by the presence of limestone. Additional details relating to the operation experiences with limestone are presented in Section 5.1.

5.2.5 Conclusion and Summary

The primary objective for the fourth year of the Tidd test program was to optimize sorbent utilization. The largest improvements in sorbent utilization were achieved by optimizing sorbent particle size. Early tests in the fourth year of operation have also confirmed improved sorbent utilization by operating with four sorbent distribution points. Other variables investigated in the fourth year of operation included testing with various coals and sorbents, including limestone.

The early tests in the fourth year of operation with 6-mesh site prepared sorbent and four sorbent distribution points represent improvements in sorbent utilization of approximately 12 to 15% at 115 inches bed level over early baseline tests with two sorbent distribution points. No definite improvements were noted at full bed level by operating with the four sorbent distribution points. These conclusions are consistent with the findings of the first three years.

Of the coals tested, the MM Pittsburgh #8 and Consol Mahoning Valley Pittsburgh #8 coals both demonstrated superior sorbent utilization over the Minnehaha coal. The Ca/S ratios calculated for the Minnehaha tests were 25 to 35% higher than the Pittsburgh #8 tests. The difference in performance may be due in part to the lower sulfur content of the Minnehaha coal (50% less than the MM

Pittsburgh #8 coal). However, the Consol coal also had a lower sulfur content (35% less) than the MM Pittsburgh #8 coal and no definite change in sorbent utilization was noticed.

Of the dolomites tested the Plum Run Greenfield appears to be more reactive by 10 to 15% over the National Lime Carey dolomite. This is consistent with observations made during the initial three years of operation. The Mulzer Laurel dolomite appears to be equally reactive as the Plum Run Greenfield dolomite.

During operation with limestone, sorbent utilization was found to be roughly equal on a mass basis, as operation with dolomite for a given sorbent particle size. However, results from these tests are not conclusive since, in both cases, operation with limestone resulted in a gradual deterioration of bed conditions. It is believed that the use of limestone somehow causes a deterioration of bed fluidization which is responsible for the noted deterioration in bed and evaporator temperature distributions and heat transfer. Additional investigation of how limestone impacts the bed is recommended.

The variable with the most significant impact on sorbent utilization investigated was sorbent size. During the fourth year of operation, series of tests were conducted with finer sorbent sizes including designer sizes having a narrow size consist range and containing few fines. The best performance results were obtained with the Plum Run Greenfield 12-mesh designer dolomite where an average Ca/S ratio, adjusted to 90% sulfur retention and 1580 F bed temperature, of 1.26 was obtained at 115 inches bed level. Based on these results, a Ca/S ratio of 1.14 is predicted at 142 inches bed level using the Grimethorpe correlation.

The significant improvements noted with the designer sorbents is thought to be due to the following factors: The smaller sorbent particles in the bed provides a greater relative surface area resulting in improved utilization of the sorbent. In addition, the finer sorbent results in finer bed particle sizes and improved fluidization which results in greater mixing and reaction with the combustion gases. Finally, the reduced fines fraction of the designer sorbents results in a lower percentage of cyclone ash which is known to have poor sulfation rates due to the very short residence time in contact with the combustion gases.

It is believed that the optimum sorbent particle sizes are those particles just over the directly elutriable size (i.e., just over #60-mesh), however, adequate margin must be provided to allow for particle attrition and acceptable flow characteristics of the bed ash. This theory is supported by the fractional analyses conducted on the bed ash and cyclone ash (see Table 5.2.1) showing that the particles in the size range of 20x60-mesh are the most highly sulfated, as well as by the results of the designer sorbent and scalping/dedusting tests. Sorbent fines are undesirable due to their very short residence times in contact with the combustion gases resulting in a poor degree of sulfation. This theory is supported by the fact that the cyclone ash tends to have a relatively low sulfation rate.

Since the optimum sorbent size appears to be comprised of a relatively narrow size range of particles, the designer of a commercial PFBC plant may be challenged to produce this size range economically. The option to purchase a designer sorbent size from a supplier of dolomite under a long term contract may be considered, however, other options may be more economical. Separation of the sorbent fines on site for other uses or outside sale, or designing a sorbent preparation system for minimal production of fines should be considered. Finally, the marketability of PFBC ashes, and predicted ash production rates must also be considered when determining the method of sorbent preparation.

5.3 In-Bed Heat Transfer

5.3.1 Background

Steam generator tubes submerged in a fluidized bed attain high rates of heat transfer due to intimate moving contact of the hot bed particles with the tubes. The particle-convective heat transfer coefficient in a well fluidized bed is on the order of three to four times that of a typical gas film coefficient in the convection pass of a conventional steam generator. This factor reduces the amount of tubing required for a given level of heat absorption. In a pressurized fluidized bed (PFB), the pressure drop through the bed is a small percentage of the operating pressure, thus the compressor delivering the air can easily tolerate the increased pressure drop associated with deep beds. In bubbling PFB units, this factor along with the desire to maximize the gas temperature to the gas turbine results in most of the steam generator surface being placed within the bed in a relatively compact tube bundle.

The degree of fluidization in the bed has a significant impact on the rate of heat transfer. At a fixed superficial fluidization velocity, the heat transfer rate varies as an inverse function of the bed particle surface mean diameter. Similarly, for a fixed mean bed particle size, the heat transfer rate varies as a direct function of the superficial fluidization velocity.

In a PFB unit the boiler bed plan area and the gas turbine volumetric flow characteristics define the superficial fluidizing velocity in the bed. This velocity was established at 3 ft/sec for the Tidd Demonstration Project. Once the design was executed the superficial velocity was fixed by the system physical constraints.

The physical make-up of a PFBC bed is a function of both the coal and sorbent feedstocks. Given the relatively high sulfur and low ash content of the design coal and the associated high design sorbent feed rate required to achieve design sulfur capture, the Tidd bed consists mostly of spent sorbent. Thus the bed particle size is directly influenced by the size of the sorbent feed. This influence on bed particle size has a direct impact on in bed heat transfer. This relationship between sorbent particle size gradation and bed fluidization presents a unique challenge to design of both the in bed tube bundle and the sorbent preparation system. The more obvious relationship of sorbent utilization versus sorbent particle size and size gradation exacerbates the challenge. Additional challenges to in-bed heat transfer are presented by reaction of the sorbent in the bed. Attrition and agglomeration contribute significantly to the size consist of the bed, thereby affecting both heat transfer and environmental performance.

Considering all of the above factors, ABB specified a prepared dolomite feed size band between minus 8 mesh with 3% minus 60 mesh and minus 18 mesh with 25% minus 60 mesh. The sorbent preparation system as designed had a predicted curve that fit within this band with a top size of 8 mesh and approximately 20% passing 60 mesh.

The in-bed boiler tube surface for the Tidd unit was sized by Babcock and Wilcox Co. (B&W) based upon the above noted sorbent preparation system predicted curve. That curve correlated to a surface mean particle size of approximately 800 microns after excluding the -60 mesh fines. Allowing for potential attrition or agglomeration, B&W assumed that the bed mean particle size would fall in the range between 750 and 1000 microns. Feeling that attrition would dominate over agglomeration, they used the finer size of this range in setting the initial surface requirements for the boiler. Recognizing that the heat transfer might be less than anticipated if agglomeration occurred or the sorbent preparation system produced coarser material, they arranged the original surface so that it did not fill to the top of the approximately 12 ft. high bed zone region of the boiler enclosure. The top of this original tube surface was at a bed height of approximately 10 ft, allowing for the addition of surface at the top of the original bundle.

5.3.2 Experience During the First Three Years of Operation

Operation in early 1991 revealed that the tube bundle as originally designed achieved approximately 75% of the design heat absorption at full bed height (126 inches design, although full heat absorption leveled off at approximately 116 inches) and design bed temperature (1580 F). Factors that were identified as contributing to this shortfall were as follows:

- Reduced fluidizing velocity in the bed due to excessive air bypassing the bed due to higher than design air leakage in the gas turbine intercept valve and excessive gas turbine seal air flow.

▸ Coarser bed material due to the increased top size of the prepared sorbent. The size of the screen in the sorbent preparation system sizer had been changed from 8 mesh to 6 mesh in order to help resolve capacity and reliability problems associated with that system.

▸ Less attrition and more agglomeration in the bed than had been originally anticipated.

During the fall of 1991,"in-bed" surface modifications were made with the intent to achieve the full design in-bed heat absorption at a reduced bed temperature of 1540 F. (The reduced bed temperature was specified due to ongoing problems with post-bed combustion.) The modifications made included the removal of some of the shielding on the existing bundle and the addition of surface at the top of the original bundle. The top of the revised bundle was now at a bed height of just under 12 ft.

While significant increases in "in-bed" heat absorption had been achieved, the revised tube bundle still had a heat absorption shortfall of approximately 7% when fully submerged at the revised design bed temperature of 1540 F. This apparent shortfall of in-bed heat transfer surface remained at the end of the original 3 year test program. Factors suspected as contributing to the remaining shortfall included tube bundle fouling due to sintering, larger than expected bed particle sizes, continued excessive air bypass around the bed and zones of reduced fluidization along the side walls of the boiler.

5.3.3 Improved Heat Absorption with Finer Sorbent

The chronic problem of deteriorating bed conditions at high bed height experienced in late 1993 (refer to Section 5.1, Bed Sintering) led to experiments in improving the bed fluidization conditions through the use of finer sorbent feed. Due to limitations of the on-site sorbent preparation system, the initial tests with finer sorbent feed were conducted with off-site prepared sorbent. This testing, which began early in the fourth year of operation, revealed that finer sorbent feed resulted in greatly improved heat transfer to the tube bundle. Compared to a site prepared -6 mesh National Lime dolomite, the use of off-site prepared -12 mesh and -20 mesh National Lime dolomite resulted in tube bundle heat absorption improvements of approximately 7% and 14%, respectively (at a bed height of 115 inches). The corresponding surface mean diameters of the bed ash drain samples for these tests ranged from 1100-1200 microns with the -6 mesh sorbent feed, 750-850 microns with the -12 mesh material and 500-600 microns with the -20 mesh material. Subsequent modifications of the sorbent preparation system led to the ability to produce -12 mesh sorbent on-site. Compared to the -6 mesh site prepared Plum Run Greenfield dolomite, the finer -12 mesh material resulted in heat absorption improvement of approximately 8% at 115 inches bed height and 11% at full bed height. The corresponding surface mean diameters of the bed ash drain samples for these tests ranged from 900 to 1200 microns for the -6 mesh sorbent feed and 700-800 microns for the -12 mesh site prepared material.

Significant Findings

Full bed height testing in February 1995 with the -12 mesh site prepared Plum Run Greenfield dolomite produced an in-bed tube bundle absorption value 5.5% greater than the original design value. This was accomplished at a mean bed temperature of 1577 F. This is close to the original design bed temperature of 1580 F, but above the revised design number of 1540 F specified when the tube bundle surface modification was incorporated in the fall of 1991. Had the test been run at the lower 1540 F bed temperature, the in-bed absorption would have been a lower value very close to the original expected in-bed absorption.

6.0 System Summaries

General system descriptions addressing the function and make-up of all systems discussed below have been previously presented in "The Tidd PFBC Demonstration Plant Project Report - First Three Years of Operation: Initial Start-up Through February 28, 1994." Therefore, these will not be repeated here. System modifications, operating experience overview, and summary and conclusions are updated to reflect the findings of the fourth year of operation.

6.1 Combustor Vessel

6.1.1 System Modifications

The pressure vessel has performed as intended without any significant modifications. However, additional penetrations were installed to address both additional instrumentation and process needs. The process needs were associated with providing air to the cyclone ash removal system, and separating the secondary cyclone ash removal system.

A belly drain was installed in the lower portion of the pressure vessel to provide the ability to confirm a water leak inside the pressure vessel. A level alarm was also installed in the dip leg of the belly drain to indicate the accumulation of water at that location.

6.1.2 Operating Experience Overview

The pressure vessel operating experience has been good, with no problems reported. A non-destructive examination of the large bed preheater and air/gas penetration welds during the spring 1993 revealed no cracks in these critical regions.

6.1.3 Final Inspection

Final inspection of the pressure vessel revealed no abnormal conditions.

6.1.4 Summary and Conclusions

The Tidd Pressure Vessel has performed without any significant problems. The shop fabrication, testing and shipment of the pressure vessel successfully demonstrated the viability of modularization of this component. Maintenance and clean-up inside the vessel was found to be time consuming. The installation of adequate lagging to encase all insulation and the addition of a vacuum header system, a compressed air header, and permanent lighting would expedite maintenance and reduce down-time.

6.2 Boiler

6.2.1 System Modifications

Sparge Ducts

The air-distribution sparge ducts deformed very early in unit operation due to uneven thermal growth between the duct tops and bottoms during bed preheating. This caused the ducts to bow in a concave manner when viewed from the side, which allowed ash to accumulate under the ducts and prevented them from returning to their original positions after preheating. The net effect was a racheting up of the duct ends over successive start ups. Restraints were added at the ends of the ducts to limit this upward movement, and knife-edged skirts were added along the duct bottoms to prevent ash build up under the ducts. Neither of these measures was successful in resolving the problem.

During the first quarter of 1991, a number of the sparge nozzles were extended down into the ducts to draw air/gas from the bottom of the ducts, thereby minimizing the differential temperature between duct tops and bottoms. However, degradation of the sparge ducts continued despite this modification.

By the fall of 1991, this convex bowing of the sparge ducts had resulted in excessive distortion and cracking of bellows-type expansion joints located near the center of the boiler. The bellows expansion joints were replaced with machined slip joints to accommodate both axial and angular movements.

Throughout 1992, the majority of the sparge ducts gradually began to sag downward over their spans from the middle of the boiler to the side walls. This sagging was believed to be caused by end forces imposed by ash packed at the end of the ducts as they expanded during bed preheating. The sparge-duct arms were completely replaced in Spring 1993. The new duct arms employed the same inward extended nozzles noted above; however, the end tie down system was revised. The previously modified slip joints were reused. In order to address the compressive end forces during bed preheating, the duct-end fluidization system was changed from a passive system that apportioned part of the duct air to the end regions at all times to an active system that used higher-pressure air (from the sorbent air receiver) to provide a blast to clean the ends of the ducts periodically during bed preheating.

From mid 1993 through mid 1994 the new ducts experienced some 20 unit start ups with essentially no distortion occurring. However, after testing extremely fine sorbent feed in June 1994, a number of the ducts were found to be significantly bowed toward adjacent ducts near the boiler side walls. The extremely fine bed material had resulted in bed drain flow control and cooling problems. Additional distortion occurred on subsequent runs as more tests with fine sorbent were conducted. This thermal deformation was most likely due to localized hot spots caused by "rat holing" of the fine bed material. Local rat holing would result in hot ash coming into contact with the sides of the duct in a very local area, thus heating that area, while the rest of the duct remained relatively cool. A second possible explanation is localized fluidization between the ducts. The finer bed material size approaches the size where the normal bed ash cooling air flow rising up between the ducts could fluidize the bed material. Such a condition would also result in the noted bed cooling problems and localized heating of sections of the ducts. However, tests with reduced bed ash cooling air flow were unsuccessful at resolving the bed ash cooling problems experienced with the finer bed ash. The significant reductions in cooling air flow tested reduced the air velocity between the ducts sufficiently to cease any fluidization in that region, thus if localized fluidization between the ducts was the cause of the problem then the noted bed drain cooling problems should have ceased.

Post Bed Combustion

Significant post-bed combustion was experienced shortly after initial coal fire. Unburned carbon elutriated from the bed would concentrate in the cyclone dip legs where combustion would occur, resulting in excessively high dip leg temperatures. In addition, unburned volatile would escape from the bed and burn at the inlet of some of the cyclone strings, resulting in excessively high gas temperatures through the affected strings. Post-bed combustion at high bed heights resulted in high gas temperature to the gas turbine. Post-bed combustion was attributed to the limited number of coal feed points (six) and the resultant high localized fuel release. Fuel discharge deflectors, "skateboards", were added in the bed above the fuel nozzle outlets, and the sparge duct nozzles directly below these areas were modified to provide higher air flow to the fuel discharge regions. Extensions were later added to the sides of the skateboards. The skateboards and additional air flow provided some help in combatting post-bed combustion; however, the biggest improvements in this area were achieved through changes in coal paste quality. Increased fines in the crushed coal, resulted in the larger, more consistent sized, and cohesive lumps of coal paste in the bed, thus slowing down the devolatization of the coal, which in-turn resulted in better distribution of volatile and more even bed temperatures.

The laminar flow of the gases in the freeboard precluded lateral mixing of the localized volatile plumes with the surrounding higher oxygen content combustion gases until they reached the turbulent zone near the cyclone inlets. The volatile would typically combust at the inlet to just one or two of the cyclone. Thus the heat release would concentrate in one or two cyclone strings, resulting in excessive temperatures in the affected strings. A steam-injection-induced freeboard-gas-mixing system was installed to spread the heat release of post-bed volatile combustion over the entire gas stream. This system was commissioned early in 1992 and was shown to spread out the heat release of the volatile to the entire gas stream. It was also shown to alleviate cyclone dip leg fires, by more evenly distributing any unburnt carbon that escaped the bed. It also evened out the oxygen levels in the seven individual cyclone strings. This system was in use almost continuously when firing coal from early 1992 through the end of the test period. While post-bed combustion problems had nearly been eliminated by early 1993 through improvements in the coal paste, continuous operation of the freeboard mixing system served as protection against sudden upsets that could occur in the event of paste preparation problems or the loss of one of the six fuel pumps.

As the third year of operation came to an end, post-bed combustion ceased to be an issue, except during dramatic upsets at high loads. At high loads, the gas temperature to the gas turbine approached the operational temperature limits of the machine and any significant increase in post-bed combustion could easily send the gas temperature to levels approaching the trip limits. With the sintering problems present at the end of the third year, this was not a significant issue since either bed level or bed temperature was sufficiently limited to provide adequate margin between the gas temperature leaving the bed and the gas turbine gas temperature trip limits. With the switch to finer sorbent feed in the middle of 1994, the propensity for post-bed combustion during upsets was reduced as a consequence of the improved fluidization experienced in the bed. This improvement was evidenced by the extended periods of full bed height/ full bed temperature operation that were experienced in early 1995 with stable high gas temperatures to the gas turbine.

During the first quarter of 1994, the skateboards were moved slightly toward the rear wall of the boiler in an attempt to improve the fore/ aft temperature distribution in the bed. During this period, the unit was being tested at relatively high load and coal paste flow rates, and the rear wall temperatures were significantly higher than the corresponding front wall temperatures. It was postulated that the higher paste flow rate was causing the paste to carry towards the back of the skateboards causing more of the fuel to release towards the rear wall. It was further postulated that by moving the skateboards rearward, more of the fuel would be diverted towards the front of the bed. After the skateboards were moved rearward, the bed temperature distribution did improve, indicating that the skateboards do impact fuel distribution. As maximum load became limited during the warmer months of 1994, the bed temperature along the boiler front wall became too high, and the skateboards were relocated back to their original positions. When high load testing resumed in late 1994 and early 1995, there was no need to relocate the skateboards rearward, since improved bed mixing and excellent temperature distribution with finer sorbent feed had improved the bed temperature distribution.

In-Bed Surface

The original in-bed surface, which was fully submerged at an indicated bed height of approximately 120 inches, provided only 73% of the design in-bed absorption. During the second quarter of 1991, shields were removed from the outlet legs of the evaporator, primary superheater and secondary superheater in the freeboard to help increase the tube bundle absorption. In fall 1991, in-bed tube surface was added. Four rows of evaporator and two rows of secondary superheater surface were added at the top of the existing bundle and part of the shielding on the bottom horizontal tubes of the primary superheaters was removed. Due to concerns about post bed combustion, the design bed temperature used for sizing the additional surface was selected as 1540 F versus the original 1580 F temperature. Performance tests conducted throughout the remainder of the first three years of operation revealed that the in-bed absorption was still approximately 7% below the original design value.

During the spring of 1994, finer sorbent feed size consists were tested to see if they could improve the bed fluidization conditions and minimize the then pervasive high load sintering problem. Dramatic improvements in bed conditions were experienced with the finer sorbent, including increased heat transfer to the tube bundle. Testing with various size consists of sorbent, revealed that in-bed heat transfer was a strong function of bed particle size, with heat transfer increasing as mean particle size decreased. In contrast to the original -6 mesh site prepared sorbent, which resulted in in-bed heat absorption at full bed height being only 93% of design, the original design in-bed heat absorption was exceeded when using a finer -12 mesh site prepared sorbent. In addition to the improvements noted in overall heat transfer, the enhanced bed agitation afforded by the finer bed material resulted in a more even bed temperature profile, which helped even out the absorption between the individual evaporator and superheater circuits in the bed.

Insulation/ Bed Liner

The boiler startup zone insulation liner originally consisted of insulating board protected from the bed by a segmented stainless steel liner attached by studs. Shortly after initial unit startup, the stainless steel liner began to warp excessively, pulling away from the wall in some locations and exposing the insulation to the bed. The startup zone insulation and liner was modified during fall 1991. Due to access difficulty, all but the upper 14 inches of the insulation and liner were replaced. The new insulation system used fiberboard insulation protected from the bed by silicon carbide tiles and castable silicon carbide refractory. The tiles covered the majority of the wall and were held in place by studs and nuts with the studs spot welded to the wall tubes and membranes. Castable refractory was used at wall penetration areas such as the fuel nozzles. The upper 14 inches of the existing insulation system was retained since it was in good condition, and access to remove it was limited. During the first quarter of 1992, the top row of ceramic tiles began to pull away from the boiler wall. This problem was attributed to incorrect stud material in this top row and the design of the interface to the upper stainless steel section. The interface design was revised, and the studs were replaced. After these changes, the ceramic tiles and castable refractory held up well; however, periodic repairs were needed as individual tiles sometimes cracked and fell off. The remaining portions of the stainless steel liner continued to warp with the sidewalls being the worse area. The sections of the stainless steel liner along the sidewalls were removed in early 1994. Castable refractory was used to cap off the top of the lower tile liner sections. The use of refractory tiles, while not totally maintenance-free, proved to be an acceptable liner design for the startup zone.

Vertical Separator

The unit experienced large vertical separator level swings and steam generator transients during initial unit operation. These swings complicated the tuning of the feedwater flow control loop and resulted in numerous combustor trips. For the most part, these problems were resolved through extensive tuning and reconfiguration of the control loops, combined with increased operator attention and procedure changes. However, upon achieving once-through operation, the unit again began to experience vertical separator level swings. It was determined that the swings, above once-through, were false indications caused by pressure fluctuations in the vicinity of the top (low pressure) taps of the differential pressure transmitters used for level indication. The top taps of the differential pressure transmitters were lowered away from the steam inlets in fall 1991. This modification proved to be successful in eliminating the false level indication swings, and no significant problems were experienced throughout the remainder of the four year operating period.

Feedwater

The feedwater check valve was originally located upstream of the economizer. In August 1991 the economizer experienced a major tube rupture which caused a loss of feedwater and rapid depressurization of the boiler. The feedwater check valve was relocated to the feedwater line downstream of the economizer, but upstream of the tie point from the boiler injection tank, in order to protect the boiler. In addition, control logic was added to recognize such an event as a "loss of feedwater" incident and initiate a gas turbine trip and feedwater injection.

Bed Temperature Monitoring

The original 18 in-bed thermocouples were augmented with 14 more in Spring 1991. This provided a much better picture of the bed conditions, not only for the surface redesign activities ongoing at this time, but also for day-to-day operation.

Oxygen Analyzers

The original boiler gas outlet oxygen analysis system consisted of three low-temperature micro fuel cell transducer type analyzers that sampled gas from three locations in the boiler freeboard. Gas samples were taken from slipstreams of combustion gases that were vented to atmosphere via small-bore tubing. A needle valve in the slipstream line controlled the gas flow. The samples were washed with water, and a pump downstream of the water wash drew the sample from the slipstream. This system had the following problems:

The analyzer cells did not indicate accurately until they were exposed to CO_2 for 12 - 24 hours, and after that they experienced excessive calibration drift.

The slipstream needle valves experienced excessive erosion due to the high dust loading and high velocity through the valves. As the needle valves wore, the slipstream flow rate would increase. This, in-turn, caused excessive erosion to the slipstream tubing, resulting in tubing failure and air in-leakage inside the combustor vessel. In addition, high slipstream flow rate raised the pressure at the gas sample extraction point, causing excessive sample flow rates and resulting in over-temperature and damage to the analyzer's tygon sample tubing.

The slipstream lines and needle valves also experienced frequent plugging due to the high ash concentration of the gas.

Wash water flow rate control problems resulted in a number of other problems, particularly sample line plugging. In a number of incidents, water from the O_2 analyzers made its way back through the gas slipstream lines during unit shutdown, resulting in flooding of the associated secondary cyclone ash removal lines and causing ash-line plugging. In addition, loss of water incidents occurred, resulting in excessive temperature and damage to the analyzer internals.

The sample pumps experienced numerous failures.

Flue gas acidic condensation resulted in slipstream and sample line corrosion and plugging.

In addition to the mechanical problems, significant deviations in oxygen concentrations were noted between the three analyzers, revealing stratified boiler freeboard gas conditions and raising concerns that the sample points might not be representative of the average flue gas conditions.

The oxygen analysis system underwent a number of evolutionary changes in order to improve its accuracy and reliability and to provide more complete measurement of the boiler exhaust gases. The major modifications are summarized as follows:

The oxygen analyzers were replaced with a new design that employed high-temperature zirconium oxide cells. The new design eliminated the water wash and sample pump through the use of air aspiration to draw the sample and a ceramic filter to remove particulate from the sample.

The gas sample points were relocated downstream of the primary cyclones in order to reduce the slipstream gas dust loading. In addition, a total of seven analyzers (one per cyclone string) were installed to insure representative measurement of the entire boiler outlet gas.

The slipstream needle valves were replaced with fixed orifices and the lines were configured to minimize ash plugging and permit easy clean out in the event that plugging was experienced. The orifice was eventually changed from metal to ceramic to preclude excessive erosion.

Periodic high-velocity air purging was employed to avoid plugging of the vent lines. This purge resulted in excessive particulate emissions to atmosphere, so the vents were configured to discharge into the boiler ventilation system (thus collecting the particulate in that system's dust collector).

High-temperature heat tracing and insulation was employed on the slipstream and sample lines to avoid acidic condensation.

The above changes eliminated most of the noted system problems; however, slipstream line plugging and erosion/corrosion were still experienced. From a practical standpoint, the system reliability was improved sufficiently to obtain accurate and representative oxygen measurements, which, in-turn, permitted extended runs and provided sufficient data for combustor performance evaluations.

6.2.2 Operating Experience Overview

The water/steam systems generally operated reliably, once the vertical separator problems were addressed. The only exception was the occurrence of persistently uneven evaporator outlet leg temperatures at high bed heights near the end of the original three-year operating period. This problem was resolved in the fourth year of operation by the improved fluidization conditions attained with the finer sorbent feed size consists.

The most significant operating issues on the air/gas side of the boiler, were bed sintering and post-bed combustion. These topics are discussed in detail in Section 5.1 and 6.2.1.

The steam generator equipment held up very well over the operating period. Tube wastage of the in-bed tube bundle, once considered a potential major liability for the bubbling bed PFBC process, proved to be no major issue over the four year operating period. The only significant erosion that was observed was on localized areas of the secondary superheater and primary superheater. The areas around the skateboards experienced locally high erosion attributable to the high velocity flow patterns caused by the skateboards and the additional air nozzles located under them. This erosion damage was repaired or mitigated through pad welding and/or shield installation. Pock marking was noted on the inlet legs of the secondary superheater. The damage is believed to be caused by insufficient oxide layer formation due to the relatively low secondary superheater inlet temperature. Wall thickness readings taken on these sections during the first three years of operation did not indicate the need for shielding or repairs. However, wall thickness readings taken in June 1994 on the vertical sections of these legs after the first upward bends revealed that tube wastage had progressed to the point where failure might occur. Shields were added on these inlet legs. Periodic inspection of platens also revealed localized erosion of secondary superheater circuits higher up in the bed; however, these areas did not progress to the point where shielding or repairs were needed.

The emergency bed cooling system which provides back-up feedwater from the boiler injection tank and boiler make-up pump in the event of a loss of feedwater event, was successfully tested from a bed height of 110 inches during the second quarter of 1991. This test verified the proper function and operation of this critical system's components and controls. No further testing of this system was performed throughout the remainder of the test program, thus it was not verified that the system was adequately sized to perform its intended function in a trip from full load.

6.2.3 System Inspection

As part of the final inspection of the boiler, two evaporator and one secondary superheater platen, all adjacent to one another were cut loose and moved into the freeboard area. Inspection of the removed platens revealed nothing more than a significant number of lost support clips, distortion of the superheater uncooled support trusses and the localized erosion on the primary and secondary superheater circuits. All were issues that were well documented through inspections performed during the four years of operation. However, inspection of the boiler enclosure front and rear walls revealed areas where a significant loss of tube wall had occurred that was not identified previously. A cut out section of the enclosure side wall also revealed significant tube wastage. The reason this tube wastage was not detected during the operating period is these areas were not accessible.

6.2.4 Summary and Conclusions

Except for the localized erosion problem, the Tidd boiler design is a commercially viable design. Boiler enclosure wall erosion will likely be addressed in future units through the use of protective refractory coatings. The localized primary and secondary superheater erosion should be easily resolved through minor design modifications and/or material changes. In addition, while the support clip loss and support truss deformation problems did not precipitate any operating problems or down time in the four years of operation at Tidd, these parts of the tube bundle will require redesign in order to survive the required life of a commercial PFBC unit's tube bundle.

6.3 Gas Cleaning Cyclones

6.3.1 System Modifications Completed

The primary and secondary cyclones have operated satisfactorily at the Tidd PFBC Demonstration Plant. However, a number of modifications were made, these are listed below.

Primary Cyclone Heat Shields

High carbon carryover into the primary cyclones and high carbon concentrations in the lower sections of the cyclone resulted in uncontrollable cyclone fires. These fires could usually be eliminated through proper coal paste preparation. However, in an attempt to reduce cyclone fires, a modification was made in Spring 1992. This modification involved the removal of insulation around the cyclone bottom discharge cones and the installation of radiant heat shields. By removing the insulation in this area, the metal temperature of the cyclone was reduced, thereby minimizing the chance of spontaneous combustion in the cyclone.

Secondary Cyclone Dip Leg Modification

The secondary cyclone dip legs were shortened during fall 1991 in an attempt to improve the secondary ash removal system capacity. Prior to this modification, ash would build up in the bottom 20 feet of the dip-leg pipe and restrict or prevent the flow of ash from the dip leg. The bottom 15 feet of the dip leg, along with the dip-leg cooler were removed from the cyclone in 1991. The bottom of the dip leg and the ash-line pickup pot were then only a few feet below the bottom cone of the cyclone. This modification did not improve ash removal system capacity as originally envisioned. While the buildup of ash in the bottom of the cyclone was reduced, the ash removal system continued to have serious capacity problems until Spring 1993 when the system was replaced in its entirety.

