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TIDD PFBC Demonstration Project

Topical Report

March 1994

Work Performed Under Contract No.: DE-FC21-87MC24132

For
U.S. Department of Energy
Office of Fossil Energy
Morgantown Energy Technology Center
Morgantown, West Virginia

By
Ohio Power Company
and
American Electric Power Service Corporation
Columbus, Ohio

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Columbus, Ohio 43215

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ACRONYMS AND ABBREVIATIONS

AB	ASEA Babcock - A business partnership between a subsidiary of ABBC and the Babcock & Wilcox Company (USA)
AEP	American Electric Power Company, Inc.
AEPSC	American Electric Power Service Corporation, a subsidiary of AEP
ABBC	ABB Carbon - a subsidiary of ASEA-Brown Boveri (subcontractor)
B&W	The Babcock & Wilcox Company (subcontractor)
BWCC	The Babcock & Wilcox Construction Company (subcontractor)
BOP	Balance of Plant
DOE	Department of Energy (United States)
EMP	Environmental Monitoring Plan
EPA	Environmental Protection Agency
ESP	Electrostatic Precipitator
GT	Gas Turbine
HGCU	Hot Gas Clean-Up
HPC	High Pressure Compressor
HPT	High Pressure Turbine
HVAC	Heating, Ventilating & Air Conditioning
I&C	Instrumentation & Control
LPC	Low Pressure Compressor
LPT	Low Pressure Turbine
NDE	Nondestructive Examination
NOVVA	Northern Ohio Valley Air Authority
NO_x	Nitrogen Oxides
NPDES	National Pollutant Discharge Elimination System
OEPA	Ohio Environmental Protection Agency

ACRONYMS AND ABBREVIATIONS

OCDO	Ohio Coal Development Office - a part of Ohio Department of Development
OPCo	Ohio Power Company
PFBC	Pressurized Fluidized Bed Combustion
POPS	Plant Operations and Performance System
ppb	Parts Per Billion
SO_2	Sulfur Dioxide

1.0 INTRODUCTION/SUMMARY

1.1 Introduction

Tidd, an electric generating station in Brilliant, Ohio, is 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 project is being co-funded by Ohio Power Company, a subsidiary of American Electric Power (AEP), the U.S. Department of Energy (DOE), and the Ohio Coal Development Office (OCDO).

Tidd is a 45 year old pulverized coal power plant which was repowered with PFBC components in order to demonstrate that this technology would burn coal efficiently while capturing 90% of the sulfur in the coal and emitting significantly less nitrogen oxides (NO_x) than conventional coal burning power plants.

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 remainder of the plant. Construction and modification of the existing facility were performed by Ohio Power Company.

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, immediately following completion of preoperational system testing. The first combined cycle operation was achieved on November 29, 1990, and on February 28, 1991, the three-year demonstration period began. This topical report describes the first 18 months of operation from January 1991 through the acceptance tests in June, 1992.

1.2 Introduction To Fluidized Bed Combustion

In fluidized bed combustion, coal and sorbent (dolomite or limestone) are fed into a boiler in which air, entering from the bottom, maintains the bed material in a highly turbulent suspended state called fluidization. This turbulence creates good contact between the air and fuel, allowing for high combustion efficiency and excellent adsorption of sulfur dioxide (SO_2) during the combustion process.

In PFBC applications, pressurized air is supplied to the combustor. Pressurizing the air concentrates a larger quantity of oxygen per unit volume. This results in a lower velocity of air through the fuel bed. The lower velocity reduces the total height required for the bed and freeboard above the bed. Also, a smaller plan area is required for the bed area as compared to an atmospheric fluidized bed. This has the advantage of requiring a much smaller pressure vessel to contain the boiler enclosure.

The mean bed temperature of a pressurized fluidized bed combustor is typically maintained in the range 1540 to 1580 F. This is well below the ash fusion temperature of coal, yet above the ignition temperature of the coal. Advantages of the low bed temperature are no slag formation and a reduction of NO_x emissions to less than half that of a conventional boiler.

1.3 Tidd PFBC Combined Cycle

The Tidd Plant is a combined cycle pressurized fluidized bed combustion system with a topping air cycle and a bottoming steam cycle (Figure 1). When operated in combined cycle mode, the pressurized fluidized bed combustor provides steam to power a steam turbine cycle, and pressurized gas to power a gas turbine. The gas turbine is coupled to a generator and a compressor that supplies combustion air to the process.

The PFBC boiler contains the fluidized bed where combustion occurs. The primary and secondary cyclone ash separators are located in the

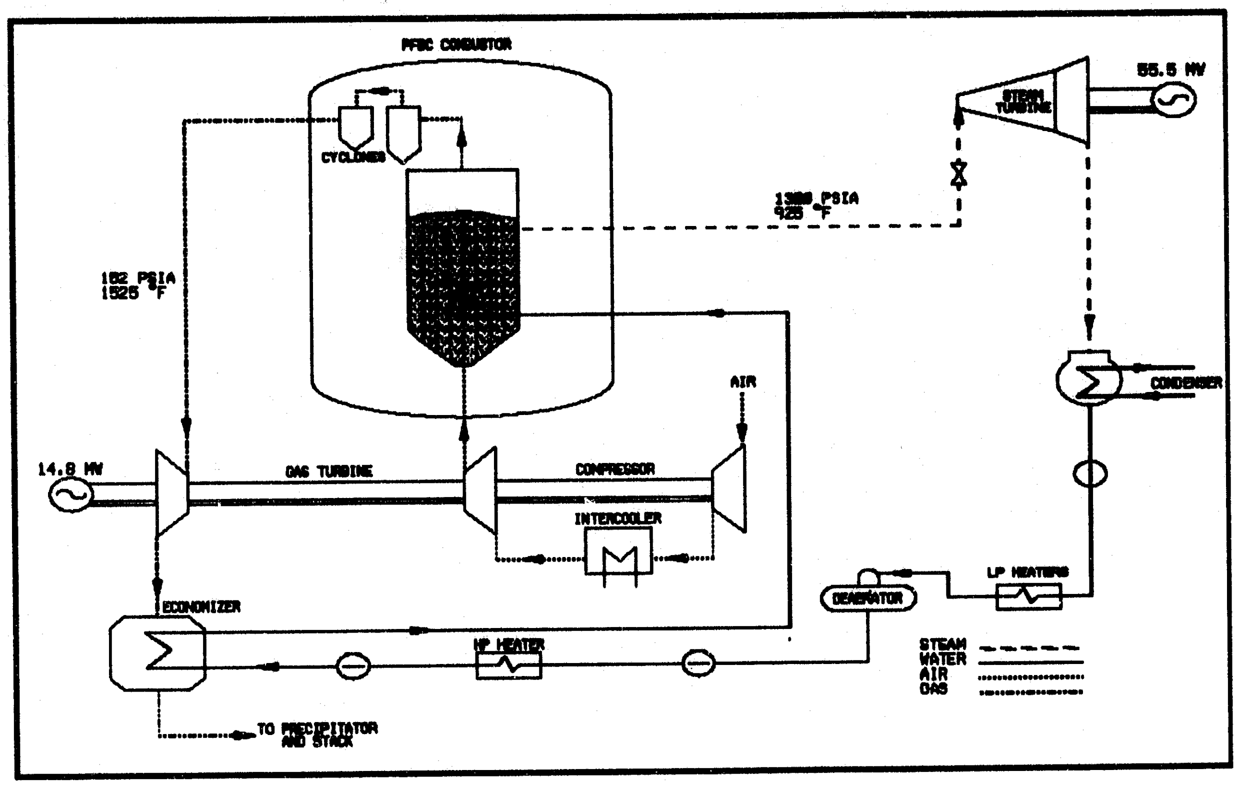

FIGURE 1
TIDD CYCLE SCHEMATIC

gas exit path, and remove particulate from the gas before it enters the gas turbine. The ash reinjection tanks store ash removed from the bed until it is needed to raise the bed level when increasing load.

The boiler is contained in a pressure vessel along with the cyclone ash separators, the bed ash reinjection vessels, cyclone ash coolers, and gas collection pipes (Figure 2). This design reduces the differential pressure across the boiler membrane walls and permits recovery of heat losses by combustion air.

At full load, the evaporator tubes, along with most of the primary and secondary superheater tubes, are located in the bed. Depending on the bed level, fewer of these tubes are immersed in the bed. By raising and lowering the bed level, heat transfer to the boiler tube bank can be controlled and load can be varied. The bed level is

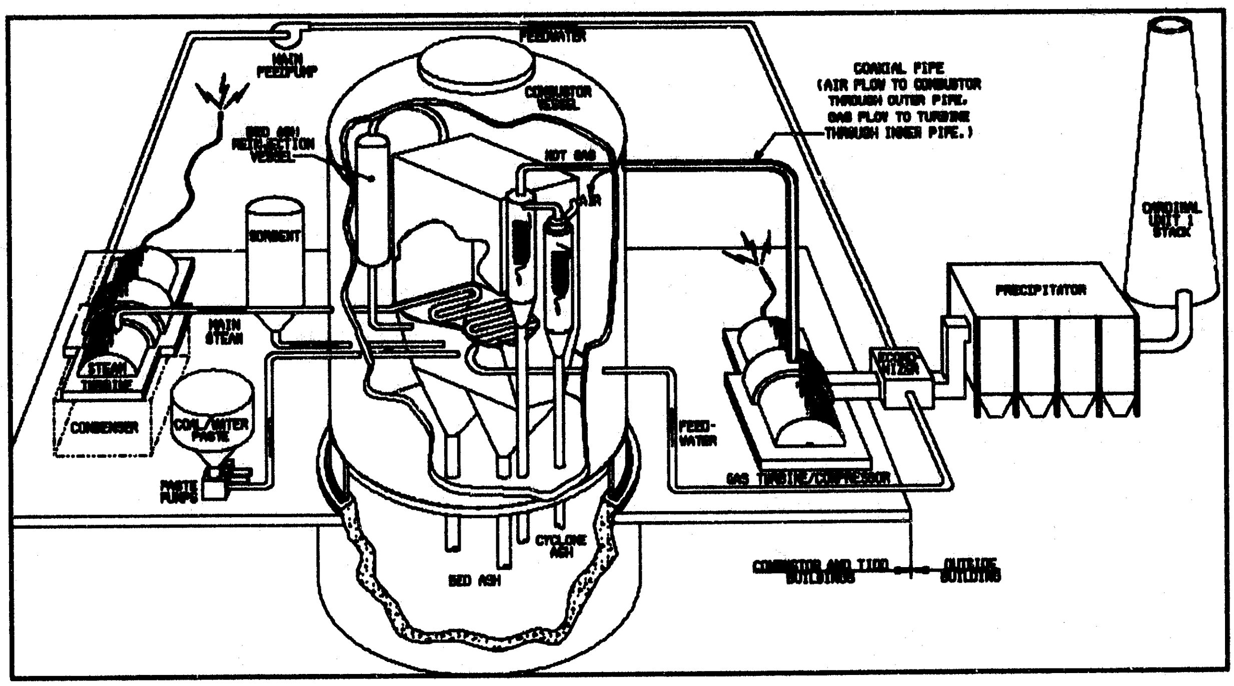

FIGURE 2

TIDD PFBC ISLAND

adjusted by transferring bed material between the bed and the reinjection vessels. Fuel feed must be adjusted to maintain bed temperature at varying bed heights. The fuel consists of crushed coal mixed with water to form a paste, which is injected into the boiler by six hydraulically operated piston pumps.

The sorbent injection system is used to convey and inject granular sorbent material (dolomite) into the boiler to obtain the required sulfur retention. The injection rate of the sorbent is controlled to achieve the required sulfur retention for a given fuel feed and operating condition.

The ash residue from the coal and sorbent that remains in the bed is cooled by air and removed from the boiler by a dual lockhopper system. About half of the ash residue elutriates from the bed and is carried out in the exhaust gas stream. In order for the gas to be utilized by the gas turbine, it must be cleaned to prevent damage to the turbine blades. The ash is removed from the flue gas by cyclone separators. A small portion of the flue gas is used to transport the separated ash through the ash coolers and out of the combustor vessel. After passing through the cyclones, the gas is conveyed to the gas turbine.

The pressurized and heated gas is expanded through the ruggedized high pressure and low pressure turbines, providing the energy to drive the compressors and a generator which produces about 20% of the plant electrical output at full load.

The flue gas, after leaving the low pressure turbine, passes across the feedwater economizer. From the economizer, the gas flows through the precipitator and on to the Cardinal Plant stack.

The boiler water-steam cycle is once-through at subcritical pressure. All once-through boilers must have some means for separating steam and water at low loads, and also a provision for maintaining a minimum water flow. A moisture separator and boiler circulating pump have been incorporated in the design. At low loads, the moisture separator acts like a steam drum to separate the water from the steam/water mixture leaving the evaporator. The boiler circulating pump recirculates the water from the moisture separator back through the boiler to maintain minimum flow.

The first step in boiler start-up is to initiate the clean-up cycle. A once-through boiler has no steam drum where solids accumulate and can be blown down. Therefore, boiler water must be of a high purity before steam generation can take place. The clean-up cycle sends feed water flow through the boiler water circuits to the vertical separator, where it is blown down to the condenser and routed through condensate polishers before returning to the boiler through the condensate and feedwater cycle. This process is continued until the water is sufficiently pure.

Once the clean-up cycle is complete, a minimum feedwater flow is established to the vertical separator. This is done prior to the fluidization of the bed.

To start the boiler process, a shallow bed of sand and/or bed material is fluidized and preheated by the oil-fired preheater. The preheater brings the bed temperature up to the ignition temperature of the coal. When the bed material has reached the required ignition temperature of 1200 F, the coal-water paste is injected and the preheater is ramped off.

Feedwater flow is established at 10% of full-load flow via a pump that recirculates water through the boiler enclosure and evaporator to maintain minimum cooling flow. Until the steaming rate reaches 10%, the separator drains will remove excess water to the condenser. While the boiler circulating pump is operating, feedwater flow is regulated to maintain separator level. The vertical separator and boiler circulating pumps are used up to approximately 40% load, above which the boiler becomes once-through and the pump is shut down. Once the pump is shut down, feedwater flow is regulated to control steam temperature, and a minimum water level in the separator is maintained to permit a restart, if necessary.

Until sufficient steam flow at temperature and pressure is available to roll the steam turbine, the pressure increase is controlled by the turbine bypass system. After steam turbine roll, the turbine throttle valve regulates pressure.

The gas turbine is motored during start-up to produce the power required to drive the compressor which supplies combustion air. As the temperature of the gas leaving the combustor increases, a decreasing amount of power is used from the grid. Eventually, the gas turbine is capable of driving the generator to produce electricity.

Changing load changing is accomplished by changing the bed level to expose more or less of the in-bed heating surface to the fluidized bed, which has high conductive heat transfer rates. On a load increase, the bed level is increased and more of the heating surface is covered with bed material. This increases the gas temperature to the gas turbine and steam generation. Feedwater flow is also increased as firing rate increases to protect the heat transfer surfaces. As the bed level increases, fuel and air flow are increased to keep the bed temperature constant. As the mass flow and temperature of gas to the gas turbine increase, so does the output of the gas turbine. Steam temperature is controlled by attemperation, and steam pressure is maintained by modulating the steam turbine throttle valve.

Shutdown is accomplished by reducing the bed level to the minimum level and stopping the fuel injection. The load on the gas turbine decreases with the boiler until it returns to a motoring condition. The gas turbine remains in operation until the bed material has cooled to protect the tube bundle and prevent sintering.

In the event of a gas turbine trip, the combustor is immediately isolated from the gas turbine by an intercept valve at the turbine inlet. The loss of air flow causes the hot bed to slump. Sufficient feedwater flow is maintained to protect the in-bed surface. In addition, special systems have been designed to depressurize the combustor vessel, inert and cool the bed material, and remove it from the bed in preparation for a restart.

When the steam turbine trips, about 50% of the steam flow is bypassed to the condenser; the remainder is vented to atmosphere using a pressure control valve. Boiler heat is rapidly reduced, and the unit is shut down in the normal manner.

1.4 Operational Overview

This topical report discusses the operational aspects of the demonstration program through the run ending July 10, 1992. Operating data for the period is summarized in Table 1. During the first eighteen months, two major outages were required to correct problems.

In mid-September, 1991, the unit was taken out of service for 12 weeks to make major modifications (see Section 6) to improve unit performance and further improve unit reliability. The unit was returned to service in December, 1991. After some initial problems, the unit began to operate more consistently; however, run durations were still limited by operating problems. From December 15, 1991, through March 5, 1992, the unit fired coal for a total of 530 hours, with the longest run being 154 hours.

In mid-March, 1992, vibration induced cracks were discovered on the low pressure turbine blade roots. A nine week outage was taken to replace the blades with a new design. During this outage, a portion

Table I: Tidd PFBC Demonstration Plant Operating Statistics Through July 10, 1992

GAS TURBINE:	
Total Starts	92
Total Operating Time	3452
BED PREHEATER:	
Total Starts	116
Total Operating Time	494
Total Operating Time > 1200 F	237
Total Operating Time < 1200 F	30
FUEL INJECTION:	
Total Starts	64
Total Operating Time	2131
Total Operating Time > 45% Load	1362
Total Operating Time > 85% Load	92
COMBUSTOR TRIPS:	
Total Trips	86
Total Trips from Bed Preheating	30
Total Trips from Coal Injection	51
Total Trips from > 45% Load	17
Total Trips from > 85% Load	2
GAS TURBINE TRIPS:	
Total Trips	92
Total Trips from Air Preheating	9
Total Trips from Bed Preheating	12
Total Trips from Fuel Injection	14
Total Trips from Shutdown or Testing	52
Total Trips from > 45% Load	5
Total Trips from > 85% Load	1
GENERATION TO DATE:	
Steam Turbine	65946 MW
Gas Turbine	14265 MW
Total Gross	79761 MW
COAL AND SORBENT USE:	
Total Coal Injected	27652 Tons
Total Sorbent Injected	14585 Tons
LONGEST CONTINUOUS COAL FIRE TO DATE:	
740 hours (June 8 - July 10, 1992)	

of the hot gas clean up test slip stream was installed. Additionally, a significant coal crusher test program was undertaken in an attempt to improve coal paste quality and crusher reliability.

The unit was returned to service on May 10, 1992, but experienced a leak in an expansion joint of the newly installed hot gas clean up piping. The one cyclone string used by hot gas clean up was blanked off to allow the unit to run with six cyclone strings.

The unit was returned to service on June 8, 1992. It ran continuously for 31 days at 70% capacity factor. During this run, the contract acceptance tests were run. The unit was taken out of service in a controlled manner on July 10, 1992, for equipment inspections.

1.5 System And Component Operating Experience Summary

During the first eighteen months of operation, experience was gained in operating the PFBC island and auxiliary equipment. This section details that experience and modifications that were made to improve the performance and operability of the equipment.

1.5.1 Post-Bed Combustion

Post-bed combustion in the cyclones was experienced during the first year of operation. Two types of fires occurred. The first type occurred mainly at low loads and were centered in the dip leg region of the cyclone. These fires were attributed to excessive carryover of carbon at the lower bed levels, and were particularly present when sorbent injection was not in service.

The other type of fire involved the entire gas stream through given cyclone strings. This type of fire was attributed to combustion of volatiles that had not burned in the bed due to oxygen depleted plumes located near the fuel nozzle outlets. Efforts were directed at achieving better distribution of the fuel in the bed, which resulted in some improvements. It was also determined that the intensity of the fires could be reduced with drier coal paste. It is believed that drier paste produces larger and more consistent sized agglomerates in the bed, which slows down the volatile release rate. The slower release rates allow the fuel agglomerates to better mix in oxygen-rich sections of the bed.

During the Fall 1991 outage, additional modifications were made to the fuel injection system to achieve better distribution of the fuel. Also, a freeboard gas mixing system that employs steam jets was installed in order to prevent excessive individual cyclone string temperatures associated with volatile fires. The intent of this system was to achieve combustion of escaping volatiles in the freeboard region. Operation of the steam jets would spread the heat release over the entire gas flow, rather than allowing it to concentrate in one or two cyclone strings where it would result in temperatures that approach material limits, and necessitate a load reduction or trip. In addition to these physical modifications, further efforts were expended during the outage to attempt to produce a drier coal paste that was pumpable.

During the runs that followed from December, 1991, to March, 1992, the above efforts produced a noticeable improvement on volatile fires; however, ongoing efforts to dry out the coal-water paste frequently resulted in coal injection line plugs. One new problem developed. The cyclone dip leg fires that had previously occurred only at low loads were now occurring at much higher loads in certain cyclone strings. These fires were able to be controlled through use of the freeboard steam mixing system that apparently acted to more evenly distribute the unburned carbon to the cyclone strings.

Presently, with improved coal paste and the use of freeboard mixing, the unit operates with no evidence of any significant dip leg or volatile fires.

1.5.2 Boiler

The amount of in-bed tube surface initially installed was insufficient and resulted in achieving only 73% of design in-bed heat absorption at the original full bed height of 126 inches. During the Fall 1991 outage, approximately 25% more in-bed surface was added above the existing tube bundle, with the intent to achieve full design absorption. Due to the presence of post-bed combustion and the gas turbine inlet temperature limitation, the design bed temperature used to size the surface addition was 1540 F versus the 1580 F original design value. At the new full bed height of 140 inches, the in-bed surface is still not sized for the original design heat input. Firing rate is limited to 93% of the original design value of 205 MWt.

1.5.3 Economizer

The finned tube economizer exhibited significantly heavier fouling than originally anticipated, which resulted in high gas-side velocities. Vibration induced by these high velocities is believed to have been the cause of four tube leaks that occurred during the Summer of 1991. During the Fall 1991 outage, four sootblowers were installed to reduce the fouling and anti-vibration ties were installed to eliminate the cause of the tube failures. While no additional tube leaks were experienced, there was still heavy fouling in regions of the economizer that the sootblowers could not reach. Therefore, four additional sootblowers were installed. However, the economizer gas exit temperature is still high.

1.5.4 Sorbent Injection System

During initial start-up, the sorbent injection system experienced operating difficulties related to valve and rotary feeder binding and wear. As a result of changes to rotary feeder material, drive modifications, and valve repair and replacements, this system is now very reliable.

In addition, the transport piping experienced severe erosion at the bends. These bends, which are essentially crosses, originally had a hardened steel lining. The all metal pipe crosses were replaced with ceramic lined crosses which have not eroded. However, the last piping segments, which are stainless steel and act as the injection nozzles, have experienced accelerated erosion. This problem is presently under investigation. The straight piping sections, which have a hardened steel lining, have not experienced erosion.

Another problem encountered with the sorbent injection system was the formation of sorbent based "clinker" deposits in the tube bundle above the injection nozzles and adjacent coal nozzles. The clinkers, which were formed from very fine sorbent particles, showed no evidence of particle melting and appeared for the first time in January, 1992. Since there had been no major changes to the sorbent injection system prior to the clinker formation, the cause for these clinkers was not readily apparent. However, by shortening the sorbent injection nozzles and changing the point of sorbent admission into the bed, the clinkers have been eliminated.

1.5.5 Coal Preparation And Coal Injection Systems

The coal preparation system was designed to crush 3/4" x 0 coal to a size that was suitable for both paste pumpability and combustion within the fluidized bed. For pumpability, the most critical requirement is that 20% of the crushed coal must be sized to minus 325 mesh, which then permits the moisture content of the paste to be lowered to approximately 25% by weight. As the percent of minus 325 mesh fines declines below 20%, the moisture content must be increased to maintain good paste pumpability characteristics.

During the first 14 months of operation, the coal crusher was not capable of producing the proper size distribution of coal required for good pumpability. With the coal fines fraction varying from 12% to 15% through minus 325 mesh, the moisture content of the paste had to be maintained in the 25% to 28% range. The additional moisture resulted in post-bed combustion and cyclone fires.