6.3.2 Operating Experience Overview

The operating experience of the cyclones has been relatively good. The cyclones have had four major problems over the operational period. These include cyclone fires, ash falls during startup, dip-leg cooler air leaks, and primary cyclone refractory erosion. These are discussed in detail below:

Primary Cyclone Fires

The primary cyclones have been subject to cyclone fires since initial operation of the unit. Cyclone fires were the result of poor combustion resulting in high carbon carryover into the cyclones. The carbon concentrated in the lower sections of the cyclones where it combined with the O_2 in the cyclone and ignited in the dip leg. This resulted in melting and fusing of ash particles. The agglomerates then fell to the bottom of the cyclone dip leg where they cooled into solids. These clinkers plugged the ash removal line. Screen cages were installed around the inlets of the ash removal suction nozzle to prevent these clinkers from blocking the ash lines. These cages, while effective at times, could still be blocked by sinters when a significant cyclone fire occurred.

Cyclone Ash Falls

Ash falls or ash peelings in the cyclones during unit start ups were first observed in fall 1991. During a lengthy outage, the interior walls of the primary and secondary cyclones began a slow, but constant, peeling of ash coating off their interior walls. As time passed, the degree of peeling increased. The #12 primary and #22 secondary were sandblasted near the end of the outage to remove all the ash buildup on the walls. Upon startup of the unit, all of the cyclones except #12 and #22 plugged immediately upon bed preheating. The unit was shut down. Subsequent inspection revealed that the ash falls overwhelmed the ash removal line pickup nozzles causing pluggage of the system. The bottom 2' to 5' of each cyclone was filled with ash peeled from the cyclone walls. Subsequent to this finding, loose ash buildup was sandblasted out of the cyclones during every shutdown where combustor entry was made. Outage sandblasting proved very successful at preventing ash falls during unit start up. The only instances where this was unsuccessful, were those few instances where sandblasting was performed early in the outage, wherein ash layer deterioration occurred subsequent to the sandblasting.

Dip-Leg Cooler Air Leaks

The cyclones and cyclone ash removal system operate at a lower pressure than the air space of the combustor vessel. Therefore, any leaks in these systems result in cooler air flowing into the cyclones and dip legs. During early 1991, leaks developed in the primary dip-leg bellows boxes, which are located at the bottom of the dip legs. When these leaks were sufficiently large, significant quantities of air would flow into the dip leg. This would displace the hot ash and gas from entering the ash line and result in cyclone dip-leg pluggage. In order to eliminate this problem, all of the flanges in the primary dip-leg bellows boxes were seal welded while the bellows boxes in the secondary cyclones were eliminated.

Primary Cyclone Refractory

The discharge section of the bottom cone of the primary cyclone is refractory lined to minimize erosion. The refractory was installed over a diamond-shaped mesh that was welded to the cyclone walls. This refractory has worked well, with no problems encountered over the period of operation. The only noteworthy item was the buildup of a very hard deposit on this refractory. During each shutdown or startup, round sections of refractory, about the size of the mesh, would spall off and drop to the bottom of the dip leg where they would remain until the bellows box was cleaned. These quarter-sized spallings would have the super-hard deposit on one side and the white refractory on the other side. Generally, they were 1/4" thick. While these "refractory chips" never plugged an ash removal suction nozzle, they had the potential to do so. Also, the flaking of the refractory was found to be a self-limiting process, and has not required any maintenance work on the cyclone refractory.

Secondary Cyclone Stirring Air

A dip-leg stirring air system was installed in the bottom of the secondary cyclone dip legs. This system consisted of an individual small-bore air line leading from a valve station outside the combustor to each of the secondary dip legs. The line branched into three nozzles spaced 120° apart and tangential to the circumference of the dip-leg pipe. In addition, each of these three tangential lines had small orifices which permitted combustor vessel air to purge into the dip leg on a continuous basis. Outside of the combustor vessel, each of these six lines was connected by an isolation valve to the sorbent injection compressed air system.

The intent of this system was two fold. The first purpose was to provide a continuous flow of purge air path to the bottom of the dip leg to prevent ash buildup on the floor of the dip leg. The second purpose was to provide an active system that could blast the dip leg with much larger amounts of purge air in case the dip leg became plugged.

The effectiveness of the passive purge air nozzles was questionable. The impact of the manual purge air blast system was noticeable. However, several fatigue failures occurred in these active purge air line. These failures caused significant quantities of combustor air to enter the dip-leg, causing operating difficulties. Therefore, in early 1993, the stirring air system was eliminated.

6.3.3 System Inspection

One primary and one secondary cyclone were internally inspected by cutting a large inspection window in the cyclone cylindrical section. A thorough examination revealed no significant erosion. In addition it was clearly established that spalling of the refractory inside the primary cyclones was insignificant in that it was limited to less than 0.25 inch in depth. Overall the cyclones appeared to be holding up well to the relatively high operating temperatures.

6.3.4 Summary and Conclusions

The gas cleaning cyclones worked exceptionally well considering their pioneering application to this service environment. The Tidd demonstration has clearly established the viability of gas cleaning cyclones in a PFBC environment. The cyclones were able to withstand extremely severe conditions and continue to clean the gas to acceptable levels. No deterioration in performance was noted during the four year demonstration period.

The modifications made to both the primary and secondary cyclones were to improve the capacity and reliability of the ash removal systems and were not as a result of cyclone operation.

6.4 Combustor Depressurization

6.4.1 System Modifications Completed

No system modifications were required.

6.4.2 Operating Experience Overview

The combustor depressurization system has operated successfully when a gas turbine trip has occurred. During the early operation of the unit, some adjustments were required in some of the valves, orifices, and pressure regulators. However, none of the problems experienced were significant.

Implementation of the Advanced Particle Filter (APF) slipstream in 1992 added significant volume between the boiler windbox and the gas turbine hot intercept valve. The impact of this change on combustor depressurization was not considered at the time. It was not until 1994, when a GT trip from high load occurred, that a problem was discovered. The additional volume slowed the depressurization rate of the components downstream of the boiler windbox, which induced a backflow of gas from the boiler into the windbox. This resulted in pluggage of bed fluidizing nozzles and a significant amount of bed ash being forced into the sparge ducts.

6.4.3 Final Inspection

No abnormal conditions were noted.

6.4.4 Summary and Conclusions

The combustor depressurization system has performed as intended. However, the combustor depressurization system is rather complex and requires a significant amount of nitrogen when it is activated. Alternate methods of addressing the concerns of gasification and sintering in a hot slumped bed should be addressed in future PFBC plants. The depressurization problem noted above would normally have required modification of the system. However, no changes were made due to the limited remaining life of the project.

6.5 Bed Preheating

6.5.1 System Modifications Completed

The major modification made to the system was to change the ring header that connected the five burners into a manifold configuration. This change was made to facilitate the removal of a single needle valve by enlarging the access area around the valves.

An alternate purge air supply was tied into the system from the L-valve receiver air tank, which operates at a higher pressure than the original process air supply. This revision was made to improve purging of the system and allow purging during unit operation.

The tie-in point of dry air into the purge air line was moved to prevent the dry-air system pressure from being pulled down when the process air pressure is lower than dry-air pressure. The spark plugs were modified so that the cable connection was not exposed to high temperatures. The flame scanner was moved to an observation port and a redundant scanner was added. Needle test valves were also added.

6.5.2 Operating Experience Overview

Overall, the bed preheating system worked very well. A problem of sticking needle valves sometimes caused difficulty in lighting the burners, but otherwise the system has been reliable. Maximum allowable burner temperature differentials were increased from ±180 F to ±350 F to keep the system from tripping out of service. Another issue was difficulty in lighting of the bed preheater on hot restarts. When the combustor vessel temperature was much above 300 F, lighting of the bed preheater was erratic.

6.5.3 Final Inspection

The system was not disassembled for inspection after final shutdown, since there was no reason to suspect any areas of degradation.

6.5.4 Summary and Conclusions

The bed preheating system was changed very little from initial to final configuration. It proved to be a very reliable system. The few improvements that were made were minor. One source of concern is the failure of the burner louvers, since the reason for the failure has not been established.

6.6 Sorbent Preparation

6.6.1 System Modifications Completed

Impact/ Dryer Mill

The sorbent preparation system experienced significant problems due to both undercapacity and erosion. The crushing zone components, including the hammers, rotor (particularly the rotor end discs) and the crushing box bottom and back liner plates, experienced excessive erosion. The following changes were implemented to combat the erosion:

Hard facing material was installed on the hammer tips. This modification dramatically extended hammer life; however, the weld build-up required reapplication at approximately 250-hour intervals.

The crushing box back and end liner plates were replaced with an abrasion-resistant alloy steel; however, this was not effective. A later modification, which included plating with a chromium carbide abrasion resistant coating, proved very successful.

The rotor was replaced with a harder erosion-resistant material. This reduced the erosion rate; however, weld buildup was still required periodically.

The rotor speed was increased. It was felt that fine material was residing in the crushing zone too long, thereby contributing to the erosion and to the prepared product's excessive minus 60 mesh fines concentration. It was felt that the higher rotor speed would help sweep the finer materials out of the crushing zone, thus minimizing the creation of excessive fines and the erosion. This change was made in late 1993 and had no apparent impact on the erosion or the product sizing; however, it did result in increased system capacity.

In addition to the erosion problem, excessive pressure drop through the mill was thought to be contributing to system capacity and product sizing problems (excessive fines). Excessive mill pressure drop caused the system fan to run back on its curve, thereby reducing the system's recirculation air flow rate. The following changes were made to the crusher:

A six foot extension piece was added to the velocity separator outlet duct, thereby allowing it to be extended down closer to the venturi discharge. This change had no impact on the mill pressure drop and, interestingly, had no significant impact on final product sizing.

The venturi plates were modified to permit a wider opening. This change decreased the mill pressure drop, thereby increasing the recirculation flow rate.

Cyclone Separator

The cyclone separator experienced excessive erosion in both the cylindrical top section and the conical section below it. The conical section was replaced with an erosion-resistant plate material; however, the new material was not successful. The next modification implemented consisted of lining both the cylindrical and conical sections with castable refractory. This modification was also unsuccessful. The refractory wore away rapidly. A second type of refractory was sprayed atop the worn material, but the new refractory experienced localized failures. The problem was finally resolved by installation of ceramic tiles in the cylindrical section and the use of a different abrasion resistant plate material in the conical section.

Air Recirculation Fan

The recirculation fan experienced excessive erosion of both the casing and the rotor. The erosion problem was resolved through application of an abrasion-resistant metal spray coating.

Due to excessive system pressure drop, the fan was operating with reduced air flow output. This problem, in conjunction with excessive system air in-leakage downstream of the impact/dryer mill (particularly at the vibratory feeder inlet and outlet expansion joints), caused reduced air flow through the mill. In order to increase the mill air flow, the speed of the fan was increased in late 1993. This change did increase the mill air flow, and resulted in an increase in system capacity; however, the fines concentration in the prepared product was not reduced.

The outlet of the fan originally employed four manually adjustable flow control louvers. The sealing components for these louvers became a source of significant air in-leakage. Since system air flow was generally below design, two of the four louvers were modified to fixed vanes, thereby eliminating their seals and the associated air in-leakage. In addition, the seal packing of the remaining two adjustable louvers was modified to reduce air in-leakage.

Vibrating Screen

The original vibratory screen experienced significant blinding which led to failure of the screen inserts. The initial screen inserts were 8-mesh cloth attached to a metal frame by adhesive. These failed rapidly, so the inserts were changed to an 8-mesh wire screen with a metal frame. These also experienced relatively rapid tearing at the screen-to-frame interface. In order to strengthen the screen inserts and, at the same time, reduce the blinding problem, the inserts were changed to a 6-mesh screen; however, the wire diameter was specified at two sizes larger than standard 6-mesh screen wire. The result was a relatively strong screen insert, which had an open area larger than 8 mesh but somewhat smaller than 6 mesh. This screen insert dramatically reduced the incidence of failure; however, such failures still occurred periodically. In addition, the screen was still susceptible to system upsets which resulted in screen blinding. Such blinding caused excessive quantities of fine material to flow back to the impact/dryer mill along with the oversized recycle product. These recycle fines were suspected as key contributors to the system's prepared product capacity and excess fines problems.

In addition to modifications to the screen inserts, weights were added to the screen assembly to increase the vibration amplitude in an attempt to minimize the screen blinding. This change was not successful.

Attempts were made in late 1993 to reduce the product sizing for relatively short-duration tests in order to evaluate the impact on bed dynamics and sorbent utilization. Through a combination of reduced system air in-leakage and the re-implementation of the 8-mesh wire screen inserts, the prepared product was made somewhat finer without a significant increase in minus 60-mesh fines. The 8-mesh screens inserts again experienced excessive blinding and rapid failure, thus use of the finer screen inserts became an operational liability, and this practice was abandoned.

Sorbent utilization testing, conducted in Spring 1994, revealed dramatic improvements in bed temperature distribution, sintering tendencies, heat transfer, and sorbent utilization. This testing was performed with "off-site" prepared sorbent, since the "on-site" system did not have the flexibility to provide alternate size consist product. The success achieved with finer sorbents provided a renewed push to modify the sorbent preparation system to allow production of finer sorbent feed stock. The screen insert blinding problem experienced with the original vibratory screen was identified as the key factor limiting the flexibility of the system. This realization led to the purchase of a new vibratory screen, which was installed in June 1994. The new screen employed two screen decks, one above the other, configured in parallel in order to attain an increase in screening area within the confines of the available component space. In addition, the new screen employed sloped screen decks in order to help avoid the blinding problems experienced with the original vibratory screen, which used a single horizontal screen deck. After a relatively short component shake-out period, the new vibratory screen proved to provide the much needed improvement in sorbent preparation system operating flexibility. Finer top size materials were now able to be produced reliably and at sufficient capacity to permit extended testing. System operation evolved to where "on-site" production of minus 12 mesh material became the normal sorbent for operation of the unit. The reduction in product size from minus 6 mesh to minus 12 mesh provided considerable improvements in all areas of operation.

The design of the new vibratory screen's two decks permitted reconfiguration to a series arrangement. This reconfiguration was employed for a single short duration test in March, 1995, where a nominal 12 X 60 mesh material was produced. This was accomplished by reconfiguring the internal and outlet chutes and installing a 50 mesh screen insert in the lower deck. The very fine material that passed through the lower deck was discarded for the short test by connecting that chute to a vacuum truck. The screen functioned well in this configuration; however, the system's output capacity was dramatically reduced forcing the unit performance test to be at very low load and for a short duration.

Air Heater

The most significant problem with the air heater was insufficient air flow caused by excessive system air in-leakage. With reduced air flow the heater outlet air temperature would run hotter for a given firing rate. The low air flow problem was combatted through periodic system repairs made to minimize air in-leakage, particularly at the vibrating feeder inlet and outlet expansion joints. In addition, the over-temperature trip control function was relocated from the local controller to the main plant control computer in order to improve its reliability.

Another problem experienced with the heater was backflow of air through the heater. This occurred whenever the 70-ton sorbent feed hopper was run empty with the system in operation. In such instances, large quantities of air would leak in through the hopper and the feeder resulting in positive system pressure upstream of the impact/dryer mill. In order to eliminate this problem, an additional level switch was added in the 70-ton sorbent feed hopper to shut down the system on extreme low level. In addition, the air heater's air intake point was relocated in order to avoid equipment damage in the event that air backflow occurred. No additional backflow events occurred after implementation of the feed hopper low level trip interlock.

Vibratory Feeder Expansion Joints

The expansion joints at the inlet and outlet of the vibratory feeder experienced numerous failures. These failures resulted in dramatically increased system air in-leakage. These failures were not readily apparent, and were usually found after a major deterioration in system product was noted. The expansion joint at the outlet of the feeder was the worst of the two, since it was exposed to much higher temperatures. Numerous changes in material compounds were attempted in order to minimize the problem, but were unsuccessful. These components continued to be a significant problem area throughout the entire Tidd test program.

System Ducting

The system ducting in the air recirculation loop experienced excessive erosion in a number of locations. The most notable areas were at the vertical-to-horizontal 90-degree elbows upstream of the cyclone separator and downstream of the recirculation fan. This problem was addressed by periodic patching of the eroded areas.

Cleated Belt Conveyor

The cleated belt conveyor experiences accumulation of large quantities of fine sorbent along the bottom of the conveyor's horizontal inlet section, which causes periodic conveyor operating problems. A number of modifications were made to combat this problem. The problem had not been totally resolved at the end of the program.

Prepared Sorbent Storage Vessel

Segregation of material sizing was experienced in the 200-ton prepared sorbent storage vessel. The segregation resulted in finer material being fed to the east sorbent injection vessel than was being fed to the west vessel. Deflector plates were added in the discharge chute between the cleated belt conveyor and storage vessel. The deflectors were successful at mixing the material, and minimized size segregation. However, the segregation problems continued to be noticeable at the end of the test period.

The two outlet cones of the storage vessel each incorporate a bin activator to ensure proper material flow. Use of these activators was discontinued, when it was determined that the vibration caused damage to flexible outlet joints and the material flowed without the aid of the activators.

6.6.2 Operating Experience Overview

This system was plagued with numerous operating problems which required extensive operator and maintenance attention. The main problems were insufficient capacity, limited product flexibility, high concentrations of minus 60-mesh fines, system air in-leakage and component erosion. Through the modifications noted above, the erosion problem was reduced and the capacity and product flexibility were improved. The installation of a new vibrating screen in mid-1994 allowed reliable on site production of finer size gradation of sorbent in sufficient quantities to sustain unit operation. The excessive wear problem was never fully resolved, since that would have necessitated a costly system redesign.

6.6.3 Final Inspection

As the system had experienced extensive maintenance attention throughout the operating period, the final inspection did not reveal anything new.

6.6.4 Summary and Conclusions

Consistent and reliable sorbent preparation is critical for operation of a PFBC facility. From a reliability standpoint, the system employed at Tidd was unacceptable due to its need for extensive maintenance attention. Elimination of excessive component wear and erosion must be resolved in future system designs. From a system and product sizing standpoint, evolution of the system design over time, most notably through the implementation of the new vibratory screen in mid-1994, led to an acceptable system configuration. However, the dramatic impact on unit performance and operation that sorbent sizing variations had at Tidd leads to the conclusion that a system with an even greater degree of prepared product flexibility may be desirable. Findings from the Tidd operating experience have provided the operating database necessary for designing and specifying the systems and components for future commercial units.

6.7 Coal Preparation

6.7.1 System Modifications Completed

There have been several modifications completed on this system over the operating period. These include:

Crusher Control Logic

The original crusher control logic was based on a variable-speed coal weight belt feeder to maintain fuel paste tank level and a variable-speed crusher to maintain level in the weigh belt feeder inlet hopper. Shortly after the crusher was started up, this crusher control philosophy was found unacceptable.

A new crusher control philosophy was developed based on torque and speed control. The crusher speed varied to match output requirements. The crusher inlet screw feeder then applied a force on the rolls of the crusher and this force was controlled by the torque of the screw feeder. This method of control was utilized during the first year of operation. However, the crusher was never able to produce the 18-20% minus 325-mesh fines required to produce good pumpable paste.

Larger motors and drives were installed in fall 1991. A series of coal crusher tests followed to optimize coal crusher operation and improve reliability. An outcome of those tests was the development of a new coal crusher control philosophy called gap control. In gap control, the crusher inlet screw feeder runs unloaded, the vibratory feeder upstream of it is adjusted to control the crusher feed-rate and the crusher roll speed controls the gap between the rolls. This control scheme was abandoned because it failed to provide the required reliability.

Another series of crusher tests was conducted in spring 1992 to determine the effect of recycling up to 50% of the crushed coal back to the crusher. In the recycle control mode, the weigh belt feeder is controlled to maintain a level in the hopper above it. The coal crusher speed is set by the operator. The gap is a function of the roller speed and throughput but is generally about 7 mm. The screw feeder runs full speed. The vibratory feeder speed is adjusted to maintain a 50% level in the hopper. Operation in the recycle mode was successful in producing the desired product quality.

Pumpability Test Loop

The original coal prep system design included a paste pumpability slipstream test loop for testing the quality of the paste. This loop was designed to extract a small slipstream sample of paste and pump it through a test loop of piping and bends. The characteristics of the paste were determined, based on the pumping power requirements and the pressure drop through the system. The paste sample quality could be correlated back to an acceptable paste quality. The test loop experienced significant plugging problems, and was replaced by a manual slump test procedure utilizing a concrete slump cone.

Larger Coal Crusher Drives

The crusher was originally supplied with 150 hp motors and variable speed drives. Larger, 200 hp motors and drives were installed to increase torque and improve product fineness.

Replacement of Coal Mixer Internal Components

The original paddles in the coal paste mixer were manufactured of a hardened carbon steel material.

Severe corrosion was discovered in June 1991. The mixer paddles, liners and arms showed significant deterioration. Over the next several months, new stainless steel arms, paddles and mixer liners were fabricated and installed. Operation since then has been acceptable, with only weld buildup required on the paddles to replace eroded material.

Crusher Roll Grooves

The original coal crusher rolls were provided with smooth surfaces. The friction generated proved to be inadequate to draw the coal into the rollers in the quantity needed to meet unit demand. Three circumferential grooves were machined into the fixed roll, to increase the friction. Over the next several years, additional grooves were added. Eventually, both the stationary and movable rolls were grooved.

Miscellaneous System Modifications

A number of other modifications were completed on the system. These include:

The physical characteristics of the coal entering the crusher had significant impact on crusher performance. Each time the coal characteristics changed, the crusher experienced operational problems and required adjustment. The equipment manufacturer suggested the addition of water sprays at the crusher inlet to stabilize coal surface moisture. These sprays were used intermittently to add water, improving the adhesion between the coal and the rolls.

Crusher roller skewing (a condition in which the gap between the rolls is significantly different from one side of the roll to the other) had been a problem. The problem was attributed to the manner in which coal flowed into the top of the crusher feed hopper. A movable damper was installed in the crusher feed hopper inlet chute to distribute the coal equally along the rollers. This effectively minimized skewing trips.

Crusher Recycle Loop

The coal crusher proved incapable of producing crushed coal with at least 20% minus 325-mesh fines. After numerous attempts to revise the crusher controls, a coal recirculation system was installed. This system provided the means to recirculate up to 50% of the crushed coal to the crusher. This modification involved installation of an adjustable damper at the inlet to the sizer bypass chute. This damper could divert up to 50% of the coal around the sizer and into the sizer bypass chute. This coal was then routed back to the crusher. Subsequent testing showed that recycling resulted in a final coal product with 20 to 30% minus 325-mesh fines. The high degree of recycle did not have significant impact on the system's throughput capacity when crushing Pittsburgh #8 coal.

6.7.2 Operating Experience Overview

Coal crusher reliability was poor during the first 18 months of operation. The crusher would frequently trip out unexpectedly. The coal product produced did not contain the proper size distribution required to produce good pumpable paste. Paste with insufficient fines required additional water to maintain its pumpability characteristics. Many unit trips occurred when paste pumps or fuel nozzles plugged. Higher moisture in the paste resulted in freeboard and/or cyclone fires.

The recycle operational mode proved most effective at improving both coal paste product consistency and crusher availability. However, recycle was not a cure-all of the coal preparation system. Crusher reliability could suddenly falter when the characteristics of the raw coal changed significantly. Analysis of coals that worked well in the crusher and coals that caused the crusher to react poorly did not provide characteristic variables that could be used to predict crusher operation. It was found that on-line testing of a specific coal in the crusher was the only acceptable method to determine if that coal could be crushed in sufficient quantities to support operation. Even that method was found unreliable if the raw coal moisture content or other characteristics varied markedly from the coal used for the test. Unavailability of the MM Pittsburgh #8 coal toward the end of the fourth year of operation forced a switch to alternate coals. A switch to one of the coals was initially successful for a few days, but later resulted in a unit trip due to crushing problems precipitated by an increase in moisture in the raw coal.

6.7.3 Final Inspection

Nothing unusual was noted during final inspection of this system.

6.7.4 Summary and Conclusions

The coal preparation system included a single crusher. The system was marginally acceptable when crushing Pittsburgh #8 coal, however, it suffered from lack of capacity when crushing other coals. A great many of the crusher problems were the result of the need to achieve a specific product gradation while maintaining the throughput required to sustain unit operation. The availability of a redundant crusher would have eliminated the need to push the single machine to its limits and would have improved both reliability and product quality. The option of installing a redundant crusher was explored and determined not to be cost effective for Tidd, considering its relatively short life. A second option - the installation of a slipstream coal crusher was also considered. This crusher would be operated to provide the minus 325-mesh size fraction for blending with the primary crusher product. Shop tests on several crusher models proved successful, but the option was not exercised due to the limited life of the project and the long lead time required for the slipstream crusher.

The system that was originally installed at Tidd was modified until it was acceptable for Tidd operations. These modifications included larger motor drives, control logic changes and the installation of a recycle loop. The limited capacity of a single crusher and the need to recycle crushed material in order to achieve desired product size consist, presented significant challenges to operation. The system was made to function acceptably when crushing Pittsburgh #8 coal. However, its ability to crush sufficient quantities of other coals was never fully demonstrated.

Variability in raw fuel moisture content created significant coal crushing problems. If the system design used at Tidd is employed in a future commercial PFBC facility, then covered storage of the raw coal should be strongly considered.

6.8 Coal Paste Injection

6.8.1 System Modifications Completed

Revised Splitting Air Flow Meters

Splitting air flow was reduced by approximately 70% during the middle of 1991 in an attempt to mitigate post-bed combustion. This change resulted in the splitting air flow meters being out of range. These were replaced with new meters, in smaller bore pipe sections, that could accurately measure the reduced flows.

Fuel Tank Agitators

As the water content of the prepared coal paste was reduced to the proper consistency during 1991, the fuel tank agitator motors began to overload. This was first addressed by increasing the size of the agitator motors from 25 to 30 hp. A number of changes were then made to the agitators in attempts to reduce the power demand. These included removal of the top row of blades and revisions to the blade angles. The latter eventually proved effective with all rows of blades being in place.

Splitting Air Configuration

The original fuel nozzle design incorporated both primary and secondary splitting. The fuel nozzles were subsequently modified to address post-bed combustion concerns. The size of the primary splitting air nozzle was significantly reduced and the secondary splitting air was eliminated. This modification was intended to alter the paste splitting to produce more consistent sized paste lumps (large enough to eliminate post-bed combustion yet small enough to prevent sintering). This modification was moderately successful in reducing the degree of post-bed combustion (Refer to Section 6.2.1 of this report for more details on post-bed combustion), however, insufficient fuel splitting was considered a possible culprit in the excessive "egg sinter" formation (Refer to Section 5.1 of this report for more details on "egg sinters") experienced in late 1993 and early 1994 at high unit loads. Due to that excessive "egg sinter" experience, the fuel nozzles were modified in early 1994, in an attempt to produce finer splitting. The primary air nozzle size was increased in diameter, and the annular secondary splitting air ports were reinstalled. The former was done to increase general splitting by permitting higher splitting air flow rates, and the latter to eliminate the collection and subsequent dripping of large paste lumps off the outer face of the fuel nozzle assembly. In addition, the primary splitting air nozzle relocated further inside the paste nozzle to ensure that its discharge jet would cover the entire area of the paste outlet. Operation with this configuration resulted in smaller sinters indicating that finer splitting was indeed occurring, but this did not eliminate the problem. Also, post-bed combustion was more pronounced at the higher splitting air flows. This configuration remained in service for the rest of the test program; however its contribution to resolving the sintering problem is considered negligible compared to that of improved fluidization through the use of finer sorbent feedstocks.

Coal Pump Wetted Parts Corrosion

The chrome plating on the carbon steel coal injection pump cylinders, spectacle plate, cutting ring and discharge valve was flaking off, and corrosion of parent metal was occurring. In addition, corrosion was found on the painted carbon steel suction lines, suction boxes and S-tubes in places where the paint had flaked off. These corrosion related problems were attributed to sulfuric acid attack from the coal paste, and they were solved through a change from chrome plated carbon steel to chrome plated stainless steel, and a change in paint compound.

Modifications to Minimize Paste Consistency Variations in the Fuel Tank

The fuel tank, which provides suction to the CWP pumps is comprised of two adjacent round tanks that are interconnected. The paste from the coal preparation system originally fed into the far side of the south section. The tank agitators were expected to mix the paste sufficiently to ensure homogeneous consistency of the paste in both sections of the tank. In practice; however, the north section tended to contain wetter paste than the south section. This paste inconsistency led to post-bed combustion problems in the north side of the boiler and more frequent plugging of the No. 4, 5, and 6 coal nozzles, which were fed from the drier south section of the tank. Numerous modifications were made to improve mixing including deflectors at the tank interconnection point and reversing of the paste tank agitators' direction of rotation. While such changes helped, they were not fully successful. The problem was eventually resolved by relocating the mixer to discharge to both tanks sections near the middle.

Fuel Nozzle Outlet Section Cracking

The outlet sections of the second generation fuel nozzle experienced cracking and erosion of the small diameter discharge sections. These outlet sections were exposed to large temperature gradients which caused cracking then spalling, which eventually resulted in increased nozzle outlet diameters. The degree of the problem and the life of these components was greatly improved through a switch from Cerium micro-alloyed austenitic stainless steel to a high chromium nickel base superalloy. The latter material appears to provide commercially acceptable nozzle outlet section life.

6.8.2 Operating Experience Overview

The coal injection system functioned reliably. This is particularly evident when considering the fact that there was no installed redundancy in the system. The most significant problem was plugging of the nozzles, lines, and pumps. While plugs occurred in the system, the plugging was actually a symptom of paste preparation system problems. Paste plugs were not prevalent in the first six months of unit operation, which is likely due to the fact that paste moisture content was kept relatively high. Plugging began to be a significant issue by the middle of 1991, when paste moisture was being reduced in order to combat post-bed combustion. Improvements in coal crushing achieved in the middle of 1992 permitted the production of dryer, more pumpable paste. With these improvements, the incidence of paste line plugging dramatically decreased, however, occasional problems still were experienced whenever there were upsets in the paste preparation system. Another factor which helped minimize plugging was the splitting of the fuel tank inlet chute to directly feed both sections of the tank, thereby eliminating the presence of drier-than-average product in the south section of the tank.

The fuel nozzle cleaning procedure following combustor trips evolved during the first two years of operation, to provide a reliable fuel nozzle/ fuel line cleaning operation after combustor trips and in the case where a single line plugged. The addition of nitrogen to the splitting air tubes, coupled with the addition of high pressure nitrogen connections to the system, were significant in reducing down time due to fuel system pluggages. The ability to clean the fuel injection system after a gas turbine trip was never adequately demonstrated.

6.8.3 Final Inspection

No abnormal conditions were noted during final inspection.

6.8.4 Summary and Conclusions

The experience from Tidd indicates that using concrete industry based piston pumps to feed coal in the form of coal water paste to a pressurized PFBC unit is both reliable and effective, provided that the paste is properly prepared. Notwithstanding the paste preparation issue, the most significant issue for designing a coal injection system will be ensuring adequate fuel distribution and providing adequate redundancy to allow operation with multiple pumps out of service. The sintering problems, which were generally attributed to inadequate fuel distribution, were all but resolved when the bed became more actively fluidized using finer sorbent. However, the design would likely benefit from more fuel distribution points to mitigate high localized heat input.

6.9 Sorbent Injection

6.9.1 System Modifications

There were several major modifications completed on this system. These are detailed below:

Lockhopper Isolation Valves:

The original design included the test installation of two different types of lockhopper isolation valves.