Numerous changes were made to the crusher system to improve the minus 325 mesh fines fraction without success. Modifications included installing larger drives, machining grooves on the flat roller surface, and testing several different control modes. Prior to the gas turbine outage in March, 1992, a recycle loop was added to the crusher. This permitted up to 100% of the feed coal to be recycled through the crusher, producing the desired amount of minus 325 mesh fines. During the 31-day continuous run in June, 1992, the suitability of this operating mode was verified. Coal paste minus 325 mesh fines ranged from 18% to 22%, and moisture contents were consistently maintained at 24% to 25% moisture by weight.

Another significant coal paste system modification was the distribution of paste within the paste storage tank (hourglass shaped in plan view). As originally designed, the paste was fed into the tank on the extreme left side of the tank, and the moisture distribution across the tank was not uniform. This maldistribution carried through to the combustion process. The three left side injection pumps and nozzles saw drier paste and were more prone to plug, and the side of the fluidized bed which saw paste with higher moisture contents experienced more significant post-bed combustion.

In May, 1992, the coal preparation system was modified to uniformly feed prepared paste into both sides of the tank. During the 31-day run, the proper size paste and good tank distribution resulted in minimal pump pluggages and more uniform post-bed temperatures.

The other modification made to the coal preparation and coal injection systems was with regard to corrosion. The Pittsburgh #8 coal, when mixed with water, produced an acidic paste (pH of 3). This resulted in significant corrosion of the coal mixer and paste pumps from November, 1990, through September, 1991. During the Fall 1991 outage, all carbon steel surfaces in the mixer and paste pumps were replaced with stainless steel, and some minor components were coated to prevent corrosive attack. To date, these modifications have been successful.

1.5.6 Gas Cleaning Cyclones And Ash Removal Systems

The gas cleaning cyclones were designed to clean the ash-laden gas stream from the freeboard down to a particulate level that would minimize erosion of gas turbine blades and components. The cyclones consist of seven parallel strings of cyclones, each with two stages of cyclones, a primary and a secondary cyclone. The ash collected in each cyclone is pneumatically transported out of the combustor vessel.

Pluggage of the secondary cyclone ash removal system resulted in a number of outages during early plant operation from December, 1990, through March, 1991.

The seven primary and seven secondary ash lines originally combined into one line which transported the combined ash stream to the cyclone ash silo. In March, 1991, the primary and secondary systems were decoupled, and the secondary ash line was routed to the precipitator inlet. In addition, modifications were made to the ash lines inside the combustor vessel to reduce pressure drop and improve transport capacity.

After these changes, secondary ash transport capacity was sufficient to permit reliable operation of the secondary ash system. At shutdowns, however, ash buildup in the cyclone dip legs would not permit restart of the unit until that ash was removed from the dip leg. In order to minimize the impact of this buildup on unit operation, the dip legs on all secondary cyclones were shortened by approximately 20 feet by the end of the Fall 1991 outage.

After the Fall 1991 outage, pluggage of the secondary ash system again impacted unit availability. In mid-January, 1992, the plugs were found to be caused by excessive pressure drop in the secondary ash line external to the combustor vessel. The excessive pressure drop was eliminated and the system began to function properly. Operation during the Spring of 1992 has indicated the secondary ash removal system was marginally acceptable. Plugs still occur at start-up; however, they generally unplug as the pressure vessel pressure increases after coal fire. During the 31-day run, one cyclone remained plugged throughout the run. This was found to be due to a restriction caused by a foreign object.

The operation of the primary ash removal system has been acceptable, except for a two month period in mid-1991. During this period, which started in June, 1991, pluggage of the primary ash removal system began to impact unit operation. At first, each plug could be traced to a system upset, usually in the sorbent injection system. It was thought that the system upset resulted in a temporary increase in ash to the cyclones, which overwhelmed the ash transport capabilities. However, in September, 1991, the system was totally dismantled and inspected as part of the Fall 1991 outage, and the real cause was discovered. During the outage, it was found that air leakage into the primary ash line flanged connections inside the combustor vessel had significantly reduced the transport capacity of the system. Therefore, the system upsets merely overwhelmed a system that was operating at marginal capacity.

During the Fall 1991 outage, all bolted flanges in the secondary and primary ash lines inside the vessel were disassembled and inspected. At that time, it was found that shop fabrication flaws in the primary and secondary ash system components resulted in significant air leakage into both systems. The majority of all bolted flanges on the secondary ash lines were eliminated and replaced by welded connections. However, due to the design of the primary ash lines, bolted flanges could not be easily eliminated. All flanges were reworked, and the system returned to service in December, 1991, with no air leakage. Air leakage continued to be a problem due to thermal cycling of the flange bolts. A program was undertaken to eliminate as many primary ash line bolted flanges as possible.

1.5.7 Gas Turbine

The gas turbine experienced a measurable amount of erosion after 2100 hours of coal fired operation.

This erosion has been due to operation with plugged primary cyclones and with one cyclone string bypassed. As a result of the observed erosions, the unit is immediately tripped when pluggage of a primary cyclone is detected.

The gas turbine air leakage rate has been higher than design, limiting the firing rate at ambient temperatures above 60 F.

Cracks were found in the root area on many of the low pressure turbine blades in March, 1992. The cracks were attributed to high order resonant vibration. New blades, designed to prevent this problem, were installed before the unit was returned to service in May, 1992.

1.5.8 Unit Performance

Unit acceptance tests were conducted in June, 1992, during the 31-day run. The tests were conducted at full bed height, with the maximum firing rate and bed temperature attainable. Test results for key parameters are presented in Table II, with design values noted for comparison. This higher firing rate was possible due to increased gas turbine compressor capacity, at lower ambient temperature, and operation with reduced excess air.

Firing rate during the tests was limited due to a combination of air delivery and in-bed tube bundle absorption capabilities. The steam flow was impacted by both in-bed and economizer absorption deficiencies. The gross unit output was affected by all of the above, plus a reduced steam cycle and gas turbine efficiency.

Table II: Tidd PFBC Demonstration Plant Full Load Unit Performance

Test Number	6	
Test Date	06/14/92	Design
Unit Firing Rate, MW	187.0	206.3
Gross Unit Output, MW	60.1	72.5
Mean Bed Temperature, deg F	1551.0	1580.0
Bed Height, inches	142.0	126.0
Excess Air, percent	19.8	25.0
Main Steam Flow, kpph	395.0	442.0
Sulfur Retention, percent	92.7	90.0
Ca/S Molar Ratio	2.1	1.6
Predicted Ca/S (90% S_r/1580 F T_{bed})	1.7	---
NOx Emissions, lb/mmBtu	0.17	0.25
Combustion Efficiency, percent	99.4	98.0
Economizer Gas Outlet Temp., deg F	419.0	355.0

1.5.9 Summary

As of June 30, 1992, the Tidd PFBC Demonstration Plant has completed over 2,100 hours of coal fired operation, while meeting its environmental performance objectives. With the 31-day continuous run, the unit met its reliability objectives. Additional testing scheduled for the remainder of the three-year demonstration period will serve to assist in establishing the design basis for future commercial PFBC plants.

The main operating problems prior to the successful runs in 1992 were attributed to the coal preparation and cyclone ash removal systems. Our experience to date emphasizes the importance of the coal preparation system in providing reliable coal injection and proper combustion, and the importance of the cyclone ash removal system in ensuring sufficiently clean gas for gas turbine survivability. While refinement of all PFBC systems will continue, the cyclone ash removal and coal preparation systems will require the most significant efforts for commercialization of the PFBC technology.

2.0 PLANT DESCRIPTION

2.1 Repowering Tidd

The Tidd Plant, which was originally commissioned in 1945, was retired in the late 1970's because it was unable to meet emission standards. At that time, OPCo determined that it would not have been economical to retrofit the plant with the necessary controls to meet the standards. However, Tidd has now been repowered with an emerging clean coal technology.

The old pulverized coal fired boiler has been replaced with a pressurized fluidized bed combustor, and a gas turbine has been added. The PFBC combined cycle system was used to repower Unit 1, one of two 110 MWe units at the Tidd site.

Much of the original equipment has been refurbished. The plant's steam cycle is utilizing many of the existing components, including the steam turbine generator, condensate and feedwater heaters, and pumps.

Many of the service buildings, control systems, and piping systems also have been utilized. The existing structures for storing and handling coal and dolomite are being used, as well as a 138,000 volt switchyard from which power is sent into AEP's transmission system.

Major new equipment that has been installed includes 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 also has been necessary to construct new foundations, buildings, and piping and electrical systems needed to integrate the PFBC system with the balance of the plant.

The new PFBC power island, which includes the combustor, gas turbine, and coal and sorbent systems, is loaded in a new building next to the wall of the original Tidd Unit 1 in one of the original ash ponds.

The new economizer, electrostatic precipitator, ash silos, and electrical control building are located nearby. This layout allows maximum use of existing Tidd facilities.

2.2 Tidd PFBC Power Island

The Tidd PFBC Demonstration Project is the nation's first PFBC plant to operate in a true combined cycle mode, with both a gas turbine and a steam turbine generation electricity. Tidd's new PFBC power island, which has been incorporated into the existing conventional steam cycle, has a steam flow of about 400,000 pounds per hour at 1300 psia and 925 F, and a gross electrical output of 60 MWe (47 MWe from the steam turbine and 13 MWe from the gas turbine).

The Tidd Plant will demonstrate a pressurized bubbling fluidized bed operating at about 175 psia. Pressurized combustion air is supplied by the gas turbine. In the combustor, air fluidizes and entrains bed materials consisting of the fuel (coal-water paste), coal ash, and dolomite sorbent.

2.3 Cycle Description

2.3.1 Heat Balance

The design full load heat balances for the gas side and the steam side of the combined cycle are shown in Figures 3 and 4, respectively. The figures show the expected performance of the unit at 100% load, 59 F ambient air temperature, and 60% ambient relative humidity.

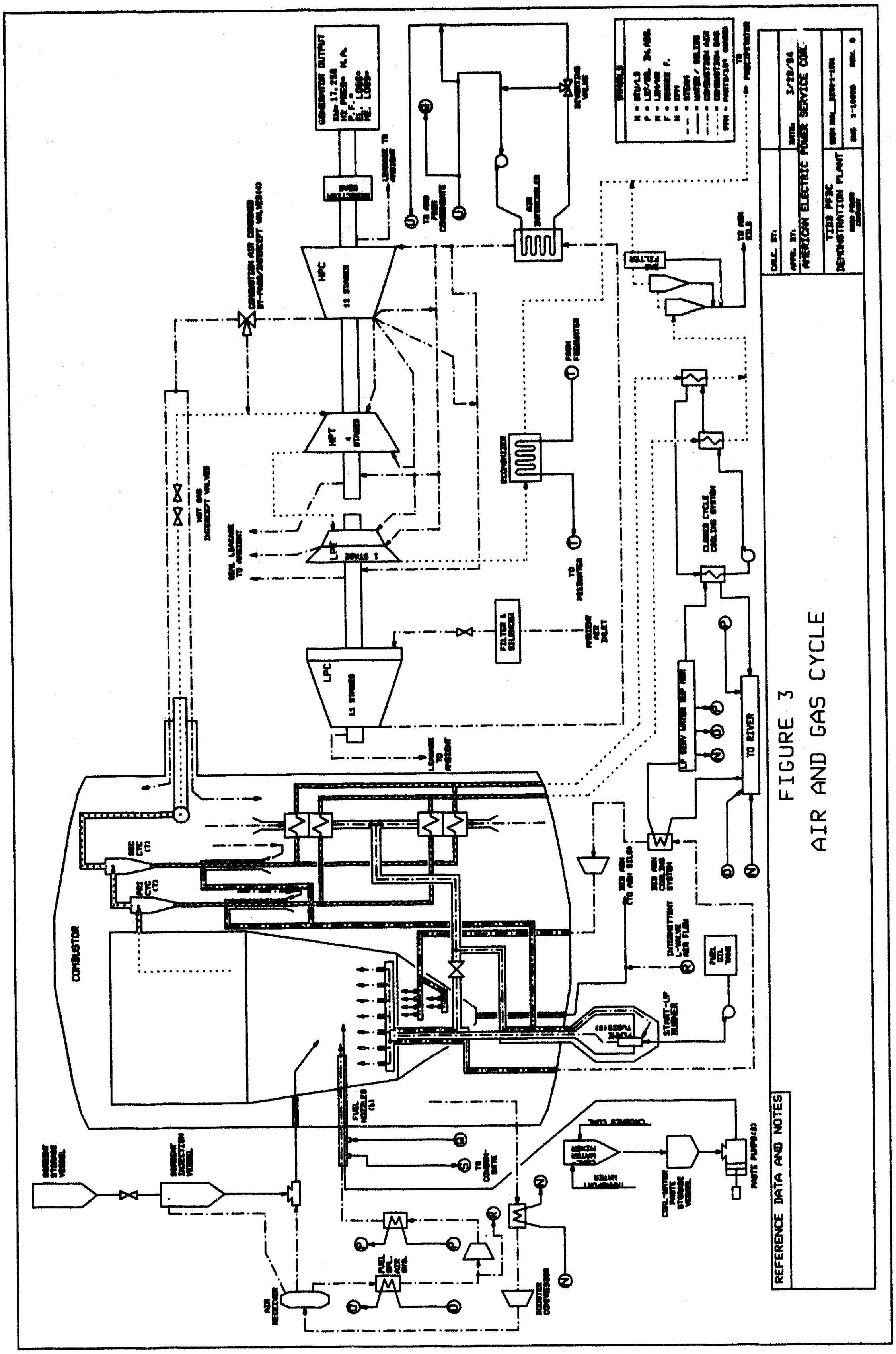

FIGURE 3
AIR AND GAS CYCLE

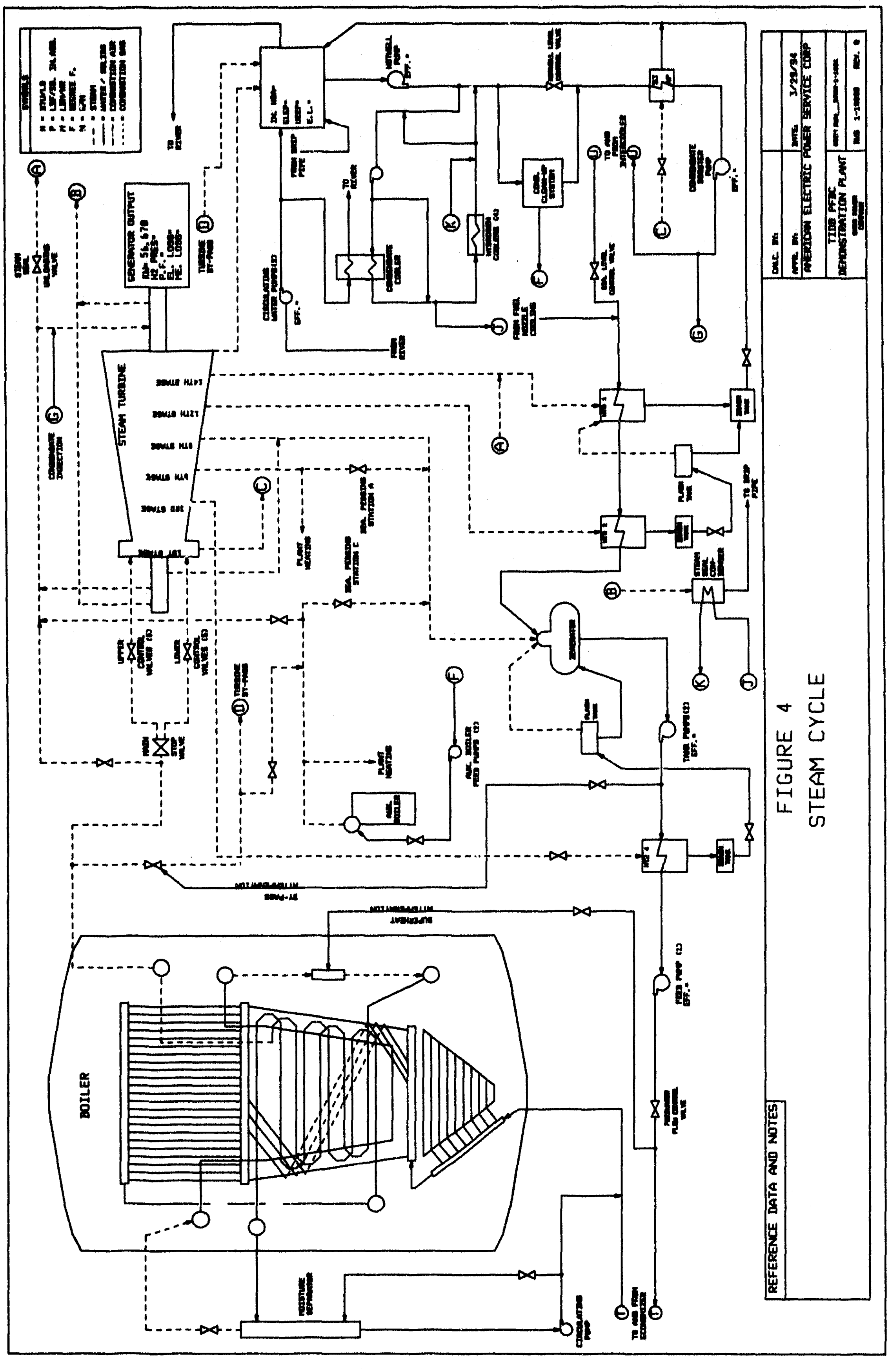

FIGURE 4
STEAM CYCLE

2.3.2 Cycle Configuration

The PFBC island was incorporated into the existing Tidd Unit 1 conventional steam cycle. The Tidd Unit 1 steam cycle is a 1940's vintage cycle, with original steam conditions of 900,000 lb/hr steam flow at 1300 psia and 925 F with no reheat, which produced an electrical output of 110 MW at a cycle efficiency of 31%. As configured for PFBC operation, the plant has a design steam flow of 440,000 lb/hr, at 1300 psia and 925 F, which produces a gross electrical output of 57 MWe from the steam turbine, and 15 MWe from the gas turbine, with a net cycle efficiency of 34%.

2.3.3 Air/Gas Cycle

Ambient air enters the low pressure compressor section of the gas turbine and is compressed to 59 psia. The compressed air is cooled by condensate in the gas turbine intercooler. The air then enters the high pressure compressor, where it is further compressed to 174 psia and 572 F (Figure 3).

The hot compressed air is then directed through the outer annulus of a coaxial air/gas pipe, and then 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.

In the fluidized bed, coal-water paste (25% by weight nominal water content) is burned at a temperature of 1540-1580 F. The sorbent is injected into the bed via a pneumatic system. For the 3.4% sulfur Pittsburgh #8 design coal and 90% sulfur retention, the full load design calcium/sulfur molar ratio is 1.64, when using dolomite as the sorbent.

After leaving the fluidized bed zone, the hot gases and entrained ash particles enter the freeboard zone, where the excess air content is controlled to about 25%. The hot gases and entrained ash then pass into seven parallel sets of cyclones, each with two cyclones in a series. The cyclones are designed to remove 99% 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, the gas is collected in a manifold and exits the pressure vessel at 149 psia. 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 146 psia.

There the hot gases are expanded through the high pressure turbine. The gas then enters the low pressure turbine where it is further expanded, and is 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) for particulate of 0.03 lbm/million Btu before being emitted to the atmosphere via the Cardinal Unit 1 flue gas stack. In testing at Tidd to date, the gas stream has exhibited particulate levels on the order of 0.01-0.02 lbm/million Btu.

2.3.4 Steam Cycle

The steam cycle (Figure 4) 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 to 817 psia, 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 to 2038 psia by the feedwater pump, and directed to the economizer where heat in the gas exiting the gas turbine further preheats the feedwater to 485 F. From there, the feedwater is routed to the pressure vessel and enters the boiler at 475 F and 1868 psia.

The feedwater enters the boiler bottom, which is comprised of the walls of the two ash hoppers. After passing through the boiler bottom, fluidized bed, and freeboard wall enclosures, it enters the in-bed evaporator surface where boiling occurs. Steam, which is two phase up to about 40% load and slightly superheated at full load, is conveyed to the vertical separator. At lower loads, the water from the separator is recirculated through the boiling surfaces with the assistance of a circulating pump. The steam from the separator then enters the in-bed primary superheater. From the primary superheater outlet, spray attemperation is used to control final steam temperature exiting the boiler. From the attemperator, steam is directed to the in-bed secondary superheater, and then exits the boiler at 1335 psia and 925 F.

During start-up and in the event of a steam turbine trip, a 50% bypass system to the condenser and a pressure control valve to atmosphere serve to dispose of the excess steam while controlling the boiler pressure/temperature decay, and preserving as much of the treated water as practical. In the event of a loss of plant power or loss of the boiler feed pump during operation, a backup feedwater system is also provided to maintain water flow to the boiler circuits exposed to the heat contained in the slumped bed.

2.4 PFBC Systems

One of the key objectives of the Tidd Demonstration Project is successfully scaling up the PFBC system from pilot plant size to the 200 MWt Tidd Plant. The 15 MWt integrated pilot plant, located at the PFBC Component Test Facility (CTF) in Sweden, was designed to test components, process variables, and control systems at near commercial size. The testing performed at the CTF has enabled AEP to verify the design conditions projected for the Tidd PFBC Demonstration Plant.

2.4.1 Pressure Vessel

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

The pressure vessel is externally insulated and is designed for internal operating conditions of 590 F and 170 psia. It consists of a vertical cylindrical shell about 70 feet high and 44 feet in diameter, with elliptical heads.

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

2.4.2 PFBC Boiler

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

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

The bed zone is designed as a deep (11.8 feet), tapered, fluidized bed in which the superheater and evaporator sections are submerged. At full load, all of the evaporator and superheater surfaces are submerged within the bed. At reduced loads, the bed level is lower, thereby exposing portions of the surface. The surface above the bed convectively cools the gases feeding to the gas side because the convective heat transfer rates are lower than those within the bed.

In the freeboard section, excess air in the hot gas is controlled to about 25%. The freeboard is sized to minimize the elutriation (separation) of fly ash by the gas flow, and is internally insulated to cut heat loss on the way to the gas turbine.

2.4.3 Bed Ash Reinjection System

Bed level is the main controlling parameter in the PFBC boiler. The bed ash reinjection system permits rapid change in the unit load by transferring bed material to and from a pair of reinjection vessels located inside the combustor pressure vessel. Special handling devices are used to admit bed material stored in the reinjection vessels into the bed, thus increasing load. To decrease unit load, bed material is pneumatically transported from the bed to reinjection vessels.

Air from the combustor pressure vessel transports the bed material to and from the reinjection vessels. The transport air flow is separated from the ash and vented outside the combustor into the main combustion flue gas. The reinjection vessels are normally at the same pressure as the boiler; however, during load decreases, they are at a slightly lower pressure.

2.4.4 Ash Removal System

Fine ash, collected in the cyclones, is continuously removed by a pneumatic transport system. The ash is cooled and a portion of the heat is recovered in the combustion air. Depressurization requires no lockhoppers or valves.

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

2.4.5 Cyclones

To reduce particulates flowing to the gas turbine, the exhaust gas leaving the upper part of the boiler freeboard passes through a series of cyclones. At Tidd, there are seven parallel strings of cyclones, each with two stages of separation. The gas is conveyed from the boiler to the first stage cyclones through connecting flues. Gas flows from the second stage cyclones to a manifold and then exits the pressure vessel. It then makes its way through the inner portion of a coaxial pipe and past the hot gas intercept valves on its way to the gas turbine. The cyclones and gas collecting pipe are insulated to minimise gas temperature losses.

2.4.6 Gas Turbine Generator

The gas turbine at the demonstration project, the GT-35P, is a modified ASEA Stal GT-35 that is uniquely suitable for PFBC applications. This turbine is arranged in line on two shafts. The variable speed, low pressure compressor is mechanically coupled to its driving low pressure turbine on one shaft. The high pressure turbine drives both the constant speed high pressure compressor and the electric generator. An epicyclic gear reducer couples the electric generator to the high pressure shaft.

With the combined cycle design, combustion gas temperatures fall when unit load is reduced because the lower bed height exposes more steam generator tubes. As gas temperature drops, the low pressure shaft speed decreases, lessening the pressure and flow of combustion air. Thus, the free spinning low pressure shaft allows the air flow to vary with unit load.

Design modifications made in the gas turbine to improve reliability in PFBC applications include decreasing loading on the first turbine stage by adding an extra stage, and increasing stability by connecting the high pressure shaft to the power turbine shaft by using a gear train.

2.4.7 Economizer

The once-through turbine exhaust gas economizer at Tidd recovers heat from the gas turbine exhaust for preheating the feedwater. Tidd's economizer is a modular design, with the flue gas flowing horizontally across vertical, in line, spirally finned water tubes. It is in series with the condensate heaters and replaces existing high pressure feedwater heaters.

2.4.8 Electrostatic Precipitator

After leaving the economizer, the gas enters the electrostatic precipitator. Here, the gas is further cleaned of particulates to the NSPS level of 0.03 pounds per million Btu. The gas is then released to the atmosphere via the flue gas stack.

2.4.9 Coal Feed System

The coal is pumped into the bed as a coal-water paste.

To form the paste, uncrushed 3/4 inch coal is fed from a 45 ton capacity surge hopper into a double roll crusher. After crushing, approximately 50% of the coal is recirculated to the crusher inlet to achieve throughput with 20% fines (minus 325 mesh). A system of conveyors then transports the crushed coal (1/4 inch) onto a three deck screen to eliminate oversized pieces, and into a pug mill type mixer, which adds 25% water by weight to the coal.

A specific coal size distribution is used to eliminate inter-particle motion and to make pumping the paste easier. The coal's moisture is measured on the weigh feeder, and water is added to the mixer to prepare the paste. It then goes directly into a fuel feed hopper which has a one hour storage capacity.

The feed hopper supplies six parallel hydraulically operated coal injection pumps that deliver the fuel to the boiler. Each pump feeds fuel into the boiler through a dedicated fuel nozzle.

2.4.10 Sorbent Feed System

Sorbent (dolomite), stored in a 70 ton capacity surge hopper, is first fed into an impact dryer mill. The size of the sorbent (1/8 inch) is controlled by a vibrating screen and heated air flowing through the mill. The sized material is swept from the mill by the hot air and then sorted by a cyclone separator and a baghouse. A vibrating screen, located at the outlet to the cyclone separator, diverts oversized material back to the mill. The final product is transported by conveyor into a 200 ton sorbent storage hopper. The hopper has two outlets to feed the sorbent injection system.

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

A new system was installed as part of the commercial PFBC plant verification testing to allow mixing sorbent fines with the coal-water paste. This system can accept sorbent fines from a bulk truck and transport the fines to the coal-water paste mixer. Testing will be conducted to evaluate the improvement in sorbent utilization due to improved sorbent fines distribution.

2.4.11 Control System

A distributed programmable logic system is used to collect signals and measurements. The control system, a Bailey Network 90, uses eight process control units divided into the following modes: gas turbine, combustor, steam turbine, balance of plant, and safety. These units perform the control of individual plant items, and also most of the coordinating control, interlocking, and automatic function involving groups of related items.

3.0 TEST PLAN

3.1 Goals and Objectives

The overall objective of the Tidd test program is to provide the data base and experience to be applied to the detailed design, operation, control, and maintenance of large scale commercial PFBC combined cycle plants.

The major goals of the test program are:

- To demonstrate that a gas turbine operated in a combined cycle mode can operate for an acceptable life between rebuilds, have acceptable availability, and be easily controlled.

- To demonstrate in-bed tube bundle survivability.

- To demonstrate that PFBC can achieve emission levels better than the requirements of the Clean Air Act.

- To investigate the commercial potential of PFBC ash.

- To demonstrate that PFBC is an economic alternative to pulverized coal-fired plants with flue gas desulfurization and other clean coal technologies.

These goals will be accomplished through data collection and tests to demonstrate:

- Scale-up to demonstration plant size.

- Operability of combined cycle systems under steady state and dynamic conditions.

- Optimized process performance over the operating range, including performance of various combinations of coals and sorbents.

- Equipment performance, including operating data over the load range, erosion characteristics of PFBC components, and development of a RAM (reliability/availability/maintainability) data base.

- Dynamic systems response, including load following.

- Operability under blackout or trip conditions and other off-normal operating modes.

3.2 Test Schedule

Table 3 provides the schedule for the Tidd test program.

Table III: Tidd PFBC Demonstration Plant Test Schedule

```
1.1      Preliminary Tests                                    1   2   3   4   5   6   7   8   9   0   1   2   3   4   5   6   7   8   9   0
1

1.1.1    Evaluate sorbent based deposit formation          x.x.|0..00..|.x.|...|...|...|...|...|.0000..|...|...|...|...|...|...|...0000|...|...|
1.1.2    Bed ash/cyclone ash generation                    |.x.x0..00..|...|...x.x.x.x.x.x.x.x.x.0000x.x.x.x.x.x.x.x.x.x.x.x.x.0000|...|...|
1.1.3    Evaluate improved coal water paste quality        x.x.|0..00..|...|...|...|...|...|...|.0000..|...|...|...|...|...|...|...0000|...|...|
1.1.4.1  Full load unit performance test                   x.x.|0..00..|...|...|...|...|...|...|.0000..|...|...|...|...|...|...|...0000|...|...|
1.1.4.2  Minimum load unit performance test                |...|0..00x.x...|...|...|...|...|...|.0000..|...|...|...|...|...|...|...0000|...|...|
1.1.5    Confirm revised control logic                     x.x.|0..00..|...|...|...|...|...|...|.0000..|...|...|...|...|...|...|...0000|...|...|
1.1.6    Complete 100-hour endurance run                   |...x0..00..|...|...|...|...|...|...|.0000..|...|...|...|...|...|...|...0000|...|...|
1.1.7    Complete 30-day reliability run                   |...|0..00xxxx..|...|...|...|...|...|.0000..|...|...|...|...|...|...|...0000|...|...|

1.2      Acceptance Tests

1.2.1    Acceptance Test                                   |...|0x.00..|...|...|...|...|...|...|.0000..|...|...|...|...|...|...|...0000|...|...|
1.2.2    Acceptance Test                                   |...|0x.00..|...|...|...|...|...|...|.0000..|...|...|...|...|...|...|...0000|...|...|
1.2.3    Contingency - Re-run acceptance test                       |...|0.x00..|...|...|...|...|...|...|.0000..|...|...|...|...|...|...|...0000|...|...|
1.2.4    Contingency - Re-run acceptance test                       |...|0.x00..|...|...|...|...|...|...|.0000..|...|...|...|...|...|...|...0000|...|...|

2.0      Dynamic Tests

2.1.1    Transients during startup                         |...|0..00..|...|...x.x.|...|...|...|.0000..|...|...|...|...|...|...|...0000|...|...|
2.1.2    Evaluate maturing bed                             |...|0..00..|...|...x.x.x.x.x.x.x.x.x.0000x.x.x.x.x.x.x.x.x.x.x.x.x.0000|...|...|
2.2      Load Response/Controls                            |...|0..00..|...|...x.x.|...|...|...|.0000..|...|...|...|...|...|...|...0000|...|...|
2.3      Response to step change Ca/S                               |...|0..00..|...|...x.x.x.x.x.x.x.x.x.0000x.x.x.x.x.x.x.x.x.x.x.x.x.0000|...|...|
2.4      Full load loss of feedwater test                  |...|0..00..|...|...|.x.|...|...|...|.0000..|...|...|...|...|...|...|...0000|...|...|
2.5      Combustor Warm-up Evaluation                               |...|0..00..|...|...x.x.|...|...|...|.0000..|...|...|...|...|...|...|...0000|...|...|

3.0      Technology Flexibility

3.1.1    Pitts 8 coal, Plum Run dolomite                   |...|0..00..|...|...x.x.|...|...|...|.0000..|...|...|...|...|...|...|...0000|...|...|
3.1.2    Pitts 8 coal, Nat'l Lime dolomite                 |...|0..00..|...|...|...x.x.|...|...|.0000..|...|...|...|...|...|...|...0000|...|...|
3.1.3    Pitts 8 coal, limestone                           |...|0..00..|...|...|...|...x.x.|...|.0000..|...|...|...|...|...|...|...0000|...|...|
3.2.1    Meigs coal, Plum Run dolomite                     |...|0..00..|...|...|...|...|...x.x.|.0000..|...|...|...|...|...|...|...0000|...|...|
3.2.2    Meigs 8 coal, Nat'l Lime dolomite                 |...|0..00..|...|...|...|...|...|...x.0000x.|...|...|...|...|...|...|...0000|...|...|
3.2.3    Meigs 8 coal, Plum Run dolomite                   |...|0..00..|...|...|...|...|...|...|.0000..x.x.|...|...|...|...|...|...0000|...|...|
3.3.1    Glenbrooke coal, Plum Run dolomite                |...|0..00..|...|...|...|...|...|...|.0000..|...x.x.|...|...|...|...|...0000|...|...|
3.3.2    Glenbrooke coal, Nat'l Lime dolomite                       |...|0..00..|...|...|...|...|...|...|.0000..|...|...x.x.|...|...|...|...0000|...|...|
3.3.3    Glenbrooke coal, Plum Run dolomite                |...|0..00..|...|...|...|...|...|...|.0000..|...|...|...x.x.|...|...|...0000|...|...|
3.4.1    PFBC-001 coal, Plum Run dolomite                  |...|0..00..|...|...|...|...|...|...|.0000..|...|...|...|...x.x.|...|...0000|...|...|
3.4.2    PFBC-001 coal, Nat'l Lime dolomite                |...|0..00..|...|...|...|...|...|...|.0000..|...|...|...|...|...x.x.|...0000|...|...|
3.4.3    PFBC-001 coal, Plum Run dolomite                  |...|0..00..|...|...|...|...|...|...|.0000..|...|...|...|...|...|...x.x.0000|...|...|

4.0      Technology Optimization

4.1.1    Excess Air Optimization                           x.x.|0..00..|...|...|...|...|...|...|.0000..|...|...|...|...|...|...|...0000|...|...|
4.1.2    Splitting Air Flow Optimization                   x.x.x0..00..|...|...|...|...|...|...|.0000..|...|...|...|...|...|...|...0000|...|...|

4.2.1    Sorbent Fines                                     |.x.|0..00..|...|...|...|...|...|...|.0000..|...|...|...|...|...|...|...0000|...|...|
4.2.2    Sorbent in Paste                                  |...|0..00..|.x.x.x.x...|.x.|.x.|.x.|.0000..|.x.|.x.|.x.|.x.|.x.|.x.|.x.0000|...|...|

4.3.1    Sec. Cyclone Ash Removal System Mods.                      x.x.|0..00..|...|...|...|...|...|...|.0000..|...|...|...|...|...|...|...0000|...|...|
4.3.2    Vacuum on Secondary Ash System                    x...|0..00..|...|...|...|...|...|...|.0000..|...|...|...|...|...|...|...0000|...|...|
4.3.3    Cyclone String Temperature Imbalance                       |...|0..00..|...|...|.x.|...|...|...|.0000..|...|...|...|...|...|...|...0000|...|...|
4.3.4    Cyclone String Dust Loading                                |.x.x0..00..|...|...|...|...|...|...|.0000..|...|...|...|...|...|...|...0000|...|...|
4.3.5    Auto trip for primary cyclone plugs               |...|0..00..|...|...|.x.|...|...|...|.0000..|...|...|...|...|...|...|...0000|...|...|

4.4.1    Freeboard Injection Optimization                  |.x.x0..00..|...|...|...|...|...|...|.0000..|...|...|...|...|...|...|...0000|...|...|
4.4.2    Five Pump Operation                               |...|0..00..|...|...|.x.|...|...|...|.0000..|...|...|...|...|...|...|...0000|...|...|

4.5      VS Bypass Valve Opening Point                     |...|0..00..|...|...x.x.|...|...|...|.0000..|...|...|...|...|...|...|...0000|...|...|

4.6      Evaluate economizer perf. with sootblowers        |.x.x0x.00..|...|...|...|...|...|...|.0000..|...|...|...|...|...|...|...0000|...|...|
4.7      RAM data base development                         xxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxx
4.8      HGCU Acceptance Tests                             |...|0..00x.|...|...|...|...|...|...|.0000..|...|...|...|...|...|...|...0000|...|...|

5.0      Commercial Plant Design Optimization Studies

5.1      Optimize sorbent utilization                      |...|0..00..|.x.x.x.x...|...|...|...|.0000..|...|...|...|...|...|...|...0000|...|...|
5.2      Optimize fuel distribution and mixing                      |...|0..00..|...|...|...|...|...|...|.0000..|...|...|...|...|...|...|...0000x.x.|...|
5.3      Evaluation/elimination of sec. cyclones           |...|0..00..|...|...|...|...|...|...|.0000..|...|...|...|...|...|...|...0000x.x.x.x.|
5.4      Low load unit efficiency optimization                      |...|0..00..|...|...|...|...|...|...|.0000..|...|...|...|...|...|...|...0000x.x.|...|
5.5      Test reheat surface addition                               |...|0..00..|...|...|...|...|...|...x.x.x.0000..|...|...|...|...|...|...|...0000|...|...|
```

4.0 PLANT OPERATIONS

This section provides a narrative of the individual operating runs from October, 1990 through September, 1992. Section 5 provides a summary of the specific tests accomplished during this time period.

4.1 Operations During First Quarter, 1991

The unit was operated on 15 occasions at bed levels up to 95 inches for a total of 376 hours (including gas turbine prewarming). The gas turbine, fuel handling, bed ash removal, and other combustor auxiliary systems, as well as all existing Tidd systems, functioned well with only minor problems.

Temporary modifications were made to improve performance of the secondary cyclone ash removal system. Purge air was added to the cyclone bellows boxes, sections of the internal ash coolers were bypassed, the external cooler was eliminated, and the ash discharge relocated to the gas turbine outlet.

Numerous problems were experienced with valves and feeders in the sorbent injection system. Feeder problems were corrected and some valves in the system were slated to be replaced for reliable operation.

The finned tube economizer experienced fouling with ash deposits.

Extensive tuning, adjustments, and modifications were made to enhance controls. Steam generator vertical separator level control was especially troublesome.

Unit load was limited to 95 inch bed level due to secondary combustion in the freeboard and cyclones which caused cyclone and gas turbine temperatures to approach design limits.

An additional improved data acquisition system (Plant Operations and Performance Systems - POPS) was installed to enhance operational monitoring of the unit.

4.2 Operations During Second Quarter, 1991

The unit was fired with oil or coal on 13 occasions at bed levels up to 126 inches for a total of 457 hours. Maximum bed height of 126 inches was reached for the first time at 07:00 hours on April 21, 1991. Boiler injection on loss of feedwater flow was tested successfully on May 18, 1991. The gas turbine cleaning with Carboblast was used for the first time on the LPC on June 2, 1991.

The economizer was mechanically cleaned and two sootblowers were installed to clean the tubes on a routine basis while the unit is operating.

4.3 Operations During Third Quarter, 1991

The unit was operated for a total of 391 hours (including gas turbine prewarming). There were nine gas turbine starts, seven bed preheating starts, and five operating periods with coal fire. The peak gross hourly output of 39 MWH was from 04:00 hours to 05:00 hours on September 7, 1991. The longest coal fire was 109 hours 44 minutes, ending at 16:39 hours on August 13, 1991.

Testing was done and data taken at different bed levels for B&W surface evaluation for the addition of heating surface.

Some parts of the coal paste preparation system and the coal injection system have exhibited signs of corrosion/erosion during this period. These problems have been attributed to the low pH of the coal paste mixture.

4.4 Operations During Fourth Quarter, 1991

The unit was operated for a total of 111 hours (including gas turbine prewarming). There were three gas turbine starts, eleven bed preheating starts, and two operating periods with coal fire. The peak gross output of 41 MWH was for the period of 12:00 hours to 13:00 hours on December 18, 1991. The longest coal fire was 24 hours 24 minutes, ending at 03:04 hours on December 19, 1991.

4.5 Operations During First Quarter, 1992

The unit was operated for a total of 633 hours (including gas turbine prewarming). There were eleven gas turbine starts, eleven bed preheating starts, and nine operating periods with coal fire. The peak gross output of 69 MWH was for the period of 00:00 hours to 01:00 hours on January 16, 1992. The longest coal fire was 154 hours 7 minutes, ending at 10:59 hours on January 10, 1992.

4.6 Operations During Second Quarter, 1992

The unit was operated for a total of 606 hours (including gas turbine prewarming). There were two gas turbine starts, three bed preheating starts, and three operating periods with coal fire. The peak gross output of 68 MWH was for the period of 22:00 hours to 23:00 hours on June 12, 1992. The longest coal fire was 510 hours beginning at 18:00 hours on June 9, 1992, and the unit was still in service at the end of the quarter (740 hours at shutdown on July 10, 1992).

5.0 TESTING AND DATA COLLECTION

After the initial unit operation and shakedown, tests were conducted to determine processes and system performance at the Tidd Plant. These tests included:

- Initial performance Tests
- Environmental Compliance Test
- Contract Acceptance Tests
- Splitting Air System Tests
- Freeboard Injection System Tests

This section provides summaries and conclusions of these tests.

5.1 Initial Performance Tests

Tests were run to evaluate the performance of the Tidd Plant and the validity of the test procedures. These tests were run prior to the addition of tube surface to the bed.

On June 25, 1991, from 14:30 to 20:30 EDT, test No. 1 was conducted at a bed height of 126 inches and maximum heat input. The firing rate was 74.5% of design full load.

On August 9, 1991, from 16:35 to 20:35 EDT, test No. 2 was conducted with the unit operating at bed height of 76.0 inches and a firing rate of 49.2% of design full load.

On August 12, 1991, from 08:45 to 13:00 EDT, test No. 3 was conducted with the unit operating at a bed height of 90.2 inches and a firing rate of 57.6% of design full load.

Babcock and Wilcox (B&W) also collected data during test No. 2 and No. 3 to redesign the tube surface.

5.1.1 Sulfur Retention

Calculated Ca/S for 90% sulfur capture was near design during test No. 1, when Pittsburgh 8 coal and Plum Run dolomite were fed in a normal mode.

Sulfur retention during test No. 2 was less than 90%. During Test No. 2, sorbent feed rate was held low in order to prevent plugged cyclones.

During test No. 3, the sorbent was National Lime No. 57 dolomite (1 inch by 4 mesh) versus the Plum Run dolomite used previously. The sorbent preparation system vendor had requested that the performance sorbent be used during system acceptance testing. Sorbent size fed to the bed was larger than normal due to a broken screen in the sorbent preparation system.

Table IV: Tidd PFBC Demonstration Plant
Sulfur Retention During Preliminary Tests

Test Number	1	3	2
Test Date	6/25/91	8/12/91	8/9/91
Bed Level, inches	126.9	90.2	76.0
Mean Bed Temperature, F	1535	1530	1531
SO_2 in Flue Gas, lb/mmBtu	.32	.53	.89
NO_x in Flue Gas, lb/mmBtu	.25	.31	.28
Sulfur Retention, percent	94.0	90.0	85.2
Ca/S Molar Ratio	2.3	3.3	2.1
Predicted Ca/S (90%/1580 F)	1.69	2.98	2.25
Design Ca/S (90%/1580 F)	1.64	1.95	2.12

5.1.2 Combustor Performance

Combustor performance was fair. The combustion efficiency was lower than the full load design combustion efficiency of 99.0%

The low combustion efficiency during test No. 2 was due to high unburned carbon loss. The unburned carbon loss was 2.3 percentage points (ppts.) versus an unburned carbon loss of 1.3 ppts. during previous tests. This could have been caused by a cyclone ash sample that was not representative (carbon in cyclone ash was 5.6%). CO at the freeboard declined over the test period.

Heat input was limited by insufficient surface area for heat transfer in the bed.

Table V: Tidd PFBC Demonstration Plant Combustor Performance During Preliminary Tests

Test Number	1	3	2
Test Date	6/25/91	8/12/91	8/9/91
Firing Rate, MWt	155	120	102.3
Combustion Efficiency, percent	98.6	98.8	98.1
Excess Air, percent	32.8	60.1	59.4
Feedwater Flow, kpph	328.5	247.0	219.1
Feedwater Temperature, F	478.0	444.5	443.7
Feedwater Pressure, psia	1593	1579	1533
Main Steam Temperature, F	925	925	925
Main Steam Pressure, psia	1324	1283	1285
Attemperation Flow, kpph	10.7	8.7	8.4
Attemperation Temperature, F	297.4	302.6	297.3

5.1.3 Gas Turbine/Compressor Performance

The gas turbine and compressor performance was evaluated. The leakage flow was calculated from energy balances on the combustor and the gas turbine. The calculated leakage is approximately three times original design.

Table VI: Tidd PFBC Demonstration Plant
Gas Turbine/Compressor Output During Preliminary Tests

Test Number	1	3	2
Test Date	6/25/91	8/12/91	8/9/91
Gas Turbine Output, MW	11.4	6.3	3.7
Air Flow to HPC, klb/hr	625.3	574.9	499.8
Air Flow to Combustor, klb/hr	543.2	506.7	426.3
Air Leakage, percent	13	11	14

5.2 Environmental Compliance Test

On February 7, 1992, a series of tests were run to determine compliance with SO_2 and NO_x emission limitations and to determine emissions of CO and particulate from the electrostatic precipitator. Testing was performed by Environmental Source Samplers, Inc. The following results were reported:

Table VII: Tidd PFBC Demonstration Plant
Environmental Compliance Test Results

Unit Conditions		
Average Heat Input	179 MWt	
Gas Temperature	415.1 F	
Stack O2	6.1% (dry)	
Stack CO2	13.1% (dry)	
Unit Output	29.6 MW	
Test Results	Average Emissions	Permit Limit
SO2	0.5067 lb/mmBtu	0.511 lb/mmBtu
NOx	0.2379 lb/mmBtu	0.5 lb/mmBtu
CO	0.0008 lb/mmBtu	0.01 lb/mmBtu
Particulate	0.0192 lb/mmBtu	0.03 lb/mmBtu

Testing at the inlet of the economiser was also performed in order to determine the dust loading to the gas turbine. The calculated gas mass flow rate was extremely high during this test also. The dust loading was determined to be 350 - 480 ppm weight during these tests.

5.3 Contract Acceptance Tests

Performance tests No. 6 and No. 7 were run on June 14 and June 15, 1992, to determine the performance of the Tidd Plant relative to the contract goals and guarantees.

5.3.1 Description

These tests were conducted during the 30-day reliability run. During the 30-day period from 6/10 to 7/10, the unit operated at a capacity factor of 69.4%. The load factor for this period was 81.0%. A 100-hour full load endurance run was also completed during this start-up. Following successful completion of the objectives of the run, the unit was removed from service for inspections.

Table VIII: Tidd PFBC Demonstration Plant
Run Parameters - TD-SU-92-09-01

Start Date (2nd coal fire)	06/09/92
Start Time (2nd coal fire)	18:00
Total Gas Turbine Operating Hours	782.5
Total Coal Fire Hours	748.0
100-hour Endurance Run Completed	6/15/92
30-day Reliability Run Completed	7/9/92
Capacity Factor	69.4%

On the morning of June 13, egg sinters were found in the bed ash. This was attributed to operating with low splitting air flow on June 13.

On June 13, firing rate was set at 22:00 EST and data collection was begun. Data collection was stopped at 06:00

on June 14. The process data evaluated for the first test was collected between 00:00 and 04:00 on June 14.

On June 14, data collection was started at 22:00 EST. The unit firing rate was not set until 00:00 because Operations was trying to match the unit conditions (air flow) from the previous night. Firing rate was 1.4 percentage points lower than the previous test due to a 3.2 F increase in ambient temperature. The process data evaluated for the second test was collected between 00:00 and 04:00 on June 15.

ASTM coal samples were obtained every two hours during the test periods using the automatic (Tema) sampler. Sorbent samples were obtained in twelve-hour composites, beginning approximately twenty-four hours before the test periods began. A grab sample of coal paste was obtained for moisture analysis every two hours during the test periods. Bed ash samples were obtained in two-hour composites between eight and twelve hours after the test periods. One cyclone ash sample was obtained from the rotary unloader just following the test periods.