Originally, Everlasting sliding double-disc valves were installed to provide inlet and outlet isolation on the east lockhopper train. Neles severe-service full-port ball valves were on the west sorbent lockhopper train. This side-by-side comparison provided operating experience with different valve types in this difficult application.

Problems were encountered with all four valves (both styles and manufacturers). The Neles ball valve on the discharge of the west lockhopper train would bind in operation. Several modifications were completed on this valve. The actuator size was upgraded twice and a local accumulator tank was installed to provide the increased actuator air requirements. Next the valve was flipped over so that it sealed opposite the material flow direction. Finally, the spring-loaded seat was replaced by a rigid fixed seat. This combination of changes seemed to solve most of the problems on this valve.

Operation of the Everlasting valves was more erratic. Sorbent material would build up in the dead spaces in the valve body cavity, restricting disc movement. Purge air was added to the valve body but this was not sufficient to prevent sorbent buildup. In late 1991, the valve was switched with the Neles ball valve and was reinstalled on top of the west sorbent lockhopper. The Everlasting valve, in combination with dead-space purge air has operated acceptably on the inlet of both lockhoppers provided adequate purge air is maintained.

The Neles ball valve was installed with modified seats and a larger operator on the discharge of the east lockhopper in late 1991. Operation of both Neles valves as bottom isolation valves has been acceptable.

The final configuration utilized Neles ball valves with rigid seats and larger actuators mounted as the bottom discharge isolation valve on both sorbent lockhoppers. The Everlasting valves, with purge air installed to blow the dead air spaces, are installed on the tops as inlet isolation valves on both lockhoppers.

Other Valve Modifications

A number of other sorbent system valves had to be modified after startup. These included valves in the lockhopper vent lines and in the sorbent transport lines. All of these valves were Cooper valves with full port stainless steel balls and floating seats. The valves would bind and stick when exposed to the fine sorbent dust in the sorbent transport system. The problem was related to dust accumulating behind the seat, creating a tight clearance, which would then bind the ball. On numerous occasions, these valves were dismantled, cleaned, modified and reinstalled only to bind up again during the next operational run. These valves were eventually replaced.

Transport Piping Upgrade

The original sorbent transport pipe was made out of SolidResist pipe which is a composite type pipe. Crosses were installed at all directional changes. The crosses were designed with dead legs in the direction of flow to absorb the impact and erosion in the bend prior to the 90° change in direction.

The discharge ends of the crosses in the sorbent injection transport pipe began to fail after approximately 350 hours of service. Temporary repairs were made by reinforcing the eroded area with plate and then building ceramic-filled boxes around the tee bends. All of the crosses were replaced with ceramic lined elbows, in fall 1991. The ceramic used was a high alumina material, ½ inch thick. At the end of the three-year period, the material still appeared to be in good condition. The straight sections of pipe were not replaced at that time.

In August 1992, an inspection of the sorbent transport pipe downstream of the combustor isolation valves revealed severe erosion of the pipe adjacent to the combustor isolation valve. It was determined that a mismatch in the bore diameters, between the pipe and the isolation valve, resulted in erosion in the pipe. The pipe was replaced with a test section of a carburized, 310H stainless steel.

The first straight section of sorbent pipe failed due to erosion after approximately 4800 hours of operation. Several days later, another hole developed just downstream of the combustor isolation valve. This leak was located in the carburized pipe that was installed in September 1992. Both leaks were due to disturbances in the flow path inside the pipe which resulted in accelerated erosion of the straight pipe. A program was implemented to replace all of the SolidResist straight piping with ½ inch thick ceramic-lined pipe. Routine inspection of the ceramic sections installed in late 1991 indicate no erosion of the ceramic sections.

Rotary Feeders

Sorbent was fed from each lockhopper by a star type rotary feeder. Numerous problems were identified early in operation. Binding of the rotary assembly, packing and bearing problems, and problems with the control range at low feeder speeds were common, due to the severe dust loading.

The first problem that developed on the feeder was with control range of the feeder at lower speeds. During initial combined cycle operations, it was found that the feeder could not be slowed sufficiently to satisfy low sorbent feed requirements. The feeder sprocket was changed, in December 1990 to improve low-speed characteristics. The need to operate at lower speeds precipitated another problem. The existing feeder drive system could not produce sufficient torque at low speeds to overcome binding in the feeder and the weight of the sorbent on top of the feeder. Purge air was introduced to the end cavities of the feeder to keep material from building up between the rotor and the end housing near the shaft packing to reduce binding.

The 1.5 hp feeder motors were replaced with 3 hp motors. This reduced the binding problems that were occurring at the lower feeder speeds.

Pickup Pots

The transition from the rotary feeder discharge to the sorbent transport pipe is a severe service location. The sorbent is discharged from the rotary feeder into a large area where it is entrained in the sorbent transport air and swept into the sorbent transport pipe. Originally, the pickup pots were fabricated from stainless steel plate. These were replaced within the first year. Over the next year, the inside surface of the pot was weld repaired with hard surfacing weld rod in order to reduce the erosion rate. Finally, in the spring of 1993, the pickup pots were replaced with ceramic lined pots. The ceramic withstood the erosion and remained in good condition throughout the remainder of the test program.

Sorbent Distribution Piping

The original plant design included two sorbent injection nozzles penetrating the combustor and boiler front wall at the same elevation as the fuel nozzles. The nozzles were between the #2 and #3 fuel nozzles and between the #4 and #5 fuel nozzles. Since early 1991, the question of sorbent distribution and its impact on sorbent utilization has been of primary concern. Several different types of sorbent distribution nozzles and configurations were tested to evaluate the impact of sorbent distribution on sorbent utilization. These tests included simple tees installed on the end of the two existing sorbent nozzles, tees with skateboards above them, and a redesigned four-point distribution system. The mechanical aspects of these modifications are briefly discussed below and the performance evaluation is discussed earlier in Section 5.2.

Original Two-Point Injection Nozzles

The original sorbent injection points were located between the fuel nozzles as discussed above and only extended about six inches into the fluidized bed. Later, they were extended to about a four foot penetration. Still later in the project, the nozzles were cut off and again only extended six inches into the fluid bed. This configuration is considered the base for sorbent utilization improvements.

Initial Tees on Four Foot Nozzles

In May 1991, in the first attempt to test redistribution of sorbent in the bed, standard 90° pipe tees were installed on the end of both sorbent injection nozzles in the bed. At the time, the sorbent injection nozzles extended four feet into the bed. The tees were removed after one run, when it was suspected that they were contributing to primary cyclone pluggages.

Tees With Skateboards

The next attempt at sorbent redistribution occurred in February 1992. During this test, tees were again installed on the ends of four feet sorbent nozzles. In addition, short pipe sections were installed on the ends of the tees and directed sorbent flow toward the adjacent fuel nozzles. Sorbent diverter plates, known as skateboards (which extended from the sorbent pipe to the coal skateboard), were installed. The entire configuration was intended to distribute the sorbent in the bed and to obtain some mixing with the fuel under the coal skateboard. This modification was abandoned due to an on-going problem with in-bed deposits. (Refer to Section 5.9 of the report covering the first 3 years of operation.)

Higher Velocities With Tees

In September 1993, heavy wall tees were reinstalled on the end of four foot extensions on the sorbent nozzles in the bed. No sorbent skateboards were installed, but the tees had pipe extensions that directed the sorbent at the center of the coal skateboards. Orifices were installed on the four ends of the tees to try and maintain velocity. The tees also had splitter plates installed down the centerline of the common inlet lines to evenly distribute the sorbent between the two discharges. This configuration operated for 487-hours. No sorbent clinker formations were observed. The tees were found to be severely eroded at the splitter plates and orifices. One leg of one tee was found totally plugged with sorbent. The tees were removed since no significant increase in sorbent utilization was observed.

Four Point Distribution

The four-point distribution system was originally installed as a temporary test arrangement. This configuration involved splitting the two sorbent pipes into four pipes outside of the boiler and then penetrating the boiler front wall with four separate sorbent nozzles. In addition, the nozzles only penetrated six inches into the fluidized bed and the flow direction was from the front wall to the rear wall. All of the piping incorporated conventional pipe sections made from heavy wall stainless steel. The two new boiler penetration points were between the #1 fuel nozzle and the reinjection nozzle on the right side of the boiler, and a mirror image on the left side. Sorbent was now injected between all adjacent fuel nozzles except the center two. This temporary piping eroded rapidly, necessitating a return to the original two-point feed configuration until ceramic line piping was obtained.

Ceramic Distribution Pipe

In early February 1994, permanent ceramic-lined sorbent distribution piping was installed that duplicated the four-point configuration outlined above. The unit was returned to service and operated in this configuration for the remainder of the test period.

6.9.2 Operating Experience Overview

During the initial six to nine months of operation, the sorbent injection system availability and reliability was poor. Numerous valve, feeder and control logic problems resulted in the system tripping out of service. Restarting the system was time consuming and difficult. Resolution of valve problems was an on-going project. The worst valves were repaired, replaced, or relocated within the first year of operation. However, valve operation reliability was still an issue on several valves well into the third year of plant operation.

Reliability of the sorbent transport system was affected by the transport piping. Since the first erosion failure occurred after 350 hours of coal fire operation, replacement of sections of the sorbent transport system was accomplished in successive, convenient outages. The ceramic pipe sections that have been installed appear to be acceptable for this type of application. Little or no subsequent wear was experienced.

Since early 1992, the general availability of the sorbent injection system has been acceptable.

6.9.3 Final Inspection

The modifications made to incorporate ceramic lined components in the sorbent injection system proved very effective. No indication of erosion was found in any component having properly installed ceramic lining.

6.9.4 Summary and Conclusions

After experiencing poor availability and reliability during the first year of operations, the sorbent injection system evolved to attain an acceptable level of performance and reliability.

6.10 Cyclone Ash Removal

Cyclone Ash Removal System Pluggage

One of the most persistent problems with cyclones was pluggage of the ash removal system. Pluggages in either the primary or secondary cyclones were immediately noticeable. The cyclone dip legs would quickly fill with ash to nearly the top of the cyclone cone. Once the primary cyclone was filled, the ash would be carried over into the secondary cyclone and would quickly overwhelm the secondary ash removal system. At that point, the secondary cyclone would begin to fill with ash. When both a primary and secondary cyclone plugged and filled with ash, untreated gas would reach the gas turbine and result in high rates of erosion. Over the first three years of operation, this scenario occurred only once - in late 1990. The unit operated for several hours until it was verified that both cyclones were plugged. Subsequent inspection revealed noticeable gas turbine erosion. Based on these observations, a policy was established to trip the unit as soon as cyclone pluggage was suspected.

It was very difficult to operate the unit for any extended time period without experiencing secondary cyclone pluggage. Secondary cyclone pluggages were originally handled in the same fashion as primary cyclone pluggage - the unit was shutdown. However, by mid 1991 it became apparent that secondary cyclone pluggages had little impact on gas turbine erosion. Therefore, from mid 1991 to early 1993, the unit was not shut-down when a secondary cyclone plugged, and was operated for a considerable amount of time with secondary cyclones plugged.

All secondary cyclones have operated properly since the secondary cyclone ash removal system was replaced in spring 1993. Since that time, the secondary cyclones have been out of service for a few hours.

6.10.1 System Modifications

The cyclone ash removal systems for both the primary and secondary cyclones have been significantly modified. The primary ash removal system was decoupled from the secondary ash removal system and had several modifications made to the system itself. The secondary ash removal system was totally replaced. The following is a brief overview of the more significant modifications made to each of these systems:

Primary Ash Removal System

The plant began initial operation with bed material on October 19, 1990, and progressed in steps up to the first coal-fired combined-cycle operation. During the run the week of December 15, 1990, the first cyclone ash removal problems occurred.

The following sections address the problems identified in the primary ash removal system:

Internal Ash Cooler Return Chambers

The internal ash coolers are an integral part of the ash cooling system designed to cool the ash to an acceptable level for discharge from the combustor vessel. Air inleakage in the primary ash system became a major issue in June through August 1991. During that period, air testing of the system revealed significant numbers of gaskets on the cooler return chambers and tee bends to be leaking so severely that the system could not be pressurized for an air leakage test. Many gaskets had to be replaced and bolts retorqued before the system could pass an acceptable leakage test.

Subsequently, the entire ash system was disassembled. A detailed inspection revealed a combination of shop fabrication and design oversights. There were significant mismatches in the mating flanges between the ash cooler pipe flanges and the return chamber casting flanges. This resulted in a reduction in seating surface of the gasket between the return chamber and the pipe flange. This 63% reduction in gasket seating surface resulted in an ineffective gasketing installation.

This problem was corrected by machining down the faces of the pipe flanges to achieve a flat and continuous gasket sealing surface. This modification appeared to be successful until mid 1993 when failures of the graphite gasket began to occur. A program to replace all of these gaskets was initiated in early 1994.

Internal Ash Cooler Return Chamber End Caps

The end of each ash cooler return chamber has a rectangular end cap which is removable for inspection of the return chamber. This end cap has a raised-face sealing surface for the gasket.

This flange was found to be a major source of air leaks. Temperature was determined to be a significant factor - the hottest return chambers leaked worst and the coolest usually did not leak at all.

A detailed inspection of these end caps revealed several design and fabrication flaws. The first was with the bolt holes cast into the end caps. The holes were designed to be 10 mm but, in fact, were slightly larger. The bolt hole location tolerance was $\pm$ 0.5 mm, which was difficult to achieve. The bolts were hex head cap screws with washer faces. The washer face O.D. was smaller than specified.

All of these factors resulted in many of the end cap bolts being off center in the end cap holes, and one side of the bolt slipping down into the bolt hole. The resultant improper torquing resulted in ineffective sealing.

In addition, inspections revealed the faces of the castings to have significant sand pits. These pits sometimes were on the narrow raised-face gasket surface. Pits in this area compromised an already marginal gasket condition. Some of the end caps were later ground down to eliminate the pits in the gasket area.

All of these bolts were replaced, along with the addition of standard flat washers and graphite gaskets in 1991. While this improved the air inleakage problem, leakage of these flanges continued to be a routine maintenance concern, approximately 20% of these gaskets were replaced during any routine outage.

Casting Quality

All of the tee bends, cooler return chambers, and cooler outlet collection headers in the original ash removal system were cast from an erosion-resistant material. While this material was very effective against erosion, the quality of the castings was marginal. Many of the castings exhibited sand pits and gas vent holes in the gasket seating area. These were replaced or repaired.

Primary Suction Nozzle Strainers And Purge Air Nozzles

A number of ash removal suction nozzle blockages were attributed to either ash sinters formed in the cyclone when a primary cyclone fire occurred or to spalling chips of cyclone refractory which break off the refractory in the cyclone. An effective modification to prevent suction nozzle blockage was installation of strainer cans around the circumference of the suction nozzle. There were no instances of blocked suction nozzle inlets from refractory chips or ash sinters, except during a significant ash fire in a primary cyclone.

Since the suction nozzles take their ash/gas stream flow off the bottom of the bellows boxes, the suction nozzles can easily be overwhelmed with ash from a cyclone ash fall or ash loading upset or "burp". This results in a pluggage of the ash line, with no reliable method to re-establish transport flow. In order to maintain a reliable source of transport flow into the ash line, a small orificed purge line was installed to channel air into the inlet of the suction nozzle. This line takes air directly from the combustor vessel and routes it directly into the suction nozzle, thereby maintaining transport flow even if gas flow from the cyclone dip leg is reduced or eliminated.

Secondary Ash Removal System

The original design for the system was based on achieving sufficient velocities within the system to transport the ash. It was also believed that the systems were balanced sufficiently, so that the secondary system could be coupled downstream to the primary ash removal system without any negative impacts on either system. The actual velocities in the system proved to be too low, and were revised upwards. The systems were decoupled after it was determined that the expected balance between the two systems was not achievable. These two modifications significantly improved system reliability.

The next major challenge was to eliminate ash buildup in the long secondary cyclone dip legs. This ash could suddenly collapse into the dip leg, and overwhelm the suction nozzle. A companion problem also existed in providing sufficient motive force to keep the dip leg clear of ash at low pressure vessel pressures, such as those encountered at start up and shutdown.

After exhausting most possibilities for making the original secondary ash removal system reliable, a decision was made to replace the system in its entirety with a new system using an independent ash line from each cyclone.

Transport Capacity

Problems with the secondary cyclone ash removal system started shortly after unit start up. Five of seven secondary cyclones plugged 7-1/2 hours into initial coal fire. The pluggages were attributed to low transport capacity during unit start-up. As a result, fluidizing purge air nozzles were installed that would keep the inlet area around the suction nozzle fluidized and permit orderly flow of ash into the suction nozzle.

Pluggages during subsequent runs confirmed that the transport capacity of the secondary ash system was marginal, especially at low combustor vessel pressures. A multi-step program was initiated to improve transport capacity. The first step was to reduce the internal ash cooler from eleven-passes to three-passes. Since this would increase the ash temperature leaving the combustor, the bypassed external ash cooler was reinstalled to aid in ash cooling. This proved helpful, but did not eliminate the problem.

Subsequently, the secondary and primary ash removal systems were decoupled, and the secondary ash removal line was routed into the precipitator inlet duct. In addition, extensive air flow tests were conducted on all seven ash lines within the combustor vessel.

The results of these air flow tests were significant. The original design assumed a high erosion potential resulting from high velocities, and the system was designed to address those concerns. The air flow tests showed that the actual velocities in the ash lines were significantly lower than design.

Modifications were made, during subsequent outages, to increase system capacity and eliminate other potential causes of pluggage. These modifications included:

Reinstallation of the secondary suction nozzle fluidizing nozzles.

Installation of "hot boxes" on the boiler bottom to preheat the air to the secondary fluidizing nozzles.

Elimination of the secondary cyclone dip leg coolers.

Implementation of a new combustor vessel startup prewarming procedure.

Increasing transport capacity by increasing the external secondary ash line to 1.6 times the original area.

Pluggage problems continued to impact the system. A decision was taken in mid 1991 to operate the unit, even if one secondary cyclone was plugged.

The following is a discussion of problems that were encountered after the first quarter of 1991:

Transport System Integrity

The secondary ash system was plagued by air leakage and deposit blockage in the ash cooler collection headers.

Throughout Summer 1991, the secondary ash system suffered five ash line plugs. Originally, it was thought that transport capacity problems were surfacing again. However after inspections, it was found that blockage of the combined ash line was the problem. The ash pipe in the thermal sleeve through the combustor vessel wall had slipped out of its seating ring. The resultant slippage had significantly restricted the area of the combined ash line. At the same time, a hard deposit had built up on the collection header between the #24 and #25 ash lines. Again, this buildup significantly restricted the cross section of the ash transport line. These problems were corrected.

Flange Air Inleakage Modifications

As discussed in the primary ash removal section, air inleakage at return chamber and tee bend flanges also impacted the secondary ash removal system. Since the early indications were that the secondary ash was not erosive, a decision was taken in fall 1991 to weld the system up solid.
All of the cast tee bends and return chambers in the seven individual ash lines were replaced by prefabricated stainless steel 90° tees, with a dead leg in the direction of flow. The return chambers were replaced by two 90° tees in series.

This modification eliminated all flanges in the secondary ash line between the suction nozzle flange up to the collection header flange.

Ash Cooler Return Chamber Erosion/Replacement

The internal secondary ash cooler return chambers were replaced in fall 1991 with solid welded stainless steel return bends.

Total Secondary Ash Removal System Replacement

The entire secondary ash removal system was replaced in early 1993. Six new lines were run from the suction nozzles to the economizer outlet duct.

6.10.2 Operating Experience Overview

Primary Ash Removal Experience

The primary ash removal system operating experience was acceptable, but its maintenance requirements were excessive and unacceptable for a commercial plant.

Over the first two years of operations, the primary cyclone ash removal system had limited impact on unit operation. However, the need to routinely repair leaks in the primary system in order to minimize air inleakage and maximize system reliability was stressed.

The final primary ash removal system configuration proved capable of performing the required function, as long as the system air leakage rate was minimized through extensive routine maintenance.

Secondary Ash Removal Experience

The original secondary ash removal system was not capable of performing its design function. The first two years of unit operations were only completed after it was acknowledged that unit operations would have to continue despite secondary cyclone pluggages. The reliability and availability of this system was totally unacceptable. No amount of maintenance could be completed to assure trouble-free operation of the system during the next operation run. The secondary ash removal system was truly the "Achilles Heel" of the plant.

At the beginning of the third year of operation (1993), it was decided to replaced the entire secondary ash system with a new system consisting of six independent ash lines. Since that system was installed, the secondary ash system operated at almost 100% reliability. From June 1993 to the end of the test program, the secondary ash system only plugged on two occasions, and suffered one deposition/erosion-related failure.

Shortly after the revised system was installed, an ash fall occurred in all six secondary cyclones during startup. Once coal fire was achieved with a corresponding higher combustor vessel pressure, all six lines were unplugged via the ash line blowback valve stations. Each line was isolated back to the economizer, high-pressure sorbent air was blown back up the line into the dip leg and then flow was re-established to the economizer. Each line was cleared individually and returned to service immediately once the blowback was completed. On another occasion, a hard deposit of ash bridged over the ash line orifice in one ash line at the economizer. The line was isolated from the combustor, the deposit rodded out and the line returned to service.

An erosion failure occurred in December 1993, on a long-radius bend outside of the combustor. A very hard deposit had built up inside the ash line and resulted in erosion of the ash line in the same vicinity as the deposit. The ash line was isolated at the combustor, the failure was isolated within the specially designed bend, and the ash line was placed back into service. All of this was accomplished within 20 minutes of the original failure.

The only problem that impacted revised secondary ash system availability was the buildup of an extremely hard deposit in the ash lines that resulted in the erosion failure. These deposits occurred in high impact areas with no regularity, and could not be predicted. No explanation of the cause of the deposits was found.

6.10.3 System Inspection

A selected sample of both the primary and secondary ash removal piping systems was removed as part of the final inspection program. The following was observed:

Primary ash removal system:

A number of erosion resistant "Tee" bends and internal ash cooler turnaround heads were sectioned for inspection. The cast material showed no significant erosion. It is expected that the service life of such bends would be acceptable in a commercial application.

Secondary ash removal system:

A number of long radius bends, installed in 1993 as part of eliminating flange connections in the secondary system, were sectioned for internal inspection. The inspection confirmed previous observations that erosion is not a significant issue in the secondary ash removal system.

6.10.4 Summary and Conclusions

The cyclone ash removal systems have had a significant negative impact on unit operations, availability and reliability. The original secondary ash removal system design did not work. The redesigned system installed in early 1993 was successful and demonstrated that pneumatic ash transport is viable for this type of application.

The current system achieved and surpassed its operation goals for availability, reliability, and maintainability. However, the system requires optimization to minimize gas transport requirements.

The primary ash removal system as installed is a partial success. The overall system design appears to be acceptable however leak tight flanges which can survive the high operating temperature are not fully proven. A high incidence of gasket failure was evident. The development of welding techniques permitting welding of the erosion resistant material into the system would significantly reduce maintenance and improve reliability. Equipment modifications would be required before the system could be commercialized. The ability to maintain the system must be thoroughly evaluated for a commercial system. The air inleakage problems associated with the hundreds of bolted flanges must be resolved. The ability to unplug ash line pluggages on-line must be fully developed. The system shows good promise, but must be improved further before it can be considered a commercial system.

6.11 Bed Ash Removal

6.11.1 System Modifications

Evaluation of the Tidd bed-ash cooling system, prior to unit start up, indicated that the system would not be capable of cooling the bed ash drains to the desired temperature. A design modification was implemented to provide additional cooling air to lower parts of the bottom hoppers. Several additional, minor modifications were made to improve the reliability of the system. The two ball valves used for lockhopper pressurization were modified with larger actuators to ensure smooth valve operation. The solenoid valves in the air lines to the L-valves were replaced and restrictive orifices removed because the pressure drop across the original valves was insufficient to allow the valves to operate. The drip chute on the end of one of the conveyors was enlarged to prevent ash build-up around the conveyor rollers. Late in the operating period, dams were added in the L-valves in an attempt to resolve ash flow through problems experienced with finer bed material.

6.11.2 Operating Experience Overview

The bed ash removal system proved to be one of the more reliable systems at Tidd. The system operated as designed and without excessive maintenance. Good flowability of the bed ash undoubtedly contributed to the high reliability of the system. The few trouble spots were ball valve seat wear and conveyor belt and roller wear. Occasionally, high ash temperature in the boiler bottom hopper bottoms was encountered, particularly when problems were experienced with the control of the L-valves. The ash cooling system functioned well until mid-1994, when finer sorbent sizes were tested. The switch to finer sorbent feed resulted in bed ash L-valve flow control problems and insufficient ash cooling. It is believed that the finer bed material tended to "rat hole" down through the boiler bottom hoppers, thus significantly reducing the contact area and time for the cooling air, resulting in excessively hot ash reaching the bottom hopper outlets. The extremely fine bed ash also tended to flow through the L-valves without pulse air present, making control of the drain rate difficult. The above noted dams that were added in the L-valves proved somewhat successful at resolving the L-valve ash flow through problem. The ash rat holing problem was never solved, and it became a severe operating difficulty whenever sorbent feed top sizes were below 12 mesh, limiting either test load or test duration.

6.11.3 System Inspection

No unusual conditions or wear were noted.

6.11.4 Summary and Conclusions

The overall performance of the system proved excellent. No forced outages were ever caused by the bed ash removal system. However, if finer ash is to be expected in future commercial PFBC units, then the bed bottoms will need to be redesigned to avoid "ratholing" and the L-valves designs will need to be modified to prevent ash flow through problems.

6.12 Bed Ash Reinjection

6.12.1 System Modifications Completed

Vent Line Orifice

The main vent line orifices were reduced in size to eliminate excessive venting capacity.

Low Load L-Valve Fluidizing Air Isolation Valve

A tight shutoff manual ball type isolation valve was added in the air supply line to the L-valve to eliminate air leakage which caused material to flow when the L-valve was not being pulsed.

Vent Line Isolation Valves

The vent line isolation valves experienced difficulty in closing completely, resulting in leakage. These valves, which originally relied only on the actuator spring to effect closure, were modified to have control air assist in the closing.

L-Valve Restriction Plates

For cost-effective design and procurement, the L-valves for Tidd and its sister units were all made the same size even though the specified maximum rate of unit load change for Tidd was only half that of the other units (2% per minute versus 4%). In order to limit the maximum ash flow rate and provide sufficient capacity turndown, restriction plates were incorporated into the Tidd L-valve vertical inlet leg. Due to problems with plugging of the L-valves, these restriction plates were removed. This modification was of some benefit.

6.12.2 Operating Experience Overview

The bed ash reinjection system functioned reliably in achieving desired bed height changes. The maximum rate of unit load change capability was specified as 2% of full load per minute; however, due to concerns about unit stability and the concern of overloading the cyclones from the additional dust loading generated when rapidly changing bed level, the system was operated with a maximum rate of change of 1% per minute.

The most significant operating issue with the system was occasional plugging in the feed lines from the reinjection vessels to the bed. Such plugs or restrictions were caused by large chunks of agglomerated bed material becoming lodged at the L-valve restriction plates. Removal of the restriction plates moved the choke point further upstream to the standpipe inlets located inside the reinjection vessels. It is now believed that the bed agglomerations which caused the plugs were not being formed in the reinjection vessels, but were rather being drawn out of the bed by the suction nozzle and lift line. This theory was borne out in the final year of operation. Bed reinjection vessel discharge line plugs were nearly non-existing after improved fluidization was attained.

When attempting to use spent bed ash to start the unit, the bed material tended to break up excessively. This resulted in problems with overloading of the primary cyclone ash removal system, which experienced numerous plugs. Feed material attrition also taxed the storage capability of the reinjection system in regard to its ability to attain sufficient start bed height. These problems were solved at Tidd through the use of sand for the initial start bed.

When the material stored in the reinjection vessels was finer than normal, uncontrollable material outflow was sometimes experienced when no fluidizing air flow was admitted to the L-valves.

The system controls include a recirculation mode to circulate material from the bed when operating at steady bed heights for extended durations. This mode of operation was intended to insure that the material stored in the vessels was relatively hot. It was felt that high feed rates of ash cooled to the combustor vessel temperature would present an excessive heat sink to the bed during rapid load increases, which were likely not tolerable by the bed temperature controls. The recirculation system was never used for this purpose and no significant bed temperature control problems were experienced. However; as noted above, the maximum rate of load change used was typically kept to less than 1% per minute. Bed ash recirculation was used to move bed material in attempts at mitigating the sintering problems encountered in early 1994.

6.12.3 System Inspection

No abnormal conditions were noted.

6.12.4 Summary and Conclusions

The bed ash reinjection system functioned very reliably and can for the most part be considered a fully commercial design. The ability for a PFBC unit to follow a load change demand has only been demonstrated at relatively low rates of change; however, this is not seen as a major issue at this time. Occasional plugging of the L-valves remains the only significant problem, however, this can be avoided if in-bed agglomerations are minimized by insuring adequate bed fluidization.

6.13 Gas Turbine/Compressor

6.13.1 System Modifications Completed

Seal/Cooling Air Orifices

The seal/cooling air orifices in the gas turbine were resized early in 1991 to balance the HP turbine 4th stage and LPT inlet and outlet disk temperatures. The seal/cooling-air orifices were again resized in spring 1992, following a testing program with an adjustable orifice, to increase the temperature at the inlet of the 1st stage of the HP turbine. One of the two was further modified for the addition of an external dry-air supply for start ups. The HPT inlet seals were modified during 1993 to incorporate a variable orifice in place of the fixed orifice and to provide an external air supply. As 1994 came to a close, unit testing shifted to attaining maximum firing rates on the unit. The gas turbine was then being subjected to the highest combined gas weight and gas temperature of the entire program. Insufficient disc cooling air to the LPT was again found to be a problem. This was resolved by increasing the size of the orifices.

Cold Air Intercept/Bypass Valves

The cold air intercept/bypass valves (called bypass valves for this section) had problems with sticking in the lower bushings early in 1991. The lower bushings were machined to a larger inside diameter twice and the effective length of the bushing was reduced once. A new design bushing and a sleeve for the valve stem were installed in fall 1991. There were no further problems with valve sticking.

The bypass valve seat was replaced with a new design seat in spring 1993. The old seat was a non-contact slip-fit design. The new design was a positive closure valve seat. This was modified to help reduce air leakage. Subsequent testing showed some improvement in air leakage from this and other modifications.

Lubricating Oil Piping

The lube oil piping to the reduction gear on the gas turbine cracked at one of the four inlet pipe stubs. The cracked pipe was seal welded and all four inlet pipes were reinforced at the stress riser location. The four fixed pipes from the header to the inlet stubs were replaced with flexible hoses to reduce potential future problems due to reduction gear vibration. This modification was completed in fall 1991.

Intercooler Heater

Repeated problems with sticking air bypass valves pointed out the importance of maintaining dry air in the turbines during shutdown periods. A heater was added, in fall 1991, to the intercooler recirculation loop to warm the air flowing through the HPC from natural chimney draft. The warmed air flowed through the turbines, eliminating condensation problems.