The ash split was determined during the dust loading tests conducted on June 23, 1992, yielding 42.5% of total ash as bed ash and 57.5% as cyclone ash.

5.3.2 Performance Goals and Guarantees

The performance of the unit compared to goal and guarantee parameters is summarized below. The unit met all performance guarantees except gas turbine MW output. The maximum heat input was limited to approximately 93% of original full load design by the air available for combustion and by gas turbine inlet temperature limitation due to boiler performance.

From a test conducted 6/23/92 with six cyclone strings in service, the dust loading to the gas turbine was 313 ppm, versus a goal of 250 ppm. It is calculated that dust loading

Table IX: Tidd PFBC Demonstration Plant Performance Goals and Guarantees

Performance Guarantees				
Test Number	6	7	Goal	Guarantee
Gas Turbine Output, MW	13.2	12.5	16.8	15.0
Main Steam Temperature, F	923	922	925	925
Ca/S at 90% Sr/S	1.82	1.93	1.64	2.00
NOx Emissions, lb/mmBtu	0.18	0.18	0.25	0.60
Combustion Efficiency, percent	99.4	99.3	---	98.0
Corrected Water Side Pressure Drop, psi	557	558	648	687
Performance Goals				
Gas Side Pressure Drop, psi	24.1	24.5	24.0	
Gas Turbine Apparent Heat Rate, Btu/kwh	49187	51122	42200	
Economizer Gas Outlet Temperature, F	419	419	322 to 355	
Mean Bed Temperature, F	1550	1532	1580	
Gas Flow to HPT, kpph	651.2	647.3	719.0	
Gas Temperature to HPT, F	1541	1520	1525	
Excess Air, percent	20.1	21.3	25.0	
Air Flow to Combustor, kpph	593.0	598.3	655.2	

with seven cyclone strings in service would be higher due to decreased cyclone inlet gas velocities.

5.3.3 Process Thermal Performance

Unit heat input was limited to approximately 93% of the original design value of 206 MWt. Although air flow to the compressor was at the full load design value, excess leakage (12.3% calculated versus 4.4% design) caused a reduction in air flow available to sustain combustion. During the tests, the low pressure compressor speed was 100 RPM below the operating limit of 5650 RPM, and the guide vanes could have been opened to increase air flow slightly. Air flow was not further increased because the high pressure compressor outlet temperature was at the set point value of 572 F (alarm 590 F, trip 610 F), and the intercooler flow control valve was at 100% open. (The intercooler heat duty was 19% above design.)

A bed temperature of 1580 F and 7% more air to the bed would be required to achieve full load at 20% excess air. It is possible that the air flow could be achieved at reduced outside air temperature (less than 30 F). It is also likely that gas temperature limits would be encountered at this bed temperature before reaching a firing rate of 206 MWt. At a bed temperature of 1540 F in the redesigned bed, it is likely that the bed would not be able to transfer sufficient energy to the steam side; that is, the bed is still undersized.

Table X: Process Performance

Test Number	6	7	
Test Date	06/14/91	06/15/91	Design
Bed Level, Inches	142	136	126
Mean Bed Temperature, F	1550	1532	1580
Mean Freeboard Temperature, F	1557.1	1539.5	1549.0
Freeboard Oxygen, Percent Wet	3.3	3.4	3.8
Excess Air, Percent	20.1	21.3	25.1
Firing Rate, MW	190.3	187.3	206.3
Firing Rate, Percent	92.2	90.8	100.0
Gas Turbine, MW	13.2	12.5	15.4
Air Leakage, Percent	12.8	11.8	4.4
Steam Turbine, MW	47.0	46.1	57.1
Steam Flow, klb/hr	395.0	390.0	442.0
Gas Temperature to Stack, F	419	419	352
Unit Heat Rate, Btu/kwh	10803	10905	9708
Paste Flow, lbs/hr	68400	67500	72924
Paste Moisture, Percent	25.2	25.3	25.0
Sorbent Flow, lbs/hr	20928	22049	18882
Bed Ash Flow, lbs/hr	10533	10959	10741
Cyclone Ash Flow, lbs/hr	14251	14826	13943
Feedwater Flow, klb/hr	378.4	373.5	426.1
Feedwater Temperature, F	456.5	454.7	485.1
Feedwater Pressure, psia	1726.0	1724.0	1889.3
Attemperation Flow, klb/hr	16.7	16.5	15.5
Attemperation Temperature, F	299.7	300.0	298.9
Main Steam Flow, klb/hr	395.1	389.9	441.6
Main Steam Temperature, F	923.0	922.0	925.0
Main Steam Pressure, psia	1324.0	1324.0	1334.8

5.3.4 Air Leakage

The air flow bypassing the combustor was determined from the measured change in oxygen in the gas stream between the freeboard and the economizer inlet. During the test periods, the average leakage was 12.3% of the calculated air flow to the high pressure compressor, versus a design value of 4.4%. In order to determine the site of the air leakage, ABB Carbon installed a set of test thermocouples around the high pressure gas turbine and intercept valve.

The gas temperature to the intercept valve was measured by process instrumentation and by test instrumentation installed by ABB Carbon. The test instrumentation indicated gas temperatures 85 F higher than the process instrumentation. This could be due to air leaking in around the process thermocouple or due to conductive cooling of the thermocouple. The process indication also varied more than the test instrumentation during the test period. This could have been due to ash alternately covering the thermocouple and breaking off.

5.3.5 Environmental Performance

The environmental performance of the unit was good. Emissions were well within the permit limitations during the test periods.

Emissions

Test Number	6	7	
Test Date	06/14/91	06/15/91	Design
SO_2 Emissions, lbs/mmBtu	0.36	0.36	0.52
NO_x Emissions, lbs/mmBtu	0.18	0.18	0.25
CO_2 Emissions, lbs/mmBtu	213.3	212.2	206.1

5.3.6 Sorbent Utilization

Sulfur capture versus design is tabulated below. The calcium to sulfur molar ratio was predicted at 90% sulfur retention, 95% sulfur retention, and at the design bed temperature of 1580 F, using the following correlation developed at Grimethorpe:

$$R = 1 - \exp(-mC)$$

where R = sulfur retention, dimensionless
m = A * exp(-3500/Tbed, deg K)
A = constant, sorbent reactivity
C = calcium to sulfur molar ratio, dimensionless

Sorbent Utilization

Test Number	6	7	
Test Date	06/14/91	06/15/91	Design
Sulfur Retention, Percent	92.6	92.9	90.0
Test Ca/S	2.05	2.21	---
Mean Bed Temperature, F	1550	1532	1580
Ca/S corrected for 90% Retention at 1580 F (Predicted)	1.73	1.78	1.64

It has been theorized that the sorbent distribution in the bed includes regions of high concentrations of sorbent fines. This could be seen as sorbent "plumes," which could result in most of the sorbent fines leaving the bed without reacting. This theory seems to be supported by the analysis of the cyclone ash samples.

5.3.7 Gas Turbine/Compressor Performance

The gas turbine did not meet the guarantee output of 15 MW. It is likely that, even if air leakage and firing rate were at design, it would not be possible to meet the guarantee output.

Table XI: Gas Turbine Performance

Test Number	6	7	
Test Date	06/14/91	06/15/91	Design
Gas Turbine, MW	13.2	12.5	15.4
Air Leakage, Percent	12.8	11.8	4.4
LPC Inlet Temperature, F	59.8	62.9	59.0
LPC Outlet Temperature, F	355.5	363.3	345.4
LPC Outlet Pressure, psia	57.3	57.6	59.3
LP Shaft Speed, RPM	5526	5585	5364
HPC Outlet Temperature, F	571.6	573.1	572.0
HPC Outlet Pressure, psia	174.9	174.0	174.0
HPC Inlet Air Flow, klb/hr (Indicated)	680.0	679.6	678.6
HPC Inlet Air Flow, klb/hr (Calculated)	676.8	669.8	678.6
Air Flow to PV, klb/hr	589.6	589.3	648.7
Int. Valve Inlet Temperature, F (Test Data)	1540.8	---	1535.3
Indicated Int. Valve Inlet Temperature (Indicated)	1455.5	1403.5	---
HPT Inlet Temperature, F (Test Data)	1527.9	---	1525.8
HPT Inlet Pressure, psia	150.8	149.5	145.5
LPT Outlet Temperature, F	738.0	728.0	781.9
LPT Outlet Pressure, psia	15.3	15.3	14.8
Intercooler Heat Duty, kw	4819	5001	4138

5.3.8 Dust Loading to the Gas Turbine

Testing to determine the dust loading to the gas turbine was performed on June 23, 1992, by Environmental Source Samplers, Inc. Their preliminary results indicate that the dust loading to the gas turbine was 313 ppmw versus a performance goal of 250 ppmw. This test was run with only six of the original seven cyclone strings in service.

5.3.9 Bed Characteristics

Bed temperature distribution was good during the test. During the run, egg sinters were found in the bed ash. This was attributed to operating with low splitting air flow early in the run. It is not clear what effect this had on unit performance.

5.3.10 Economizer Performance

The economizer was fouled during the test periods. This resulted in high fuel gas losses and caused a 10 klb/hr reduction in steam flow test (1.3 MW penalty). Additional sootblowers were installed to improve the economizer performance.

Table XII: Economizer Performance

Test Number	6	7	
Test Date	06/14/91	06/15/91	Design
Feedwater Flow, klb/hr	378.4	373.5	426.1
Inlet Temperature, F	299.7	300.0	298.9
Inlet Pressure, psia	1726.0	1724.0	1889.3
Outlet Temperature, F	456.5	454.7	485.1
Gas Flow, klb/hr	740.1	729.5	723.6
Inlet Temperature, F	738.0	728.0	781.9
Inlet Pressure, psia	15.3	15.3	14.8
Outlet Temperature, F	418.9	419.1	352.2
Draft Loss, psi	0.6	0.5	

5.3.11 Ash Analysis

The observed loss of CO_2 from the sorbent in the cyclone ash was less than the extent of sulfation in both samples. This could be due to unreacted sorbent blowing through the bed, along with a quantity of highly sulfated bed ash particles. The highly sulfated bed ash material (greater than 75% sulfation) would cause the apparent sulfation of the cyclone ash to be in an acceptable range, while the unreacted sorbent would give CO_2 in excess of what would be expected.

During the preliminary testing, it was noted that the bed ash available at the bed ash sampler was much less than in previous tests. It was determined that this was likely due to modifications to the bed ash transfer station. For this reason, the bed ash was sampled at the samplers and at the lockhopper discharge. Both samples were analyzed with no apparent bias in the results of the chemical analysis between the two samples. However, the size consist of the samples was biased and prior testing has shown that the chemical analysis varies with sample size consist.

5.3.12 Conclusion

The unit performed as expected and, with the exception of the high air leakage, near design. The gas turbine MW output guarantee was not achieved.

5.4 Splitting Air Tests

To achieve proper fuel combustion, compressed air is used to split (atomize) the paste into small particles. The original fuel nozzle design consisted of three unicentric pipes of 8 inch, 6 inch, and 3 inch nominal size. The outermost annulus was the secondary splitting air passage. The middle annulus was a cooling water jacket and the inner pipe was the fuel passage. The original basis for the splitting air flow control curve was to maintain a constant momentum of splitting air throughout the load range to achieve consistent fuel splitting. In order to maintain constant splitting air momentum, the mass flow increased with increasing pressure vessel pressure to compensate for increased density (decreased velocity) at the higher pressures. At the time of the original fuel nozzle design, ABB Carbon was very concerned about sinter formation, so splitting air flow demand was set high in order to achieve good splitting. Unfortunately, this high degree of splitting resulted in excessive post-bed combustion at the higher unit loads. The splitting air flow demand curve was gradually reduced to as low as 30% of the original design in order to reduce the degree of post-bed combustion.

ABB Carbon decided to reevaluate the design of the fuel nozzle and, through atmospheric testing, developed a new design that incorporated just the primary splitting air flow at the center of the nozzle outlet. They found that with the original design, the secondary splitting air tended to oversplit the particles on the outside of the paste stream. The new nozzle design proved to allow reasonably good control of particle size and consistency by varying splitting air flow.

Through atmospheric testing, ABB Carbon defined a point of optimum splitting air flow. They then extrapolated the results to full load pressure vessel pressure at a constant momentum. The Vartan Plant was started up in the Fall of 1991 using this new curve with the revised fuel nozzles. ABB Carbon found that at the lower loads, they had significantly higher front wall bed temperatures than at the rear wall and had significantly lower O_2 readings in the side wall cyclones than in the corner rear wall cyclones. Splitting air flow was optimized through testing at Vartan to achieve even front to rear wall bed temperatures, even cyclone string O_2 readings, no sinters and no cyclone fires. This testing resulted in a new curve in which mass flow was high at low loads and dropped off with load to approximately the same mass flow at full pressure vessel pressure as that for the curve developed from atmospheric testing. It was theorized that the increased splitting air flow at low loads tends to force the fuel further toward the rear wall, eliminating the O_2 and bed temperature imbalance. Then as bed level and load increases, the splitting air momentum required decreases due to the increased momentum of the paste itself and the improved mass transfer due to the deeper bed.

This new curve was used at the start-up of Tidd after the Fall 1991 outage during which the revised fuel nozzles were installed. This curve provided acceptable performance; however, with the relatively wet coal paste, post-bed combustion was still occurring. Attempts were made up through February, 1992, to reduce splitting air at high loads to combat cyclone fires; however, this sometimes resulted in sinter formation. A revised curve was developed during testing in February, 1992, using the same testing criteria as that used at Vartan. This curve produced flows 1.5 times higher than the Vartan curve at 50 inch bed level, and 1.1 times higher than the Vartan curve at 125 inch bed level. The revised Tidd curve remained in use up until May, 1992.

In preparation for the first run after the Spring 1992 outage, it was decided to increase the splitting air flow curve by 20% at the higher loads by biasing the demand. This was done as a precaution since the coal crushing improvements during the Spring had resulted in a much drier paste and there was concern that sinters might occur. This approach was used during the 30-day run that began on June 9, 1992. Early in the run when the unit reached relatively high loads, sinters began to show up in the bed ash. (With the decreasing mass flow curve, the possibility for sinters increases with higher loads.) Further increases in bias were then made in an attempt to eliminate the sinters. It was found that with 2500 lbs/hr of splitting air, sinters were eliminated even at the highest load attained. The splitting air curve was revised to a flat 2500 lbs/hr demand beyond 28 psig pressure vessel pressure (below which it just serves as a purge flow while rolling up the gas turbine). This curve is presently in use.

With a splitting air curve originating from data received through tests at Vartan, it was possible to obtain optimized conditions at Tidd. The difference from the starting point was substantial at part load conditions, while the full load performance was essentially the same. It is possible to manipulate the bed temperature distribution between the front and rear walls both at part and full load by using the splitting air to divert the paste flow beneath the paste nozzle distribution plates. This feature is to be utilized mainly as a tool to obtain as even temperature distribution in the bed as possible. At full load conditions, it is also possible to control the extent of freeboard heat release, a feature that should be used to obtain maximum possible output from the plant at full bed height conditions by minimizing freeboard heat release.

5.5 Freeboard Injection Test

A system which injects steam into the freeboard was designed to combat cyclone fires. The system was intended to ensure that all of the post-bed heat release occurred in the freeboard region. When the system was placed in service early in 1992, it was discovered that operation of the system not only precluded volatile (gas) fires in the cyclones, but also provided more even inlet temperatures, particularly flow rates and oxygen concentrations between the cyclone strings. The improved particulate flow distribution resulted in improved control of cyclone dip leg (ash) fires. (Previously, ash fires had caused dip leg temperature to approach the material limits and resulted in tripping the unit on more than one occasion.)

A test was performed to optimize the effects of freeboard mixing on temperature levels, particulate flow distribution downstream of the bed, and O_2 distribution.

The test results are summarized below. In general, freeboard injection achieved good mixing of the gas, as seen from cyclone inlet gas temperatures and cyclone string O_2 readings. In addition, it served to redistribute ash loading to the various cyclone strings as indicated by cyclone suction nozzle temperatures.

Table XIII: Freeboard Injection Test at Bed Height = 50 Inches

	0% Flow	25% Flow	50% Flow	100% Flow
O_2 Mean, Percent Net	12.8	13.1	13.1	13.2
O_2 Diff Min./Max, Percent	4.5	4.4	2.2	1.0
O_2 Standard Dev., Percent	1.7	1.8	0.8	0.3
Freeboard Temperature Mean, F	1078	1072	1076	1070
Freeboard Temperature Diff. Min./Max, F	31	41	34	26
Freeboard Standard Dev, F	13	20	16	12
Pri Cyc Inlet Mean, F	1076	1063	1065	1062
Pri Cyc Inlet Diff Min/Max (6 Strings)	23	37	25	7
Pri Cyc Inlet Standard Dev (6 Strings)	8.8	14.2	9.9	2.4
Pri Cyc Inlet Mean, (7 Strings)	1070	1056	1059	1055
Pri Cyc Inlet Diff Min/Max (7 Strings)	60	75	63	48
Pri Cyc Inlet Standard Dev (7 Strings)	18	23	20	17
Pri Dip Leg Mean	994	994	995	998
Pri Dip Leg Diff Min/Max	98	97	102	101
Pri Dip Leg Standard Dev	42	41	39	36
Pri Nozzle Mean, F	806	804	809	810
Pri Nozzle Diff Min/Max	124	105	78	85
Pri Nozzle Standard Dev	42	35	27	32
Freeboard Steam Injection Flow, kpph	0	1.65	3.3	6.6
Freeboard Steam Injection Press, psig	0	275	445	740

The effects of freeboard injection continued to improve with increased flow, up to wide open valve position (6600 lbs/hr flow).

O_2 distribution was most improved when injector increased from 0 to 3300 lb/hr flow. Cyclone inlet temperature distribution showed most improvement from 3300 to 6600 lb/hr flow. A flow of 5300 lbs/hr (650 psi pressure set point) was selected for continuous operation to allow operating margin.

6.0 MAJOR EQUIPMENT ISSUES AND MODIFICATIONS

6.1 Boiler

Additional Surface

During the Fall 1991 outage, approximately 25 percent more in-bed surface was added above the existing tube bundle to increase the heat absorption.

With the additional in-bed surface added during the Fall 1991 outage, on February 21, 1992, the full bed height was determined to be 140 inches. At this bed height, with a bed temperature of 1575 F, the total heat absorbed by the boiler (combustor terminal to combustor terminal) was 129.5 MWt, which is slightly higher than the full load heat balance value of 128.2 MWt. At this condition, the steam generation rate was 432,000 lbs/hr, which is approximately 8,000 lbs/hr below the full load heat balance value. This lower steam flow is attributable to less than design performance of the economizer, which is producing a lower final feedwater temperature with a corresponding much higher exit gas temperature. However, the gas temperature was too high for normal operation. Due to gas turbine material considerations, the unit must be operated at a bed temperature below 1580 F at 142 inches bed height limiting heat input to 93% of original design full load.

In-bed tube erosion has not been an issue. Only minor tube erosion, due to localized flow disturbances, has occurred in localized areas near the bottom of the bundle.

Post-Bed Combustion

There are essentially two types of post-bed combustion that have been experienced with this unit. They are "ash fires" and gas fires."

Ash Fires

This type of post-bed combustion is theorized to be caused by combustion of carryover carbon particles that become concentrated in the cyclone dip legs and burn when the gas temperature and carbon concentration are sufficiently high. These fires are indicated by extremely high cyclone dip leg temperatures relative to freeboard temperatures. A combustor trip will occur if the dip leg temperature exceeds 1670 F for 30 minutes and instantaneously at 1750 F. The unit experienced such a trip on 1/16/92. Because of sintering found in the cyclone dip legs, it is believed that the ash fires attain much higher temperature further down the dip leg.

It was originally believed that this type of fire only occurred at intermediate bed levels where ash concentration in the exit gas and freeboard temperature were high. This was proven false in the runs following the Fall 1991 outage where cyclone ash fires were present all the way up to the bed level of 121 inches.

It was felt that gas and ash mixing induced by freeboard steam injection might have an impact on reducing ash fires by more evenly distributing the carbon particles to the seven cyclone strings. As such, freeboard injection was placed in service at a 40 inch bed level during the run that started on 1/21/92. This system was set at its original operating pressure of 350 psig. As bed level was increased past 90 inches, an ash fire became evident. At a bed level of 105 inches, the freeboard injection steam pressure was increased to 450 psig. Shortly thereafter, the ash fires began to subside. In subsequent runs where freeboard injection was placed in service at a set pressure of 650 psig, no major cyclone dip leg ash fires have occurred. It is now believed that cyclone ash fires can be effectively controlled with the use of freeboard steam injection.

<u>Gas Fires</u>

This type of post-bed combustion is believed to be caused by incomplete in-bed combustion of volatiles released from the coal upon admission to the bed. If the coal water paste is split too finely, the volatiles are released very quickly in the area immediately surrounding the fuel injection nozzle. Because of limited side-to-side mixing of air in the bed, this localised release of volatiles can overwhelm the oxygen available in this area, allowing volatiles to rise in plumes through the bed and escape into the freeboard. These plumes subsequently ignite in the cyclones or in the freeboard, if the freeboard injection system is in service. The resulting combustion raises the gas temperature.

Prior to the Fall 1991 outage, gas fires typically were present in only one or two cyclone strings, which resulted in extremely high temperature throughout the affected cyclone strings. The original intent of the freeboard injection system was to more evenly distribute this post-bed heat release to all seven cyclone strings by inducing gas mixing in the freeboard. Thus, individual cyclone temperatures would be reduced.

In addition, new fuel nozzles were installed during the outage with the intent to produce larger and more consistent size paste particles to slow down the volatile release rate. Thus, the volatiles would be released over a much broader area of the bed as the paste particles moved side to side, and, therefore, would be exposed to more air.

The new fuel nozzles appear to be functioning as intended, since the total post-bed heat release due to gas fires is much lower than evidenced prior to the outage. In addition, the use of freeboard injection distributes this heat release to the entire gas stream. However, during most of the runs following the outage, post-bed combustion was still present in sufficient quantity to limit bed level and/or bed temperature due to high gas turbine inlet temperature.

Two factors affect the size of the paste particle in the bed: splitting air and paste moisture content. A reduction in splitting air and coal moisture both work to increase paste particle size. However, it is theorized that splitting of wet paste results in a less consistent particle size than with dry paste. With wet paste, a reduction in splitting air to minimize post-bed combustion can result in the generation of sinters due to the larger fraction of paste particles. Whereas, with dry paste, the more even particle size split permits control of post-bed combustion without sintering. Such a condition was achieved on 2/21/92 where a 142 inch bed level was attained at a bed temperature of 1575 F without any sinter formation.

In order to attain pumpable dry paste, the percentage of fines in the paste must be approximately 18-20%. To date, such good quality dry paste has not been achieved for extended periods. This must be addressed before full load operation can be sustained.

Start-Up Zone Liner

The upper row of ceramic tiles pulled away from the wall. This problem was attributed to a combination of incorrect hold-down stud material and excessive loading from the stainless steel angle that forms the transition to the stainless steel plate section of the liner. This problem did not hamper unit operation. A new top row design with a revised transition arrangement was installed to correct the problem.

6.2 Sorbent Injection System

At initial start-up, the sorbent injection system experienced numerous operating difficulties related to valve and rotary feeder malfunction and wear. Severe erosion of the sorbent transport piping was also a problem. Through various material changes and equipment replacement, the system is now reliable.

Beginning with the run that started on 1/25/92, sorbent based clinkers began forming in the tube bundle above the sorbent injection nozzles and adjacent coal injection nozzles.

A number of changes were made to the sorbent injection nozzles as attempts to eliminate these formations. These arrangement changes had some impact on the location of the formations; however, they were not successful at eliminating the deposits.

It has now been theorized that reduced sorbent transport velocity and consequently less distribution into the bed may be responsible for the formations. During the 2/29/92 to 3/5/92 run, sorbent transport velocity was increased after indication of a formation had been identified. Inspections after the run revealed that clinkers had indeed been formed; however, they had broken up. The present theory is that the increased transport velocity eliminated the cause of the clinker. Further operation is necessary to prove this theory.