Reduction Gear Vibration Indication

Reduction gear vibration indication had been erratic during early operation. The vibration transducers were bolted to the rounded flange of the gear casing, causing flexing of the transducers and resultant erratic readings. Flat spots were machined into the flange in July 1991 to mount the transducers. This helped the symptoms but did not solve the problem over the load range. Boxes were manufactured for mounting over the transducers to protect them from suspected magnetic fields. It was found that the best arrangement was mounting the transducers on top of the boxes (bolted to the flange) with the transducer mounting arrangement changed from a three-bolt design to a center-stud design. This modification helped with agreement between station indication and portable vibration test equipment indication, but problems remained with the erratic indication. A capacitor was installed in the electronics to filter the high frequency vibration. This provided some minor benefit. A mechanical filter was supplied by ABBC to install between the accelerometers and the boxes. This did not seem to provide any benefit. The grounding system was changed, which greatly improved vibration indication. The mechanical filters were eventually removed, and a high temperature glue was used to provide better mechanical fastening.

LPT Guide Vane Ring

The LPT inlet guide vanes experienced some sticking problems due to combustor ash in the guide vane pivot bushings. The bushings were modified in fall 1991. The modification included enlarged bushings and a new seal rings in the outer guide vane ring. There have not been any additional problems with sticking guide vanes at Tidd since the modification.

The unit experienced five gas turbine trips prior to November 1990, related to failure of the LPT guide vane position feedback loop to NET 90. A redundant feedback signal was installed to prevent false trips and to help locate the problem. The redundant feedback loop did prevent several false trips.

A guide vane linkage sticking problem at another PFBC plant in Europe caused a modification of the linkage ball joints, bushings, and bolt material during the LP turbine blade outage in spring 1993. Tidd did not experience any problems with the guide vane linkages prior to or after the modification.

HPT Casing Seal Air

An internal HPT casing erosion problem was found at another PFBC plant in Europe in summer 1991. The modification performed at Tidd to eliminate the erosion involved plugging the internal seal air passage and welding in new seal air connections from the seal air valves. The erosion on the Tidd HPT casing was mild enough that no repair to the casing was required.

HPT Inlet Thermowells

The HPT inlet thermowells were modified in fall 1991 to reduce air leakage between the inner and outer coaxial pipes. A second thermowell was added to the 90-degree elbow in the coaxial pipe and the attachment was changed to a threaded connection to the inner pipe. Air leakage reduction from this modification was too small to measure.

Intercept Valve Casing

The intercept valve casing attachment to the HPT was modified during the bed addition outage in fall 1991. The connection originally used two piston seal rings to provide the seal between the air and gas side of the connection. Due to air leakage concerns, the connection was modified to include a bellows assembly. The air leakage reduction from this modification was insignificant.

HPT Outlet Pressure Tap

The HPT outlet pressure tap plugged with ash periodically in fall 1991. This pressure measurement was part of the turbine trip interlocks. The tap was modified to provide a continuous supply of purge air from the plant dry air supply piped to the orifice. No more plugging problems were experienced.

Speed Transducers

The zero speed transducers supplied with the gas turbine for the HP and LP shafts had failed by fall 1991, due to overheating. They were replaced with higher temperature pickups.

Seal Air Valve

The seal air valves experienced sticking problems by fall 1991. A modification to allow each valve to be manually jacked open during gas turbine startup. This feature was used several times.

Control Fluid

The control fluid system had problems with the trip header pressure dropping below the trip limit when the two control fluid pumps switched running/stand-by condition. A constant air bleed valve was installed in the control fluid pump discharge lines to prevent the stand-by pump from becoming air-locked. This modification did not prevent the trip header pressure from dipping during pump transfer. This was finally solved by slightly lowering the control fluid temperature set point. The air bleed valves did help prevent startup problems following maintenance when the pumps were inadvertently not filled with oil. This modification was installed in spring 1992.

LPC Throttle Valve

The LPC throttle valve is a barrel-shaped cylinder that seals the inlet to the LPC while the de-humidifier is operating. The valve was originally designed to be closed by three hydraulic cylinders spaced around the valve. However, it was found to be extremely difficult to keep the cylinders operating in unison to keep the valve from becoming jammed. The hydraulic cylinders were removed and the valve was closed by hand with a chain-fall. The valve did not seal well in the open position during operation, allowing dirt to bypass the air inlet filters. The valve was sealed from the outside with various materials with limited success. The valve V-seal was reversed and a shim installed underneath to give it greater compression during the 1992 gas turbine outage. This provided a good seal with no leakage. The outside of the valve was sealed with RTV after it was decided not to close the valve for gas turbine dehumidification (the intercooler heater was installed).

HPT Outlet Guide Vane Ring

The HPT outlet guide vane ring had a single anti-rotation pin. This pin broke, allowing the ring to rotate at one of the PFBC plants in Europe. A second anti-rotation pin was installed from the outside of the Tidd HPT casing during the 1992 gas turbine outage.

Air Intake Hood

The gas turbine air intake housing was installed with louvers to prevent rain from clogging the intake filters. However, during winter 1991, the air intake filters were plugged with snow three times which caused the filter by-pass blow-in doors to open. A modification was installed in 1992 to replace the louvers with weather hoods. The weather hoods, which were designed for both rain and snow, did not completely prevent snow from plugging the air intake filters. A thin filter blanket was used to collect the snow until the blanket also plugged. The thin filter blanket was then easily removed to remove the snow.

Low Pressure Turbine Blades

The LPT was opened for inspection in spring 1992 after cracks were found in the LPT blade roots at a PFBC plant in Europe. Nine blades on the Tidd LPT were found cracked below the platform at the front corner of the suction side of each blade. The cracks were caused by a resonant frequency vibration that caused high-cycle fatigue. The blades were replaced with a new design intended to reduce these stresses. Modifications included trimming the trailing edge, machining a larger radius in the blade root hook fit, shot peening the blade root hook fit and installing dampener buttons between the blades.

In February 1993, the LPT threw two blades. The cracks initiated from under the platform at the rear of the suction side of each blade. The blades again were redesigned to eliminate the problem with high-cycle fatigue from resonant frequency vibration. The modifications included trimming the support beam from under the rear suction side of the blade platform, and rounding and blending the rear corner of the suction side of the blade root. After replacement of the entire row of blades, a visual inspection of the inlet and outlet side of the blade roots was performed after approximately every 500 hours of operation. No additional cracking was observed in the remainder of the test program.

HPT Shaft Seal

Sealing air for the HPT is supplied by the HPC via orifices and from seal leakage from the HPC exhaust. Inadequate sealing at the inlet of the HPT allowed leakage of this sealing air to the gas flow through the HPT. This seal was modified during 1993 to reduced the leakage.

LPT Flow Guide Manhole

Visual inspection of the LPT blade airfoils was difficult due to a lack of borescope inspection plugs and the distance from the exhaust flow guide turning vanes. A manhole was cut in the exhaust flow guide to allow access to the blades and guide vanes for visual inspection.

6.13.2 Operating Experience Overview

Very little was required in the way of routine maintenance for the gas turbine. The gas turbine had several chronic problems that were difficult to remedy. The first problem noted involved the electronics. The European instrumentation had compatibility problems with American-made equipment. This caused considerable hours of effort to "debug" erratic indications. Many of these problems were caused by different sensitivities and different grounding philosophies. The second major problem was air leakage from the calculated air flow through the HPC to the LPT exhaust, as determined by the calculated air available to the combustor. A test program was conducted after the 1993 LPT blade failure outage to help locate the air leaks. A number of modifications were made, as noted in the sections above, and some leakage was reduced. The third major problem and the most damaging to gas turbine availability, was the LPT blade design. Several long outages were initiated by cracks in the LPT blade roots. The blade root problem necessitated a series of tests to determine operating ranges that were detrimental to the LPT blades and needed to be avoided.

Other problems experienced included LPC stationary guide vane cracking in the first and second stages. ABBC recommended a modification following the discovery of the cracks in December 1993. The guide vane rings were repaired and inspected periodically for any new cracks. A more rigid cleaning schedule was imposed to reduce the risk of further cracking. Another problem was ash plugging of the HPT seal air passages where the seal air thermocouples were located. This caused some operational uncertainty due to high temperatures.

Erosion on the machine continued to be relatively minor with the exception of the erosion observed at the low pressure turbine inlet guide rings. Erosion at this location had been previously identified and a revised design was proposed. However, owing to the cost and schedule to modify the machine, it was decided that the relatively short life of the Tidd project did not warrant this modification. Erosion in this area required constant attention. The LPT inlet guide vane rings were rebuilt twice during the fourth year of operation. Some erosion damage was also observed at the base of the suction side of the low pressure turbine blades. This did not require attention.

The intercooler experienced a number of tube leaks during the fourth year of operation. These were confined to the tube sheet crevice region and appeared to be due to stress corrosion initiated in surface indentations on the outside (air side) of the tubes. In the fall of 1994 the two top rows of tubes were plugged and the remaining rows were sleeved through the tube sheet region.

6.13.3 System Inspection

Inspection of the gas turbine, subsequent to unit shutdown, provided no surprises. The inspection confirmed the areas of erosion which had been noted during operation. The LPT inlet guide vane rings showed significant erosion. The erosion previously observed on the low pressure turbine blading was still evident. Other areas of erosion were observed throughout the machine. None were considered of great consequence.

6.13.4 Summary and Conclusion

The use of a gas turbine in a flue gas environment no doubt presents some unique challenges. The first-of-a-kind Tidd gas turbine performed well. However, erosion at the LPT guide vane ring was significant in the Tidd machine. It does appear that the revised design incorporated at other operating plants has mitigated if not eliminated this problem. The LPT blade failure issue remains to be addressed.

The Tidd experience clearly demonstrated that a gas turbine can operate in a coal fired flue gas environment with cyclone based particulate cleaning. The operating time at Tidd was sufficient to conclude that erosion is not an insurmountable problem and, in fact, is manageable with the appropriate design. The mechanical failures of the low pressure turbine blades and the development of cracks in both the LPT blade and the LP compressor are considered to be problems not atypical of a first design. It is expected that these issues will be addressed as the technology matures and lessons learned are backfed into the design.

6.14 Gas Turbine Generator and Frequency Converter Systems

6.14.1 System Modifications Completed

No revisions were required on this system.

6.14.2 Operating Experience Overview

The system has operated exceptionally well, with all control, indication, and alarms functioning as expected.

6.14.3 System Inspection

No abnormal conditions were observed.

6.14.4 Summary and Conclusions

The Gas Turbine generator has operated as designed with adequate capacity for this application. The same is true for the Variable Frequency Drive (VFD), the acceleration and horsepower required for startup is well within the capacity of the VFD. The excitation control performed as expected.

6.15 Precipitator

6.15.1 System Modifications

In late 1992 a temporary humidification system was tested to address high opacity, which was experienced during start ups. In addition, upgraded controls were installed as a test, which automatically adjusted the semipulse ratio, voltage, and current as required to overcome back corona.

6.15.2 Operating Experience Overview

The ESP has met its design guarantees during its initial performance testing. However, opacity exceedances occurred during the following operational events:

During startup and at low-bed levels, when the flue gas is at reduced temperature.

When operating at very high calcium-to-sulfur molar ratios, which results in an increased quantity of unreacted sorbent in the ash and a lower concentration of SO_3 in the flue gas.

The opacity exceedances were due to the very fine ash particle size, and monitoring problems associated with the installation of the opacity meter. Although opacity exceedances have occurred, the particulate emissions have remained below the permit limits. (Refer to Section 4.8, Environmental Compliance Tests.)

A humidification system was installed at the ESP inlet in 1992. However, not enough heat was available in the flue gas to vaporize the water, and the precipitator inlet screen and nozzles plugged. The opacity exceedances during startup continued to be a problem during the entire operational period. It is believed that these problems were due to the higher resistivity of the ash at a lower gas temperature and when containing a larger amount of unreacted sorbent.

Because the ESP is energized prior to coal fire, the ash tends to adhere to the plates and wires, and must be rapped off with the field de-energized.

Pluggage of the ash hoppers has been a chronic problem at Tidd. The mean particle size of the ash collected by the ESP is about 2 microns, and the angle of repose of the ash has been measured to be 90°.

6.15.3 System Inspection

No abnormal conditions were observed.

6.15.4 Summary and Conclusions

Operation of the Electrostatic Precipitator at the Tidd PFBC Demonstration Plant has demonstrated two important features:

The ability of an ESP to successfully collect the high-resistivity and very fine (mean particle size less than 2 microns) ash from the PFBC process.

The viability of 16 inch plate spacing in this application as opposed to the norm of 12 inch plate spacing.

The high opacity during start up has been an ongoing issue with the ESP, however, it is believed that if this were an issue with a commercial plant, a humidification system or SO_3 injection system could be installed to improve ESP performance during start up.

6.16 Economizer

6.16.1 System Modifications

The major modification to the economizer was the addition of eight air-powered soot blowers to remove accumulated ash from the fin-tubed economizer surfaces. Four soot blowers were added in fall 1991 and four more were added in 1992.

Anti-vibration bars were installed between economizer tubes to preclude gas flow induced vibration.

A loop seal with a 12 inch drain line was installed in the gas side of the economizer to prevent the gas side from flooding in case of a large tube leak in the economizer.

The vent and drain piping external to the economizer was heat traced and insulated for freeze protection.

Due to a fabrication omission, the economizer did not include seals between the casing and the lower return bends of the economizer. These bends were enclosed in metal boxes attached to the bottom of the casing to seal the gas side from atmospheric pressure.

6.16.2 Operating Experience Overview

The economizer experienced gas-side fouling due to ash particles collecting between the fins on the tubes. In August 1991, the economizer experienced a large feedwater leak which is believed to have been caused by vibration of the tubes due to high gas velocity which, in turn, was caused by ash accumulation on the tubes. Following this event, four soot blowers and anti-vibration bars were installed in the economizer to prevent future occurrences. The economizer fouling was greatly reduced, but not eliminated entirely. Therefore, four additional soot blowers were installed in 1992. Since installation of the eight soot blowers, the unit has performed better but ash deposition was not eliminated entirely.

The economizer performance (heat absorption), following modification, remained below design, resulting in higher exit gas temperature and lower final feedwater temperature. This off-design performance impacted steam flow by approximately 10,000 pounds per hour and reduced steam turbine generator output by approximately 1.3 MW at full load.

6.16.3 System Inspection

No abnormal conditions were observed.

6.16.4 Summary and Conclusions

The original design was based on the prediction that ash would not foul the economizer. However, this design premise proved erroneous, the finned tubes formed a trap in which ash would collect and result in high gas velocities, tube vibration and ultimately, failure of the tube-to-header connections. Economizer performance remained below design despite the addition of eight soot blowers. The tenacious adherence properties of the very fine fly ash contained in the gas turbine exhaust will need to be considered in defining the economizer design parameters for commercial units.

6.17 Gas Turbine Lube Oil

6.17.1 System Modifications Completed

The only modification to this system was the installation of a demister in the vapor extractor exhaust piping during the 1991 outage.

6.17.2 Operating Experience Overview

The gas turbine lube oil system has functioned reliably with very few operational problems.

6.17.3 System Inspection

No abnormal conditions were noted.

6.17.4 Summary and Conclusions

The gas turbine lube oil system design used at Tidd is sufficiently reliable for use in a commercial P200 PFBC facility.

6.18 Gas Turbine Control Fluid

6.18.1 System Modifications Completed

The control fluid system had problems with the trip header pressure dropping below the trip limit when the two control fluid pumps switched operating conditions. A constant air bleed valve was installed in the control fluid pump discharge lines to prevent the stand-by pump from becoming air-locked. This modification did not prevent the trip header pressure from dipping during pump transfer. This was finally solved by lowering the control fluid temperature setpoint slightly. The air bleed valves did help following maintenance when the pumps were inadvertently not filled with oil. This modification was installed in spring 1992.

6.18.2 Operating Experience Overview

The GT control fluid system has functioned reliably with very few operational problems. There were two instances of unit trips, during the fourth year of operation, caused by this system. These were due to the failures of a pressure switch and an "O" ring.

6.18.3 System Inspection

No abnormal conditions were noted.

6.18.4 Summary and Conclusions

The GT control fluid system design used at Tidd is sufficiently reliable for use in a commercial P200 PFBC facility.

6.19 Network-90 Control System

6.19.1 System Modifications

The original master modules were to be redundant Multifunction Controllers (MFC). In the event that the main module would fail, the backup would immediately take over. Before the system left the factory floor it was discovered that 20 seconds was needed for the backup to take over. During this time, all variables would hold their last good values. This was determined to be unacceptable. The MFCs were upgraded to Multifunction Processors (MFP) which required only 6 seconds for the back up module to take control.

System checkout was designed for two groups to be developing the control program and performing simulation tests while two groups test and verify inputs and outputs. Three engineering workstations, two management command consoles and one additional Computer Interface Unit (CIU) were added. This equipment became a permanent part of the system.

Availability of the two original Management Command Systems (MCS) was unacceptable. One additional MCS with two screens and two keyboards was added to the control room. The third MCS was used by operation and management personnel for monitoring. It was also used as a backup in case one of the original two units failed. One additional CRT screen was installed on the original two MCS consoles.

Four Computer Interface Units were added for data acquisition. Hot Gas Clean Up added one Process Control Unit (PCU) with two MFPs and two relay/termination cabinets and an Operator Interface System (OIS). Three MFPs were added to accommodate expanding logic programs. Ground detection alarm circuits with test switches were added to all 125-volt d.c. power supplies. Special double-wide relays were added so that critical control valves could be controlled from two different PCUs.

6.19.2 Operating Experience Overview

Overall, the Network-90 control system operated satisfactorily. Size and complexity was increased by 75% with few problems. PCU reliability was good. All problems were eventually resolved.

The biggest shortfall of the system was data storage. Trend data could be stored in the MCSs for up to three days. Thereafter it was dumped to reel-to-reel storage tape. A multi-tasking Encore computer to support a "Plant Operations and Performance System" called "POPS" was added for the purpose of trending and data storage. The POPS system accessed data directly from the plant loop through two Computer Interface Units. Trend data storage in the control program was not needed by POPS. Network-90 Trends were reduced to a minimum and the original reel-to-reel tape drive was used strictly for environmental data storage.

Power supplies had the worst failure rate of all Network-90 equipment. During the first six months following power-up, 25% of the Module Power Supplies failed. Since then the failure rates dropped to less than 10% per year. Later failures were heat/dirt-related. The PCUs required frequent cleaning to prevent dirt from reducing cooling capacities.

During initial checkout and startup the Management Command System would crash repeatedly. The units would then need to be reset, which took 17 minutes. A control room humidifier was added to reduce the static electricity. Bailey Controls added anti-static kits to each MCS. This reduced the number of MCS crashes to an acceptable level.

MCS software was continually being upgraded by Bailey. The system was purchased with Rev K.1 software. Tidd then became the test site for Rev L.4. Several more upgrades were installed until we finally settled on Rev Q1.1. MCS software revisions were difficult and time-consuming to load, and usually caused other system problems. Software revisions sometimes required firmware changes in other equipment.

Network-90 controls are sensitive to radio frequency (RF). Radio transmissions in close proximity to MCS consoles or PCU cabinets cause abnormal operations. Control rooms were posted: "NO RADIOS". Control room radios were replaced with remote units and the transmitters were moved to a different location.

The computer interface units (CIUs) were a source of system problems. A defective CIU could cause the plant loop to stop communicating. MCS screens could then display incorrect or old data. This was confusing to the operators, increasing the risk of improper operator action. Extreme caution had to be taken when starting equipment connected to the plant loop.

The panel-mounted digital control stations were removed from the system and abandoned in place. On several occasions this equipment caused erratic and uncontrollable operation of critical devices. The exact cause was never found. It was suspected to be in the card edge connectors and PCU daisy chain cable connectors. MCS operation became adequate as the operators gained experience.

Operator interface screens received favorable acceptance by operations. The screen of choice became the "Mimic". The most useful screens developed into the ones with the most information on them.

The capacity of the system had its limits. Overloading the loop was a concern. Loop interface equipment startup caused a surge in loop data traffic. When the traffic reached some undefined high level, the loop "crashed" and the operators were left with no ability to interface with the system.

6.19.3 System Inspection

No final inspection of the control system was deemed necessary.

6.19.4 Summary and Conclusions

The Bailey Network-90 control system served the PFBC combined cycle very well. Its flexibility and ease of control and protection logic programming was an asset. After early failures, the equipment reliability became acceptable. The system had to be kept clean. Future installations should include a more dirt-free environment with reliable heating, venting, and air conditioning equipment.

6.20 Boiler Ventilation

6.20.1 System Modifications Completed

The operators on the system's two combustor isolation valves were replaced with larger size operators due to problems experienced with closing of the valves.

A blind flange connection was added on the vent line from the bed ash lockhoppers. This connection was used to connect the temporary hose used to evacuate the ash/sand transport air when filling the bed ash reinjection vessels.

The atmospheric vent line on the collection hopper, into which the bag filter discharged, was closed off, causing the hopper to run under vacuum. Prior to this modification, air was drawn up into the bag filter fluidizing the collected dust particles in the filter hopper, which inhibited hopper draining.

The oxygen analyzer gas slipstream vent lines to atmosphere were plugging, so high-velocity air purging was employed to periodically clean out the vent lines. This line cleaning resulted in excessive dust emissions to atmosphere. In order to preclude such fugitive dust emissions, the seven oxygen analyzer vent lines were tied into a common vent line that normally discharged to atmosphere, but was connected to the boiler ventilation system vent collection header for dust evacuation during line cleaning.

6.20.2 Operating Experience Overview

The boiler ventilation system functioned very reliably with very few operational problems. The only significant drawback was the need for the NET 90 control system to be in service in order to operate boiler ventilation, since the system was mostly used during outages.

6.20.3 System Inspection

No abnormal conditions were noted.

6.20.4 Summary and Conclusions

The boiler ventilation system design used at Tidd is sufficiently reliable for use in a commercial PFBC facility.

6.21 Nitrogen Gas

6.21.1 System Modifications

The only significant modification to the nitrogen systems was to replace the original vaporizer with one of triple the capacity (33,000 versus 10,000 standard cubic feet per hour). The original vaporizer was inadequate during periods of high system demand and would cause the buffer tank pressure to drop below 280 psig during load decreases. Under load reductions, the bed ash reinjection system nitrogen consumption proved higher than expected.

A removable spool piece was added to the nitrogen supply line from the buffer tank for safety isolation during plant outages.

6.21.2 Operating Experience Overview

The nitrogen systems performed their functions very well. Although the high-pressure system was never called into duty for a loss-of-feedwater event, it was successfully demonstrated during a test of the boiler injection system on May 18, 1991. The high-pressure cylinders required topping off about twice a month. The tank pressure dropped below the minimum during outages when the system was isolated from the injection tank and the line to the injection tank was vented.

The liquid system also functioned as designed following enlargement of the vaporizer. The liquid system required refilling about three times a month.

6.21.3 System Inspection

No abnormal conditions were noted.

6.21.4 Summary and Conclusions

The nitrogen systems were silent support systems which did not receive much attention, but did their jobs when necessary. The systems required only one modification from the initial design.

6.22 Process Air

6.22.1 System Modifications Completed

A number of changes were made to the process air system. These modifications included:

Bed ash cooling air lines were added to supply additional cooling air to two additional lower elevations in the boiler bottom hoppers.

A moisture separator was installed downstream of the process air cooler.

The seals on the guide vanes of the startup fans were replaced with a lower leakage design.

A duct was added inside the combustor vessel to extend the combustor vessel air space system interface pipe down into the bottom of the combustor vessel. This line was installed to direct warm air down to the bottom of the vessel for the "Combustor Warming" mode of operation, which was a new mode added to help heat up the combustor and thereby minimize gas turbine air preheating operation.

A tie-in was installed in the process air system's combustor air space interface pipe between the combustor and that line's combustor isolation valve in order to supply air at combustor vessel pressure to the Advanced Particle Filter (APF) system for ash transport. This tie point was used later to supply tempering air to the APF's inlet gas pipe.

A tie-in was installed at the bed ash lockhopper pressurization line to provide pressurization air to the APF ash removal lockhoppers.

6.22.2 Operating Experience Overview

This system functioned reliably throughout the operating period. The only system issue of note was startup fan surging in the "Combustor Pressurization" mode. If gas turbine alignment to the combustor vessel took too long, the pressure vessel pressure would reach too high a level and the startup fan package would surge as it ran back on its operating curve at low delivered flow. This problem was much worse on hot restarts. It was combatted at times through manual positioning of the combustor cooling system's discharge isolation valve. Partial opening of this valve induced a vent flow from the combustor, which then limited the combustor vessel pressure attained and kept the fan operating further out on its characteristic curve.

6.22.3 System Inspection

No abnormal conditions were noted.

6.22.4 Summary and Conclusions

The process air system design used at Tidd is sufficiently reliable for use in a commercial PFBC facility.

6.23 Combustor Cooling

6.23.1 System Modifications Completed

Due to the large volume of hot pressurized air stored in the combustor vessel, concerns were raised about inadvertent opening of the single combustor inlet isolation valve while the unit was in service. Such inadvertent valve opening would present personnel danger in the combustor building basement. Therefore, a second isolation valve was installed on the combustor inlet line. No second valve was installed on the combustor outlet line, since hot air exiting the combustor through inadvertent opening of the outlet valve would pass safely to the outside atmosphere through the discharge piping which exhausted through the combustor building roof.

6.23.2 Operating Experience Overview

The system cooled the combustor vessel to personnel access temperature levels within 1-1/2 to 2-1/2 days depending on ambient air temperature. Initial personnel access to the lower and middle regions of the vessel was possible sooner than at the vessel top, which remained hot much longer. The overall time frame was longer than expected, which is believed to be due to channeling of the cooling air. There is no distribution ducting for the cooling air, thus it takes the path of least resistance up through the vessel air space.

It was found that in order to achieve sufficient combustor ventilation, the fan had to be run at fairly high volumetric flow rates. Such flow rates resulted in excessive noise in the combustor and excessive air heating due to fan compression. The use of the combustor cooling fan for ventilation purposes was therefore abandoned. In its place, temporary tube axial fans were installed at various combustor penetrations during each outage to induce a flow of air through the vessel. In addition, operation of the boiler ventilation system was found to produce a good ventilation air flow into the combustor vessel and boiler enclosure.

6.23.3 System Inspection

No abnormal conditions were noted.

6.23.4 Summary and Recommendations

The system functioned adequately with respect to combustor cool down. The long cool down time experienced at Tidd; however, will likely not be acceptable for a commercial PFBC facility. Increased cooling air flow rates along with improved distribution inside the combustor vessel will likely be necessary. In addition some means to cool the ambient air (i.e. cooled by well water or river water) will likely be needed to avoid extended cool down times in the summer months.

The combustor cooling system did not provide adequate ventilation of the combustor vessel. A commercial facility would require a more sophisticated system to provide a combination of sufficient flow of relatively cool ventilation air along with proper distribution to insure that the combustor vessel work environment is adequately cool to achieve reasonable outage activity productivity.

Appendix I - Tidd PFBC Operations and Maintenance Narrative

Operational Narrative

Startup TD-SU-94-04-01 - March 1 - 9, 1994

The goal of the run was to achieve full bed height at 1540 F bed temperature without sintering the bed.

The gas turbine was rolled at 1409 hours, paralleled at 1443 hours and the gas turbine valves opened at 1451 hours on March 2. A leak was found on the external piping of the primary ash system. The gas turbine was tripped at 1510 hours to repair the leak.

After the leak was repaired the gas turbine was rolled at 1832 hours, paralleled at 1846 hours and valves opened to the combustor at 1915 hours on March 2. The bed preheater was lit at 0147 hours on March 3. When vertical separator pressure started increasing the vertical pressure control valve stuck and then opened rapidly causing a high level in the vertical separator and a combustor trip at 0214 hours.

At 0252 hours the bed preheater was relit. The vertical separator pressure control valve was manually opened. The steam turbine was rolled and paralleled at 0757 hours on March 3rd.

Coal firing was attempted at 0913 hours but aborted when #2 and #4 paste pumps would not pump (the nozzles were plugged). All lines were reversed, clean blown and then blown out with nitrogen. A coal fire was then accomplished at 1022 hours on March 3rd.

Once through boiler operation occurred at 1641 hours on March 3. As was done on the last run, main steam temperature was set at 900 F and the attemperator biased to force as much feedwater flow through the evaporator as was possible to help control high evaporator tube temperatures.

Bed level was held at 115 inches to allow time to purge the start up sand from the bed. At 2100 hours on March 4 bed level was raised to 142 inches with bed temperature at 1520 F. Splitting air flow was increased to 6000 pph. Sulfur retention was maintained at 90%. A performance test was conducted at these conditions on March 5 and 6.

The HGCU backpulse compressor 4th stage rings failed on March 5th and the backup compressors were used while repairs were made.

At 0015 hours on March 7 bed level was raised to 150 inches with bed temperature at 1520 F to evaluate the sulfur retention with a deeper bed. Splitting air flow was lowered to 800 pph from 1000 pph on #1 and #6 fuel nozzles with 5470 pph total flow to reduce the high cyclone inlet temperatures on #12 and #16 primary cyclones. A performance test was conducted at these conditions on March 7.

On March 8 bed level was lowered to 142 inches, bed temperature raised to 1540 F, splitting air flow lowered from 800 pph to 600 pph on #1 and #6 fuel nozzles and total splitting air flow lowered to 5200 pph to try to improve bed conditions for a performance test at 142 inches bed level and 1540 F bed temperature. By 2330 hours all the signs confirmed that the bed was again sintered. Bed temperature was lowered to 1520 F and bed material from the reinjection vessels was fed into the bed to help purge out the sinters. At 0600 hours on March 9th conditions had not improved and bed temperature was lowered to 1510 F.

While trying to make a paste product with fewer fines to test the effect of the size distribution of the paste on sinter production, the paste pumpability drastically reduced due to incoming coal changing. At 1125 hours #6 paste pump plugged. While trying to unplug this pump to return it to service #4 paste pump plugged. The combustor was manually tripped at 1130 hours on March 9 due to the unstable bed conditions. The paste pumps were reversed and clean blown. All blew clean except for #4 fuel nozzle.

The bed ash reinjection vessels were filled from the bed (in anticipation of a hot restart), bed level was lowered to below the fuel nozzles and the gas turbine removed from service at 1643 hours on March 9. The combustor was tagged out to maintenance for mechanical cleaning of #4 fuel nozzle. While the fuel nozzle cleaning was being completed the paste tank was emptied and cleaned.

Startup TD-SU-94-04-02 - March 10, 1994

The gas turbine was rolled at 1409 hours, paralleled at 1429 hours and the valves opened to the combustor at 1457 hours on March 10. An oil fire was established at 1617 hours.

The #12 and #16 primary cyclone suction nozzles and dipleg temperatures indicated that these cyclones were plugged. Pressure vessel pressure was increased to the maximum obtainable pressure in an attempt to blow out the plugs. This attempt was not successful. The combustor was tripped at 1829 hours on March 10.

After cooling the bed material the gas turbine was removed from service at 1941 hours on March 10th. The bed material was removed and the combustor cooled for maintenance outage activities.

Startup TD-SU-94-05-01 - March 15 - 23, 1994

The goal of the run was again to operate the unit at full bed height without sintering the bed.

The gas turbine was rolled at 2102 hours on March 15th. The gas turbine was tripped when a control fluid leak was found on one of the gas turbine air valves. This leak was repaired and the gas turbine rolled at 2234 hours, paralleled at 2250 hours and the valves opened to the combustor at 2254 hours on March 15.

At 0448 hours on March 16 an oil fire was established with the bed preheater. While in the bed preheating mode a leak was found on the splitting air header pressure relief valve fitting. Plant air was connected to each fuel nozzle splitting air line to provide purge air to the nozzles while the leak was repaired.

The steam turbine was rolled and paralleled at 1124 hours on March 16. A coal fire was established at 1448 hours and once through boiler operation achieved at 1824 hours on March 16.

On March 18, after purging the start up sand from the bed, bed level was increased. With a bed temperature of 1520 F, 140 inches bed level was the highest load that was attainable. Air flow was at the maximum and the O_2 level was at the minimum. The heat transfer in the bed was very high. Bed level was lowered to 137 inches to give some margin on excess air for the weekend. During the early evening signs of sintering were seen at these conditions. High cyclone inlet temperature on #16 primary cyclone forced a bed temperature cut to 1510 F during the night of March 18.

On March 19 the performance of the fuel prep system crusher deteriorated forcing a load cut to 122 inches bed level and bed temperature of 1490 F. Following several minor mechanical changes the crusher throughput was increased enough to support full load but the left side gap would still not open up. This produced a paste product that was less than desirable. Bed sintering was evident from the time that the bed level was increased from 115 inches and for the remainder of the run.

At 1400 hours On March 21 splitting air flow was increased to 6000 pph to try to reduce the sinter production. At 0900 hours bed level was increased to 129 inches and bed temperature raised to 1520 F to see if the change in splitting air flow had improved the situation.

Since more than 700 hours of coal fire had been logged on the APF at temperatures less than 1400 F without any increase in the differential pressure across the filter, it was decided to allow these temperatures to increase up as high as 1450 F. Tempering air to the APF was removed from service to allow this to happen and to increase the amount of fluidizing air through the bed to see if this would improve the sintering situation. It did not appear so.

On March 22 the bed conditions had not improved and bed level was moved down and back up to try to shake out the sinters from the tube bundle. No significant improvement was seen. At 1245 hours bed level was then lowered to 113 inches and bed temperature dropped to 1480 F and left overnight to allow the bed to purge of any sinters that had been shaken loose.

Overnight the APF head metal temperature had increased to 550 F in one spot. Fiberfrax insulation was pumped into this hot spot and the temperature was reduced to approximately 350 F.

On the morning of March 23 bed conditions still did not seem to be much improved. At 1050 hours on March 23 the gas turbine tripped on low lube oil pressure. During the outage the trip pressure switch was found to be faulty.

The bed was inerted with nitrogen and then cooled using gas circulation. All bed material was removed, the combustor was force cooled and then released to maintenance for outage work.

Startup TD-SU-94-06-01 - March 30 - April 19, 1994

The purpose of the run was to log at least 30 days operation for a reliability run, to conduct testing for hazardous air pollutants and to try to determine the threshold for sintering.

The gas turbine was rolled at 1456 hours, paralleled at 1522 hours and valves opened to the combustor at 1528 hours on March 30. The gas turbine low pressure compressor was polished with Carboblast during the air warming period (the compressor had been liquid cleaned during the outage).

Oil fire was established at 2201 hours. A failed cooling coil on the auxiliary boiler steam sample contaminated the condensate cycle causing a delay in releasing the steam turbine for rolling. The steam turbine was rolled and paralleled at 0444 hours on March 31.

Coal fire was initiated at 0908 hours on March 31 with 5 pumps. The #5 paste pump would not pump. When the pump was cleaned the strainer was found to be plugged with dry coal.

Following coal fire problems were experienced with removing ash from the APF. The ash seemed to be hanging up in the cone at the bottom. Using the ash blow out air valves and the air cannon seemed to help.

A leak developed on the impulse line to the APF gas flow meter. This instrument was removed from service and the line plugged. The bed level was increased to 115 inches and held there to purge the start up sand from the bed.

While holding at 115 inches to mature the bed a problem developed with the fuel prep system crusher. The crusher tripped several times on high current. The paste tank level was extremely low before the problem was traced to low accumulator pressure on the right side of the crusher. After increasing this pressure the crusher system functioned properly.

After the bed had matured bed level was increased to 125 inches and bed temperature raised to 1540 F to evaluate if these conditions could be maintained without sintering the bed. Within 24 hours signs of sintering were being observed. Six hours later bed level and bed temperature were lowered (115 inches, 1500 F) to avoid letting the bed get to a condition from which it would be harder to recover.

The next day bed conditions had improved slightly. Air flow was increased (increasing pressure vessel pressure) to try to determine if higher pressure would have any effect on the sintering of the bed. Bed temperature was also increased at this time from 1500 F to 1520 F. After only a few hours the signs of sintering were again showing. Air flow was reduced to normal and bed temperature was lowered to 1500 F and later to 1480 F. Bed level was slowly lowered to 80 inches and then raised back to 115 inches in an attempt to clean out the tube bundle of sinters.

By April 8, the bed conditions were somewhat improved. Bed level and temperature were held constant at 115 inches, 1500 F, 90% sulfur retention for the next several days to provide steady state conditions for the hazardous air pollutant testing.

A unit performance test was conducted on April 9.

Hazardous air pollutant testing was set up and conducted by Radian personnel from April 11 through April 15.

On April 18 a leak developed internal to the combustor on the ceramic lined sorbent injection piping.

The combustor was tripped at 2043 hours on April 18 due to the sorbent piping leak. After cooling the bed the gas turbine was removed from service at 0149 hours on April 19.

Startup TD-SU-94-07-01 - April 29 - June 16, 1994

The objective of the run was to test the effects of smaller size sorbent on the fluidization of the bed.

During the outage several broken candles were found in the APF and it was decided to isolate HGCU from PFBC for this run, which would allow APF repairs to be made in parallel with unit operations. The fuel nozzles skateboards were moved back to their original position. Orifices were installed in the two outer sorbent injection nozzles to try to balance sorbent flows.

Warming of the combustor was accomplished and the gas turbine was rolled at 0737 hours, paralleled at 0754 hours and air flow established through the combustor at 0802 hours on April 29, 1994. During this air heating period the LPC was dry cleaned using Carboblast.

An oil fire was established at 1309 hours but a combustor trip followed when the vertical separator pressure control valve stuck and popped open causing the vertical separator level to go extremely high. An oil fire was re-established at 1400 hours. The steam turbine was rolled and paralleled at 2000 hours on April 29. A coal fire was initiated at 2038 hours and sorbent injection started at 2210 hours on April 29.

The anti-skewing control modification for the fuel preparation system crusher which was installed during the outage worked very well. This modification allowed a more uniform paste product to be produced.

Once through boiler operation was achieved at 0046 hours on April 30.

Bed level was increased to 90 inches with bed temperature at 1515 F and maintained there while the bed matured. This lower bed level for maturing the bed was to prevent higher fuel flows (possible sintering conditions) while the dense start up bed was present.

On May 1 bed level was increased to 115 inches and bed temperature was reduced to 1500 F. Sulfur retention was maintained at 90%. These conditions were maintained for about one week to confirm that no sinters were being made.

A unit performance test was conducted on May 2 at the above conditions using Tidd plant prepared Plum Run Greenfield (PRG) sorbent and Pittsburgh #8 coal.

During this week a few trucks of #12 National Lime Carey (NLC) sorbent were received as a test to determine if material received this way could be unloaded into the sorbent preparation system storage vessel fast enough to support unit operation. It was confirmed that this could be done.

On May 6 the south bed ash reinjection vessel outlet plugged off and remained that way for the remainder of the run.

On May 9 the shipments of NLC #12 sorbent started to arrive on site for a four day test. This material began to be injected to the bed at about 0400 hours on May 10. A series of unit performance tests at 115 inches and 90% sulfur retention with bed temperature at 1500 F, 1540 F and 1580 F were conducted from 1600 hours on May 11 to 1200 hours on May 13. Bed temperature was reduced to 1500 degrees at 1600 hours on May 13.

When the shipments of NLC #12 sorbent stopped, NLC sorbent was prepared with the sorbent prep system. When this material was introduced into the bed the fluidization started to deteriorate as evidenced by some of the evaporator tube temperatures increasing into alarm and erratic bed temperatures.

A unit performance test was conducted on May 16. The conditions for the test were, 115 inches bed level, 1500 F bed temperature, 90% sulfur retention with NLC (Tidd plant prepared). Following this test the bed temperature was increased to 1580 F at 0800 hours on May 17. Bed conditions gradually worsened. Density was on the decrease, five evaporator tube temperatures were in high alarm and some of the bed temperatures began to be very erratic indicating fluidization problems. At 1138 hours on May 18 bed temperature was reduced to 1500 F.

By May 19 the NLC sorbent was depleted and the unit was operating on PRG sorbent which was prepared on Tidd site. The unit was maintained at 115 inches bed level, 1500 F bed temperature and 90% sulfur retention until May 23. Bed conditions did not change.

On May 23 the LPC was dry cleaned with Carboblast in an effort to increase air flow. Air flow had been noticeably reduced for the last week.

At 2200 hours on May 23, approximately 75 tons of NLC #20 sorbent was started into the bed with the sorbent injection system. This short test was to determine if bed level could be maintained with this smaller size of sorbent feed. Bed ash production was lower but bed level was able to be maintained. Bed temperature distribution and evaporator temperatures improved significantly on May 24 with this material. When this material ran out the bed conditions again started to deteriorate.

Another small delivery (175 tons) of #20 NLC sorbent was received on May 25 for testing. Again, when this material was introduced into the bed the unstable conditions significantly improved. Bed ash production was estimated to be 4 klbs/hr and it was decided that the unit could withstand a four day test with this #20 sorbent.

As was previously seen, when this small delivery of #20 material was all used and the unit was returned to Tidd plant prepared material the bed conditions worsened.

On May 27 a hydraulic leak developed on #6 paste pump. The pump was removed from service to repair the leak. With the unstable bed conditions, the removal of this paste pump from service caused very high bed and evaporator tube temperatures on the right side of the boiler. After returning #6 paste pump to service the bed conditions returned to the previous unstable but maintainable condition.

The unit remained at this condition for the next three days to see if any improvement could be seen. No improvement was observed.

On May 30 the trucked shipments of #20 NL sorbent began arriving on site for a four day test. At approximately 0630 hours on May 31 this material started to be injected into the bed. Bed conditions immediately began to improve.

On June 1 bed temperature was increased to 1580 F and bed level was lowered to 113 inches. Also on June 1 the LPC was Carboblast cleaned (the gas turbine performance was still decreasing).

On June 1 the quarterly stack dust loading test was completed. Unit performance tests and sampling were conducted from 1200 hours on June 1st to 2400 hours on June 3.

On June 2 sulfur retention was increased to 95%, but was lowered back to 90% a short time later because of high temperatures in the bed ash removal system. The bed bottom cooling could not maintain adequate cooling of ash with the higher sorbent flow rate required for 95% sulfur retention.

At 1100 hours on June 3 bed temperature was lowered to 1500 F. The problem with high temperatures in the bed ash removal system continued. The smaller size bed material seemed to just flow out of the ash removal system without any pulsing. This caused overheating and subsequent trips on the removal system. The sorbent fines that were remaining in the 500 ton storage vessel were mixed with the paste to reduce the required dry sorbent feed rate to help reduce the amount of bed ash removal required to maintain bed level. Bed temperature was also lowered to 1480 F to reduce bed ash production.

On June 5, while still fighting to keep bed level down, the south bed ash removal system plugged off in the bed bottom area. The north bed ash reinjection vessel was called into service to maintain bed level (bed level had increased to 123 inches). Efforts to unplug by blowing up through the bed bottom were unsuccessful. The south removal system was isolated, the pressure in the lockhopper reduced to 25 psi less than the bed bottom pressure and then the isolation valve was opened. This maneuver cleared out the plug and dropped bed level by six inches. Once the south bed ash removal system was unplugged the bed level could be controlled, but temperatures in the removal system were still elevated.

After the bed ash removal system had recovered from the high temperatures, the north bed ash reinjection vessel was emptied back into the bed.

On June 6 the deliveries of PRG #12 sorbent started arriving at site, but it was midday on June 7 before this material made it to the bed.

Installation of the new sorbent prep sizer screen began on June 6 while the unit was being tested with the 12 PRG sorbent.

Due to the anticipated high ambient temperatures and subsequent lower available air flow, bed level was lowered to 108 inches for a series of tests with 12 PRG sorbent.

On June 8 bed temperature was increased to 1580 F and a unit performance test conducted at 108 inches with 90% sulfur retention from 0000 to 1200 hours on June 9. At 1200 hours sulfur retention was increased to 95% for a test, but the test was aborted when the increased bed drain flow again presented a problem with high temperature trips of the bed ash removal system.

After the 95% sulfur retention test was aborted bed level was increased to 115 inches, bed temperature reduced to 1500 F and sulfur retention maintained at 90%. A unit performance test was conducted from 0000 to 1200 hours on June 10 at these conditions. At 1200 hours air flow was lowered for a unit performance test to compare the effects of excess air on sulfur retention. This test was not successful, however, due to gas turbine conditions prohibiting achieving the desired conditions. It was identified that the HPT was fouled to the point of restricting the operation of the gas turbine. When air flow was cut without cutting load, the HPC pressure ratio alarm came in.

At 0200 hours on June 10 the drive belts failed on the #2 vapor extractor for the gas turbine lube oil. The #1 vapor extractor was placed in service. The belts were replaced on the #2 vapor extractor.

On June 10 the differential pressure on the sorbent booster compressor inlet fines filter increased to 160 inches of water. This differential pressure was monitored closely for the remainder of the run. It approached 190 inches before the unit was shut down.

On June 11 the new sorbent prep sizer screen was initially operated. The bed support springs were undersized and the screen did not function properly because of the spring problem. Additional PRG #12 was ordered to be used until the screen could be adjusted to function well enough to support unit operation.

On June 11 and 12 Ohio 6A coal was test crushed in the fuel prep system. The crusher system could not be adjusted to make an acceptable paste product. While using this paste, #3 paste pump plugged and was removed from service to clean. Other paste pumps also experienced high differential pressures before the marginal paste in the tank was diluted with #8 coal paste. Bed level was reduced to 110 inches and bed temperature lowered to 1480 F during this period of time.

On June 12 a noise was discovered in the gas turbine exciter. A problem was suspected with diode mounting. To prevent further damage it was decided to remove the unit from service.

Unit load was reduced and the steam turbine was removed from service to perform the annual overspeed test. This test was successfully completed and the combustor tripped at 2016 hours on June 13. The gas turbine was used to cool the bed and then removed from service at 2255 hours on June 13. The combustor was cooled to approximately 400 F in anticipation of dry cleaning of the HPT before opening the combustor.

Startup TD-SU-94-08-01 - July 14 - 15, 1994

The combustor was released by Maintenance at 1150 hours on July 14, 1994.

The purpose of the run was to evaluate #10 and #12 mesh plant prepared sorbent for sulfur capture and for the effect it would have on fluidization and bed temperature distribution. The performance of the APF candles was also to be evaluated during this run.

The gas turbine was rolled at 0051 hours, paralleled at 0104 hours, and air flow established through the combustor at 0113 hours on July 15, 1994. The gas turbine LPC was dry cleaned with Carboblast during the air heating period.

The bed preheater was lit at 0554 hours, but a combustor trip was suffered at 0615 hours when the vertical separator level was forced low due to the vertical separator pressure control valve sticking closed.

A gas turbine trip occurred at 0650 hours due to high fictive disc temperature/gas inlet temperature difference. This resulted due to the short bed preheater firing period.

Startup TD-SU-94-08-02 - July 15 - 16, 1994

Following the required cooldown period for the gas turbine discs, the gas turbine was rolled at 1235 hours, paralleled at 1301 hours, and air flow established through the combustor at 1310 hours on July 15, 1994. The HPT was dry cleaned with Carboblast during the air heating period.The bed preheater was lit at 1754 hours, the steam turbine was rolled and paralleled at 0009 hours on July 16. A coal fire was established at 0156 hours and sorbent injection was started at 0343 hours on July 16.

At 0427 hours the combustor was tripped by the operator when three paste pumps tripped due to high hydraulic fluid temperature.

The bed material was put into the reinjection vessels to prepare for a hot restart.

Startup TD-SU-94-08-03 - July 16, 1994

After the bed level was lowered to 6 inches, the bed preheater was initiated at 0748 hours. Oil fire was not accomplished, however, until boiler wall differential pressure was lowered to about 4.1 psid and the oil pressure on the bed preheater header increased to about 540 psig. Successful oil fire was at 0931 hours. The steam turbine was rolled and paralleled at 1200 hours on July 16. A coal fire was established at 1259 hours. The #5 paste pump did not pump and was removed from service. Primary cyclones #13 and #15 did not respond to the coal fire temperature increase. Air flow was increased to the guide vane limit but did not help in clearing out these cyclones. The combustor was tripped at 1355 hours. The combustor was cooled and the gas turbine removed from service at 1708 hours on July 16, 1994.

Startup TD-SU-94-09-01 - July 20 - 27, 1994

The combustor was released by the maintenance department at 2215 hours on July 19, 1994. The gas turbine was rolled at 0912 hours, paralleled at 0955 hours and air flow established through the combustor at 1000 hours on July 20. Oil fire was established at 1432 hours. The steam turbine was rolled and paralleled at 1835 hours on July 20. A coal fire was established at 1918 hours. The sorbent injection system was started at 2014 hours on July 20.

While increasing load, the gas turbine #5 bearing horizontal vibration increased into alarm. Load on the gas turbine generator was limited to about 2 MW for the entire run to keep the vibration below 450 mils/sec. Arrangements were made for an ABB Stal turbine balance expert to come and analyze and balance the gas turbine. The unit was maintained at 82 - 85 inches bed level and 1480 F bed temperature until he arrived on site. After the arrival of the balance engineer, vibration readings were taken and the combustor was tripped at 1208 hours on July 27, 1994. Bed material was put into the reinjection vessels for a hot restart following the balance shot.

The gas turbine was removed from service at 1534 hours on July 27.

Startup TD-SU-94-09-02 - July 28 - August 25, 1994

Following the balance shot, the gas turbine was released by the maintenance department at 0220 hours on July 28, 1994.

The purpose of the run was to check the balance of the gas turbine and to evaluate the performance of the boiler with smaller sized sorbent.

The gas turbine was rolled at 0402 hours, paralleled at 0423 hours and air flow established through the combustor at 0442 hours on July 28. Vibration on the #5 bearing was much improved and vibration levels on all bearings on the gas turbine were acceptable.

Oil fire was established at 0521 hours on the first attempt. The hot combustor restart procedure was used. The steam turbine was rolled and paralleled at 0844 hours on July 28. A coal fire was established at 0959 hours. The sorbent injection system was started at 1131 hours on July 28. Bed level was increased to 90 inches with bed temperature at 1580 F and held there to allow the bed to mature.

A unit performance test was conducted on July 31 from 0400 to 1600 hours at the above conditions with Pittsburgh #8 coal and plant prepared #12 Plum Run Greenfield sorbent at 90% sulfur retention.

On July 31 the new #12 screens on the sorbent prep sizer blinded. These screens were removed and 10 mesh screens were installed.

At the completion of the 90 inches, 1580 F, 90% sulfur retention test, bed level was increased to 110 inches in preparation for a performance test at these conditions. This test was started at 0800 hours on the morning of August 1. A relative accuracy test on continuous emission monitors was also conducted at the same time. The unit performance test was aborted in the afternoon when bed level and bed temperature had to be reduced due to high metal temperatures on the APF head. The hot spots were pumped with pumpable insulation and were all lowered to less than 500°F.

On August 2 bed temperature was increased to 1580 F and bed level was maintained at 90 inches. Air flow was increased to obtain an average O_2 level of 6-7%. Sulfur retention was held at 90% with plant prepared #10 PRG sorbent. A unit performance test was conducted from 1600 - 2400 hours.

On August 3 air flow was lowered to obtain an average O_2 level of 3.5%. All other unit operating parameters were unchanged. A unit performance test was started at 2000 hours and was completed at 0400 hours on August 4. Following the above test bed temperature was lowered to 1500°F and air flow lowered to obtain an average O_2 level of 3.5%. A unit performance test was started at 0800 hours on August 5, but was cancelled due to bed ash removal problems.

The HPT was dry cleaned with Carboblast on August 5. No effects were seen.

The APF ash removal system plugged on the evening of August 5 and several pieces of candle were removed from the ash line.

A unit performance test was conducted on August 6 from 0700 to 1500 hours. The conditions for the test were 90 inches bed level, 1500 F bed temperature, 90% sulfur retention with plant prepared #10 PRG sorbent, and 3.5% average O_2.

Following the above test bed level was increased to 112 inches and bed temperature increased to 1580 F. Hot spots again appeared on the APF head. Tempering air was used to the APF to control the high temperatures on the head. Sulfur retention was held at 90% with plant prepared #10 PRG sorbent. A unit performance test was conducted from 0000 - 0800 hours on August 8th.

Bed temperature was lowered to 1500 F while all other unit parameters remained the same, and a performance test was conducted from 2000 hour on August 8 to 0400 hours on August 9.

On August 9 the hot spots on the APF head were pumped with insulation, bed temperature was increased to 1580 F and sulfur retention was increased to 95% with plant prepared #10 PRG sorbent.

A performance test was conducted from 2000 hours on August 10 to 0800 hours on August 11 at 112 inches bed level, 1580 F bed temperature and 95% sulfur retention with plant prepared #10 PRG sorbent.

On August 11 one of the #10 screens in the sorbent prep sizer developed a rip. The #10 screens were removed and a set of #12 screens installed.

On August 12 bed temperature was lowered to 1540 F and sulfur retention lowered to 90% (#12 plant prepared PRG) to set for the weekend while evaluating the capacity of the sorbent preparation system with the #12 screens in the sizer. The HPT and LPC were dry cleaned with Carboblast.
On August 14 conditions were set at 107 inches bed level, 1580 F bed temperature and 90% sulfur retention with #12 plant prepared PRG for a unit performance test. The test was conducted from 1500 - 2300 hours.

A 95% sulfur retention test preparation was started on August 15 but was aborted due to the high differential pressure on the APF.

On August 16 #12 mesh self cleaning screens were installed in the sorbent prep sizer.

On August 16 PRG #12 designer sorbent that had been stored in the 500 ton fines storage hopper was transported into the 200 ton sorbent storage vessel. This material started into the bed early morning on August 17th. The bed was allowed to stabilize on this material and then a unit performance test was conducted from 0000 - 1200 hours on August 18. The conditions for the test were 103 inches bed level, 1580 F bed temperature and 90% sulfur retention on the #12 PRG designer sorbent. Average O_2 was maintained at 3.5%.

On August 19 the weekly dry cleaning of the LPC and HPT were done. The isolation valves to the HPT leaked through which did not allow a complete filling of the dose tank which resulted in a small blasting dose.

After all of the #12 PRG designer sorbent was used the bed was stabilized on #12 plant prepared #12 PRG sorbent.

Sulfur retention was increased to 95% on #12 plant prepared PRG and a performance test conducted from 0000 - 0800 hours on August 22. Bed temperature was 1580 F and bed level was 107 inches.

On August 24 100 tons of #18 mesh NL Bucyrus designer limestone was introduced to the bed. This was done for a test to see if sintering would be a problem. The bed density dropped drastically but no other adverse conditions were suffered.

After the limestone was depleted the density increased back toward its original value. Conditions were set for another unit performance test at 110 inches bed level, 1580 F bed temperature and 90% sulfur retention with #12 plant prepared PRG sorbent on August 26.

At 1746 hours on August 25, 1994 the steam turbine tripped on an underfrequency/ overcurrent relay. The "Unit In Parallel" interlock relay was found mechanically stuck Which allowed the underfrequency/ overcurrent relay operation to trip the steam turbine.

The combustor was tripped by the operator at 1747 hours, the gas turbine was removed from service at 2042 hours and the combustor was cooled and released to maintenance for outage work.

Sorbent injection feed with both rotary feeders was erratic for the entire run, especially the west rotary feeder. Several parameters were changed on the sorbent preparation system storage vessel and on the sorbent injection system to try to find the reason for the erratic feed.

Appendix I

Startup TD-SU-94-10-01 - September 2 - 10, 1994

The combustor was released by the maintenance department at 2140 hours on September 1, 1994.

The purpose of the run was to do complete spoiling of #11 primary cyclone and to evaluate the effects on the APF. Continued evaluation of finer sorbent as bed material was also a goal.

The gas turbine was rolled at 1256 hours, paralleled at 1316 hours and air flow established through the combustor at 1323 hours on September 2. The gas turbine LPC was dry cleaned with Carboblast during the air heating period. Oil fire was established at 1754 hours. The steam turbine was rolled and paralleled at 2122 hours but the oil overspeed trip test did not function. The steam turbine was tripped and the problem traced to a failed solenoid on the oil trip circuit. The coil was replaced and then tested successfully.

A coal fire was established at 0104 hours on September 3. Number 5 paste pump would not pump and was removed from service, clean blown and returned to service. The steam turbine was rolled and paralleled at 0218 hours on September 3. Sorbent injection was started at 0230 hours on September 3. Bed level was increased and once through boiler operation achieved at 0324 hours on September 3. Bed level was held at about 90 inches with bed temperature at 1500 F while the bed matured.

On September 5 the APF backpulsing was changed to a "uniform cleaning" mode in preparation for "complete" spoiling of #11 primary cyclone.

On September 6 #11 primary cyclone complete spoiling was commissioned. The ash loading to the APF was significantly increased. The new APF emergency ash line was used from time to time to supplement the normal ash removal system.

On September 7 bed temperature was increased to 1580 F and bed level was increased to 115 inches.

A unit performance test was conducted from 0700 - 1500 hours on September 8.

On September 9 the new emergency ash line for the APF plugged and the old emergency ash line was used to assist the APF ash removal system while the new line was removed from service and unplugged.

While the APF old emergency ash line was in service a leak developed in the first elbow.

With both of the APF emergency ash lines unavailable to help remove ash from the APF, the complete spoiling system for #11 primary cyclone was removed from service.

The APF new emergency ash line was returned to service at 0030 hours on September 10 and complete spoiling of #11 primary cyclone restarted at 0132 hours on September 10.

Shortly after midnight on September 10 a sorbent injection piping leak developed upstream of HCV-B840 and could not be isolated to repair. The combustor was tripped at 0407 hours on September 10.

Bed material was put into the reinjection vessels for a restart. The gas turbine removed from service at 0857 hours on September 10, 1994. The combustor was cooled and released to maintenance.

Startup TD-SU-94-11-01 - September 21 - October 21, 1994

The gas turbine was released by the maintenance department at 1340 hours on September 21, 1994. The purpose of the run was to continue evaluation of different sorbent feeds materials and sizes.

The gas turbine was rolled at 0337 hours, paralleled at 0359 hours and air flow established through the combustor at 0411 hours on September 22. Oil fire was established at 0905 hours. The steam turbine was rolled and paralleled at 1553 hours. A coal fire was established at 1702 hours. Sorbent injection was started at 1755 hours. Bed level was increased and once through boiler operation achieved at 2134 hours. Bed level was held at about 95 inches with bed temperature at 1500 F while the bed matured.

On September 24th bed level was raised to 110 inches and bed temperature was increased to 1580 F in preparation for a unit performance test.

On September 24 HCV-J926, the isolation valve between the APF surge hopper and lockhopper, started leaking through too much to continue using the normal ash removal system. The emergency ash line was placed in service.

A unit performance test was conducted on September 25 from 0900 hours to 1700 hours at 110 inches bed level, 1580 F bed temperature and 90% sulfur retention with plant prepared #12 PRG sorbent. The unit was maintained at these conditions through September 29 at which time #12 designer PRG sorbent was introduced into the bed. A unit performance test was conducted at these conditions from 1100 hours on September 30 to 1100 hours on October 1st 1994. A relative accuracy test was also conducted on September 30 on the stack continuous emissions monitors.

On September 30 #27 cyclone stopped transporting ash. It appears to be an air leak on the ash line or dipleg.

On October 2, 1994 bed temperature was lowered to 1540 F due to high temperatures in the bed ash removal system.

On October 4, 1994 the bed ash removal bucket elevator belt splice required repair. A vacuum service truck was used to remove bed ash from the atmospheric hopper while the splice was repaired. Also on October 4, the plant started receiving #20 Plum Run (Greenfield and Peebles mix) designer sorbent for the upcoming test. (Delivery by bulk truck.)

On October 5, 1994, bed level was raised in an attempt to determine what parameter would be the limit for full load. Air flow again was the stopping parameter at 715 kpph due to LPT shaft speed. (Outside air temperature was 44 F.) A bed level of 129 inches was achieved at a bed temperature of 1580 F. Steam flow was 420 kpph, which resulted in 64.4 MW. Another restriction was that the precipitator inlet duct pressure was also at the limit of 25 inches of water pressure.

Bed level was reduced to 116" and air flow lowered to 670 kpph in preparation for the test on #20 PR designer sorbent. The #20 PR sorbent started into the bed at about 0900 hours on October 5.

On October 6, 1994 bed level was lowered to 108 inches due to the higher density and resultant fuel flow requirements caused by the #20 sorbent. A unit performance test was conducted from 1100 hours on October 6 through 1100 hours on October 7, 1994. Bed bottom temperatures were running hot while performing this test. Due to these high temperatures, the planned 95% sulfur retention test on #20 PR designer sorbent was cancelled.

On October 7, 1994 the HGCU APF emergency ash line developed a leak and was removed from service. The alternate ash line was placed in service while the leak was weld repaired. When returning the emergency ash line to service it plugged. The alternate ash line was also restricted when trying to place it in service. Both of these lines were unplugged and the emergency ash line returned to service.

Bed temperature was lowered to 1500 F on the evening of October 7, 1994 to help with the removal of the hot bed material in the bed bottom and the resultant high bed ash removal system temperatures.

On October 8, 1994, after the hot material in the bed bottom was worked through, bed temperature was increased to 1580 F. When increasing bed temperature it was again noted that the duct opacity noticeably decreases above 1560 F bed temperature.

On October 11, 1994 the #18 Bucyrus Limestone started arriving on the plant site. When this material was introduced into the bed on October 12, 1994 the density started to decrease noticeably.

On October 12, number 6 paste pump was removed from service due to a problem with the "S" tube not traveling completely. A solenoid was replaced and the pump was returned to service.

On October 13, the bed density continued to decrease and by early afternoon bed temperatures and evaporator tube temperatures were erratic to the point of cancelling the test that was in progress. This test was started at 1100 hours and was aborted at 1430 hours. Bed temperature was lowered to 1480 F and plant prepared #12 Plum Run Greenfield dolomite was used as sorbent feed.

The unit was run at these conditions for the next several days to clean up the bed and to recover from the effects of the limestone.

On October 17, 1994 the sorbent preparation system sizer was tested in the "scalping - dedusting" mode. This is a double screen set up to eliminate the minus 50 mesh particles. Tests were run over the next three days on the sorbent preparation system sizer. While doing these tests, designer NL Carey sorbent was used to supplement the plant preparation system.

On October 17, 1994, #11 primary cyclone was completely spoiled to reevaluate the APF candle cleaning with the larger particles going to the APF.

On October 20, the steam turbine auto voltage regulator started swinging. The regulator was placed in manual while the Performance Department investigated the problem. The problem could not be corrected on-line and the regulator was left in manual for the remainder of the run.