6.3 Economiser

Fouling

The sootblowers installed in between the first and second banks and third and fourth banks were effective in keeping most of the economiser surface free of ash accumulation. However, the first four rows of the economiser became progressively more fouled with each successive run. These four rows experienced ash accumulation in the finned region off all tubes with some bridging occurring fore to aft. The last two rows of the second bank also experienced a less significant ash accumulation.

While this fouling contributed to the economiser's poor performance, the major concern was the possibility of side-to-side bridging and an attendant velocity and pressure drop increase. Vibration induced by the high velocity is believed to be the cause of four tube failures that occurred during mid-1991. In order to resolve this issue, eight sootblowers and anti-vibration bars have been added. No further tube failures have been experienced.

Performance

The economizer performance was below design resulting in higher exit gas temperature and lower final feed water temperature.

This off-design performance impacted steam flow by approximately 10,000 lbs/hr and reduced steam turbine generator output by approximately 1.3 MW at full load.

6.4 Cyclone Ash Removal System

Operation of the primary cyclone ash removal system has generally been acceptable, except for a two-month period in mid-1991 when pluggage of the primary ash removal system began to impact unit operation. At first, each pluggage could be traced to a process upset, usually in the sorbent injection system. It was believed that the process upset resulted in a temporary increase in ash loading to the cyclones which overwhelmed the transport capacity. However, the system was totally dismantled and inspected as part of the Fall 1991 outage, and the real cause was discovered. It was found that air in-leakage into the primary ash line flanged connections inside the combustor vessel significantly reduced the transport capacity of the system.

During early plant operation, from December 1990 to March 1991, pluggage of the secondary cyclone ash removal system resulted in unacceptable unit availability. Numerous modifications were made to reduce pressure drop in this system and thus increase transport capacity. Originally, the seven primary and seven secondary ash lines combined into one line which was routed to the cyclone ash silo. By March 1991, the primary and secondary cyclone ash removal systems were decoupled and the secondary cyclone ash line was routed to the precipitator inlet. In addition, several modifications were made to the ash lines inside of the combustor vessel to further improve transport capacity.

Starting in March 1991, secondary ash transport capacity during unit operation was sufficient to permit reliable operation of the secondary ash system. At shutdowns, however, ash buildup in the cyclone dip legs would not permit restart of the unit until the ash was removed from the dip leg.

During the Fall 1991 major outage, several major modifications were made to the cyclone ash removal system to address the problems with the system. These included the following:

- Cut off secondary cyclone dip legs.

- Elimination of flanges in secondary ash lines by welding up the flanges.

- Rerouting the secondary ash pipe external to the combustor vessel.

- Replace all gaskets in the primary ash lines internal to the combustor vessel.

- Inspect and rework primary ash line tee bends internal to the combustor.

- Machine ash pipe flange surfaces and overhaul entire internal primary ash coolers.

- Significantly reduce air inleakage into both transport systems.

- Sandblasted the interior of P13 and S23 cyclones to remove ash layer that was peeling off the cyclone walls.

- Installation of suction nozzle thermocouples.

After the Fall 1991 outage, pluggage of the secondary ash system again adversely impacted unit availability. In mid-January 1992, pluggage was found to be caused by excessive pressure drop in the secondary ash line outside of the combustor vessel. The pressure drop was reduced by redesign and replacement of the ash line and the system began to function properly. The secondary ash removal system is now considered marginally acceptable. Pluggages will occasionally occur at start-up, but experience has shown that they tend to clear themselves when combustor vessel pressure increases after firing coal. During the 31-day run, one secondary cyclone remained plugged; however, subsequent inspection revealed the pluggage was due to a restriction of the ash pick-up nozzle by a foreign object.

6.5 Coal Crusher

Status as of July 1992

Prior to the Fall 1991 outage, the crusher ran primarily in torque or speed control. In this method of operation, the crusher speed varies to match coal injection paste tank level.

The screw feeder than applies a force on the rolls and this force is controlled by the torque of the screw feeder.

During the initial operation period, this is the manner in which the crusher operated. In this mode, the crusher was never capable of producing consistent coal fines in the minus 325 mesh size. Good pumpability of the coal water paste (with low water content) requires 18 to 20% minus 325 mesh; however, the fines average 10% to 15% minus 325 mesh. The paste must have a low water content in order to produce consistent sized paste particles in the bed, which is in turn needed to avoid excessive post-bed combustion.

During the Fall 1991 outage, large drive motors were installed on the crusher, and a week long crusher optimization test was conducted to develop an operating mode for the crusher that would produce an optimum product. The result of this test program was the development of the gap control mode for the crusher control. In this mode, the inlet screw feeder runs unloaded, the vibratory feeder above the crusher controls the crusher feed rate and the crusher speed rate, and the crusher speed controls the roller gap.

At first, this new control mode was thought to a viable control scheme for the crusher. However, in subsequent operating run, it was found that variations in coal and moisture content had a significant effect on how the crusher operated.

During the run of 1/24/92, coal backed up into the T1 hopper over the crusher and would not pass between the rolls. Paste tank level could not be maintained. Bed level was dropped and the crusher control mode was switched back to torque control.

Minor adjustments to the crusher were attempted in an effort to optimize the fines in the coal. These variations included the following:

- Operation in torque control mode.
- Operation in gap control mode.
- Variations of hydraulic pressure (55 to 90 bar) on the rolls with various combinations of nitrogen pressure (30 to 80 bar), which is the spring constant on the hydraulic system.
- Operation with varying coal level in the T1 inlet hopper.
- Operation with no coal level in the T1 inlet hopper.
- Alternating the length of the coal flow along the rolls by putting plates in above the rolls and taking the plates back out.
- Addition of more grooves in the crusher rolls to improve friction. Originally, only one groove was installed in the fixed roll. Before the 2/29 run, eight more grooves were installed on the fixed roll and 1-1/2 grooves on the movable roll. Operation with these grooves showed no improvement in fines content of the product.
- On 3/7/92, a recirculation system was installed to recirculate up to 100 percent of the feed coal. In addition, the two deck screen was modified from a 1-1/2" x 1-1/2" top screen and 1/2" x 1/2" bottom screen to a three deck screen of 1-1/2" x 1-1/2" top, 1/2" x 1/2" middle, and 1/4" x 1/4" bottom. The 1/2" and 1/4" screen sizes were recirculated through the crusher.

These modifications have been effective in producing a higher amount of minus 325 mesh fines. The 31-day continuous run in June - July 1992 verified this mode of operation when the minus 325 mesh fraction ranged from 18 to 22 percent and the coal paste was consistently maintained at 24 to 25 percent moisture by weight.

Another problem experienced with the coal system was rapid corrosion of carbon steel surfaces in contact with paste. The nominally 3.5 percent sulfur Pittsburgh No. 8 coal being tested at Tidd, when mixed with water, produces a paste with a pH as low as 3. This resulted in significant corrosion damage to the coal paste mixer and coal paste pumps from November 1990 to September 1991. During the Fall 1991 outage, all carbon steel surfaces in the mixer and paste pumps were replaced with austenitic stainless steel. To date, these modifications have been successful.

The coal preparation system has also demonstrated a sensitivity to the type and moisture content of the coal being fed. The crusher has experienced pluggage and slipping of coal between the rollers when there has been a significant change in the surface moisture of the coal.

6.6 Gas Turbine

The gas turbine has experienced a measurable amount of erosion. Periodic inspections have shown that normal unit operation produces very little erosion; however, the erosion rate increases significantly when cyclone ash removal lines are plugged. The most serious erosion has occurred when the primary cyclone ash removal line plugs. In such an event, the corresponding secondary ash removal line is overwhelmed and quickly plugs.

Primary cyclones normally collect 98 percent of the ash in the gas stream and the secondary cyclones remove approximately 33 percent of the remainder. When an entire string plugs, the gas turbine dust loading increases more than tenfold. A more important factor, however, is the size of the particles reaching the gas turbine. Each cyclone stage collects progressively smaller particles, with the normal secondary cyclone exhaust dust containing virtually no particles larger than five microns. When an entire string is plugged, the gas turbine is exposed to particles as large as 250 microns. The erosion rate is much more sensitive to particle size than to dust loading. Generally, when only a secondary cyclone ash removal line plugs, the increase in erosion rate is minimal. However, during the 31-day run, the unit was operated with one secondary cyclone plugged and erosion was higher than anticipated.

An ongoing problem with the gas turbine has been bypassing of air from the high pressure compressor directly into the turbine. The present estimate of this leakage is approximately three times the design value for seal and cooling air flow. Given the limits on compressor volumetric flow, this leakage results in limiting the unit firing rate. Modifications to a suspected are of leakage during the Fall 1991 outage did not resolve the problem, and investigations are continuing to identify the cause of the leakage.

The LPT guide vanes had been experiencing problems with feedback causing the guide vanes to open. A redundant feedback loop for position indication was installed. A ground was added to the voltage regulator card. No feedback failures have occurred since that time.

The gas turbine tripped one hour after a combustor trip on 1/10/92 due to a bad HPT outlet temperature thermocouple. The other HPT outlet temperature thermocouple failed on 1/22/92, but the gas turbine trip from those thermocouples had been blocked prior to the failure. Both failures involved a burn through of the thermocouple wire. The thermocouples were replaced with ones that had a longer metal sheath to prevent burn through.

The gas turbine blow in doors opened three times in January, 1992, due to snow pluggage at the air intake filters. This can cause problems with fouling of the LPC blading with a resultant loss of air flow, and foreign object damage of the LPC blading, which would require replacement of the blading. A hood was installed over the air intake housing to prevent snow from blowing into the filters.

The unit tripped on 1/25/92 when a 1A and 1B transformer differential trip operated causing a steam turbine trip from the unit HEAs. At the same time as the transformer differential trip, the south boiler feed pump was started. The resultant sag in reserve bus voltage caused the gas turbine control fluid pump to trip. The standby control fluid pump started; however, the sag in control fluid pressure during the sag in reserve bus voltage caused air bypass valve HCV-T120 to drift off the open limit switch, which caused a gas turbine and combustor trip. A modification to the control fluid piping was implemented to ensure that the standby pump was primed with pressurized oil.

Several blades in the first five rows of the HPC experienced foreign object damage. Damage of gas turbine compressor blades can cause high cycle fatigue cracks due to vibration from stall at the disruption of flow over the blade surface.

The HPT had three eroded inlet guide vanes at the six o'clock position and erosion of the second, third, and fourth stage rotating blade tips. This erosion is not an operational liability. It has a slight effect on the efficiency of the turbine.

In mid-March, 1992, fatigue cracks were discovered in the blade roots of nine of the 45 low-pressure gas turbine blades. The cracks were due to resonant vibration at certain operating speeds of the variable-speed shaft. This problem was generic to the design of the GT-35P gas turbine, and not due to the PFBC process. The turbine blades were replaced during the ensuing nine-week outage.

7.0 CONCLUSION

Throughout the first 15 months of operation of the Tidd PFBC Demonstration Plant, the Tidd PFBC Demonstration Plant has completed over 2,000 hours of coal-fired operation and has met its environmental performance objectives. With the 100-hour run at full load and the 31-day continuous run, the unit has met its reliability objectives. Also, with the exception of the deficiency in gas turbine power output, the PFBC power island equipment has met all performance guarantees.

The system experience to date has provided important input into the design of future PFBC plants. The gas turbine has demonstrated its ability to operate on the by-products of coal combustion without significant erosion or corrosion. The tube bundle has demonstrated its ability to operate in a bubbling fluidized bed without tube wastage.

The main operating problems experienced during the initial operating period are mainly associated with the coal preparation and cyclone ash removal systems. Our experience with these systems emphasizes the importance of proper coal preparation to achieve reliable coal injection and proper coal combustion within the bed. Of similar importance is performance of the cyclone ash removal system to ensure that the exhaust gas is sufficiently clean for gas turbine survivability.

8.0 REFERENCES

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First Quarter, 1991, April 1991
Second Quarter, 1991, July 1991
Third Quarter, 1991, October, 1991
Fourth Quarter, 1991, January, 1992
First Quarter, 1992, April, 1992
Second Quarter, 1992, July, 1992

APPENDIX I

OPERATIONS NARRATIVE OF RUNS

APPENDIX I - OPERATIONS NARRATIVE OF RUNS

The following is an operations narrative for each of the runs during the first eighteen months of operation.

<u>Start-Up TD-SU-91-01-01</u>

The unit was started up on January 7, 1991. The gas turbine was rolled and paralleled on January 7, 1991 at 2356 hours. The bed preheater was placed in service on January 8, 1991 at 1034 hours. The steam turbine was rolled and paralleled at 1311 hours on this date. Soon after the bed preheater was fired, it was noticed that the temperatures on P16 and P11 primary ash cyclones were running considerably lower than the rest of the cyclones. Initially, it was suspected that this was due to pluggage in these two cyclones. Based on this, a decision was made to remove the unit from service to inspect this system. Inspections indicated that the problem with P16 and P11 primary ash cyclones was caused by in-leakage of air from the pressure vessel to the cyclones at the first flange downstream of the bellows box.

<u>Start-Up TD-SU-91-02-01</u>

The unit was started up on January 10, 1991. During start-up, it was noticed that the S26 secondary cyclone temperature was significantly lower than the other cyclones. It was suspected that this was due to pluggage in this cyclone. As start-up continued, bed level was increased to approximately 40 inches, and sorbent injection was initiated. During this period, the temperature on P16 primary cyclone increased to the point that it was suspected that there was a fire in this cyclone. Air flow was increased by 100 kpph in an attempt to reduce overall cyclone temperatures. During this activity, a gas turbine trip was generated by the failure of the air flow controller.

The unit was secured in a normal manner and prepared for restarting.

<u>Start-Up TD-SU-91-02-02</u>

The unit was restarted on January 13, 1991. The gas turbine was placed in service on January 13, 1991 at 0844 hours, followed by the bed preheater at 1624 hours. The combustor was tripped at 1737 hours due to an extreme high alarm on S26 cyclone air cooling temperature. The bed preheater was returned to service at 1750 hours, followed by the steam turbine at 2026 hours. Coal injection was initiated at 2141. Bed level was increased in steps to approximately 60 inches, and sorbent injection was initiated. During this period, it became evident that several of the secondary cyclones were becoming plugged. A steam turbine trip was generated at 0451 hours on January 14, 1991, due to the failure of the steam turbine stop valve to open during transfer from full arc to partial arc admission. A combustor trip was generated at 0504 hours on January 14, 1991, when the belt drive on the splitting air compressor failed, resulting in a low nitrogen buffer tank pressure trip.

The unit was secured in a normal manner and released to the Maintenance Department for outage work.

Start-Up TD-SU-91-03-01

The unit was started up on January 19, 1991. The gas turbine was rolled and paralleled at 1926 hours on January 20, 1991. The bed preheater was placed in service at 0834 hours on January 21, 1991, but tripped at 1022 to check thermocouples. The bed preheater was returned to service at 1036 hours and then tripped again at 1121 hours due to loss of flame. The bed preheater was returned to service at 1333 hours, with flames being monitored locally by Operations. The steam turbine was rolled and paralleled at 1537 hours. Coal injection was initiated at 1718 hours. Bed level was increased to 47 inches, at which point a leak was discovered in the north sorbent injection line at a flanged connection. Bed level was reduced to 30 inches and the sorbent injection system removed from service to repair the leak. During this period, it became evident that secondary cyclone S21 had become plugged. Air flow was increased slowly to 650 kpph in an effort to remove the obstruction. This did not prove to be successful, and a decision was made to remove the unit from service to inspect this cyclone.

The gas turbine was tripped at 0345 hours on January 22, 1991, and preparations made to turn the unit over to Maintenance for outage activities.

Start-Up TD-SU-91-04-01

The unit was started up on January 27, 1991. The gas turbine was placed in service at 1658 hours on January 27, 1991. While holding at 2500 RPM, a frequency converter trip was suffered. No reason for this trip was immediately evident, and the gas turbine was rolled back off at 1739 and paralleled at 1744. No further problems were encountered.

The bed preheater was placed in service at 0821 on January 29, 1991. The steam turbine was rolled and paralleled at 1131, coal injection was established at 1236, and sorbent injection was initiated at 1418. Over the next several hours, bed level was increased to 57 inches and the following activities were performed:

1. Cyclone monitoring for indications of pluggage and/or fires.
2. Biasing of individual paste pump flows to balance bed temperature distribution.
3. Verifying operation of mechanical components and logics in System 268, sorbent injection system.

At 2143, the boiler circulation pump stopped automatically. This resulted in a vertical separator level upset. When the vertical separator level increased to over 9 feet, a steam turbine trip was generated. As a result of this trip, a combustor trip was generated at 2146 due to high secondary superheater outlet temperature. The combustor and steam turbine were secured following the trips and preparations made to hot restart the unit.

The bed reheater was placed in service at 2254 on January 28, 1991, and coal injection initiated at 0158 on January 29, 1991. The steam turbine was rolled and paralleled at 0330 hours. Over the next several hours, bed level was increased to 65 inches, while the following activities were performed.

1. At approximately 0730 hours, indications of pluggage in secondary cyclones S21 and S27 were noted.
2. Biasing of paste pumps continued during the period to attempt to balance bed temperature distribution.
3. Sorbent injection system testing continued.

At 1149 hours, the cyclone ash sample connection flange was discovered to be leaking significant quantities of ash and gas. As a result of this and increasing suspicion of pluggage in S21 and S27 secondary cyclones, a decision was made to remove the unit from service.

The combustor was tripped via the panel push button at 1149 hours. The gas turbine was tripped via the panel push button at 1727 hours. The unit was secured in a normal manner and plans made to turn the unit over to Maintenance for outage work.

Start-Up TD-SU-91-05-01

The unit was started up on February 3, 1991. The gas turbine was rolled and paralleled at 0708 hours on February 4, 1991. The bed preheater was placed in service at 1755 hours this date. The steam turbine was rolled and paralleled at 2348 hours, and coal fire was established at 0034 hours on February 5, 1991. Over the next several hours, bed level was gradually increased to 55 inches. Sorbent injection was established at 0255 hours via the east injection line. During this time period, the #1 and #6 paste pumps were biased to balance the bed temperature distribution. The results of this biasing was very favorable, with the higher bed temperature being approximately 1575°F.

At 0658 hours, sorbent injection flow was lost due to the premature opening of the east vessel vent valves. This line had been tripped earlier and due to the failure of the east sorbent injection vessel discharge valve HCV-B815 to receive a close command, the shutdown sequence had been interrupted. The operator at this time determined that this was a feeder trip instead of a system trip and had, therefore, restarted the feeder in manual. Sorbent injection flow was then continued due to leakage of material through the open HCV-B815 valve to the now manually running feeder. At 0658 hours, while attempting to place the west sorbent injection line in service, a manual trip of the west line was initiated in an effort to realign the logics to start the injection sequence. This manual trip, in conjunction with standing trip on the east line, initiated a command to reduce transport air flow to its purge flow rate. As purge flow is not adequate to inject material, the injection piping was quickly plugged by the material being fed from the east vessel, and transport air flow decreased to 0. At this time, a bed level decrease was initiated due to the loss of sorbent. Due to the sudden loss of transport air flow, the operator then placed the flow control valve (FCV-P230) in manual and increased its output to 100%. This resulted in the material that had plugged the line being swept into the boiler. At this time, it became evident that secondary cyclone S21 was beginning to plug. Several attempts were made over the next hour to reestablish sorbent flow with no success. During this time, a suspected reverse flow of gas was occurring through the north injection nozzle. When the temperature on the north line increased to 656°F, a decision was made to abort the attempts to reestablish sorbent flow and remove the unit from service.

The combustor was tripped at 0900 hours via the MCS. The bed was cooled with the gas turbine, and the gas turbine was tripped at 1403 via the MCS. The unit was secured in a normal manner and preparations made to release the unit to Maintenance for outage work.

Start-Up TD-SU-91-06-01

The unit was started up on Friday, February 8, 1991. The gas turbine was rolled and paralleled at 0355 hours on February 9, 1991. The bed preheater was placed in service at 1232 hours on this date. The steam turbine was rolled and paralleled at 2045 hours on this date. At 2122 hours, a coal fire was established. At 2300 hours, the sorbent injection system was placed in service and sorbent flow was established via the west injection train.

At approximately 2330 hours, the trended indication on the plant monitoring computer for secondary cyclone S26 dip leg temperature rate of change suddenly increased. At this time, the dip leg temperature was observed to be increasing. This temperature increased approximately 20°F over 5 minutes and then began decreasing at a rate of approximately 11°/min. This temperature continued to decrease over the next hour and it was decided that this cyclone was plugged.

At this time, a decision was made to remove the unit from service due to pluggage in secondary cyclone S26. The combustor was tripped from the panel push button at 0059 hours on February 10, 1991. The combustor was cooled via the gas turbine until 0304 hours this date, at which time the gas turbine was tripped via the panel push button. The unit was secured in a normal manner and preparations were made to release the unit to Maintenance for outage activities.

Start-Up TD-SU-91-07-01

The unit was started up on February 18, 1991. The gas turbine was rolled and paralleled at 2116 hours on February 18, 1991. The bed preheater was placed in service at 0811 hours on February 19, 1991. At 0856, a gas turbine trip was suffered due to an excessive vertical separator level swing. This was caused by the sudden opening of the vertical separator pressure control valve PCV-B200. It was found that this valve was locked in the closed position due to the valve operator handwheel being run down to the closed position. The valve was placed in manual control from the MCS, and the handwheel then run to the open position. At this time, the valve pulsed to auto and immediately went to the full open position due to vertical separator pressure being greater than set point. The sudden opening of this valve caused the vertical separator level to go high. When the vertical separator level increased to a level over 9 feet, the feed water flow control valve was ordered closed. This caused a gas turbine trip due to low total boiler circulation flow. As the vertical separator level increased, PCV-B200 was ordered closed automatically to prevent carryover to the superheaters. This action forced the vertical separator level low.

The unit was secured in a normal manner and preparations made for a hot restart.

Start-Up TD-SU-91-07-02

The unit was restarted on February 19, 1991. The gas turbine was rolled and paralleled at 1219 hours. The bed preheater was placed in service 1416 hours. At 1630 hours, the steam turbine was rolled and paralleled. A one hour sparge duct relaxation procedure was performed and completed at 1838 hours. Bed material was then added and bed level increased to 28 inches. Fuel injection was initiated at 0023 hours on February 20, 1991. Bed level was then increased to 40 inches and sorbent injection was established at 0220 hours.

Over the next several hours, bed level was increased to 55 inches. During this period of time, problems developed in the fuel preparation system. At 0420 hours, the #1 paste tank agitator tripped. This was found to be due to very dry material in the paste tanks. Over the course of the evening, several trips of the coal crusher had occurred and during this period it was suspected that the block valve in the water supply to the mixer was ordered closed and not reopened. This led to the delivery of dry coal to the paste tanks. Further investigation revealed that the #1 agitator motor had failed. At 0558 hours, the #5 and #6 paste pumps tripped due to high injection line differential pressure.

At 0601 hours, the combustor was tripped via the panel push button and the unit was secured in a normal manner. A decision was made to not remove the gas turbine from service in anticipation of a quick repair to the failed agitator motor. This motor was repaired at a local shop and returned to the site at approximately 1800 hours.

At 2224 hours on February 20, 1991, the bed preheater was placed in service. During the course of the evening, the status of secondary cyclone S24 was closely monitored. The air cooling temperature has consistently indicated a problem with flow through this dip leg.

Bed level was increased to 28 inches and at 0309 hours on February 21, 1991, fuel injection was placed in service. Bed level was then increased to 40 inches, and sorbent injection was established at 0550 hours via the west injection line. Over the next several hours, bed level was increased to 65 inches and preparations made to transfer to once-through operation. During this period, it became increasingly evident that secondary cyclone S24 was plugging.

At 1449 hours, the boiler circulation pump was removed from service and once-through operation achieved. During the next hour, the main steam attemperator was placed in service and unit gross load stabilized at approximately 33 MW.

At 1600 hours, the combustor was tripped due to excessive vertical separator pressure swings. The unit was cooled down and the gas turbine was tripped at 2015 hours. This unit was secured in a normal manner and preparations made to release the unit to Maintenance for outage activities.

Start-Up TD-SU-91-08-01

The unit was started up on February 26, 1991. During this run, new procedures were to be implemented to improve warming of the secondary ash dip legs, internal secondary ash coolers and associated piping.

Following the revised warming procedures, the gas turbine was rolled and paralleled at 1725 hours on February 27, 1991. The bed preheater was placed in service at 2252 hours and bed level was increased to 28 inches for steam turbine roll and fuel injection.

The steam turbine was rolled and paralleled at 0138 hours on February 28, 1991. Fuel injection was initiated at 0318 hours. At 0322, the #3 paste pump was removed from service due to a plugged injection nozzle. After attempting to clear the plugged line for approximately 1 hour, a decision was made to trip the combustor. The combustor was tripped via the manual push button at 0415 hours and the unit secured in a normal manner.

The gas turbine was tripped from the MCS at 0733 hours to permit Maintenance to clear the obstruction from the #3 fuel line.

Start-Up TD-SU-91-09-01

The unit was started up on February 28, 1991. The gas turbine was rolled and paralleled at 1208 hours on February 28, 1991. The bed preheater was placed in service at 1428 hours. At 1637 hours, the steam turbine was rolled and paralleled. At 1740 hours, sorbent injection was initiated via the west line. At 1742 hours, fuel injection was initiated.

Over the next several hours, bed level was increased to approximately 73 inches and preparations made to transfer to once-through operation. During this period of time, evidence of plugging of secondary cyclones S25 and S27 was seen.

At 73 inches, bed level preparations were made to transfer to once-through operation. As this was done, a sudden increase in vertical separator level was experienced. Due to this, PCV-B200 was ordered to its minimum opening. The resulting upset to vertical separator level pressure and feed water flow caused the boiler circulation pump to auto stop.

At this time, the primary and secondary superheater tube temperatures were observed to be rapidly increasing. At 2221 hours, a combustor trip was generated due to high secondary superheater temperature. The unit was then secured and cooled in a normal manner.

At 0127 hours on March 1, 1991, a gas turbine trip was initiated via the MCS and preparations made to turn the unit over to Maintenance for outage activities.

Start-Up TD-SU-91-10-01

The unit was started up on March 7, 1991. At approximately 0430 hours on March 8, 1991, the high level alarm on the combustor belly drain was received. Over the next 4 hours, several gallons of water were removed via the drain from the combustor bottom. At 0800 hours, a decision was made to suspend warming procedures and to hydro the boiler for leaks. When Systems 741 (boiler ventilation system) and 758 (process air system) were removed from service, the amount of moisture at the belly drain significantly decreased. The results of the hydro showed no leakage from the boiler. At 1033 hours, warming procedures were restarted.

The gas turbine was rolled and paralleled at 1705 hours. At 1803 hours, water was observed coming from the secondary ash piping at the economizer. At this time, a decision was made to trip the gas turbine. The unit was then secured in a normal manner and preparations made to turn the unit over to Maintenance for outage activities.

Start-Up TD-SU-91-11-01

The unit was started up on March 10, 1991. The dip leg warming procedure was initiated at 2206 hours on March 10, 1991. For this start-up, warming flow through the secondary ash system was established by pulling air through the system by attaching a portable vacuum source at the secondary ash outlet pipe outside the combustor penetration. Gas recirculation via Systems 741 (boiler ventilation system) and 758 (process air system) was initiated at 2215 hours. At 0900 hours on

March 11, 1991, the bed preheater bypass valve, HCV-P100, was manually closed to increase boiler wall differential and, thereby, increase warming flow through the dip legs. During this time, the test thermocouples on S21 and S24 ash line and purge air lines were showing conflicting indications as to the effectiveness of the warming procedures. At 1530 hours, the vacuum source at the secondary ash outlet was removed and a reverse flow of heated dry air from the external ash cooler was initiated. The results of this indicated that all secondary ash lines were open and warming.

At 1658 hours, the start-up fans were placed in the start-up pressurization mode and the gas turbine rolled to 2500 RPM. This mode of operation was continued for approximately 45 minutes to force warm air through the dip legs. At 1742 hours, the gas turbine generator was paralleled and air flow established through the combustor. At 2348, the bed preheater was placed in service and immediately tripped due to high burner temperatures. At this time, it became apparent that the boiler wall differential was significantly lower than expected for this mode of operation.

At 0000 hours on March 12, 1992, a combustor trip was initiated from the panel in order to reopen HCV-P100 to check the change in boiler wall differential. At this time, a decision was made to remove the unit from service for inspection of combustor internals to determine the reasons for the low boiler wall differential.

The gas turbine was tripped at 0212 hours, and the unit secured in a normal manner. Preparations were then made to turn the unit over to Maintenance for outage activities.

<u>Start-Up TD-SU-91-12-01</u>

The unit was started up on March 12, 1991. At 1726 hours on March 12, 1992, gas circulation flow was established to prewarm the combustor internals. At 1734 hours, secondary dip leg warming was established.

The gas turbine was rolled and paralleled at 2333 hours. Bed level was then increased to 28 inches. At 0804 hours on March 13, 1991, an oil fire was established. The steam turbine was rolled at 1018 hours. A steam turbine trip was generated at 1120 hours when the generator field automatic circuit breaker was closed. Investigation revealed no problems with this automatic circuit breaker and the turbine was then rolled and paralleled at 1240 hours.

Sorbent injection was initiated at 1245 hours via the west line. At 1251 hours, fuel injection was initiated.

At 1328 hours, a gas turbine trip was experienced due to a surge of the high pressure compressor. Investigation revealed that a gas turbine control card had failed.

The unit was secured in a normal manner and preparations made to restart the unit.

Start-Up TD-SU-91-12-02

The unit was started up on March 13, 1991. The gas turbine was rolled and paralleled at 2146 hours on March 13, 1991. The bed preheater was placed in service at 0144 hours on March 14, 1991. The steam turbine was rolled and paralleled at 0429 hours. At 0447 hours, sorbent injection was initiated via the west line. Fuel injection was initiated at 0453 hours.

Over the next several hours, bed level was increased to an indicated 70 inches and conditions allowed to stabilize. At 1042 hours, the main steam temperature control was placed in automatic. At 1043 hours, the boiler circulation pump was removed from service and once-through operation established. At 1152 hours, sorbent feed rate was increased due to a suspected fire in primary cyclone P11 and P17. The result of this was an increase in cyclone temperatures. At this point, sorbent flow was then decreased and air flow increased. This resulted in a decrease in cyclone temperatures. At 1532 hours, the steam turbine voltage regulator was placed in automatic. At 1550 hours, the vertical separator level control valve was placed in automatic and set to control the vertical separator level at less than 7 feet. At 1554 hours, the #1 paste pump was biased to 0.7. This action appeared to also help the fire in P17 cyclone.

The unit was held at a stable load for approximately 12 hours. Beginning at 2209 hours, problems with the west sorbent rotary feeder were experienced. Over the next three hours, this feeder tripped a total of four times. Investigation revealed that the feeder was mechanically binding. The feeder was operated several times in the forward and reverse directions locally, and Maintenance loosened the packing at the shaft penetrations. These actions resolved the problem. The west injection line was returned to service at 0241 hours on March 14, 1991, and no further problems were experienced.

At 0538 hours, the deaerator steam supply was transferred from pegging Station "C" to Station "A" (auxiliary steam to sixth stage extraction).

Over the next several hours, bed level was increased to an indicated level of 95 inches. At 1133 hours, the steam turbine generator was placed in automatic. At 1331 hours, the rupture diaphragm at the V-102 orifice failed. Prior to this failure, an ash leak had developed on the rotary feeder and this feeder had been removed from service for maintenance. An immediate load decrease was initiated. At 1345 hours, the boiler circulation pump auto started. At 1402 hours, auxiliary power was transferred from normal to reserve. At 1407 hours, a combustor trip occurred due to high bed temperature.

At 1431 hours, the gas turbine was tripped by operator action. The unit was secured in a normal manner and preparation made to release the unit to Maintenance for outage activities.

Start-Up TD-SU-91-13-01

The unit was stared on April 1, 1991. The gas turbine was rolled and paralleled at 1355 hours. At 2140 hours, the bed preheater was placed in service. At 0006 hours on April 2, 1991, the steam turbine was rolled and paralleled.

At 0719 hours, fuel injection was initiated. The #1 and #6 paste pumps started, the other pumps were blocked from starting due to the low splitting air flow not being tuned out when the revised splitting air flow control scheme was implemented. As a result of this, the function group was ordered off. This resulted in an increased demand for splitting air flow to prevent a backflow of material into the nozzles. At this time, the splitting air compressor was in "MANUAL UNLOAD" and was, therefore, unable to supply this demand. This resulted in a combustor trip at 0721 hours.

The unit was secured in a normal manner and at 0758 hours, the bed preheater was returned to service. At 0922 hours, the steam turbine was rolled and paralleled. At 1014 hours, sorbent injection flow was established via the east line. At 1028 hours, fuel injection was established.

At 1618 hours, the unit was transferred to once-through operation. Over the next several hours, bed level was increased to 91 inches. At 0313 hours on April 3, 1991, a combustor trip was experienced due to all three vertical separator level instruments showing out of range. This was due to a low vertical separator level caused by level swings during once-through operation.

The unit was secured in a normal manner and preparations were made to restart the unit. At 0434 hours, the bed preheater was placed in service. At 0706 hours, sorbent injection was initiated via the east line. At 0716 hours, fuel injection was initiated. On starting, all six fuel lines indicated a high line differential pressure and the function group was ordered off. At 1010 hours, the steam turbine was rolled and paralleled. Fuel injection was attempted several times with high line differential pressure resulting. At this time, water was added to the paste tank. This resulted in the fuel line differential pressure decreasing to normal.

At 1731 hours, the unit was transferred to once-through operation. Over the next several hours, bed level was increased to 97 inches. At 2130 hours, it became apparent that secondary cyclone S23 had plugged. At 2344 hours, the vertical separator bypass valve was opened. This resulted in an upset to boiler pressure and at 2350 hours, this valve was reclosed.

At 0115 hours, a slow increase in bed level was initiated to determine the upper operating limit. As bed level increased, the gas temperature to the HPT approached the maximum limit. At this time, bed temperature set point was gradually decreased to 1515°F. At approximately 0115 hours, secondary cyclone S23 dip leg and ash cooler temperatures began to increase. Over the next hour, it appeared that this cyclone had cleared itself of the pluggage.

At 0258 hours, bed level had reached a level of 106 inches. At this time, a bed level decrease was initiated to stabilize conditions. At 0259, a gas turbine trip was experienced due to high temperature (1058°F) at the LPT inlet.

The unit was secured in a normal manner and preparations were made to release the unit to maintenance for outage activities.

Start-Up TD-SU-91-14-01

The gas turbine was rolled and paralleled at 0017 hours on April 19, 1991. Air preheating requirements were met and the bed preheater placed in service at 0759 hours. At 0800 hours, a gas turbine trip was experienced due to high fictive disc temperatures.

The unit was secured in a normal manner and preparations were made to restart the unit.

Start-Up TD-SU-91-14-02

The unit was restarted on April 19, 1991. The gas turbine was rolled and paralleled at 1132 hours. At 1211 hours, a gas turbine trip was initiated by the operator. This was due to a leak at the System 271 ash sampler connection.

The unit was secured and preparations made for maintenance to repair the leak.

Start-Up TD-SU-91-15-01

The unit was restarted on April 19, 1991. The gas turbine was rolled and paralleled at 1527 hours. At 1558 hours, a gas turbine trip was initiated by the operator. This was due again to a leak at the System 271 ash sampler connection.

The unit was secured and preparations were made for maintenance to repair the leak.

Start-Up TD-SU-91-16-01

The unit was restarted on April 19, 1991. The gas turbine was rolled and paralleled at 1920 hours. The bed preheater was placed in service at 2250 hours.

At 0309 hours on April 20, 1991, the steam turbine was rolled and paralleled. At 0355 hours, sorbent injection was initiated via the east line. At 0405 hours, fuel injection was initiated.

Over the next several hours, bed level was increased to 65 inches and preparations were made to transfer to once-through operation. At 1247 hours, the boiler circulation pump was removed from service and once-through operation established.

Bed level was raised to 90 inches by a combination of bed reinjection and sorbent injection. During this time period, the following activities were performed:

1. Splitting air flow was reduced to .3 of the original curve.
2. Economizer test sootblower was operated two times and data taken.
3. Maintenance repaired a leak on the expansion joint on the bottom of the west sorbent injection vessel.
4. Biased paste pump flows to obtain optimum bed temperature distribution.

At 2300 hours, the bed ash removal system was placed in manual and bed level allowed to begin increasing from sorbent injection. At 0030 hours on April 21, 1991, the bed level increase was stopped at 105 inches and operating data was taken.

At 0137 hours, bed level was decreased to 100 inches due to secondary cyclones #22 and #23 dip leg temperatures increasing above freeboard temperature. During this period, the moisture content of the fuel was reduced from approximately 29 percent to approximately 26 percent. This action lowered the cyclone temperatures.

At 0228 hours, the bed level was allowed to begin increasing from sorbent injection. At 0350 hours, splitting air flow was further reduced from .3 to .25 of the original curve. At approximately 0700 hours, a bed level of 126 inches was achieved. Over the next one and one half hours, bed temperature set point was gradually increased from 1525° to 1560°F. At 1560°F, the gas turbine inlet temperature was observed to be approaching its limit. Due to this, the bed temperature set point was gradually reduced to 1527°F.

Bed level was then slowly reduced to 80 inches. As bed level was reduced, the boiler and bed temperature distribution deteriorated and bed level indication became erratic.

At 2050 hours, the boiler circulation pump was placed in service. At 2103 hours, a bed level decrease to 65 inches was initiated. At 2128 hours, the combustor tripped on low bed temperatures in zone one due to partial defluidization of the bed (outage inspections revealed "egg" sinter formation in the bed). The steam turbine was tripped at 2129 hours.

At 0105 hours on April 22, 1991, the gas turbine was tripped via the panel bush button. The unit was secured in a normal manner and preparations made to release the unit to maintenance for outage activities.

Start-Up TD-SU-91-17-01

The unit was started up on April 25, 1991. While setting up equipment for the start-up, an unusual hissing noise was heard while racking in VCB 1C2 (one of the gas turbine generator breakers). Initial investigations led us to believe that the phase #3 vacuum interrupter had failed. A Siemens representative was summoned to the site. The breaker was disassembled and all three vacuum bottles were tested, reassembled and high potted. These tests revealed no problems. Final resolution was that as the VCB was racked in, the capacitance of the VCB caused a hissing noise as the breaker stabs came into contact with the bus.

Start-up activities continued on April 29, 1991. Over the next two days, a total of four gas turbine trips were experienced due to high horizontal vibration on #1 bearing. These trips occurred as the turbine was released to ramp from 2500 RPM to rated speed. An investigation was made but revealed no physical problems, as the indicated high vibration could not be substantiated with test vibration equipment. The turbine was successfully rolled to rated speed and paralleled at 0919 hours on May 1, 1991.

At 1800 hours, the bed preheater was placed in service. The steam turbine was rolled and paralleled at 2012 hours. At 2131 hours, sorbent injection was established via the west line. Fuel injection was initiated at 2137 hours. Bed level was then increased to 45 inches.

At 0316 hours on May 2, 1991, bed level was increased to 65 inches and the unit transferred to once-through operation. At 0512 hours, bed level was increased to 75 inches and conditions stabilized. This condition was maintained for approximately eight hours while the steam turbine was warmed to meet overspeed requirements.

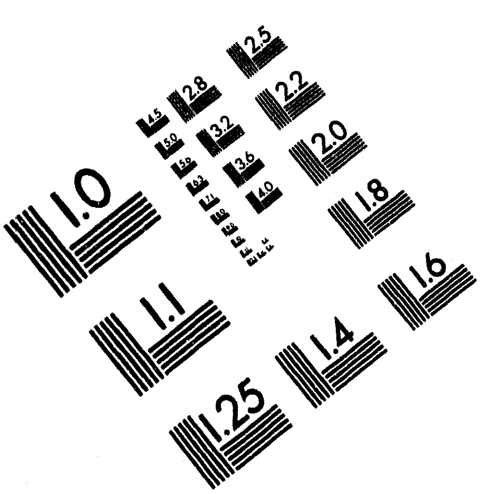
At 1102 hours, a bed level decrease was initiated in preparation for steam turbine overspeed tests. At 1309 hours, the steam turbine generator was removed from parallel. Over the next two hours, the following tests were completed.

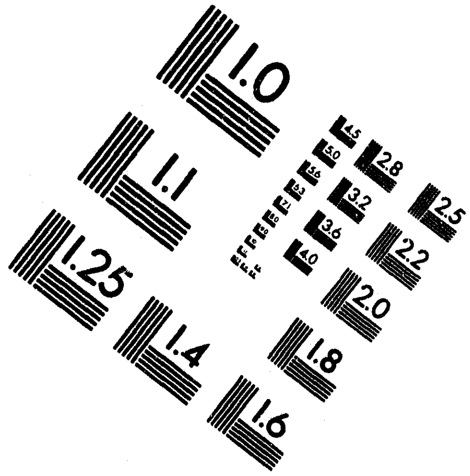
1. Steam turbine governor high and low speed stops checked.
2. Steam turbine overspeeds checked:
   - Test #1 1911 RPM
   - Test #2 1908 RPM
   - Test #3 1907 RPM

At 1556 hours, the steam turbine was paralleled with the system and start-up activities continued. Over the next eight hours, bed level was increased to 123 inches in preparation for a loss of feedwater (boiler injection) test.

At 0004 hours on May 3, 1991, the feedwater flow control valve (FCV-F100) was placed in manual and closed to initiate a loss of feedwater. At this time, the following trips were experienced as listed.

1. Combustor trip.
2. Steam turbine trip.
3. Gas turbine trip.





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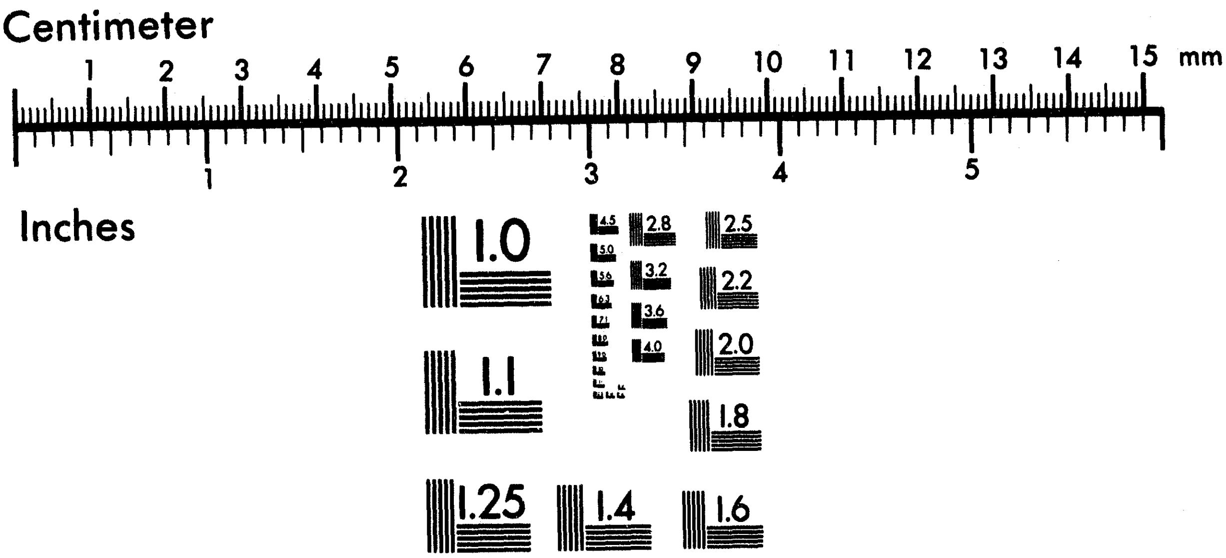

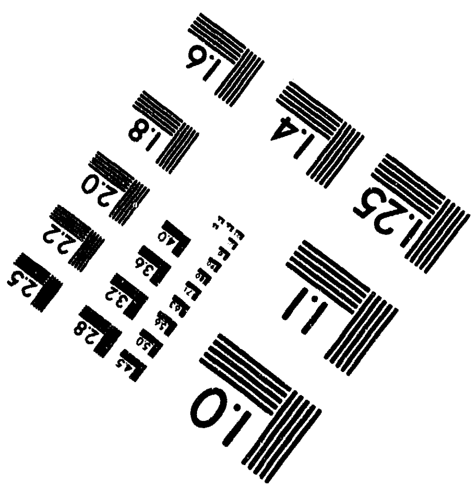

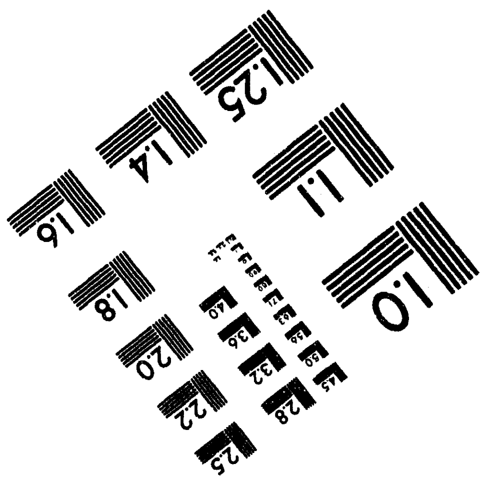

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Start-Up TD-SU-91-19-01

The unit was started up on May 17, 1991, for the purpose of testing the boiler injection system.

The gas turbine was rolled at 2325 hours and at 2333 hours, tripped due to high vibration on the LPC #1 bearing rear horizontal pickup. The gas turbine was rolled and paralleled on May 18, 1991 at 0022 hours.

An oil fire was established at 0208 hours. The steam turbine was rolled and paralleled at 0520 hours. At 0545 hours, sorbent injection was initiated via the east line. At 0553 hours, fuel injection was initiated.

Over the next three hours, bed level was increased to 70 inches. Once-through operation was achieved at 0856 hours.

Bed level was allowed to increase via fuel and sorbent injection. At 1345 hours, the vertical separator bypass valve (HCV-B205A) was opened. At 1348 hours, this valve tripped closed due to bad steam quality indication. This was determined to be false and the valve was reopened at 1353 hours.

During the period of time that bed level was increasing, numerous trips of the fuel preparation system were experienced. This led to a decrease in paste tank level to one inch.

At 1634 hours, the boiler injection test was initiated by manually closing the feedwater flow control valve (FCV-F100). This action initiated a gas turbine trip with satisfactory operation of all boiler protection schemes.

At 1850 hours, the feedwater flow control valve was returned to service and feedwater flow established. The unit was secured in a normal manner and preparations made to restart the gas turbine to remove the bed material to the bed ash reinjection vessels.

Start-Up TD-SU-91-19-02

The unit was started up on May 19, 1991. Combustor warming was initiated at 1112 hours.

The gas turbine was rolled and paralleled at 0134 hours on May 20, 1991. An oil fire was established at 0715 hours. The steam turbine was rolled and paralleled at 1046 hours. Sorbent injection was initiated at 1145 hours. Fuel injection was initiated at 1152 hours. The #1 and #6 paste pumps showed over hydraulic pressure (plugged lines) and the function group was placed in the off position immediately.

While investigating the problems with #1 and #6 fuel lines, low splitting air flow was indicated on both lines which initiated a combustor trip.

Investigation revealed that the #1 and #6 fuel lines were plugged. The combustor was cooled via the gas turbine. At 1318 hours, the gas turbine was tripped and preparations were made to release the unit to maintenance for cleaning the obstructed fuel lines.

<u>Start-Up TD-SU-91-20-01</u>

The unit was started up on May 20, 1991. The gas turbine was rolled and paralleled at 2025 hours. At 2331 hours, an oil fire was established.