On October 21, the gas turbine LPC was Carbo-blasted.

In preparation for a scheduled shut down of the unit, the coal bunkers, the sorbent 200 ton storage vessel, and the sorbent injection vessels were emptied for outage work.

The combustor was tripped at 1139 hours on October 21, 1994. The bed material was cooled with the gas turbine and then the turbine was removed from service at 1451 hours. The combustor was further cooled and then released to maintenance for outage work.

Startup TD-SU-94-12-01 - November 30 - December 2, 1994

The combustor was released by the Maintenance Department at 1630 hours on November 30, 1994.

The gas turbine was rolled at 1006 hours on December 1, 1994 but tripped at 1021 hours.

The gas turbine was again rolled at 1141 hours, paralleled at 1156 hours and air flow established through the combustor at 1207 hours on December 1, 1994. During the air warming period, vibration was experienced on the gas turbine #3/4 bearing. This vibration was as high as 250 mils/sec at times.

Oil fire was established at 1715 hours. The steam turbine was rolled at 1220 hours. Checks were made on the voltage regulator controls and limits. The steam turbine was paralleled at 0006 hours on December 2, 1994. A coal fire was established at 0107 hours on five pumps. A hydraulic oil leak was found on #6 paste pump. Coal fire was accomplished with bed temperature at 1100°F as a test for sparge duct life extension. The #6 paste pump was placed in service at 0403 hours following the hydraulic leak repair. Sorbent injection was started at 0247 hours. Bed level was increased and once through boiler operation achieved at 0638 hours.

At 0650 hours a leak was discovered on an instrument connection on the boiler injection tank piping. Due to the inability to isolate this leak, the combustor was tripped at 0655 hours on December 2.

In order to isolate the boiler injection tank for repairs to be made, boiler circulation had to be taken off. The gas turbine was tripped at 1346 hours, boiler circulation stopped, and the repair made to the boiler injection tank piping.

Startup TD-SU-94-12-02 - December 2, 1994 - January 2, 1995

The boiler injection tank was released by the Maintenance Department at 1437 hours on December 2, 1994, following a weld repair to the piping tee.

The gas turbine was rolled at 1730 hours, paralleled at 1743 hours, and air flow established through the combustor at 1752 hours on December 2. The vibration on the gas turbine #3/4 bearing was similar to the previous start up. An oil fire was established at 1915 hours. The steam turbine was rolled and paralleled at 2238 hours. A coal fire was established at 2314 hours. Coal fire was again accomplished with bed temperature at 1100 F as a test for sparge duct life extension. The #1 paste pump would not pump and coal fire was established with 5 paste pumps. The #1 paste pump was reversed, clean blown and placed in service at 0023 hours on December 3, 1994.

While increasing air flow the #2 gas turbine bearing vibration increased into alarm while the #3/4 bearing vibration decreased.

Sorbent injection was started at 0042 hours on December 3.

After air flow was increased where the LPT shaft speed was above the 4500 rpm critical speed range, the vibration on #2 bearing decreased below the alarm point.

Bed level was increased and once through boiler operation achieved at 0144 hours on December 3, 1994.

The duct opacity was higher than normal (35%) during most of the start up until bed temperature was increased to 1580 F.

Bed level was held at about 95 inches with bed temperature at 1580 F while the bed matured.

On December 4, 1994, bed level was raised to 115 inches in preparation for unit performance testing on National Lime #12 designer sorbent. Due to warm ambient temperatures, this testing was delayed.

A test was conducted at 115 inches bed level and 1580 F bed temperature at 90% sulfur retention on normal plant prepared PRG sorbent from 0800 hours to 1600 hours on December 7, 1994.

Approximately 200 tons of Minnehaha coal was received during this week and was test crushed. The crusher worked well with this coal but the firing rate increased about 15% due to the lower BTU of the coal and the sorbent injection demand decreased significantly due to the lower sulfur content in the coal.

On December 12, 1994 unit load was increased to find what would be the load limiting parameter. Air flow was increased to 740 kpph and bed level was increased to 130 inches with bed temperature at 1580 F. Steam flow was at 440 kpph with total plant output being 68.5 MW.

A short time later the LPT outlet disc cooling temperature increased into alarm. Unit load reduction was required to keep this disc cooling air temperature below the 620 F limit (123 inches bed level with 720 kpph air flow sufficiently reduced this disc temperature).

On December 13, 1994, #12 designer National Lime sorbent was introduced into the bed. Density remained constant at about 43 lbs/ ft^3. A unit performance test was started at 1200 hours on December 14 at 123 inches bed level, 1580 F bed temperature with 720 kpph air flow using #12 NL designer sorbent. This test was ended at 0600 hours on December 15, 1994.

On December 18, 1994, conditions were set for a 95% sulfur retention test at 122 inches bed level and 1580 F bed temperature. The actual test started at 0800 hours on December 19 and lasted until 1600 hours, with a bed ash production test following.

Sulfur retention was then lowered to 90% and held for the bed to stabilize at these conditions.

A unit performance test at 122 inches bed level, 1580 F bed temperature, and 90% sulfur retention was conducted from 0000 hours to 0800 hours on December 21, 1994.

At the completion of this test bed level was lowered to 115 inches and bed temperature reduced to 1540 F for easier operating conditions for the holiday weekend.

Unit load was increased on December 29 to stabilize for a unit performance test on December 30, 1994.

A unit performance test was conducted at 122 inches bed level, 1580 F bed temperature, and 90% sulfur retention with plant prepared #12 PRG sorbent from 0800 hours to 1600 hours on December 30, 1994.

Startup TD-SU-95-01-01 - January 13, 1995

The combustor was released by the Maintenance Department at 1412 hours on January 12, 1995.

The gas turbine was rolled at 0341 hours on January 13, 1995, and paralleled at 0406 hours. Air flow was established at 0414 hours. The LPC was Carboblasted. An oil fire was established on January 13, 1995, at 0805 hours. The steam turbine was rolled at 1201 hours, and paralleled at 1253 hours on January 13, 1995. A coal fire was established at 1324 hours on January 13, 1995. Bed temperature for light-off was 1059 F as a further test for sparge duct life extension. To get 1050 F bed temperature, only 1150 F set point was required for the bed preheater.

At 1510 hours, #3 paste pump quit pumping, apparently due to a plugged strainer. At 1550 hours, #3 pump was returned to service.

Sorbent injection was placed in service at 1415 hours, January 13, 1995.

At approximately 1700 hours, #16 cyclone plugged. At 1747 hours, the combustor was tripped. The gas turbine was removed from service at 1931 hours, January 13, 1995.

Startup TD-SU-95-02-01 - January 18 - January 19, 1995

The combustor was released by the Maintenance Department at 2030 hours on January 17, 1995.

The gas turbine was rolled at 0523 hours on January 18. At 0541 hours, the gas turbine was placed in parallel, and at 0547 hours air flow was established. An oil fire was established at 1124 hours on January 18, 1995. The steam turbine was rolled at 1435 hours and placed in parallel at 1518 hours. A coal fire was established at 1553 hours, once again at 1050 F bed temperature.

Difficulties getting the cyclone ash baghouse to pulse and the resulting high differential pressure prevented the unit from going once through. While working on this problem, the gas turbine tripped at 0839 hours on January 19, 1995. The gas trip occurred due to a bypass-intercept valve, HCV-T122, going closed.

The bed was nitrogen inerted and gas recirculation placed in service to cool the bed material.

The unit was prepared for a re-start by pulling all 6 fuel nozzles and cleaning from the outside. The gas turbine valve was inspected and a small piece of O-ring material was found in the orifice.

Startup TD-SU-95-02-02 - January 20 - January 21, 1995

The combustor was released by the Maintenance Department at 0613 hours on January 20, 1995.

On Friday, January 20, 1995, the gas turbine was rolled at 1125 hours. At 1157 hours, the gas turbine was placed in parallel, and at 1225 hours air flow was established. An oil fire was established at 1247 hours on January 20, 1995. The steam turbine was rolled at 1533 hours and placed in parallel at 1607 hours. After gas turbine roll, bed temperatures were very unusual. Following oil fire, these bed thermocouple remained low, but did respond some. The bed had the appearance of poor fluidization. A coal fire was established at 1735 hours, at 1050 F bed temperature.

The bed continued to have low temperature spots. Eventually, several evaporator tubes came into alarm while still below once through. It was decided to trip the unit and inspect the bed and sparge ducts. The combustor was tripped at 0044 hours, January 21, 1995. The gas turbine was taken off at 0618 hours, January 21, 1995.

Startup TD-SU-95-03-01 - January 26 - February 2, 1995

The combustor was released by the Maintenance Department at 2306 hours on January 25, 1995.

On Thursday, January 26, 1995, the gas turbine was rolled at 1257 hours. At 1327 hours, the gas turbine was placed in parallel, and at 1336 hours air flow was established.

An oil fire was established at 1815 hours on January 26, 1995. The steam turbine was rolled at 2222 hours and placed in parallel at 2323 hours.

At 0058 hours, January 27, 1995, coal was lit. Once through occurred at 0652 hours on January 27, 1995. The bed was matured and on Monday, January 30, 1995, the bed level was increased to 125 inches and bed temperature raised from 1540 F to 1580 F. Ambient temperatures reaching a high of 40 F limited the unit at this bed level. Bed temperature distribution was excellent and the evaporator tube profile was nearly flat.

Problems with backpulsing were experienced which in turn led to high ash temperatures on the HGCU alternate ash line. The process air lines used for transport on the alternate ash line and emergency ash line were discovered to be plugged. The Maintenance Department was able to get them both open.

Several unusual excursions took place on the HGCU system on February 1, 1995. Tube sheet differential, ash temperatures, and gas turbine vibration were affected.

Early the morning of February 2, 1995, a blind flange in HGCU system, located on the backup cyclone outlet, was found to be hot, necessitating the removal of the unit from service. The combustor was tripped at 0205 hours on February 2, 1995. The gas turbine was removed from service at 1024 hours on February 2, 1995.

Startup TD-SU-95-04-01 - February 8 - February 9, 1995

The combustor was released by the Maintenance Department at 2300 hours on February 7, 1995.

On Wednesday, February 8, 1995, the gas turbine was rolled at 1043 hours. At 1115 hours, the gas turbine was placed in parallel, and at 1122 hours air flow was established.

An oil fire was established at 1850 hours on February 8, 1995. The steam turbine was rolled at 2308 hours and placed in parallel at 0014 hours on February 9, 1995.

At 0030 hours, February 9, 1995, coal was lit. Once through occurred at 0542 hours on February 9, 1995.

An instrument line on the economizer froze and broke. This resulted in a combustor trip at 1509 hours on February 9, 1995 due to high S.S.H. temperatures. The unit was readied for a hot re-start.

Startup TD-SU-95-04-02 - February 9 - February 10, 1995

The unit was hot re-started following isolation of the economizer instrument and taking the bed up into 274 vessels.An oil fire was established at 2326 hours on February 9, 1995. The steam turbine was rolled at 0255 hours on February 10, 1995 and placed in parallel at 0329 hours.At 0408 hours, February 10, 1995, coal was lit. Once through occurred at 1018 hours on February 10, 1995. The combustor was tripped at 1834 hours on February 10, 1995 due to a gasket failure on the line going to the HGCU surge hopper.

Startup TD-SU-95-04-03 - February 11 - February 12, 1995

The unit was hot re-started following the repair of the gasket leak in the line going to the HGCU surge hopper.

On February 11, 1995, oil fire was established at 0454 hours, steam turbine was rolled at 0844 hours and paralleled at 0915 hours, coal fire was lit at 0926 hours, and once through occurred at 1222 hours.

The unit was brought up to 128 inches bed height. Steam flow reached 440,000 lb/hr and load went to 70.1 MW. The alternate ash line and emergency ash line in the HGCU system were plugged by 2 pieces of broken candle. Ash backed up and the water screw cooler tripped. The lockhopper was not able to remove ash fast enough and the ash level came up in the APF. The combustor was manually tripped at 1751 hours on February 12, 1995.

While trying to unplug the alternate ash line, the Jarecki valve stuck open. The valve handle was broken while trying to get the valve closed, necessitating a gas turbine trip at 0028 hours on February 13, 1995.

Startup TD-SU-95-05-01 - February 13 - February 16, 1995

The unit was hot re-started following a shutdown due to a high ash level in the HGCU APF.

The alternate ash line had plugged due to a broken candle piece which led to the ash backing up to the screw cooler. The screw cooler promptly tripped, which prevented the removal rate necessary using the lock hopper to get the ash level back down. While removing the ash, a stuck valve on the alternate ash line led to a gas turbine trip.

The gas turbine was rolled at 0548 hours on February 13, 1995, paralleled at 0606 hours, and air flow established at 0647 hours.

On February 13, 1995, an oil fire was established at 0814 hours, steam turbine was rolled at 1100 hours and paralleled at 1136 hours, coal fire was lit at 1143 hours, and once through occurred at 1607 hours.

Number 26 ash line had to be blown out using high pressure nitrogen.

The unit was brought up to 112 inches bed level, at which time several hot spots appeared on the APF. Leak Repair, Inc. spent a day pumping Fiberfrax to bring the temperatures down.

On February 16, 1995, problems developed with the fuel preparation system. The coal crusher was not able to properly crush the coal and the paste fines were low. All pump DP's increased. At 1243 hours, on February 16, 1995. it became necessary to trip the unit due to both #2 and #3 paste pumps not pumping.

Appendix I

Startup TD-SU-95-06-01 - February 18 - March 8, 1995

Subsequent to the shutdown on February 16, 1995, it was determined that the likely cause of the crushing problems was the old and possibly mixed coal type which was being reclaimed from what was now a depleted north coal pile. Therefore, the fuel nozzles were cleaned, the coal bunkers were emptied and a switch was made to the south coal pile. The unit was restarted on February 18, 1995. The gas turbine was rolled at 0848 hours, paralleled at 0924 hours and air flow was established at 1003 hours. Oil fire was established at 1533 hours and the steam turbine was rolled at 1805 hours, paralleled at 1850 hours. and coal fired at 1929 hours.

The unit was brought up to 133 inches bed level at 1580 F bed temperature on off-site prepared #12 Plum Run dolomite. Four tests were run in the period between February 23 and March 1,1995. Four additional tests were conducted prior to unit shutdown on March 8, 1995.

On March 8 problems developed with the fuel preparation system. The coal crusher was again unable to adequately crush the coal and the paste fines were low. All coal paste pump pressure drops increased due to the poor paste quality. At 1440 hours on March 8, it became apparent that a unit shutdown was imminent, and the combustor was tripped. Extremely wet coal was determined to be the cause of these crushing difficulties.

Startup TD-SU-95-07-01 - March 14 - March 30, 1995

The unit was released for operation at 2050 hours on March 13, 1995. The cause of coal crushing difficulties was suspected to be high moisture content in the coal. The coal was now being received on a daily basis, since the test program was scheduled to terminate operation on March 30, 1995. Based on the hypothesis that wet coal was the problem, the fuel nozzles were cleaned, the rolls of the crusher were dressed and the minimum gap reset, and the coal bunkers were purged of the wet coal. This coupled with a more consistent coal supply permitted resumption of operation.

The gas turbine was rolled at 0531 hours on March 14, 1995, and paralleled at 0552 hours. Air flow was established at 0603 hours. The steam turbine was rolled at 1355 hours and paralleled at 1506 hours. Coal fire was established at 1715 hours.

The unit was brought up to 115 inches bed level and 1580 F bed temperature on site prepared Plum Run dolomite. Two tests were conducted the week of March 13, 1995. The sorbent preparation system was subsequently set up in the scalping/dedusting mode and the bed level reduced to 90 inches in order to complete two more tests. National Limestone was introduced into the bed on March 27, 1995. One test at 115 inches bed height was completed.

The combustor was tripped for the final time at 0827 hours on March 30, 1995.

Outage Narrative

Outage TD-OT-94-04-01 - March 10 - 15, 1994

Moved #6 fuel nozzle skateboard 8 inches toward front boiler wall and 7 inches to north.

Replaced HGCU screw cooler hydraulic drive motor.

Outage TD-OT-94-05-01 - March 23 - 30, 1994

Machined fuel prep crusher rolls flat and then added grooves.

Modified chute from vibrating feeder CVF-1 to hopper T-1.

Replaced bearing on south screw of fuel prep crusher feed screw.

Replaced economizer outlet duct expansion joint.

Installed probes on APF dirty and clean gas sample locations for HAP testing.

Liquid cleaned gas turbine low pressure compressor.

Cleaned Graham vacuum pump seal water cooler.

Replaced conveyor belt on bed ash Flexowell belt.

Repaired O2 analyzer sample lines.

Installed air filter in HGCU pulse valve pilot solenoid air supply.

Replaced 4th stage rings in HGCU backpulse compressor.

Outage TD-OT-94-06-01 - April 19 - 28, 1994

The unit was shut down due to a leak on the sorbent injection ceramic lined pipe.

Repaired mitered joints of ceramic lined sorbent injection piping.

Replaced the fines filter on the sorbent booster compressor.

Installed orifices on the two outside sorbent nozzles inside of the bed.

Rebuilt sorbent prep system fan inlet vane housing.

Moved fuel injection skateboards back to original position.

Repaired leaks on primary cyclone ash lines in primary ash coolers.

Replaced the primary and secondary cyclone dipleg thermocouple with continuous lead type.

Filled bed ash reinjection vessels with sand and bed material for startup.

Isolated HGCU from PFBC.

Replaced one of the paste tank level transmitters due to wear.

Installed anti-skewing controls on the fuel prep system crusher.

Replaced the gear boxes on the paste tank agitators to reduce current draw on motors (40% speed reduction).

Replaced bent shaft on #5 paste pump HMC valve.

Inspected gas turbine LPT blade roots with video boroscope.

Liquid cleaned gas turbine LPC.

Replaced failed gas turbine HPT shaft speed pickup.

Replaced fourth stage rings on HGCU backpulse compressor.

Revised oiling system on fourth stage of HGCU backpulse compressor.

Replaced the impulse tubing on the APF gas flow meter.

Outage TD-OT-94-07-01 - Beginning June 13, 1994

The unit was removed from service due to a noise in the gas turbine exciter.

Dry cleaned the gas turbine HPT using Carboblast.

Removed the gas turbine LPT for inspection of blade roots (No indication of root or other cracking).

Removed gas turbine LPT inlet guide vane and made repairs to erosion areas. Replaced outer ring.

Rebuilt 10 bed ash removal system valves.

Inspected south bed ash reinjection vessel for pluggage and filled both vessels with sand and bed material for startup.

Tied HGCU to PFBC.

Added a second high ash level probe to APF.

Installed complete detuning system for #11 primary cyclone.

Repaired 18 tube leaks in steam turbine condenser.

Repaired lube oil leak on #3 bearing on steam turbine.

Installed new sorbent prep system sizer screen assembly.

Inspected sorbent injection ceramic lined piping.

Repaired air leaks on splitting air compressor cylinders.

Rebuilt vertical separator level control valve, LCV-U200A.

Rebuilt vertical separator pressure control valve, PCV-B200.

Installed "dam" on each of the bed ash removal "L" valves to try to reduce flow through.

Mechanically cleaned all process air distribution pipes.

Inspected and cleaned water side of process air cooler.

Installed tube shields on secondary superheater tubes.

Repaired leaks on primary ash system lines inside of primary ash coolers.

Outage TD-OT-94-08-03 - July 16 - 19, 1994

Inspected and cleaned primary ash cyclones

Inspected and cleaned secondary ash cyclones

Repaired sparge duct end fluidization ball valve

Outage TD-OT-94-09-01 - July 27 - 28, 1994

Installed balance shot on the gas turbine HPC shaft

Outage TD-OT-94-09-02 - August 25 - September 1, 1994

Repaired leaking gaskets on gas turbine lube oil system at #5 bearing

Replaced HCV-T441 (HPT cleaning valve)

Repaired leak in gas turbine intercooler

Replaced brushes on gas turbine DC lube oil pump motor

Inspected HCV-B820 (west sorbent injection upper isolation valve)

Replaced several valves on sorbent injection vent system

Replaced liners and hammers on sorbent prep drying mill

Repaired several fuel prep system leaks

Replaced brushes on #1 chemical feed pump motor

Repaired thermocouple and heaters on #1 and #7 HGCU expansion joints

Completed installation of HGCU alternate ash line to primary ash line and changed V-102 to 54 mm

Rebuilt fourth stage of HGCU backpulse compressor

Repaired stack bypass damper

Replaced seat on vertical separator power operated relief valve

Replaced five bed thermocouple

Outage TD-OT-94-10-01 - September 10 - 21, 1994

Repaired two tube leaks in secondary superheater

Replaced sorbent injection spool pieces upstream of isolation valves

Machined grooves in fixed roll of fuel prep crusher

Repaired sorbent velocity separator cone

Rebuilt sorbent prep rotary feeders SRA-1 and SRA-2

Replaced gear box on bed ash removal bucket elevator

Repaired leak in gas turbine intercooler

Outage TD-OT-94-11-01 - October 21 - December 1, 1994

Inspected, cleaned and metalized LPT blades for erosion.

Inspected, cleaned and metalized LPT inlet guide vanes for erosion.

Repaired disc cooling air supply valves.

Repaired leak in intercooler, plugged top two rows, and sleeved remaining tubes 6 inches in on each end.

Replaced check valve and added HSOV in cleaning compressor discharge line.

Tested DC lube oil pump.

Liquid cleaned LPT.

Removed head for candle replacement.

Removed worn out BUC ash line, rotated BUC ash collection chamber and installed new BUC ash line.

Replaced BUC ash pickup nozzle.

Replaced #2 expansion joint.

Replaced HCV-J926 (lockhopper equalizing valve).

Repaired HCV-J927.

Repaired shroud in APF.

HGCU Isolated from PFBC.

Completed boiler air test.

Vacuum cleaned freeboard, combustor bottom, sparge ducts, windbox and preheater.

Inspected stack breaching damper.

Inspected rupture disks.

Repaired lap joints on economizer inlet duct.

Repaired actuator coil on PCV-M001B (SSH vent valve).

Pulled number thirteen secondary superheater platen, removed tube samples and reinstalled platen.

Inspected and cleaned primary ash cyclones.

Air tested primary ash lines and replaced several gaskets in internal ash coolers.

Inspected and cleaned secondary ash cyclones.

Air tested secondary ash lines and repaired leaks.

Repaired worn ash lines on #22, 25, 26, and 27 cyclones.

Modified #11 primary cyclone to be straight through gas flow. (No cyclone action.)

Replaced cyclone ash silo fluidizing blower.

Replaced blades on coal water mixer.

Machined moveable roll wheel on crusher.

Replaced reject screw feeder outboard seal.

Replaced all six fuel nozzles.

Adjusted paste pump "S" tube seal fits.

Repaired hydraulic hose leak on #6 paste pump.

Calibrated all six paste pumps.

Rebuilt drying mill hammers, rotor and liner.

Repaired cyclone separator.

Metalized system fan rotor and blades.

Repaired velocity separator and expansion joint above separator.

Ran production rate test on sizer screen set up in the "scalping/dedusting" mode.

Replaced spool pieces between combustor and isolation valves with ceramic lined spool pieces.

Modified HCV-B840 and HCV-B850 to fit to new ceramic lined spool pieces.

Installed purge air on valve cavities for HCV-B818, HCV-B828, HCV-B831 and HCV-B832.

Installed larger valve operators on HCV-B831 and HCV-B832.

Replace ceramic lined piping on injection lines inside of the combustor.

Replaced the fine filter on the sorbent booster compressor.

Inspected and cleaned sorbent booster compressor inlet guide vane assembly.

Replaced expansion joints between 200 ton storage vessel and injection vessels.

Repaired leak on boiler ventilation bag house.

Made repairs and adjustment to steam turbine voltage regulator.

Replaced valve plug on LCV-U200A.

Inspected and cleaned O^2 analyzer blowdown line and valve.

Installed larger valve operators on HCV-J270 and HCV-J280 (bed ash reinjection).

Filled bed ash reinjection vessels with sand and bed material for startup.

Conducted interlock checks.

Outage TD-OT-95-01-01 - January 2 - January 12, 1995

Krupp-Polysius coal crusher movable roll gear box bearing failed causing the unit to be removed from service. The gear boxes on both the movable and stationary rolls were replaced.

Restored HGCU system to service.
Video borescoped LPT inner guide vane ring, some wear was identified. V-12 and V-13 orifices, which supply cooling air to the LPT disc, were enlarged to 18 and 28 mm respectively to mitigate high disc temperatures. A bypass orifice (10.5 mm) was installed around V-13 to provide the opportunity to further increase cooling air, if required.

A water leak in the gas turbine intercooler was repaired.

The sorbent booster compressor inlet guide vane assembly was disassembled to eliminate binding.

The number 7 cyclone O2 analyzer tubing was completely replaced. The number 3 cyclone O2 analyzer tubing was partially replaced.

Repaired leaks on primary ash piping inside the internal ash coolers.

Outage TD-OT-95-02-01 - January 13 - January 17, 1995

The unit was removed from service due to pluggage of the number 16 primary cyclone.

Inspected and cleaned primary cyclones and HGCU ash removal system.

Appendix I

Outage TD-OT-95-03-01 - January 19 - January 20, 1995

The gas turbine was tripped due to a control fluid problem. A piece of O-ring was found blocking control fluid flow.

Outage TD-OT-95-04-01 January 21 - January 25, 1995

Difficulty was noted in obtaining acceptable bed fluidization. the unit was removed from service. Inspection revealed excessive ash buildup in the sparge ducts. The sparge ducts and sparge nozzles were cleaned.

Outage TD-OT-95-05-01 - February 2 - February 7, 1995

The unit was removed from service due to elevated temperatures (1400 F) at the HGCU backup cyclone. Inspection revealed missing insulation. In addition a steel liner had failed causing metal fragments to enter the gas turbine. The area was re-insulated and the gas turbine inspected for damage. The gas turbine had a number of damaged blades (due to several pieces of metal having passed through the machine). However, the damage was not sufficient to preclude running the unit to the end of the test period.

Outage TD-OT-95-06-01 - February 16 - February 18, 1995

The unit was shut down due to poor paste quality, which resulted in fuel line pluggages. All fuel nozzles were disassembled and cleaned. All coal bunkers, paste tanks, and the truck hopper were emptied of coal which appeared to have created the crushing and fuel line pluggage. The coal crusher rolls were readjusted.

The advanced particle filter was inspected for broken candles. A number of candle pieces were removed from the ash transport line. Installed a screen at the inlet of the alternate ash removal line to preclude pluggage from broken candles.

Appendix II - Tidd PFBC Operations Time Log

This appendix presents the operating hours and statistics for each of the unit operational periods.