At 0247 hours on May 21, 1991, the steam turbine was rolled and paralleled. Sorbent injection was initiated at 0324 hours. Fuel injection was initiated at 0326 hours. At 0327 hours, fuel injection was stopped due to a plugged line on #5 paste pump. At 0350 hours, sorbent injection stopped. At 0359, sorbent injection was returned to service. After reversing all six paste pumps and clean blowing all six paste lines, fuel injection was initiated at 0406 hours with no further problems.

Bed level was then increased to 70 inches and at [illegible] hours, once-through operation was achieved.

At this time, bed level was further increased to 90 inches and held for the next 40 hours. During this time period, the following activities were performed.

1. Systems tuning.
2. Check for effects of turbulence on lower vertical separator level taps.
3. Increasing bed temperature.
4. Testing the bed reinjection system bed level control.
5. Opening and closing vertical separator bypass valve to determine effects on boiler operation.
6. Varying splitting air flow to determine effects on combustion.

At 1413 hours on May 23, 1991, a bed level increase to 100 inches was initiated. At 1700 hours, a leak was discovered in the sorbent injection piping. At 1711 hours, a bed level decrease was initiated and auxiliary power was transferred to the reserve source. At 1716 hours, a combustor trip was initiated due to the sorbent system leak.

The combustor was cooled via the gas turbine and the gas turbine was tripped at 2012 hours. Preparations were then made to release the unit to maintenance for outage activities.

Start-Up TD-SU-91-21-01

The unit was started up on June 2, 1991. The gas turbine was rolled and paralleled at 0112 hours on June 3, 1991. The bed preheater was placed in service at 0754 hours. At 0714 hours, the LPC was injected with Carboblast material. This appeared to have no negative effect on gas turbine operation. At 0833 hours, the LPC was injected a second time with Carboblast. The bed preheater was placed in service at 0859 hours. The steam turbine was rolled and paralleled at 1226 hours.

At 1447 hours, the west sorbent injection line was placed in service to test single line operation. At 1510 hours, sorbent injection was transferred to the east line due to pluggage in the west vessel. At 1532 hours, the west line was returned to service and unplugged by closing the equalizing line and pressurizing the vessel by opening the fluidizing line.

At 1714 hours, the fuel injection function group was placed in service. The function group was then taken back off due to #2 paste line being plugged. At 1720 hours, sorbent injection was stopped while the #2 paste line was clean blown.

At 1820 hours, sorbent injection was initiated via the west line. At 1821 hours, fuel injection was initiated. At this time, the #1 paste pump was determined to be not pumping. At 1907 hours, the combustor was tripped by the operator due to one bed temperature being above 1700°F and unstable evaporator tube temperatures.

At 2025 hours, the bed preheater was placed in service. At 2305 hours, the steam turbine was rolled and paralleled. At 2319 hours, sorbent injection was initiated via the west line. At 2320 hours, fuel injection was initiated.

At 2350 hours, a bed level increase to 45 inches was initiated. At 0051 hours, the combustor was tripped by the operator, due to #11 primary ash cyclone pluggage. This pluggage was suspected to have been caused by the modified sorbent nozzle "T"s which had been installed during the outage. The unit was then cooled down via the gas turbine. The gas turbine was then tripped at 0208 hours and the unit released to Maintenance for outage work.

Start-Up TD-SU-91-22-01

The unit was started up on June 5, 1991. The gas turbine was rolled and paralleled at 1221 hours on June 6, 1991. The bed preheater was placed in service at 2055 hours. The steam turbine was rolled and paralleled at 2336 hours.

At 0343 hours on June 7, 1991, the fuel injection function group was placed in service. At 0346 hours, the function group was taken back off due to #2 paste line being plugged. After the line was clean blown, the function group was placed in service at 0419.

At 0500 hours, sorbent injection was initiated using the west line.

Bed level was gradually increased to 70 inches. A low velocity test was performed on the sorbent injection system. The transport air flow was slowly lowered and when the velocity reached 12 feet per second, the line appeared to plug and the velocity was increased back to the normal setting of 26 feet per second. At 0955, it was observed that #25 secondary cyclone appeared to be plugged. The #3 paste pump was tripped at 1123 hours to test the effects of loosing a paste pump. The combustor was tripped at 1128 hours because of high bed temperatures.

The gas turbine tripped at 1132 because of a LPC surge. The gas turbine lube oil system was removed from service to repair a leak on the gear piping. The lube oil system was returned to service and the gas turbine restarted at 1629 hours to cool the combustor. The gas turbine was then tripped at 2324 and cooling was continued with combustor cooling and released to Maintenance.

Start-Up TD-SU-91-23-01

The unit was started up on June 12, 1991. The gas turbine was rolled and paralleled at 0915 hours on June 12, 1991. Problems were experienced with the LPT inlet guide vane position amplifier and the turbine was tripped from the MCS at 1233 hours. This problem was corrected and the gas turbine was restarted and paralleled at 1752 hours. The bed preheater was placed in service at 2236 hours. The steam turbine was rolled and paralleled at 0201 hours on June 13, 1991.

At 0243 hours, the fuel injection function group was placed in service. Sorbent injection was initiated using the east line at 0312. Bed level was gradually increased to 90 inches with the bed ash reinjection system. Problems were experienced when #3 and #5 coal paste pumps tripped because of low splitting air flow.

Secondary ash cyclones #24 and #26 indicated that they were at least partially plugged.

At 0427 on June 15, 1991, the combustor tripped on gas cleaning system temperatures because of a loss of communications with the safety node. During the cooling period, the gas turbine tripped because of the LPC pressure ratio trip. Once of the gas turbine bypass valves (HCV-T120) stuck at approximately 25% open. The combustor cooling was completed with the boiler ventilation system and the combustor cooling fan for maintenance outage work.

Start-Up TD-SU-91-24-01

The unit was started up on June 24, 1991, to perform the stack monitoring test, to determine the dust loading before and after the precipitator, to perform testing for boiler tube surface evaluation, and to test sorbent utilization.

The gas turbine was rolled and paralleled at 0338 hours on June 24, 1991. The combustor was warmed and the bed preheater was placed in service at 0952 hours. The steam turbine was rolled and paralleled at 1248 hours.

At 1301 hours, the sorbent injection function group was placed in service using the east line. Coal injection was initiated at 1307 hours. The #2 paste pump injection line required clean blowing to clean the nozzle and was put in service at 1337 hours. Plugging problems were experienced with the west sorbent injection vessel outlet to the rotary feeder and in the transport line after the isolation valve. Bed level was gradually increased to 126 inches with the bed ash reinjection system and sorbent injection over the next day. Secondary ash cyclones #22 and #23 indicated high temperatures during this period of operation.

Preliminary data was collected on June 25 at full bed height for the boiler surface evaluation and sorbent utilization.

At 0818 on June 26, the #2 coal injection line plugged causing a bed temperature upset. Temperatures increased on the #12, #22 and #23 cyclones, resulting in a combustor trip at 0826 hours.

The bed level was lowered for bed preheater start and at 1531 on June 26, an oil fire was established. The steam turbine was rolled and paralleled at 1852 hours. Sorbent injection was started with the west line at 1746 hours and coal injection was attempted at 1856 hours. Problems with coal injection lines being plugged (#2, #4, #5 and #6) delayed coal fire. Finally at 0224 on June 27, a coal fire was established. At 0716 hours, the #2 coal injection line plugged. This resulted in high bed temperatures and the combustor was tripped from the control panel at 0724 hours. At 0727 hours, the gas turbine tripped because of a LPC pressure ratio trip. The bed was inerted with nitrogen and cooled with gas circulation. Maintenance cleaned the coal injection lines and the coal paste pumps were also cleaned. Water was added to the paste tank to increase moisture content to make it more pumpable.

Start-Up TD-SU-91-24-02

The unit was restarted on June 28, 1991, following the mechanical cleaning of the fuel lines. The gas turbine was rolled and paralleled at 0434 hours. The bed level was lowered and the bed preheater was placed in service at 0817 hours. The steam turbine was rolled and paralleled at 1048 hours.

At 1117 hours, the sorbent injection function group was placed in service using the east line. Coal injection was initiated at 1120 hours. Bed level was gradually increased to 110 inches with the bed ash reinjection system and sorbent injection. Bed level was then increased with only sorbent injection to 110 inches. During this time, #22 and #23 secondary cyclones temperatures increased to near the limit. Bed level was lowered to 100 inches in an attempt to lower these temperatures. The bed temperature set point was also lowered from 1540 to 1535 degrees for the same reason.

During the early hours of June 29, problems were encountered on the fuel preparation system. The screw feeder tripped and the crusher roll gap skew tripped the crusher drives. The bed level was lowered to 90 inches at this time to reduce coal demand in order for the preparation system to keep up with usage while the problems were being addressed.

Adjustments were made to the crusher drives and shortly after noon, the fuel preparation system seemed to be able to remain in service and keep ahead of the demand for a higher bed level. At 1204 hours, the #3 coal paste pump tripped because of low splitting air flow. This pump was quickly returned to service before the bed temperatures became spread. The bed level was increased to 100 inches. At 1608, the #3 coal paste pump tripped again and was again returned to service. At this time, it was determined that #3 pump was tripped due to low splitting air flow caused by blowing the sootblowers, which take air from the splitting air system.

The LPT gas inlet temperature was approaching the high limit and the bed temperature set point was lowered to avoid excessively high temperature. The bed level was increased to 126 inches.

With stable conditions at 126 inches bed level, bed temperature of

1520°, and sorbent flow demand to maintain less than .5 lbs/mBtu SO_2, the stack monitoring test was started at 1014 hours on June 30. This test was completed at 1637 hours and a one hour precipitator particle size test was conducted. During the rest of this day and the night, the bed level was maintained at 126 inches, and the bed temperature was controlled to keep the LPT inlet temperature below 1060°. The bed temperature set point eventually was lowered to 1516°F.

At 0830 on July 1, precipitator testing began. Three tests were run, each lasting approximately two hours. During this time, data was also collected for the tube surface evaluation and sorbent utilization tests.

At 2032 hours, the bed temperature set point was lowered to 1509° because of high temperature in #12 primary cyclone. At 2200 hours, the #3 coal paste pump tripped on low splitting air flow and at 2223 hours, the combustor tripped due to #12 primary cyclone temperature high trip.

The bed was lowered with the bed ash reinjection system and bed ash removal system. At 0553 hours on July 2, Bailey N-90 module "AD" failed issuing a combustor trip. Maintenance cleaned the #3 and #5 coal injection lines in preparation for a restart. At 1020 hours, the gas turbine was tripped from the MCS. When the gas turbine valves tripped closed, HCV-T121 (bypass valve) stuck approximately 20% open.

Inspection of the coal-water mixer revealed that the mixer blades were worn badly and some pieces were missing. The combustor was cooled and the unit released to Maintenance for the planned outage.

Start-Up TD-SU-91-25-01

The unit was started on July 21, 1991. The gas turbine was rolled and paralleled at 2358 hours. During unit warm-up, a system response rate test was conducted on the bed ash reinjection system. The bed preheater was initiated, but did not light. The Performance Department investigated the problem, but found no cause for the problem. The bed preheater was successfully placed in service at 0842 hours on July 22, 1991. The steam turbine was rolled and paralleled at 1308 hours.

Sorbent injection was initiated at 1329 hours with the east line. Problems were experienced when attempting fuel injection with #1 and #4 pumps not pumping. Sorbent injection was removed from service, the coal injection lines were clean blown, and the #1 splitting air line was also blown out. Sorbent injection was restarted at 1657 hours. Coal injection was then successfully initiated at 1704 hours. (A logic problem was found that was limiting the signal to the paste pumps.)

At 1713 hours, the #3 coal paste pump tripped due to low splitting air flow. The other pumps were biased in an attempt to stabilize bed temperatures. The #3 paste line was clean blown and the splitting air lines blown out with higher pressure air and nitrogen. The pump was then put back in service at 1938 hours.

The east sorbent injection feeder tripped twice. It was returned to service once, then the west was placed in service so that the east rotary feeder could be repacked.

Bed level was increased to a level for once-through boiler operation, but was lowered when the vertical separator level became unstable. Once again bed level was raised, the boiler circulation pump shut off automatically, and once-through boiler operation was achieved at 0050 hours on July 23, 1991. Bed level was maintained at 75" with the bed ash reinjection system in bed level control.

It was observed about this time that #16 primary cyclone was plugged. The gas turbine opacity was at a higher value than normal, and the #16 dip leg temperature and ash cooler temperatures were much lower than the others. Sorbent injection was stopped for a short time in an attempt to unplug the cyclone, but was unsuccessful.

At 0306 hours, the combustor was tripped from the MCS because of the plugged #16 cyclone. The steam turbine tripped at 0307 hours.

The boiler circulation pump failed to start due to motor overload on decreasing steam flow after the combustor trip. The feedwater flow control was placed on hand and lowered to 100 kpph to keep the vertical separator level from going too high. At 0404 hours, the gas turbine tripped because of high fictive disk temperatures.

Start-Up TD-SU-91-26-01

The unit was started on July 28, 1991. The warming procedure was accomplished by having the secondary ash piping disconnected and pulling vacuum on cyclones while circulating feedwater and using boiler ventilation system in the warming mode until the temperatures for dew point were exceeded. The gas turbine was rolled and paralleled at 2222 hours. The bed preheater was initiated at 0531 hours on July 29, but did not light. The Performance Department investigated this, but found no problem. The preheater was successfully placed in service at 0731 hours. The steam turbine was rolled and paralleled at 1056 hours.

Sorbent injection was initiated at 1114 hours with the west line. Coal injection was initiated at 1135 hours.

Bed level was increased toward a level for once-through boiler operation. Once-through boiler operation was achieved at 1648 hours, with an indicated bed level of 56 inches. Bed level taps looked fine, but the bed density seemed to be high. Bed level was maintained to control main steam flow at approximately 220 kpph with System 272 in-bed level control. The indicated density slowly decreased and indications of bed level slowly came together with the actual level.

At 0307 hours on July 30, 1991, the #4 coal injection line plugged at the nozzle. Splitting air flow and paste flow both stopped. Over the next day, several attempts were made to unplug them by using different methods. The coal nozzle was at least partially unplugged, but the primary splitting air flow tube appeared to remain plugged.

During the early hours of July 30, the #24 cyclone appeared to have plugged or have significant air leakage as evidence by the dip leg temperature decreasing drastically and the ash cooler temperatures dropping to pressure vessel air temperature. At 0530 hours on July 30, the #2 O_2 analyzer vent line plugged and pressurized the analyzer, causing damage to the pump, the cooler, and other components of the analyzer cabinet.

Over the next day, bias adjustments were made to the remaining five paste pumps in an attempt to maintain an evenly distributed bed temperature and to control evaporator tube temperatures. Conditions continued to deteriorate, with freeboard temperatures and cyclone temperatures increasing. The main steam attemporator bias was used to help control evaporator temperatures, and finally bed temperature and main steam temperature set points were lowered to keep bed temperatures from being too high.

At 1018 hours on July 31, the motor for crusher #2 at station #3 failed. At 1151 hours, the deluge system on coal conveyors actuated falsely. The cause was determined to be a defective section of Protectowire in the N-2 conveyor. The system was cleaned and returned to service with a standby fire watch.

At 0515 hours on August 1, the combustor was tripped because of the bed temperature imbalance and the inability to control temperatures.

Bed level was lowered by taking bed material up into the reinjection vessels, and then by removing material with bed ash removal. The gas turbine was tripped at 1200 hours from the MCS. The combustor was cooled with the boiler ventilation system, combustor cooling fan, start-up fans, and condensate circulation in preparation for outage work.

During the run, adjustments were made to the coal crusher. Data and samples were taken for evaluation to determine which settings provide the best product.

Start-Up TD-SU-91-27-01

The unit was started on August 7, 1991. The warming procedure was accomplished by having the secondary ash piping disconnected and pulling vacuum on cyclones. The gas turbine was rolled and paralleled at 0947 hours on August 8. The air flow and the LPT inlet guide vane seemed abnormal as the warming was continued. At 1122 hours, the gas turbine was tripped as air flow was continuing to decrease. The inlet guide vane control circuit was checked, but no problems were found. Because of the nature of the failure, it was suspected that the position feedback circuit was again the problem. The amplifier for this feedback was replaced.

Start-Up TD-SU-91-28-01

Following repairs to the LPT inlet guide vane position feedback amplifier, the gas turbine was rolled and paralleled again at 1717 hours. The bed preheater was initiated at 2248 hours, with an oil fire at 2253 hours.

The steam turbine was rolled and paralleled at 0146 hours on August 9. Coal injection was initiated at 0253 hours, air flow increased to 500 kpph, and sorbent initiated at 0300 hours with the east line. Sorbent was held until air flow was at 500 kpph to help ensure that cyclones would remain clear.

Bed level indication and density did not seem to be normal. The level was slowly increased and these indications seemed to work their way to normal. Coal paste pump biasing was done to equalize bed temperatures. Once-through boiler operation was achieved at 1049 hours, with an indicated bed level of 59 inches.

Bed level was increased to 75 inches and sorbent flow rate was increased to maintain SO_2 compliance. At 2047 hours, the #4 coal paste pump tripped, apparently because of water getting into the control cabinet. It was returned to service at 2256 hours in manual at an 11% demand, and was increased to match the others and returned to automatic.

While cleaning the coal-water mixer on the evening of August 9, it was discovered that the liner and blades were suffering from wear. Some sections of the liner were removed to prevent them from coming off and entering the paste tank. The mixer was removed from service for inspection, and repairs were made as time permitted between batch making of paste. (This continued until the unit tripped.)

On August 10, the bed level was increased to a 90 inch level and stabilized. At 0325 hours on August 10, the #17 primary cyclone dip leg temperature increased above freeboard temperatures. Bed temperature was lowered to keep the cyclone temperature from getting too high and the temperatures were closely monitored.

At 0134 hours on August 12, the sorbent preparation system was removed from service and a hole was discovered in the cyclone separator.

Maintenance repaired this hole, and the system was returned to service.

Bed level was held at 90 inches because of the coal preparation system problems, sorbent preparation rate limitations, and high temperatures on #17 cyclone.

Relative accuracy tests were conducted on the stack monitoring equipment on August 13.

At 1639 hours on August 13, the combustor tripped when the boiler depressurized rapidly due to a large leak in the economizer. The steam turbine tripped at 1640 hours. The gas turbine was tripped at 1647 hours. The gas turbine outlet duct was flooded. Feedwater could not be maintained to the boiler. Bed bottom cooling was established and bed material reduced. The slumped bed temperature was 1200°F at this time. Combustor cooling was continued with the boiler ventilation and the process air system.

Start-Up TD-SU-91-29-01

The gas turbine was rolled and paralleled at 1550 hours on August 23. A combustor trip was experienced at 1608 hours when #2 and #5 splitting air flows went bolow the trip value. The combustor trip was reset. The bed preheater was initiated at 2357 hours. The steam turbine was rolled at 0235 hours on August 24. After testing the overspeed oil trip when increasing steam flow to the turbine, a combustor trip and a gas turbine trip were experienced because of low boiler circulation flow. The vertical separator level dropped very low (probably caused by the level control valve). The boiler circulation pump tripped on low net positive suction pressure. After nitrogen inerting and gas circulation cooling was complete, the bed cooling was completed by the process air system in the air cooling mode.

Start-Up TD-SU-91-30-01

The gas turbine was rolled and paralleled at 0833 hours on August 24, 1991. The bed preheater was initiated at 1022 hours. The steam turbine was rolled and paralleled at 1408 hours.

Fuel injection was initiated at 1455 hours. Air flow was increased and sorbent injection was initiated at 1545 hours with the west line.

As soon as coal fire was established, it was observed that #17 cyclone dip leg temperature did not increase and the ash cooler temperatures were lower than pressure vessel air temperature. Once-through boiler operation was achieved at 2226 hours, with an indicated bed level of 62 inches.

As the bed level was increased, the apparent leak on #17 cyclone disappeared and the temperatures came in line with the other cyclones.

At 0549 hours on August 25, while lowering bed level with the north bed reinjection line, the vent valves stuck open causing the bed level to decrease to 71 inches. At this time, several cyclones had fires in them. As conditions stabilized, all fires were brought under control.

At approximately 1200 hours, it was observed that #13 cyclone had plugged. Attempts were made to reduce the ash loading to this cyclone and allow it to unplug. No success was experienced. Evidence showed that #23 was getting significant ash carryover and at 1543 hours, the combustor was tripped because of the plugged #13 and #23 cyclones. Bed level was first lowered by the bed ash reinjection system, and then by the bed ash removal system.

The gas turbine was tripped at 2003 hours from the MCS and the unit cooled for outage work.

<u>Start-Up TD-SU-91-31-01</u>

The gas turbine was rolled and paralleled at 1505 hours on September 4, 1991. The bed preheater was initiated at 0039 hours on September 5. The boiler pressure control valve was not controlling pressure and was placed on manual. When the pressure was caught, the vertical separator level decreased rapidly, causing the low net positive suction head preventing the boiler circulation pump from running. At 0149 hours, a combustor trip and a gas turbine trip were issued because of low boiler circulation flow. The unit was secured and prepared to restart.

Start-Up TD-SU-91-32-01

The gas turbine was rolled and paralleled at 0536 hours on September 5. Bed level taps appeared to be plugged and the bed level was lowered and raised while the Performance Department worked at getting the taps unplugged. The bed preheater was initiated at 1442 hours. The steam turbine was rolled and paralleled at 1752 hours.

Fuel injection was initiated at 1851 hours, but the #6 pump tripped because of low differential pressure. The fuel lines sequenced through reversing and then were clean blown. The function group was again ordered on and a coal fire established at 2001 hours. Air flow was increased to 500 kpph, and sorbent injection was initiated at 2105 hours with the west line at minimum speed because of high fines in the sorbent.

At 2328 hours, a combustor and a steam turbine trip were experienced because of a low vertical separator level. At 0226 hours on September 6, an oil fire was established. The steam turbine was rolled and paralleled again at 0458 hours. At 0511 hours, a coal fire was established.

Air flow was raised to 500 kpph, and sorbent injection was initiated at 0613 hours with the west line.

Bed level was increased with bed ash reinjection, and once-through boiler operation was achieved at 0954 hours, with an indicated bed level of 64 inches. Bed level was allowed to increase from sorbent injection toward 90 inches. A bed temperature of 1545°F was maintained.

Problems were experienced during this period with the coal preparation system crushers. The problems were tracked to speed transmitters on the crusher motors.

At 0220 hours, the #24 cyclone dip leg temperature was observed to drop. This temperature and the ash cooler temperatures were watched closely, and it was determined that the cyclone was not plugged because of the dip leg temperature still being active.

A bed ash production test was conducted using the bed ash reinjection system. The test was run for approximately four hours, with an average production rate of 8.2 kpph.

At 0704 hours on September 7, the #6 coal paste pump tripped because of low differential pressure. The paste pump, the S-tube, and the high side of the differential pressure instrument were cleaned. The pump was returned to service at 0905 hours, with everything checking okay. At 1020 hours, the #3 paste pump tripped and was restarted without any problems (low differential pressure appeared to be the cause of the trip).

At 1745 hours, problems were experienced with the #6 coal paste pump flow control. Performance was called to investigate and at 0040 hours on September 8, the pump was removed from service to replace the speed control card. The pump was returned to service at 0200 hours.

At 0805 hours, a leak was discovered on the sorbent transport line and preparations were made to remove the unit from service. The combustor was tripped manually at 1205 hours, the steam turbine tripped at 1207 hours. The bed material was taken up into the bed ash reinjection vessels, and then the gas turbine was tripped at 1618 hours. Preparations were made to repair the sorbent piping leak and to investigate the #6 coal paste pump speed control problems.

Start-Up TD-SU-91-33-01

The gas turbine was rolled and paralleled at 1812 hours on September 11. Bed level tap #1 appeared to be plugged, and attempts to unplug it did not help. Tap #1 and tap #2 were valved together. Bed level was increased to 26 inches in preparation for bed preheater lighting. At 2345 hours, problems were noticed on the #4 coal paste pump. Upon investigation, it was found that part of the chrome lining of the paste cylinders was coming off.