Fourth Year (1994/1995) Operating Hours Data

Tidd PFBC Operations Time Log March 1, 1994 Through March 30, 1995							
RUN # Starting with 94-04-01	94-04-01	94-04-02	94-05-01	94-06-01	94-07-01	94-07-01	94-07-01
Run Starting:	01-Mar	10-Mar	15-Mar	30-Mar	29-Apr	29-Apr	29-Apr
Summary of Outage Statistics:							
Outage Duration - Hours:	56.0	31.0	136.9	186.0	263.3	0	0
YTD Outage Hours:	56.0	86.9	223.9	409.8	673.1	673.1	673.1
Summary of Operating Statistics:							
Gas Turbine Time On:	6:32 pm	2:09 pm	10:34 pm	02:56 pm	07:37 pm	12:00 am	12:00 am
Gas Turbine Date On:	02-Mar	10-Mar	15-Mar	30-Mar	29-Apr	01-May	01-Jun
Gas Turbine Time Off:	4:43 pm	07:41 pm	10:50 am	01:49 am	11:59 pm	11:59 pm	10:55 pm
Gas Turbine Date Off:	09-Mar	10-Mar	23-Mar	19-Apr	30-Apr	31-May	13-Jun
GT Operation This Run - Hours:	166.2	5.5	180.3	466.9	40.4	744.0	310.92
Total GT Hours YTD	167.2	172.7	354.4	821.3	861.7	1605.7	1927.2
Steam Turbine Time On:	07:57 am	06:29 pm	11:24 am	04:49 am	08:00 pm	12:00 am	12:00 am
Steam Turbine Date On:	03-Mar	10-Mar	16-Mar	31-Mar	29-Apr	01-May	01-Jun
Steam Turbine Operation for this Run - Hours:	147.6	0	167.4	447.9	28.0	744.0	308.3
Total Steam Turbine Hours YTD	147.6	147.6	315.0	762.9	790.9	1534.9	1843.2
Unit Availability YTD based on Steam Turbine hours:	72.51%	62.93%	58.46%	65.05%	54.02%	69.51%	73.25%

Tidd PFBC Operations Time Log March 1, 1994 Through March 30, 1995							
RUN # Starting with 94-04-01	94-04-01	94-04-02	94-05-01	94-06-01	94-07-01	94-07-01	94-07-01
Run Starting:	01-Mar	10-Mar	15-Mar	30-Mar	29-Apr	29-Apr	29-Apr
Coal Time On:	10:22 am	06:29 pm	02:48 pm	09:04 am	08:38 pm	12:00 am	12:00 am
Coal Date On:	03-Mar	10-Mar	16-Mar	1-Mar	29-Apr	01 -May	01-Jun
Coal Time Off:	11:30 am	06:29 pm	10:50 am	08:43 pm	11:59 pm	11:59 pm	08:16 pm
Coal Date Off:	09-Mar	10-Mar	23-Mar	18-Apr	30-Apr	31-May	13-Jun
Coal Time This Run - Hours:	145.1	0	164.0	443.7	27.4	744.0	308.3
Grand Total Coal Time - Hours:	6201.7	6201.7	6365.7	6809.4	6836.7	7580.7	7889.0
Total Coal Fire Hours - Fourth Year:	145.1	145.1	309.2	752.8	780.2	1524.2	1832.4
Availability YTD Based on Coal Fire:	71.66%	62.15%	57.48%	64.25%	53.33%	69.06%	72.85%
Maximum Unit Load Achieved - MW:	62	0	62	58	57	57	57
Gross Generation for Run - MWHr:	7738	0	8421	20477	833	35198	15202
Gross Output Factor for This Run @70MWG:	74.92%	0%	71.85%	65.31%	42.50%	67.58%	70.45%
Gross Generation YTD - MWHrs:	7738	7738	16159	36636	37469	72667	87869
Gross Capacity Factor @70MWG:	54.32%	47.14%	42.84%	44.63%	36.56%	47.02%	49.89%
Gross Output Factor YTD @70 MWG:	74.92%	74.92%	73.29%	68.60%	67.68%	67.63%	68.10%

Fourth Year (1994/1995) Operating Hours Data - Continued

Tidd PFBC Operations Time Log March 1, 1994 Through March 30, 1995								
RUN # Starting with 94-08-01	94-08-01	94-08-02	94-08-03	94-09-01	94-09-02	94-09-02	94-10-01	94-11-01
Run Starting:	14-Jul	15-Jul	16-Jul	20-Jul	28-Jul	28-Jul	02-Sept	21-Sept
Summary of Outage Statistics:								
Outage Duration - Hours:	754.0	17.9	7.6	100.7	20.6	0.0	200.5	299.8
YTD Outage Hours:	1427.1	1445.0	1452.6	1553.2	1573.8	1573.8	1774.3	2074.1
Summary of Operating Statistics:								
Gas Turbine Time On:	12:51 am	12:35 pm	04:27 am	09:12 am	04:02 pm	12:00 am	12:56 pm	03:37 am
Gas Turbine Date On:	15-Jul	15-Jul	16-Jul	20-Jul	28-Jul	01-Aug	03-Sep	22-Sept
Gas Turbine Time Off:	06:50 am	04:27 am	05:08 pm	03:34 pm	11:59 pm	08:42 pm	08:57 am	11:59 pm
Gas Turbine Date Off:	15-Jul	16-Jul	16-Jul	27-Jul	31-Jul	25-Aug	10-Sep	30-Sept
GT Operation This Run - Hours:	6.0	15.9	12.7	174.4	92.0	596.7	188.0	212.4
Total GT Hours YTD	1933.2	1949.1	1961.8	2136.1	2228.1	2824.8	3012.8	3225.2
Steam Turbine Time On:	06:15 am	12:09 am	12:00 pm	06:35 pm	08:44 am	12:00 am	02:18 am	03:53 pm
Steam Turbine Date On:	15-Jul	16-Jul	16-Jul	20-Jul	28-Jul	01-Aug	03-Sept	22-Sept
Steam Turbine Operation For This Run - Hours:	0.0	4.3	1.9	161.6	87.3	593.8	169.8	200.1
Total Steam Turbine Hours YTD Starting March 1, 1994:	1843.2	1847.5	1849.4	2011.0	2098.3	2692.1	2861.9	3062.0
Unit Availability YTD based on Steam Turbine Hours:	56.36%	56.11%	56.01%	56.42%	57.14%	63.11%	61.73%	59.62%

Appendix II

Tidd PFBC Operations Time Log March 1, 1994 Through March 30. 1995								
RUN # Starting with 94-08-01	94-08-01	94-08-02	94-08-03	94-09-01	94-09-02	94-09-02	94-10-01	94-11-01
Run Starting:	14-Jul	15-Jul	16-Jul	20-Jul	28-Jul	28-Jul	02-Sept	21-Sept
Coal Time On:	06:15 am	01:56 am	12:59 pm	07:18 pm	09:59 am	12:00 am	01:04 am	04:57 pm
Coal Date On:	15-Jul	16-Jul	16-Jul	20-Jul	28-Jul	01-Aug	03-Sept	22-Sept
Coal Time Off:	06:15 am	04:27 am	01:55 pm	12:08 pm	11:59 pm	05:47 am	04:07 am	11:59 pm
Coal Date Off:	15-Jul	16-Jul	16-Jul	27-Jul	31-Jul	25-Aug	10-Sept	30-Sept
Coal Time This Run - Hours:	0.0	2.5	0.9	160.8	86.0	593.8	171.0	199.0
Grand Total Coal Time - Hours:	7889.0	7891.5	7892.4	8053.2	8139.2	8733.0	8904.0	9103.0
Total Coal Fire Hours - Fourth Year:	1832.4	1834.9	1835.8	1996.6	2082.6	2676.5	2847.5	3046.5
Availability YTD Based on Coal Fire:	56.05%	55.75%	55.62%	56.04%	56.73%	62.76%	61.43%	59.33%
Maximum Unit Load Achieved - MW:	0	8	6	34	60	60	59	64
Gross Generation for Run - MWHr:	0	18	7	3823	3724	25740	7022	8977
Gross Output Factor for this Run @ 70MWG:	0	5.98	5.22%	33.81%	60.96%	61.93%	59.07%	64.08%
Gross Generation YTD - MWHrs.	87869	87887	87894	91717	95441	121181	128203	137180
Gross Capacity Factor @ 70MWG:	38.38%	38.13%	38.03%	36.76%	37.13%	40.58%	39.50%	38.16%
Gross Output Factor YTD @ 70 MWG:	68.10%	67.96%	67.90%	65.16%	64.98%	64.31%	64.00%	64.00%

Fourth Year (1994/1995) Operating Hours Data - Continued

Tidd PFBC Operations Time Log March 1, 1994 Through March 30, 1995								
RUN # Starting with 94-11-01	94-11-01	94-12-01	94-12-02	94-12-02	95-01-01	95-02-01	95-02-02	95-03-01
Run Starting:	21-Sept	30-Nov	02-Dec	02-Dec	13-Jan	18-Jan	20-Jan	26-Jan
Summary of Outage Statistics:								
Outage Duration - Hours:	0.0	996.4	15.7	0.0	265.9	117.5	31.5	142.7
YTD Outage Hours:	2074.1	3070.6	3086.3	3086.3	3352.2	3469.7	3501.2	3643.8
Summary of Operating Statistics:								
Gas Turbine Time On:	12:00 am	11:41 am	05:30 pm	12:00 am	03:41 am	05:23 am	11:25 am	12:57 pm
Gas Turbine Date On:	01-Oct	01-Dec	02-Dec	01-Jan	13-Jan	18-Jan	20-Jan	26-Jan
Gas Turbine Time Off:	02:51 pm	01:46 pm	11:59 pm	08:44 pm	07:31 pm	08:39 am	06:18 am	10:24 am
Gas Turbine Date Off:	21-Oct	02-Dec	31-Dec	02-Jan	13-Jan	19-Feb	21-Jan	02-Feb
GT Operation This Run - Hours:	494.9	26.1	702.5	44.7	15.8	27.3	18.9	165.5
Total GT Hours YTD Starting March 1, 1994:	3720.1	3746.4	4448.9	4493.6	4509.4	4336.7	4555.6	4721.1
Steam Turbine Time On:	12:00 am	12:06 am	10:38 pm	12:00 am	12:53 pm	03:18 pm	04:07 pm	11:23 pm
Steam Turbine Date On:	01-Oct	02-Dec	02-Dec	01-Jan	13-Jan	18-Jan	20-Jan	26-Jan
Steam Turbine Operation For This Run - Hours:	491.7	6.8	697.4	35.0	4.9	17.4	8.6	146.7
Total Steam Turbine Hours YTD	3553.6	3560.4	4257.8	4292.8	4297.7	4315.1	4323.7	4470.4
Unit Availability YTD based on Steam Turbine hours:	63.14%	53.69%	57.98%	58.17%	56.18%	55.43%	55.25%	55.09%

Appendix II

Tidd PFBC Operations Time Log March 1, 1994 Through March 30, 1995								
RUN # Starting with 94-11-01	94-11-01	94-12-01	94-12-02	94-12-02	95-01-01	95-02-01	95-02-02	95-03-01
Coal Time On:	12:00 am	01:07 am	11:14 pm	12:00 am	01:24 pm	03:53 pm	05:35 pm	12:58 am
Coal Date On:	01-Oct	02-Dec	02-Dec	01-Jan	13-Jan	18-Jan	20-Jan	27-Jan
Coal Time Off:	11:39 am	06:55 am	11:59 pm	10:57 am	05:47 pm	08:39 am	12:44 am	02:05 am
Coal Date Off:	21-Oct	02-Dec	31-Dec	02-Jan	13-Jan	19-Jan	21-Jan	02-Feb
Coal Time This Run - Hours:	491.7	5.8	696.8	35.0	4.4	16.6	7.2	145.1
Grand Total Coal Time - Hours:	9594.8	9600.6	10297.4	10332.4	10336.8	10353.5	10360.7	10505.8
Total Coal Fire Hours - Fourth Year:	3538.3	3544.1	4240.9	4275.9	4280.3	4296.9	4304.1	4449.2
Availability YTD Based on Coal Fire:	62.88%	53.46%	57.75%	57.95%	55.96%	55.20%	55.01%	54.84%
Maximum Unit Load Achieved - MW:	64	13	68	68	11	14	14	68
Gross Generation for Run - MWHr:	25945	54	39534	1854	22	169	76	7880
Gross Output Factor for This Run @70MWG:	75.39%	11.32%	80.99%	75.78%	6.41%	13.92%	12.60%	76.74%
Gross Generation YTD - MWHrs:	163125	163179	202713	204567	204589	204758	204834	212714
Gross Capacity Factor @ 70MWG:	41.41%	35.16%	39.43%	39.60%	38.21%	37.58%	37.40%	37.45%
Gross Output Factor YTD @ 70 MWG:	65.58%	65.47%	68.02%	68.08%	68.01%	67.79%	67.68%	67.98%

Fourth Year (1994/1995) Operating Hours Data - Continued

Tidd PFBC Operations Time Log March 1, 1994 Through March 30, 1995						
RUN # Starting with 95-04-01	95-04-01	95-04-02	95-04-03	95-05-01	95-06-01	95-07-01
Run Starting:	08-Feb	09-Feb	11-Feb	13-Feb	18-Feb	14-Mar
Summary of Outage Statistics:						
Outage Duration - Hours:	166.2	12.3	14.7	17.8	54.1	143.2
YTD Outage Hours:	3810.0	3822.3	3837.0	3854.8	3908.9	4052.1
Summary of Operating Statistics:						
Gas Turbine Time On:	10:43 am	03:09 pm	06:34 pm	05:48 am	08:48 am	05:31 am
Gas Turbine Date On:	08-Feb	09-Feb	10-Feb	13-Feb	18-Feb	14-Mar
Gas Turbine Time Off:	03:09 pm	06:34 pm	12:28 am	04:15 pm	06:56 pm	04:13 pm
Gas Turbine Date Off:	09-Feb	10-Feb	13-Feb	16-Feb	08-Mar	30-Mar
GT Operation This Run - Hours:	28.4	27.4	53.9	82.5	442.1	394.7
Total GT Hours YTD Starting	4749.5	4776.9	4830.8	4913.3	5355.4	5750.1
Steam Turbine Time On:	12:14 am	03:29 am	09:15 am	11:36 am	06:50 pm	01:55 pm
Steam Turbine Date On:	09-Feb	10-Feb	11-Feb	13-Feb	18-Feb	14-Mar
Steam Turbine Operation For This Run - Hours:	14.9	15.1	32.6	73.1	427.8	378.5
Total Steam Turbine Hours YTD Starting March 1, 1994:	4485.2	4500.3	4532.9	4606.0	5033.8	5412.3
Unit Availability YTD Based on Steam Turbine Hours:	54.07%	54.07%	54.16%	54.44%	56.29%	57.19%

Tidd PFBC Operations Time Log March 1, 1994 Through March 30, 1995						
RUN # Starting with 95-04-01	95-04-01	95-04-02	95-04-03	95-05-01	95-06-01	95-07-01
Run Starting:	08-Feb	09-Feb	11-Feb	13-Feb	18-Feb	14-Mar
Coal Time On:	12:30 am	04:08 am	09:26 am	11:43 am	07:29 pm	05:15 pm
Coal Date On:	09-Feb	10-Feb	11-Feb	13-Feb	18-Feb	14-Mar
Coal Time Off:	03:09 pm	06:34 pm	05:51 pm	12:43 pm	02:40 pm	08:27 am
Coal Date Off:	09-Feb	10-Feb	12-Feb	16-Feb	08-Mar	30-Mar
Coal Time This Run - Hours:	14.7	14.4	32.4	73.0	427.2	375.2
Grand Total Coal Time - Hours:	10520.4	10534.9	10567.3	10640.3	11067.5	11442.7
Total Coal Fire Hours - Fourth Year:	4463.9	4478.3	4510.7	4583.7	5010.9	5386.1
Availability YTD Based on Coal Fire:	53.82%	53.82%	53.90%	54.18%	56.04%	56.91%
Maximum Unit Load Achieved - MW:	42	68	70.1	63	72	68
Gross Generation for Run - MWHr:	377	430	1817	3674	24786	16670
Gross Output Factor for this Run @ 70 MWG:	36.11%	40.73%	79.62%	71.78%	82.76%	62.91%
Gross Generation YTD - MWHrs:	213091	213521	215338	219012	243798	260468
Gross Capacity Factor @ 70MWG:	36.70%	36.65%	36.75%	36.98%	38.95%	39.32%
Gross Output Factor YTD @ 70 MWG:	67.78%	67.78%	67.87%	67.93%	69.19%	68.75%

Appendix III - Tidd PFBC Test Results

TEST NUMBER	1	2	3	4	5	6
TEST DATE	06/25/91	08/09/91	08/12/91	02/05/92	02/07/92	06/14/92
TEST PERIOD				1335-1605	0900-1520	0000-0400
COAL AND SORBENT TYPES						
COAL TYPE	MM Pitts 8	MM Pitts 8	MM Pitts 8	MM Pitts 8	MM Pitts 8	MM Pitts 8
SORBENT TYPE	PRG	PRG	NL Carey	PRG	PRG	PRG
SORBENT MESH SIZE	#6 site	#6 site	#6 site	#6 site	#6 site	#6 site
OPERATING DATA						
BED LEVEL, INCHES	126.9	76.0	90.2	130.8	131.0	142.3
ST GEN OUTPUT, MW	37.8	22.9	25.9	47.2	45.5	47.0
GT GEN OUTPUT, MW	11.4	3.7	6.3	14.8	14.2	13.2
MEAN BED TEMP, F	1535.1	1530.5	1529.9	1534.8	1534.8	1551.0
INT VALVE INLET TEMP, F	1535.6	1247.4	1338.0	1508.4	1484.9	1540.8
AVG. BED OUTLET O2, %	5.1	7.8	8.3	4.2	4.6	3.3
AIR FLOW (indicated), KPPH	625.3	499.9	575.0	709.8	709.7	680.0
FEEDWATER FLOW, KPPH	328.5	219.1	247.0	386.2	373.7	395.1
COAL PASTE FLOW (calc.), PPH	57503	38918	45668	68933	65177	67934
TOTAL SORBENT FLOW, PPH	20090	13360	21780	22660	23340	20930
SORBENT IN PASTE, %	0.0	0.0	0.0	0.0	0.0	0.0
BED ASH FLOW (calc.), PPH	4730	7946	11496	12212	12212	9882
CYC ASH FLOW (calc.), PPH	17918	7146	11517	13303	13647	14904
EMISSIONS						
NOX LVG ESP, LB/MMBTU	0.26	0.29	0.34	0.23	0.22	0.17
SO2 LVG ESP, LB/MMBTU	0.34	0.95	0.59	0.54	0.53	0.35
FEEDSTOCK ANALYSIS						
COAL SO2, LB/MMBTU	5.35	5.33	5.52	5.30	5.30	4.83
PASTE MOISTURE, % WGT.	24.09	26.31	25.36	28.25	28.25	25.22
SORBENT CaO (D/B), % WGT.	28.16	28.50	28.88	27.97	27.97	26.85
CYC ASH SULFATION, %	N/A	N/A	N/A	N/A	N/A	44.4
BED ASH SULFATION, %	N/A	N/A	N/A	N/A	N/A	47.5
CALCULATED RESULTS						
FIRING RATE, Mwt	165.2	107.6	128.2	187.1	177.8	188.7
SULFUR CAPTURE, %	93.6	82.2	89.4	89.8	90.0	92.7
Ca/S RATIO (actual)	2.15	2.23	2.98	2.14	2.43	2.07
Ca/S @ 90% SR, 1580F BED	1.64	2.68	2.76	1.97	2.22	1.71
Ca/S @ 95% SR, 1580F BED	2.13	3.49	3.59	2.57	2.88	2.23

Appendix III

TEST NUMBER	7	8	9	10	11	12
TEST DATE	06/15/92	08/12/92	08/18/92	08/20/92	08/25/92	12/16/92
TEST PERIOD	0000-0400	1200-0000	2000-0800	2000-0700	0800-2100	0730-1130
COAL AND SORBENT TYPES						
COAL TYPE	MM Pitts 8	MM Pitts 8	MM Pitts 8	MM Pitts 8	MM Pitts 8	Ohio 6A
SORBENT TYPE	PRG	PRG	PRG	PRG	PRG	PRG
SORBENT MESH SIZE	#6 site	#6 site	#6 site	#6 site	#6 site	#6 site
OPERATING DATA						
BED LEVEL, INCHES	142.1	117.0	116.1	116.3	115.3	118.7
ST GEN OUTPUT, MW	46.1	42.1	41.1	43.4	40.8	42.3
GT GEN OUTPUT, MW	12.5	9.3	9.6	10.7	8.7	10.1
MEAN BED TEMP, F	1532.3	1543.7	1547.2	1548.3	1552.5	1538.0
INT VALVE INLET TEMP, F	1488.8	1433.0	1422.4	1436.0	1407.6	1433.5
AVG. BED OUTLET O2, %	3.4	3.5	3.6	3.1	3.5	3.9
AIR FLOW (indicated), KPPH	679.6	621.4	620.2	630.7	621.7	619.6
FEEDWATER FLOW, KPPH	389.9	359.3	351.7	368.3	350.9	352.4
COAL PASTE FLOW (calc.), PPH	66138	59007	61647	66530	63481	56102
TOTAL SORBENT FLOW, PPH	22050	21220	25870	28840	22150	16430
SORBENT IN PASTE, %	0.0	0.0	61.0	100.0	44.0	0.0
BED ASH FLOW (calc.), PPH	9882	6980	7850	13740	4907	7013
CYC ASH FLOW (calc.), PPH	15755	16474	18972	15805	19469	11168
EMISSIONS						
NOX LVG ESP, LB/MMBTU	0.17	0.19	0.19	0.22	0.19	0.18
SO2 LVG ESP, LB/MMBTU	0.35	0.53	0.51	0.43	0.53	0.50
FEEDSTOCK ANALYSIS						
COAL SO2, LB/MMBTU	5.02	5.01	5.08	4.88	4.93	4.61
PASTE MOISTURE, % WGT.	25.27	26.10	30.35	32.39	32.00	26.03
SORBENT CaO (D/B), % WGT.	28.03	30.67	30.56	30.08	30.84	30.67
CYC ASH SULFATION, %	41.1	28.1	28.0	26.3	27.7	28.3
BED ASH SULFATION, %	50.0	36.9	32.3	31.3	46.7	37.8
CALCULATED RESULTS						
FIRING RATE, MWt	183.2	164.4	162.2	169.8	162.7	162.2
SULFUR CAPTURE, %	93.0	89.4	89.9	91.1	89.3	89.3
Ca/S RATIO (actual)	2.26	2.65	3.22	3.51	2.85	2.26
Ca/S @ 90% SR, 1580F BED	1.77	2.52	3.03	3.13	2.78	2.14
Ca/S @ 95% SR, 1580F BED	2.31	3.28	3.94	4.07	3.61	2.79

Appendix III

TEST NUMBER	13	14	15	16	17	18
TEST DATE	01/22/93	01/25/93	01/27/93	01/29/93	07/22/93	07/22/93
TEST PERIOD	1800-0200	0800-2000	0800-2000	2000-0800	0800-1600	2000-0400
COAL AND SORBENT TYPES						
COAL TYPE	Ohio 6A	Ohio 6A	Ohio 6A	MM Pitts 8	MM Pitts 8	MM Pitts 8
SORBENT TYPE	PRG	PRG	PRG	PRG	PRG	PRG
SORBENT MESH SIZE	#6 site	#6 site	#6 site	#6 site	#6 site	#6 site
OPERATING DATA						
BED LEVEL, INCHES	116.7	81.1	117.2	118.9	95.0	94.6
ST GEN OUTPUT, MW	41.6	25.7	40.7	41.8	28.7	29.1
GT GEN OUTPUT, MW	10.5	4.2	10.0	10.4	4.3	5.0
MEAN BED TEMP, F	1540.3	1540.1	1541.4	1539.0	1533.0	1532.8
INT VALVE INLET TEMP, F	1451.9	1195.8	1416.3	1398.9	1237.7	1226.5
AVG. BED OUTLET O2, %	4.4	7.7	4.9	4.2	8.2	8.0
AIR FLOW (indicated), KPPH	619.8	513.5	620.0	620.2	630.1	628.1
FEEDWATER FLOW, KPPH	349.3	235.6	343.2	350.1	267.0	269.7
COAL PASTE FLOW (calc.), PPH	54730	36668	53449	59071	44354	44351
TOTAL SORBENT FLOW, PPH	15320	11420	16050	18260	14010	14890
SORBENT IN PASTE, %	0.0	0.0	0.0	0.0	0.0	0.0
BED ASH FLOW (calc.), PPH	7180	4440	7010	7745	4674	6245
CYC ASH FLOW (calc.), PPH	9843	7804	10777	13056	11270	10494
EMISSIONS						
NOX LVG ESP, LB/MMBTU	0.20	0.15	0.22	0.22	0.28	0.30
SO2 LVG ESP, LB/MMBTU	0.43	0.50	0.37	0.51	0.55	0.50
FEEDSTOCK ANALYSIS						
COAL SO2, LB/MMBTU	4.36	4.34	4.41	4.73	4.46	4.43
PASTE MOISTURE, % WGT.	25.24	25.66	23.69	26.04	25.64	24.84
SORBENT CaO (D/B), % WGT.	27.82	29.32	30.79	31.70	28.90	29.94
CYC ASH SULFATION, %	49.5	32.0	31.1	31.0	26.5	24.3
BED ASH SULFATION, %	40.5	37.3	37.7	42.0	32.8	34.8
CALCULATED RESULTS						
FIRING RATE, MWt	161.8	108.1	159.1	163.2	124.8	125.9
SULFUR CAPTURE, %	90.2	88.5	91.5	89.2	87.7	88.6
Ca/S RATIO (actual)	2.03	2.40	2.28	2.34	2.44	2.68
Ca/S @ 90% SR, 1580F BED	1.85	2.35	1.96	2.22	2.43	2.58
Ca/S @ 95% SR, 1580F BED	2.41	3.06	2.55	2.88	3.16	3.36

TEST NUMBER	19	20	21	22	23	24
TEST DATE	07/26/93	07/27/93	07/28/93	07/29/93	07/31/93	08/04/93
TEST PERIOD	1200-2000	000-0800	1200-2000	0000-0800	0800-1600	1100-1900
COAL AND SORBENT TYPES						
COAL TYPE	MM Pitts 8	MM Pitts 8	MM Pitts 8	MM Pitts 8	MM Pitts 8	MM Pitts 8
SORBENT TYPE	PRG	PRG	PRG	PRG	PRG	PRG
SORBENT MESH SIZE	#6 site	#6 site	#6 site	#6 site	#6 site	#6 site
OPERATING DATA						
BED LEVEL, INCHES	80.9	81.0	80.3	80.4	80.5	77.0
ST GEN OUTPUT, MW	24.1	24.1	23.3	23.7	24.0	23.1
GT GEN OUTPUT, MW	1.1	2.0	1.1	2.0	1.9	2.0
MEAN BED TEMP, F	1534.0	1535.3	1535.1	1535.9	1535.3	1532.2
INT VALVE INLET TEMP, F	1163.9	1161.6	1144.5	1148.9	1153.3	1165.6
AVG. BED OUTLET O2, %	9.2	9.2	9.0	9.0	9.2	9.5
AIR FLOW (indicated), KPPH	599.8	605.1	567.7	584.8	590.6	592.6
FEEDWATER FLOW, KPPH	230.7	232.1	224.9	228.4	230.1	221.3
COAL PASTE FLOW (calc.), PPH	38656	39094	36972	37708	39085	37450
TOTAL SORBENT FLOW, PPH	12100	13520	16500	17150	21120	10760
SORBENT IN PASTE, %	0.0	0.0	0.0	0.0	0.0	0.0
BED ASH FLOW (calc.), PPH	5128	5285	5848	6173	7790	4670
CYC ASH FLOW (calc.), PPH	8833	9822	11190	11566	13801	7940
EMISSIONS						
NOX LVG ESP, LB/MMBTU	0.19	0.21	0.22	0.23	0.22	0.20
SO2 LVG ESP, LB/MMBTU	0.51	0.57	0.25	0.25	0.32	0.83
FEEDSTOCK ANALYSIS						
COAL SO2, LB/MMBTU	4.55	4.56	4.63	4.60	5.57	4.74
PASTE MOISTURE, % WGT.	26.86	26.73	26.94	26.40	27.05	27.10
SORBENT CaO (D/B), % WGT.	29.09	28.90	28.38	28.41	29.02	29.14
CYC ASH SULFATION, %	27.6	26.8	25.0	23.3	22.8	29.9
BED ASH SULFATION, %	35.4	34.1	27.4	29.4	27.7	36.9
CALCULATED RESULTS						
FIRING RATE, Mwt	106.6	108.1	102.4	105.2	106.8	103.7
SULFUR CAPTURE, %	88.9	87.4	94.6	94.5	94.2	82.5
Ca/S RATIO (actual)	2.43	2.66	3.32	3.38	3.45	2.14
Ca/S @ 90% SR, 1580F BED	2.32	2.70	2.39	2.45	2.55	2.56
Ca/S @ 95% SR, 1580F BED	3.01	3.51	3.11	3.19	3.32	3.33

TEST NUMBER	25	26	27	28	29	30
TEST DATE	08/05/93	08/13/93	08/13/93	08/21/93	08/21/93	08/23/93
TEST PERIOD	0000-0700	0800-1600	2000-0400	0700-1500	1700-0100	1300-2000
COAL AND SORBENT TYPES						
COAL TYPE	MM Pitts 8	MM Pitts 8	MM Pitts 8	MM Pitts 8	MM Pitts 8	MM Pitts 8
SORBENT TYPE	PRG	PRG	PRG	PRG	PRG	PRG
SORBENT MESH SIZE	#6 site	#6 site	#6 site	#6 site	#6 site	#6 site
OPERATING DATA						
BED LEVEL, INCHES	77.6	118.1	117.7	118.7	118.3	118.0
ST GEN OUTPUT, MW	23.0	40.0	40.5	41.8	41.6	40.9
GT GEN OUTPUT, MW	2.4	9.2	9.6	10.2	9.9	9.5
MEAN BED TEMP, F	1529.5	1538.5	1538.3	1542.2	1543.7	1540.8
INT VALVE INLET TEMP, F	1160.5	1426.3	1422.9	1435.9	1437.7	1436.2
AVG. BED OUTLET O2, %	9.5	4.2	4.2	3.8	3.7	4.0
AIR FLOW (indicated), KPPH	594.0	619.8	619.4	630.1	630.0	620.0
FEEDWATER FLOW, KPPH	221.4	349.2	353.1	362.8	360.7	354.0
COAL PASTE FLOW (calc.), PPH	37271	55233	59241	58763	59613	59139
TOTAL SORBENT FLOW, PPH	11490	21930	21020	28410	24220	19370
SORBENT IN PASTE, %	0.0	0.0	0.0	0.0	0.0	0.0
BED ASH FLOW (calc.), PPH	4815	9255	9255	10950	10010	11705
CYC ASH FLOW (calc.), PPH	8245	14112	13967	18530	15692	9594
EMISSIONS						
NOX LVG ESP, LB/MMBTU	0.19	0.22	0.22	0.21	0.22	0.23
SO2 LVG ESP, LB/MMBTU	0.82	0.47	0.53	0.23	0.28	0.47
FEEDSTOCK ANALYSIS						
COAL SO2, LB/MMBTU	4.73	4.98	4.87	4.93	4.93	4.80
PASTE MOISTURE, % WGT.	26.79	24.18	26.43	24.63	26.63	27.94
SORBENT CaO (D/B), % WGT.	29.13	28.99	28.97	29.10	29.03	29.17
CYC ASH SULFATION, %	29.3	29.2	28.2	N/A	N/A	28.2
BED ASH SULFATION, %	36.2	34.9	32.5	31.3	36.4	32.1
CALCULATED RESULTS						
FIRING RATE, Mwt	104.0	159.2	163.2	166.4	167.0	163.6
SULFUR CAPTURE, %	82.6	90.6	89.1	95.3	94.3	90.1
Ca/S RATIO (actual)	2.28	2.69	2.57	3.38	2.87	2.41
Ca/S @ 90% SR, 1580F BED	2.71	2.41	2.45	2.36	2.14	2.22
Ca/S @ 95% SR, 1580F BED	3.52	3.14	3.19	3.07	2.78	2.88

Appendix III

TEST NUMBER	31	32	33	34	35	36
TEST DATE	09/02/93	09/04/93	09/11/93	09/13/93	09/14/93	09/16/93
TEST PERIOD	0800-1600	0600-1100	0000-1200	0000-1200	1600-2300	1100-2300
COAL AND SORBENT TYPES						
COAL TYPE	MM Pitts 8	MM Pitts 8	MM Pitts 8	MM Pitts 8	MM Pitts 8	MM Pitts 8
SORBENT TYPE	PRG	PRG	PRG	Peebles	Peebles	NL Carey
SORBENT MESH SIZE	#6 site	#6 site	#6 site	#6 site	#6 site	#6 site
OPERATING DATA						
BED LEVEL, INCHES	113.3	78.9	119.8	84.3	83.5	83.0
ST GEN OUTPUT, MW	38.6	24.7	40.1	26.1	26.4	26.6
GT GEN OUTPUT, MW	9.2	2.6	10.0	2.5	2.8	3.5
MEAN BED TEMP, F	1537.3	1537.9	1539.2	1536.3	1536.6	1535.8
INT VALVE INLET TEMP, F	1418.5	1172.4	1426.9	1186.4	1192.7	1190.5
AVG. BED OUTLET O2, %	4.0	8.6	4.3	9.0	8.6	8.7
AIR FLOW (indicated), KPPH	616.4	580.3	619.3	609.5	599.6	609.9
FEEDWATER FLOW, KPPH	340.8	236.3	349.8	242.9	245.8	246.0
COAL PASTE FLOW (calc.), PPH	57238	41003	58347	39582	39845	40606
TOTAL SORBENT FLOW, PPH	17670	14940	17690	16280	22020	25130
SORBENT IN PASTE, %	52.9	29.1	0.0	0.0	0.0	0.0
BED ASH FLOW (calc.), PPH	5158	4515	7363	6513	7068	8710
CYC ASH FLOW (calc.), PPH	14793	11928	13022	10373	14604	15369
EMISSIONS						
NOX LVG ESP, LB/MMBTU	0.20	0.20	0.23	0.21	0.21	0.23
SO2 LVG ESP, LB/MMBTU	0.46	0.36	0.76	0.52	0.29	0.26
FEEDSTOCK ANALYSIS						
COAL SO2, LB/MMBTU	4.92	4.98	5.57	4.92	4.92	5.13
PASTE MOISTURE, % WGT.	28.47	29.51	27.23	26.65	26.17	26.82
SORBENT CaO (D/B), % WGT.	29.89	29.67	28.78	28.97	29.39	28.67
CYC ASH SULFATION, %	26.4	28.2	N/A	N/A	N/A	N/A
BED ASH SULFATION, %	47.4	32.1	42.1	N/A	N/A	N/A
CALCULATED RESULTS						
FIRING RATE, Mwt	156.3	108.5	161.8	111.5	112.1	112.8
SULFUR CAPTURE, %	90.6	92.8	86.3	89.4	94.0	95.0
Ca/S RATIO (actual)	2.30	2.75	1.89	2.88	3.93	4.18
Ca/S @ 90% SR, 1580F BED	2.06	2.21	2.02	2.70	2.94	2.94
Ca/S @ 95% SR, 1580F BED	2.68	2.88	2.62	3.52	3.82	3.82

TEST NUMBER	37	38	39	40	41	42
TEST DATE	09/17/93	09/23/93	10/19/93	10/21/93	10/31/93	11/02/93
TEST PERIOD	1300-0100	0000-1200	2200-0200	2000-0400	2000-0400	0000-0800
COAL AND SORBENT TYPES						
COAL TYPE	MM Pitts 8	MM Pitts 8	MM Pitts 8	MM Pitts 8	MM Pitts 8	MM Pitts 8
SORBENT TYPE	NL Carey	PRG	PRG	PRG	PRG	PRG
SORBENT MESH SIZE	#6 site	#6 site	#6 site	#6 site	#6 site	#6 site
OPERATING DATA						
BED LEVEL, INCHES	83.0	128.2	116.4	114.5	114.3	141.3
ST GEN OUTPUT, MW	26.6	42.9	38.0	41.5	41.0	45.6
GT GEN OUTPUT, MW	3.3	11.6	8.9	9.9	10.0	13.2
MEAN BED TEMP, F	1536.2	1539.0	1481.5	1540.0	1543.0	1539.5
INT VALVE INLET TEMP, F	1195.6	1492.6	1367.3	1392.3	1394.4	1514.9
AVG. BED OUTLET O2, %	8.7	3.7	5.3	4.4	4.7	3.7
AIR FLOW (indicated), KPPH	610.0	653.9	625.3	624.9	630.2	659.1
FEEDWATER FLOW, KPPH	246.9	367.4	324.1	348.9	345.8	379.6
COAL PASTE FLOW (calc.), PPH	41013	61846	55368	59436	56977	60463
TOTAL SORBENT FLOW, PPH	17810	26160	19950	22970	19660	20090
SORBENT IN PASTE, %	0.0	0.0	0.0	0.0	0.0	0.0
BED ASH FLOW (calc.), PPH	7027	11980	9300	11019	9285	9070
CYC ASH FLOW (calc.), PPH	11380	15363	12111	13892	12164	13612
EMISSIONS						
NOX LVG ESP, LB/MMBTU	0.21	0.20	0.29	0.25	0.25	0.33
SO2 LVG ESP, LB/MMBTU	0.52	0.46	0.59	0.53	0.50	0.46
FEEDSTOCK ANALYSIS						
COAL SO2, LB/MMBTU	5.22	5.12	4.91	5.54	5.23	5.28
PASTE MOISTURE, % WGT.	26.89	27.14	27.75	27.29	26.08	23.10
SORBENT CaO (D/B), % WGT.	29.06	29.44	29.02	29.15	29.22	29.20
CYC ASH SULFATION, %	N/A	N/A	28.5	29.8	31.9	N/A
BED ASH SULFATION, %	N/A	N/A	30.9	31.0	38.5	N/A
CALCULATED RESULTS						
FIRING RATE, MWt	113.5	171.4	152.6	162.8	161.4	176.8
SULFUR CAPTURE, %	90.1	91.0	87.9	90.5	90.5	91.2
Ca/S RATIO (actual)	2.97	2.94	2.59	2.49	2.28	2.11
Ca/S @ 90% SR, 1580F BED	2.70	2.59	2.29	2.24	2.07	1.84
Ca/S @ 95% SR, 1580F BED	3.52	3.36	2.98	2.92	2.69	2.39

TEST NUMBER	43	44	45	46	47	48
TEST DATE	11/28/93	12/02/93	01/18/94	01/19/94	01/21/94	03/06/94
TEST PERIOD	2000-400	2000-0400	800-1500	800-1600	0000-0700	0000-1200
COAL AND SORBENT TYPES						
COAL TYPE	MM Pitts 8	MM Pitts 8	MM Pitts 8	MM Pitts 8	MM Pitts 8	MM Pitts 8
SORBENT TYPE	PRG	PRG	PRG	PRG	PRG	PRG
SORBENT MESH SIZE	#6 site	#6 site	#6 site	#6 site	#6 site	#6 site
OPERATING DATA						
BED LEVEL, INCHES	114.7	141.1	114.5	114.2	114.2	141.8
ST GEN OUTPUT, MW	42.2	42.1	41.2	40.0	37.6	44.5
GT GEN OUTPUT, MW	10.6	12.3	11.8	11.7	11.0	13.5
MEAN BED TEMP, F	1540.9	1480.0	1538.1	1532.7	1498.8	1527.8
INT VALVE INLET TEMP, F	1388.7	1468.5	1374.7	1379.9	1358.8	1507.7
AVG. BED OUTLET O2, %	5.1	4.9	6.2	5.6	5.7	4.2
AIR FLOW (indicated), KPPH	669.2	679.8	705.2	658.2	627.2	711.5
FEEDWATER FLOW, KPPH	355.3	347.3	341.6	336.5	319.3	384.3
COAL PASTE FLOW (calc.), PPH	60537	64053	58096	57000	55852	63232
TOTAL SORBENT FLOW, PPH	21150	24850	20890	19730	18010	19630
SORBENT IN PASTE, %	0.0	22.7	0.0	0.0	0.0	0.0
BED ASH FLOW (calc.), PPH	8823	8620	9377	9377	9040	8430
CYC ASH FLOW (calc.), PPH	14611	17692	13625	12321	11225	14150
EMISSIONS						
NOX LVG ESP, LB/MMBTU	0.24	0.28	0.27	0.25	0.26	0.19
SO2 LVG ESP, LB/MMBTU	0.48	0.25	0.51	0.54	0.55	0.44
FEEDSTOCK ANALYSIS						
COAL SO2, LB/MMBTU	5.34	5.13	5.47	5.54	5.07	5.05
PASTE MOISTURE, % WGT.	26.50	30.09	25.42	26.83	28.33	24.88
SORBENT CaO (D/B), % WGT.	29.04	29.42	28.18	28.45	28.24	28.59
CYC ASH SULFATION, %	30.4	28.5	29.2	29.8	29.8	40.1
BED ASH SULFATION, %	40.3	36.2	40.4	41.1	43.6	44.1
CALCULATED RESULTS						
FIRING RATE, MWt	167.7	169.4	163.6	159.3	152.0	180.9
SULFUR CAPTURE, %	91.1	95.2	90.6	90.2	89.1	91.2
Ca/S RATIO (actual)	2.30	2.82	2.21	2.13	2.22	2.06
Ca/S @ 90% SR, 1580F BED	2.03	1.73	1.97	1.92	1.94	1.75
Ca/S @ 95% SR, 1580F BED	2.63	2.25	2.56	2.50	2.52	2.28

TEST NUMBER	49	50	51	52	53	54
TEST DATE	03/07/94	04/05/94	4/9/94	05/02/94	05/11/94	05/12/94
TEST PERIOD	1400-2200	0600-1200	0900-1500	1500-2200	1700-2300	0100-0900
COAL AND SORBENT TYPES						
COAL TYPE	MM Pitts 8	MM Pitts 8	MM Pitts 8	MM Pitts 8	MM Pitts 8	MM Pitts 8
SORBENT TYPE	PRG	PRG	PRG	PRG	NL Carey	NL Carey
SORBENT MESH SIZE	#6 site	#6 site	#6 site	#6 site	#12 design	#12 design
OPERATING DATA						
BED LEVEL, INCHES	148.6	126.4	114.4	113.9	114.5	114.1
ST GEN OUTPUT, MW	43.3	43.6	37.3	39.6	41.1	43.5
GT GEN OUTPUT, MW	12.6	12.1	8.0	9.2	8.1	9.4
MEAN BED TEMP, F	1527.1	1546.2	1504.2	1499.5	1502.1	1540.7
INT VALVE INLET TEMP, F	1505.3	1476.2	1355.4	1383.3	1365.5	1392.4
AVG. BED OUTLET O2, %	4.2	4.2	5.6	5.0	5.0	4.3
AIR FLOW (indicated), KPPH	699.3	680.8	640.1	636.4	641.5	650.0
FEEDWATER FLOW, KPPH	374.6	379.1	332.0	351.0	359.2	378.0
COAL PASTE FLOW (calc.), PPH	61871	65499	55792	58922	60519	64547
TOTAL SORBENT FLOW, PPH	18170	22970	18790	21300	17070	17310
SORBENT IN PASTE, %	0.0	0.0	0.0	0.0	0.0	0.0
BED ASH FLOW (calc.), PPH	7626	11500	9660	8917	10358	11000
CYC ASH FLOW (calc.), PPH	13608	15148	12554	14963	10279	10579
EMISSIONS						
NOX LVG ESP, LB/MMBTU	0.21	0.22	0.28	0.23	0.30	0.26
SO2 LVG ESP, LB/MMBTU	0.45	0.47	0.51	0.52	0.46	0.49
FEEDSTOCK ANALYSIS						
COAL SO2, LB/MMBTU	4.89	5.47	5.25	5.44	4.92	5.08
PASTE MOISTURE, % WGT.	25.06	25.47	24.97	25.77	26.13	26.93
SORBENT CaO (D/B), % WGT.	27.98	28.80	28.45	29.00	28.34	28.07
CYC ASH SULFATION, %	43.9	35.1	35.5	28.8	36.7	36.1
BED ASH SULFATION, %	42.2	33.1	38.3	40.0	41.1	43.0
CALCULATED RESULTS						
FIRING RATE, MWt	176.5	179.9	154.4	164.5	167.8	175.4
SULFUR CAPTURE, %	90.7	91.3	90.3	90.5	90.7	90.4
Ca/S RATIO (actual)	1.98	2.25	2.21	2.31	1.96	1.83
Ca/S @ 90% SR, 1580F BED	1.72	1.98	1.86	1.91	1.62	1.66
Ca/S @ 95% SR, 1580F BED	2.23	2.58	2.42	2.49	2.11	2.16

TEST NUMBER	55	56	57	58	59	60
TEST DATE	05/12/94	05/16/94	05/18/94	06/01/94	06/04/94	06/09/94
TEST PERIOD	1900-0700	1000-1800	0200-1000	2200-0600	0000-0600	0000-1200
COAL AND SORBENT TYPES						
COAL TYPE	MM Pitts 8	MM Pitts 8	MM Pitts 8	MM Pitts 8	MM Pitts 8	MM Pitts 8
SORBENT TYPE	NL Carey	NL Carey	NL Carey	NL Carey	NL Carey	PRG
SORBENT MESH SIZE	#12 design	#6 site	#6 site	#20 design	#20 design	#12 design
OPERATING DATA						
BED LEVEL, INCHES	114.9	114.1	115.0	113.1	118.3	107.3
ST GEN OUTPUT, MW	45.9	37.7	42.2	47.3	43.9	44.0
GT GEN OUTPUT, MW	11.0	9.1	10.9	9.3	8.4	8.2
MEAN BED TEMP, F	1579.8	1497.7	1574.5	1574.8	1475.0	1576.4
INT VALVE INLET TEMP, F	1432.7	1395.4	1439.4	1369.2	1347.9	1346.8
AVG. BED OUTLET O2, %	3.7	5.2	4.4	2.9	4.0	3.8
AIR FLOW (indicated), KPPH	651.7	630.1	643.9	629.9	629.4	618.7
FEEDWATER FLOW, KPPH	394.5	335.9	369.1	415.2	388.5	392.0
COAL PASTE FLOW (calc.), PPH	67904	58858	64570	67055	64333	65254
TOTAL SORBENT FLOW, PPH	18310	23230	23840	16300	13130	12580
SORBENT IN PASTE, %	0.0	0.0	0.0	0.0	0.0	0.0
BED ASH FLOW (calc.), PPH	13640	10923	12000	5123	5000	9000
CYC ASH FLOW (calc.), PPH	8756	14868	15543	15427	12677	8946
EMISSIONS						
NOX LVG ESP, LB/MMBTU	0.20	0.24	0.20	0.19	0.26	0.22
SO2 LVG ESP, LB/MMBTU	0.48	0.57	0.49	0.46	0.74	0.54
FEEDSTOCK ANALYSIS						
COAL SO2, LB/MMBTU	5.01	5.54	5.63	5.32	5.34	5.24
PASTE MOISTURE, % WGT.	27.17	26.77	26.51	26.16	26.76	27.05
SORBENT CaO (D/B), % WGT.	28.60	28.80	28.53	28.58	28.99	27.93
CYC ASH SULFATION, %	36.9	29.2	31.2	33.1	33.1	43.8
BED ASH SULFATION, %	46.2	28.2	32.2	70.7	83.8	71.9
CALCULATED RESULTS						
FIRING RATE, MWt	185.1	160.1	174.0	187.9	177.4	177.8
SULFUR CAPTURE, %	90.5	89.7	91.3	91.4	86.1	89.8
Ca/S RATIO (actual)	1.89	2.53	2.33	1.56	1.35	1.26
Ca/S @ 90% SR, 1580F BED	1.85	2.15	2.17	1.45	1.26	1.27
Ca/S @ 95% SR, 1580F BED	2.41	2.80	2.82	1.89	1.63	1.65

TEST NUMBER	61	62	63	64	65	66
TEST DATE	06/10/94	06/10/94	07/31/94	08/01/94	08/02/94	08/03/94
TEST PERIOD	0400-1200	1600-2200	0600-1400	0600-1300	1600-2400	1400-2000
COAL AND SORBENT TYPES						
COAL TYPE	MM Pitts 8	MM Pitts 8	MM Pitts 8	MM Pitts 8	MM Pitts 8	MM Pitts 8
SORBENT TYPE	PRG	PRG	PRG	PRG	PRG	PRG
SORBENT MESH SIZE	#12 design	#12 design	#12 site	#10 site	#10 site	#10 site
OPERATING DATA						
BED LEVEL, INCHES	114.6	114.6	89.3	107.7	86.8	85.0
ST GEN OUTPUT, MW	41.2	41.0	32.7	41.3	29.5	27.7
GT GEN OUTPUT, MW	7.0	6.8	4.6	8.3	3.6	3.1
MEAN BED TEMP, F	1498.6	1497.8	1576.8	1580.3	1581.0	1584.3
INT VALVE INLET TEMP, F	1331.9	1331.9	1242.7	1382.7	1224.9	1253.2
AVG. BED OUTLET O2, %	4.5	3.8	6.7	3.8	7.3	4.0
AIR FLOW (indicated), KPPH	614.2	583.0	628.1	629.7	604.9	429.9
FEEDWATER FLOW, KPPH	370.9	369.0	307.9	372.5	282.2	270.4
COAL PASTE FLOW (calc.), PPH	62752	61939	52693	60802	47266	42746
TOTAL SORBENT FLOW, PPH	11430	12640	10240	13740	12890	13280
SORBENT IN PASTE, %	0.0	0.0	0.0	0.0	0.0	0.0
BED ASH FLOW (calc.), PPH	8500	8500	4430	5800	4630	4593
CYC ASH FLOW (calc.), PPH	7779	9112	9858	11712	11424	10984
EMISSIONS						
NOX LVG ESP, LB/MMBTU	0.29	0.33	0.24	0.20	0.25	0.19
SO2 LVG ESP, LB/MMBTU	0.59	0.63	0.50	0.50	0.65	0.50
FEEDSTOCK ANALYSIS						
COAL SO2, LB/MMBTU	4.99	5.31	4.25	4.52	5.15	5.10
PASTE MOISTURE, % WGT.	27.86	27.07	27.61	26.58	25.80	26.31
SORBENT CaO (D/B), % WGT.	29.62	28.15	28.92	29.17	29.13	29.16
CYC ASH SULFATION, %	42.8	N/A	N/A	N/A	N/A	N/A
BED ASH SULFATION, %	72.4	72.4	61.7	63.5	54.5	57.8
CALCULATED RESULTS						
FIRING RATE, MWt	170.8	167.8	142.7	170.6	130.3	118.4
SULFUR CAPTURE, %	88.1	88.1	88.3	88.9	87.4	90.2
Ca/S RATIO (actual)	1.33	1.34	1.64	1.74	1.88	2.15
Ca/S @ 90% SR, 1580F BED	1.22	1.22	1.74	1.83	2.09	2.15
Ca/S @ 95% SR, 1580F BED	1.58	1.59	2.27	2.38	2.72	2.80

TEST NUMBER	67	68	69	70	71	72
TEST DATE	08/06/94	08/08/94	08/08/94	08/11/94	08/14/94	08/18/94
TEST PERIOD	0800-1400	0000-0600	2000-0400	0000-0600	1700-2200	0100-1100
COAL AND SORBENT TYPES						
COAL TYPE	MM Pitts 8	MM Pitts 8	MM Pitts 8	MM Pitts 8	MM Pitts 8	MM Pitts 8
SORBENT TYPE	PRG	PRG	PRG	PRG	PRG	PRG
SORBENT MESH SIZE	#10 site	#10 site	#10 site	#10 site	#12 site	#12 design
OPERATING DATA						
BED LEVEL, INCHES	87.6	110.6	110.7	112.9	109.5	104.8
ST GEN OUTPUT, MW	24.5	40.5	35.8	41.5	41.3	44.1
GT GEN OUTPUT, MW	3.0	8.5	6.6	9.8	9.2	8.3
MEAN BED TEMP, F	1497.7	1576.0	1496.5	1576.0	1578.9	1578.1
INT VALVE INLET TEMP, F	1228.6	1379.9	1322.8	1425.9	1386.5	1358.1
AVG. BED OUTLET O2, %	3.8	4.1	5.7	3.9	4.1	3.6
AIR FLOW (indicated). KPPH	379.2	629.8	629.9	642.1	635.3	639.7
FEEDWATER FLOW. KPPH	246.0	366.3	331.2	375.7	373.5	390.9
COAL PASTE FLOW (calc.), PPH	39411	61856	56719	63834	63534	63411
TOTAL SORBENT FLOW, PPH	13480	16620	16980	21710	19400	13330
SORBENT IN PASTE, %	0.0	0.0	0.0	0.0	0.0	0.0
BED ASH FLOW (calc.), PPH	4666	6389	6073	7998	7147	7737
CYC ASH FLOW (calc.), PPH	10914	14388	14902	16572	15604	10215
EMISSIONS						
NOX LVG ESP, LB/MMBTU	0.18	0.20	0.26	0.19	0.20	0.21
SO2 LVG ESP, LB/MMBTU	0.58	0.47	0.56	0.31	0.46	0.54
FEEDSTOCK ANALYSIS						
COAL SO2, LB/MMBTU	5.26	5.41	5.46	4.99	5.38	4.98
PASTE MOISTURE, % WGT.	26.28	26.56	25.85	26.35	26.66	25.82
SORBENT CaO (D/B), % WGT.	28.73	28.78	28.89	28.84	28.80	28.54
CYC ASH SULFATION, %	N/A	N/A	N/A	N/A	N/A	N/A
BED ASH SULFATION, %	45.5	53.3	53.7	51.0	59.9	69.7
CALCULATED RESULTS						
FIRING RATE, MWt	107.8	168.9	154.4	176.2	174.2	177.4
SULFUR CAPTURE, %	89.1	91.4	89.7	93.8	91.5	89.1
Ca/S RATIO (actual)	2.29	1.76	1.95	2.39	2.00	1.45
Ca/S @ 90% SR, 1580F BED	2.00	1.64	1.66	1.96	1.87	1.50
Ca/S @ 95% SR. 1580F BED	2.61	2.13	2.15	2.55	2.43	1.95

TEST NUMBER	73	74	75	76	77	78
TEST DATE	08/22/94	9/8/94	09/25/94	09/30/94	10/06/94	10/13/94
TEST PERIOD	0100-0700	0700-1500	800-1600	1800-0600	1800-0600	1100-1430
COAL AND SORBENT TYPES						
COAL TYPE	MM Pitts 8	MM Pitts 8	MM Pitts 8	MM Pitts 8	MM Pitts 8	MM Pitts 8
SORBENT TYPE	PRG	PRG	PRG	PRG	PRG/P	Bucyrus
SORBENT MESH SIZE	#12 site	#12 site	#12 site	#12 design	#20 design	#18 design
OPERATING DATA						
BED LEVEL, INCHES	108.5	116.2	107.7	114.2	107.5	117.1
ST GEN OUTPUT, MW	43.0	46.8	44.3	48.7	48.9	41.5
GT GEN OUTPUT, MW	8.9	10.1	8.7	10.3	9.9	10.3
MEAN BED TEMP, F	1584.4	1573.0	1581.2	1577.3	1577.9	1571.1
INT VALVE INLET TEMP, F	1377.8	1420.0	1373.3	1400.1	1368.0	1427.2
AVG. BED OUTLET O2, %	3.7	3.1	3.7	3.1	3.4	4.9
AIR FLOW (indicated), KPPH	640.1	649.9	654.1	668.9	674.9	659.8
FEEDWATER FLOW, KPPH	381.1	399.1	381.8	416.2	417.4	362.8
COAL PASTE FLOW (calc.), PPH	62516	67805	64885	69814	70835	60485
TOTAL SORBENT FLOW, PPH	19640	15180	16750	13310	15640	11940
SORBENT IN PASTE, %	0.0	0.0	0.0	0.0	0.0	0.0
BED ASH FLOW (calc.), PPH	9183	6386	7049	8946	6769	7000
CYC ASH FLOW (calc.), PPH	13872	13164	14065	9779	14683	10342
EMISSIONS						
NOX LVG ESP, LB/MMBTU	0.21	0.21	0.21	0.20	0.24	0.22
SO2 LVG ESP, LB/MMBTU	0.31	0.58	0.51	0.50	0.51	0.47
FEEDSTOCK ANALYSIS						
COAL SO2, LB/MMBTU	5.48	5.18	5.29	4.99	5.21	4.90
PASTE MOISTURE, % WGT.	25.50	28.01	27.11	27.36	26.84	27.82
SORBENT CaO (D/B), % WGT.	29.05	29.53	29.22	28.85	28.87	40.87
CYC ASH SULFATION, %	34.1	36.8	36.9	41.6	39.2	30.4
BED ASH SULFATION, %	59.8	63.1	65.7	69.8	70.3	58.8
CALCULATED RESULTS						
FIRING RATE, MWt	174.5	184.8	176.6	190.7	191.8	167.3
SULFUR CAPTURE, %	94.4	88.8	90.4	89.9	90.2	90.5
Ca/S RATIO (actual)	2.00	1.57	1.76	1.35	1.51	2.00
Ca/S @ 90% SR, 1580F BED	1.61	1.63	1.73	1.35	1.50	1.92
Ca/S @ 95% SR, 1580F BED	2.10	2.12	2.25	1.76	1.95	2.49

TEST NUMBER	79	80	81	82	83	84
TEST DATE	12/07/94	12/14/94	12/19/94	12/21/94	12/30/94	02/01/95
TEST PERIOD	0800-1600	1200-0500	0800-1600	0000-0800	1230-1600	2200-0155
COAL AND SORBENT TYPES						
COAL TYPE	MM Pitts 8	MM Pitts 8	MM Pitts 8	MM Pitts 8	MM Pitts 8	MM Pitts 8
SORBENT TYPE	PRG	NL Carey	PRG	PRG	PRG	PRG
SORBENT MESH SIZE	#12 site	#12 design	#12 site	#12 site	#12 site	#12 site
OPERATING DATA						
BED LEVEL, INCHES	114.0	125.4	125.9	125.7	123.8	128.2
ST GEN OUTPUT, MW	46.7	50.0	50.3	50.6	50.1	51.7
GT GEN OUTPUT, MW	10.6	14.0	13.8	14.3	13.6	14.0
MEAN BED TEMP, F	1576.1	1573.7	1573.7	1573.7	1574.6	1579.0
INT VALVE INLET TEMP, F	1423.8	1509.2	1501.3	1507.9	1494.8	1516.8
AVG. BED OUTLET O2, %	3.8	3.6	3.5	3.5	3.5	3.3
AIR FLOW (indicated). KPPH	664.8	715.0	718.9	719.9	714.6	724.3
FEEDWATER FLOW, KPPH	393.5	420.6	422.2	425.6	420.4	432.7
COAL PASTE FLOW (calc.), PPH	65898	73119	76184	74445	75358	74158
TOTAL SORBENT FLOW, PPH	16260	20030	23370	18480	16190	15560
SORBENT IN PASTE, %	0.0	0.0	0.0	0.0	0.0	0.0
BED ASH FLOW (calc.), PPH	5940	13000	9380	7000	6052	6500
CYC ASH FLOW (calc.), PPH	14718	11182	19741	16515	15978	14636
EMISSIONS						
NOX LVG ESP. LB/MMBTU	0.18	0.18	0.20	0.19	0.20	0.17
SO2 LVG ESP, LB/MMBTU	0.48	0.54	0.34	0.49	0.48	0.48
FEEDSTOCK ANALYSIS						
COAL SO2, LB/MMBTU	4.65	5.34	5.62	5.15	4.46	4.48
PASTE MOISTURE, % WGT.	26.57	27.24	27.30	27.77	28.44	26.46
SORBENT CaO (D/B), % WGT.	29.02	29.58	28.98	28.97	29.18	29.81
CYC ASH SULFATION, %	34.0	34.6	34.7	36.2	36.0	N/A
BED ASH SULFATION, %	63.9	44.3	53.6	57.8	59.0	N/A
CALCULATED RESULTS						
FIRING RATE, MWt	182.6	200.9	201.7	201.2	199.4	203.7
SULFUR CAPTURE. %	89.7	90.0	93.9	90.5	89.3	89.2
Ca/S RATIO (actual)	1.86	1.85	2.00	1.73	1.78	1.71
Ca/S @ 90% SR, 1580F BED	1.87	1.83	1.63	1.67	1.82	1.76
Ca/S @ 95% SR. 1580F BED	2.44	2.38	2.12	2.17	2.36	2.29

TEST NUMBER	85	86	87	88	89	90
TEST DATE	02/22/95	02/24/95	02/27/95	02/28/95	03/02/95	03/04/95
TEST PERIOD	0200-0600	2300-0600	0200-0800	0000-0800	0600-1400	0000-0600
COAL AND SORBENT TYPES						
COAL TYPE	MM Pitts 8	MM Pitts 8	MM Pitts 8	Minnehaha	Minnehaha	Consol MV
SORBENT TYPE	PRG	PRG	Mulzer	Mulzer	PRG	PRG
SORBENT MESH SIZE	#12 design	#12 site	#12 site	#12 site	#12 site	#12 site
OPERATING DATA						
BED LEVEL, INCHES	132.3	134.1	116.0	114.0	124.5	141.3
ST GEN OUTPUT, MW	57.1	54.5	48.8	47.6	50.6	53.0
GT GEN OUTPUT, MW	15.0	15.2	11.9	12.0	15.0	15.1
MEAN BED TEMP, F	1582.3	1577.4	1581.7	1580.8	1577.6	1562.5
INT VALVE INLET TEMP, F	1542.4	1552.4	1448.9	1436.0	1505.2	1557.9
AVG. BED OUTLET O2, %	2.6	2.9	3.5	3.4	3.4	2.9
AIR FLOW (indicated), KPPH	735.0	734.8	680.1	669.4	729.9	720.6
FEEDWATER FLOW, KPPH	468.1	452.4	412.0	398.3	425.9	442.9
COAL PASTE FLOW (calc.), PPH	78474	77729	69655	87081	81482	79142
TOTAL SORBENT FLOW, PPH	15960	18890	16680	10140	16510	11910
SORBENT IN PASTE, %	0.0	0.0	0.0	0.0	0.0	0.0
BED ASH FLOW (calc.), PPH	9390	7000	7860	3858	5947	4673
CYC ASH FLOW (calc.), PPH	11626	16735	14738	10909	14896	15198
EMISSIONS						
NOX LVG ESP, LB/MMBTU	0.15	0.17	0.18	0.21	0.25	0.17
SO2 LVG ESP, LB/MMBTU	0.45	0.40	0.51	0.30	0.12	0.37
FEEDSTOCK ANALYSIS						
COAL SO2, LB/MMBTU	4.88	4.85	4.94	2.49	2.53	3.50
PASTE MOISTURE, % WGT.	27.19	27.27	26.40	40.97	34.35	27.32
SORBENT CaO (D/B), % WGT.	29.39	29.98	28.68	28.97	29.14	29.88
CYC ASH SULFATION, %	N/A	42.8	36.9	N/A	N/A	34.7
BED ASH SULFATION, %	69.6	58.4	59.6	54.9	41.7	54.3
CALCULATED RESULTS						
FIRING RATE, MWt	217.0	212.8	188.8	193.6	202.4	207.1
SULFUR CAPTURE, %	90.8	91.8	89.7	87.9	95.4	89.4
Ca/S RATIO (actual)	1.49	1.84	1.72	2.04	3.16	1.65
Ca/S @ 90% SR, 1580F BED	1.44	1.68	1.75	2.23	2.35	1.63
Ca/S @ 95% SR, 1580F BED	1.88	2.19	2.28	2.90	3.06	2.12

Appendix III

TEST NUMBER	91	92	93	94	95
TEST DATE	03/05/95	03/07/95	03/17/95	03/23/95	03/28/95
TEST PERIOD	2000-0400	0800-1600	0200-0800	0000-0900	0900-1400
COAL AND SORBENT TYPES					
COAL TYPE	Consol MV	Consol MV	Consol MV	Consol MV	Consol MV
SORBENT TYPE	PRG	PRG	PRG	PRG	Delaware
SORBENT MESH SIZE	#12 site	#12 site	#12 site	#12 x 60	#12 site
OPERATING DATA					
BED LEVEL, INCHES	116.7	90.6	90.3	91.0	117.9
ST GEN OUTPUT, MW	48.1	35.5	34.4	35.6	37.2
GT GEN OUTPUT, MW	11.2	4.5	5.6	6.0	9.2
MEAN BED TEMP, F	1579.6	1580.4	1580.8	1581.5	1496.9
INT VALVE INLET TEMP, F	1438.4	1255.9	1241.8	1255.9	1391.7
AVG. BED OUTLET O2, %	3.9	5.1	5.8	5.8	5.8
AIR FLOW (indicated), KPPH	690.1	532.8	551.8	569.6	649.5
FEEDWATER FLOW, KPPH	403.7	312.3	306.3	314.5	326.4
COAL PASTE FLOW (calc.), PPH	72296	53273	53548	54948	53681
TOTAL SORBENT FLOW, PPH	13130	9060	7950	7200	9680
SORBENT IN PASTE, %	0.0	0.0	0.0	0.0	0.0
BED ASH FLOW (calc.), PPH	4877	3387	3150	4660	3940
CYC ASH FLOW (calc.), PPH	14466	10462	9525	8613	13170
EMISSIONS					
NOX LVG ESP, LB/MMBTU	0.21	0.20	0.23	0.23	0.24
SO2 LVG ESP, LB/MMBTU	0.30	0.29	0.23	0.33	0.37
FEEDSTOCK ANALYSIS					
COAL SO2, LB/MMBTU	3.36	3.07	2.87	3.26	3.34
PASTE MOISTURE, % WGT.	28.06	27.52	27.85	28.30	21.81
SORBENT CaO (D/B), % WGT.	29.36	29.37	28.75	28.86	46.07
CYC ASH SULFATION, %	32.1	27.0	N/A	31.3	40.5
BED ASH SULFATION, %	52.7	51.9	54.2	51.0	33.2
CALCULATED RESULTS					
FIRING RATE, MWt	189.2	139.9	140.0	141.7	149.8
SULFUR CAPTURE, %	91.2	90.7	92.0	89.8	89.0
Ca/S RATIO (actual)	2.04	2.08	1.91	1.51	2.99
Ca/S @ 90% SR, 1580F BED	1.93	2.02	1.75	1.52	2.62
Ca/S @ 95% SR, 1580F BED	2.51	2.62	2.27	1.98	3.41

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