It was decided to stop the start-up and secure the unit. Bed material from the reinjection vessels was removed into the bed and then taken out through the bed ash removal system.

The gas turbine was tripped from the MCS at 0730 hours on September 12. The unit was then released to Maintenance for the Fall outage.

Start-Up TD-SU-91-34-01

Boiler circulation was started at 1755 hours on December 7, and air heating started at 0233 hours on December 8. The gas turbine was rolled and paralleled at 1338 hours.

While running the splitting air compressor at the reduced loading of the new system design, the compressor was noticed to heat up. A bypass valve and line was temporarily installed back to the sorbent air receiver.

Problems were encountered with the bed preheater lighting. One problem was the needle valve sticking, and another was the ignitor not being energized from the control system. The bed preheater was successfully fired at 0342 hours on Monday, December 9, but a combustor trip was experienced at 0345 when the vertical separator level "swelled" and reached the high level trip.

The combustor trip was reset and the bed preheater was put back in service at 0430 hours. A combustor trip was suffered at 0556 when boiler circulation flow decreased to less than 24 kpph. The combustor trip was reset and the bed preheater restarted at 0655 hours. The temperature set point was kept at minimum to comply with the bed zone refractory curing procedure. The bed zone refractory curing was completed.

Problems were experienced at this time with the vertical separator level and were traced to the drain valve (LCV-U200A) sticking. Silica was high on main steam, which caused a hold until the cycle was cleaned sufficiently to proceed.

During this time, the temperatures on the secondary cyclone ash removal system indicated that at least part of the cyclones were plugged, and it was determined to shut down after the sparge duct relaxing to clean/inspect the secondary cyclones. (During the outage, ash "peelings" were found in all of the secondary cyclone pickup pots, except for #23).

As the steam turbine was rolled, the speed did not act as normal, and the combustor was tripped to avoid further problems with the steam turbine. Upon further investigation, it was determined that the speed indication was faulty. At 2048 hours, the bed preheater was restarted. At 2238 hours, the steam turbine was rolled; and at 2347 hours, the generator was paralleled.

While raising the bed preheater temperature to the 1550° sparge duct relaxing temperature point, a high wind box temperature trip was experienced at 0013 hours on December 10. The steam turbine was tripped at 0015 hours. The bed preheater was restarted at 0045 hours to continue the sparge duct relaxing. The sparge duct relaxation was completed and the bed preheater function group ordered off at 0324 hours. Cooling of the boiler/combustor was continued for maintenance outage work.

Start-Up TD-SU-91-35-01

Boiler circulation was started at 0137 hours on December 12, and air heating started at 0700 hours. The gas turbine was rolled and paralleled at 1330 hours.

The bed preheater oil fire was established at 1837 hours and at 1839 hours, the combustor tripped on high vertical separator level. The bed preheater was restarted with oil fire at 1901 hours, and the combustor tripped at 1902 hours on high vertical separator level. A third bed preheater ignition was accomplished at 1925 hours, with a combustor trip at 1926 hours (high vertical separator level). The vertical separator drain valve (LCV-U200A) and the vertical separator pressure control valve (PCV-B200) both were found to have control problems.

The bed preheater was initiated again at 1958 hours. At 2059 hours, the bed level was increased toward 25 inches.

At 2235 hours, it was decided that the temperatures on #14, #24 and #25 cyclones indicated that they were plugged.

At 2236 hours, the combustor was tripped because of the plugged cyclones. The combustor was cooled and at 0103 hours on December 13, the gas turbine was tripped from the MCS. (Outage inspection of the bed revealed that the bed material had a high concentration of fines for unknown reasons.)

Start-Up TD-SU-91-36-01

Boiler circulation was started at 2040 hours on December 15, and air heating started at 0211 hours on December 16. The gas turbine was rolled and paralleled at 1650 hours.

The bed preheater oil fire was established at 2139 hours. Bed level was increased with 274 System to a start bed level of 25 inches (using sand).

At 0200 hours on December 17, the steam turbine generator was paralleled. Coal fire was established at 0503 hours and sorbent injection started with the west line at 0522 hours.

The gas turbine seal air valves did not switch from the LPC supply to the HPC supply and had to be physically assisted. Problems were also experienced with the gas turbine air flow control again. The symptoms point to the LPT inlet guide vane position feedback.

Bed level was increased and pumps were biased for bed temperature distribution. Once-through boiler operation was established at 1226 hours at a bed level of 58 inches.

At 1909 hours, a combustor trip was experienced when adjusting a temperature trip point on the cyclone ash removal system. All systems were secured and an oil fire started at 2146 hours. We again experienced problems with the bed preheater light off, as the needle valves appeared to be stuck.

Start-Up TD-SU-92-01-01

The combustor was released at 1542 hours on January 8, 1992. Gas circulation warming was placed in service at 1952 hours on the same date. The gas turbine was rolled up, and at 1120 hours on January 9, 1992, it was paralleled with the system. At 1609 hours, an oil fire was achieved. At this time, #24 cyclone showed signs of being plugged. Used "stirring" air and secondary ash valve to try to get it to recover.

At 1951 hours, January 9, 1992, the freeboard mixing system was commissioned. The system seemed to have a significant impact on gas distribution once above 600 psig set point. A coal fire was established at 0034 hours on January 10, 1992, and at 1910 hours, the unit went to once-through operation.

At approximately 2000 hours on January 10, 1992, #24 cyclone unplugged. Shortly afterwards, it again showed signs that it was plugged. Pulsing the cyclone ash system cleared it.

At 2330 hours on January 10, 1992, the combustor tripped due to a logic problem that indicated two bed temperature thermocouples had failed.

At 0053 hours on January 11, 1992, the gas turbine tripped due to a HPT outlet thermocouple failing high. The bed temperature was low at the time; therefore, nitrogen cooling was not required.

<u>Start-Up TD-SU-92-01-02</u>

Following a trip due to a failed HPT outlet thermocouple, the gas turbine was rolled at 0415 hours and paralleled at 0430 hours on January 11, 1992. An oil fire was established at 0614 hours. At 0944 hours, a coal fire was established. At this time, #21, #24 and #27 cyclones appeared to be plugged. Pulsing of the outlet valve and blowing of stirring air cleared #21 and #27 cyclones, while #24 showed only a slight response.

At 1231 hours on January 11, 1992, the combustor tripped on high bed temperature as a result of losing #6 paste pump. At 1432 hours, an oil fire was reestablished. While bed temperatures were being increased, the fuel nozzles were blown clean.

The #2 paste line could not be cleared and at 2139 hours, the bed preheater was shut off and at 2143 hours, the gas turbine was tripped to facilitate the Maintenance Department's cleaning of the fuel lines.

<u>Start-Up TD-SU-92-02-01</u>

Following the shutdown for cleaning coal paste lines, the gas turbine was rolled at 1138 hours on January 12, 1992. At 1501 hours, an oil fire was established. Coal was lit at 2108 hours. At 2129 hours, the gas turbine tripped due to the lack of a breaker status feedback on a feed pump which logics used as a part of the loss of feedwater scheme.

Nitrogen inerting was required since bed temperatures were above 1100°F at the time of the slump. Gas recirculation mode was required to further cool the bed.

<u>Start-Up TD-SU-92-02-02</u>

The bed was cooled following a slumped bed trip, and the gas turbine was rolled at 0814 hours on January 13, 1992. At 1443 hours, an oil fire was established and coal was lit at 2052 hours. At 2055 hours, the fuel injection function group was taken off since #4 pump had not started pumping. The pump was reversed and blown clean and at 2100 hours, a coal fire was established. At this time, cyclones #23, #24 and #27 had low temperatures. At 2145 hours, the #23 cyclone temperatures increased and at 2330 hours, #24 cyclone temperatures increased, indicating that they unplugged.

At 0418 hours on January 14, 1992, #6 paste pump was removed from service because it was no longer pumping. At 0638 hours, the combustor tripped on low bed temperature while #6 paste line was being blown clean with nitrogen.

The gas turbine inlet guide vane DCS station required troubleshooting prior to lighting off again.

At 2157 hours on January 14, 1992, an oil fire was established and coal fire followed at 0258 hours on January 15, 1992. Cyclone suction nozzle temperatures were low on #23, #24, #25 and #27. As pressure vessel pressure was increased, the secondary cyclone ash lines cleared and by 0600 hours, #27 was the only one remaining with a low suction nozzle temperature.

Bed level was increased after the ash inventory in the bed ash recirculation vessels was high enough to "make a run" to approximately 110 inches. By 2250 hours on January 15, 1992, a bed level of approximately 115 inches was reached at an air flow of 690 kpph and a bed temperature of 1560°F. This provided 408 kpph steam flow and 63 megawatts.

At 0030 hours on January 16, 1992, the sorbent injection system tripped for unknown reasons and could not be restarted. At 2042 hours, #6 paste pump tripped on over hydraulic pressure. At 0059 hours, the combustor was tripped due to high temperature on #15 cyclone. At this time, it was decided to shut down the unit and cool for inspections and maintenance.

Start-Up TD-SU-92-03-01

The combustor was released at 1535 hours on January 20, 1992. Gas circulation mode warming was established at 2220 hours. The gas turbine was rolled at 0922 hours on January 21, 1992, paralleled at 0842 hours, and air flow established at 0848 hours. At 1317 hours, an oil fire was established. The steam turbine was rolled at 1600 hours and in parallel at 1652 hours.

A coal fire was established at 1852 hours on January 21, 1992. Air flow was increased to 500 kpph, and sorbent injection placed in service at 2005 hours.

At this time, we began experiencing difficulties with the coal crusher. The coal was not going through the crusher and was backing up in T1 hopper.

Once-through operation was achieved at 0630 hours on January 22, 1992, and bed level was increased. Cyclone fires were prevalent from 70 inches bed level to approximately 110 inches. Bed level was increased to 132 inches. Gross generation was 66 megawatts at an air flow of 710 kpph, fuel flow of 60 kpph, and a steam flow of 408 kpph.

At 1547 hours, #6 paste pump tripped on low splitting air flow. The pump was restarted, but tripped again on low splitting air flow. The local needle valve was opened and the pump restarted. It did not trip, but would not pump. The fuel master station was put on hand and lowered, pumps were biased, main steam temperature set point was lowered, attemperator bias was lowered, and in-bed level was reduced.

The unit was stabilized while #6 pump suction box was cleaned and the line blown clean. At 1646 hours, #6 pump was successfully returned to service.

The unit required 21 kpph sorbent flow for SO_2 compliance, and the bed ash removal system needed tuning to keep up. Throughout the night of January 22, 1992, bed density decreased, resulting in fuel flow decreasing, megawatts decreasing, freeboard and cyclone temperatures decreasing.

On January 21, 1992, it appeared that the north paste tank had wetter paste since pumps #1, #2 and #3 line differentials were lower than #4, #5 and #6, and the north tank agitator amps were lower than the south tank agitator amps. The associated cyclone strings (#5, #6 and #7) had much higher temperatures. At 1725 hours, sinters were observed in the bed ash. It was speculated that earlier testing of splitting air (down to .65 of the curve) may have caused the sinters.

At 1955 hours on January 23, 1992, #25 cyclone temperatures all dropped, indicating a plug.

On January 24, 1992, more problems were encountered with the crusher not taking coal. By the evening of January 24, 1992, the CWP tank level was approaching the low alarm point. Bed level was dropped rapidly, while the crusher was returned to the "old" mode of operation. Tank level was at "0" inches before the fuel preparation system began gaining on the tank level.

At 1407 hours on January 25, 1992, the unit tripped due to a BDD operation (transformer 1A differential protection) while starting a feed pump. (Later investigation showed 10A and 10B auxiliary transformer CT's polarity were reversed.) The gas turbine also tripped due to HCV-T120 (an intercept/bypass valve) coming off of its open limit switch. This occurred due to a drop in voltage at the trip when auxiliaries transferred in the middle of starting the south boiler feed pump. The voltage drop caused the control fluid pump breaker to open, which resulted in HCV-T120 moving.

Nitrogen inerting was required and gas recirculation was used to cool the bed. The unit was secured in preparation for a maintenance outage.

Start-Up TD-SU-92-04-01

The combustor was released at 1600 hours on February 2, 1992. Gas circulation mode warming was established at 2124 hours. The gas turbine was rolled on February 3, 1992 at 0939 hours and paralleled at 0952 hours. The valves were opened to establish air flow at 1003 hours.

An oil fire was established at 1444 hours on February 3, 1992, the steam turbine was rolled at 1703 hours and paralleled at 1759 hours. Establishing a start bed took longer than normal as it seemed that bed ash reinjection vessels had an abnormally high amount of fine material. A coal fire was established at 0052 hours on February 4, 1992. Sorbent injection was placed in service at 0152 hours.

On February 4, 1992 at 1120 hours, #6 paste pump stopped pumping for a short period and then started pumping again.

Once-through operation was achieved at 1514 hours on February 4, 1992.

Bed level was increased to 120 inches with no evidence of cyclone fires. At 2000 hours on February 4, 1992, bed level was increased to 128 inches. By 2155 hours, bed level had been increased but to 133 inches.

At 0528 hours on February 5, 1992, the #4 paste pump tripped on low splitting air flow. The pump was restarted and began pumping again.

The east sorbent injection feeder packing blew out and had to be changed. This required single line operation on sorbent injection. To vent, refill, repressurize and place back in service required 18 minutes.

The bed level was brought up to almost 140 inches early the morning of February 6, 1992, to check the effect of higher bed level on cyclone inlet temperatures. This was performed at a bed temperature of 1525°F. In general, conditions were worse than at 130 inches and higher bed temperature; therefore, bed level was decreased back to 130 inches.

The stack monitoring equipment testing was conducted on Friday, February 7, 1992. The unit operated smoothly throughout the test, although sinters were found in the bed ash samples. Early Saturday morning, February 8, 1992, the #5 paste pump became erratic. It ran until 1431 hours when it came into alarm and stopped pumping. At 1435 hours, it was restarted and it began pumping once again.

The unit ran along fairly smooth the remainder of the weekend, with the exception that it appeared that a sorbent accumulation in the tube bundle was developing.

Evaporator tube temperatures, in the area of the north sorbent injection nozzle, indicated that heat transfer was not very good in this area. (Outage inspection revealed a sorbent accumulation in this area.)

On Monday, February 10, 1992 at 1059 hours, the combustor was manually tripped by the operator due to 30 kpph mismatch in steam flow versus feedwater flow and numerous superheater tube temperature high alarms. It was later discovered that two economizer pressure transmitter impulse lines had separated at union fittings and the water flow was blowing to atmosphere. The unit was cooled down in a normal manner in preparation for a maintenance outage.

Start-Up TD-SU-92-05-01

The combustor was released on February 15, 1992 at 2003 hours. At 2346 hours, gas recirculation was placed in service to warm the combustor. The gas turbine was rolled on February 15, 1992 at 1650 hours, and paralleled at 1705 hours. Air flow was established 11 minutes later. The bed preheater was lit at 2144 hours, but tripped on low temperature on #1 burner. At 2158 hours, another attempt resulted in no flame. At 2212 hours, an oil fire was successful. At 2243 hours on February 16, 1992, the gas turbine tripped due to a logic problem.

Start-Up TD-SU-92-05-02

Following the gas turbine trip on February 16, 1992, the gas turbine was rolled at 0312 hours on February 17, 1992. The turbine was paralleled at 0332 hours, and an oil fire was established at 0406 hours. After oil firing, temperatures on the cyclone ash system showed that #22 and #26 cyclones were open, but the other secondary cyclones were plugged. The cyclones were pulsed and all but #23 were cleared.

At 1809 hours on February 17, 1992, coal injection was placed in service. At 1903 hours, a coal fire was established. At 2000 hours, air flow was increased to 500 kpph. At this time, #23 cyclone cleared. At 2146 hours, sorbent injection was placed in service. No obvious effects of the new "T"s in the sorbent feed nozzles and skateboards were immediately apparent. The unit was brought to 50 inch bed level for testing.

A freeboard mixing steam test was run, which indicated that 650 to 750 psig is the best pressure range for gas distribution.

At 2000 hours on February 18, 1992, a splitting air test was conducted, which indicated that 1.5 times our original curve is best at this 50 inch bed level.

Sorbent testing was started at 0930 hours on February 19, 1992, to evaluate the effects of single nozzle feed.

At 1900 hours on February 19, 1992, the bed level dropped 10 inches rapidly, and the south bed ash removal system tripped on high temperature.

At 0300 hours on February 20, 1992, bed level was increased with intent to come to 125 inches. Once-through operation occurred at 0350 hours.

At 0911 hours, a bed level of 125 inches was reached. Evaporator tube temperatures indicated the presence of a sorbent accumulation in the tube bundle.

Paste pump biases were changed to near 1.0 on all six pumps. At 1619 hours on February 20, 1992, splitting air flow was brought down to a bias of 1.0 for testing. At 1713 hours, splitting air was brought back to 1.1 to check repeatability.

At 1846 hours, bed temperature was dropped to 1520°F to bring the bed to full bed height.

At approximately 2100 hours, the bed level was brought to 142 inches. The post-bed combustion was very limited. The paste being made seemed to have more fines due to the crusher being operated heavily loaded.

Moisture in the paste has been drastically reduced. Bed temperature was increased in steps from 1540 to 1575°F. At 0148 hours on February 21, 1992, gross generation peaked at 70 megawatts at a steam flow of 429 kpph.

Many paste pump problems were experienced during this run.

At 0345 hours, the combustor was tripped for cooldown and inspection of tube bundle for deposits.

Start-Up TD-SU-92-06-01

The gas turbine was rolled at 1532 hours, and was paralleled at 1548 hours on February 28, 1992. Air flow was established at 1558 hours, and an oil fire achieved at 2147 hours.

A coal fire was established at 0608 hours on February 28, 1992.

The north reinjection vessel would not feed out any bed material.

A stable operating condition was achieved on the crusher with 5 to 8 kwh/ton energy input. It did not appear, however, that more fines were achieved with the higher energy input as was expected.

The paste moisture content was decreased as the energy input to the crusher was increased, having expected better fines. This may have led to more problems than normal with the paste pumps plugging.

Due to evaporator temperatures indicating the possibility of having formed a deposit, sorbent transport velocity was increased. At 1325 hours on March 2, 1992, the velocity was set to 30.5 ft/sec.

During the run, the south reinjection vessel also seemed to plug up and would not allow bed material to flow out of it to the bed.

Also during the run, the #26 cyclone appeared to plug, but later unplugged and returned to normal conditions.

At 0029 hours on March 3, 1992, the #5 paste pump tripped on low splitting air flow. The next 15 hours were spent trying to return the pump to service. It was returned to service at 1606 hours. At 2013 hours, the #4 paste pump tripped on over hydraulic pressure. All attempts to return it to service were unsuccessful. At 1749 hours on March 4, 1992, the #5 paste pump again tripped on low splitting air flow and the combustor was tripped by the operator at 1753 hours due to unstable firing conditions, with two paste pumps out of service.

Start-Up TD-SU-92-07-01

The gas turbine was rolled at 1347 hours on March 15, 1992, and paralleled at 1403 hours, and air flow established at 1418 hours.

The bed preheater was lit at 2035 hours, and the steam turbine was rolled at 2326 hours and paralleled at 0159 hours. While establishing start bed level via bed ash reinjection, it was observed that the ash evidently consisted of a high number of fines. Secondary cyclones #23, #24 and #25 showed signs of pluggage, and opacity ran high.

A coal fire was not established because of the inability to produce an acceptable coal paste. The crusher was skewing badly and oversized material was getting through. This coal appeared to be much drier than the coal used during the coal crusher testing of the previous week. At 1143 hours on March 16, 1992, the bed preheater was removed from service, followed by the gas turbine. Maintenance started on installation of water spray nozzles above the crusher to attempt to correct the crusher skewing problems.

Start-Up TD-SU-92-07-02

Water sprays were installed in the chute above the crusher to try to correct the crusher skewing problem. This worked well and following testing of the coal preparation system, the gas turbine was rolled on March 17, 1992 at 0519 hours, paralleled at 0536 hours, and air flow established at 0601 hours.

Throughout the entire day of March 17, 1992, the bed preheater could not be lit off. A decision was made to shut down and inspect the bed preheater. The gas turbine was tripped at 1652 hours on March 17, 1992.

Start-Up TD-SU-92-08-01

The bed ash reinjection vessels, particularly the south, was injecting material into the bed without any pulsing.

The steam turbine generator was rolled and paralleled at 0039 hours on December 18. A coal fire was established at 0240 hours. Sorbent injection was started at 0322 hours with the west line. Bed level was increased and paste pumps were biased in order to obtain better bed temperature distribution.

Bed level was increased to the point to match the 40.5 kpph fuel input (previously 90 inches), and then held there to evaluate. At this time, #13 cyclone dip leg temperature increased to 100° above freeboard. Paste pump biases were returned to 1.0, air flow was increased, and bed temperature set point was raised all in an attempt to put out the fire in #13 cyclone dip leg temperature. After changing the pump biases, all primary cyclone dip leg temperatures increased to above freeboard. Air flow was increased and bed temperature was increased to try to get the cyclone fires out. Bed level was then reduced to 70 inches. This seemed to at least control the primary cyclone temperatures from going any higher. Splitting air flow was increased to 115% and then lowered to 95%, with no success in lowering the temperatures.

At 0202 hours on December 19, the #23 cyclone was determined to be plugged. Air flow was increased in an attempt to unplug. At 0304 hours, a combustor trip was initiated because of the plugged secondary cyclone. At 0306 hours, the steam turbine tripped.

The gas turbine was tripped from the panel at 0445 hours, and the combustor was continued to be cooled with the boiler ventilation system for outage work.

The combustor was released by the Maintenance Department at 1545 hours on May 19, 1992. Warming this start-up included hot gas clean up bypass cyclone and associated inlet and outlet piping. Secondary cyclone warming was aided by pulling a vacuum on the line during start-up.

A number of attempts at rolling the gas turbine up to speed were unsuccessful due to HPC outlet pressure taps being plugged, causing false trips on HPC low efficiency.

The gas turbine was successfully rolled at 1917 hours on May 20, 1992, and air flow was established at 2012 hours. There was a hold while preheating with the gas turbine to dry out the HGCU refractory.

The bed preheater was lit off at 0429 hours on May 21, 1992. The bypass cyclone was noted to have several hot spots right after the oil fire, with the manway nozzle being at 150°F for a 450°F gas temperature to the cyclone. Oil fire was held to maintain temperature requirements for HGCU refractory curing.

At 1221 hours on May 21, 1992, the steam turbine was rolled; parallel occurred at 1411 hours.

Coal fire was initiated at 2026 hours on May 21, 1992. At 2110 hours, #6 paste pump tripped on low-low splitting air flow. Number 6 pump could not be returned to service until 2342 hours cn May 21, 1992, due to difficulties getting the line and splitting air nozzle blown clear.

During the early morning hours of May 22, 1992, testing was conducted, with ABB involvement, to get the LPT blade strain gauge data.

Number 24 cyclone plugged during the start-up and remained plugged to this point despite several air flow increases and resultant pressure vessel pressure increases.

At 0700 hours on May 22, 1992, conditions were:

Bed Level	58 inches
Bed Temp	1525°F
ST MW	14.5
GT MW	0
GT Opacity	79
Stack Opacity	70
Fuel Flow	25 kpph
Air Flow	530 kpph
Pressure Vessel Pressure	100 psig
Bypass Cyclone Inlet	955°F
Splitting Air Bias	1.0
Sorbent Flow	8 kpph

The unit had been experiencing high opacity, and after trying all combinations of rapper and TR set adjustments, the TR sets were put into "intermittent" operation, one at a time, and the stack opacity took four distinct step changes from 70% to approximately 40%. It appeared that the fields were in a "back corona" problem.

At 0715 hours, the unit went once-through. Bed level was increased to 75 inches, where additional GT tests were run for LPT blade testing (up to 5750 RPM LP shaft speed).

HGCU piping continued to have hot spots. Overall, piping was hotter than expected. Fans were required on several expansion joints and sections of piping.

At 1405 hours on May 22, 1992, the TR sets were placed back in energy management from intermittent operation as a test. Opacity dropped from 36% to 20%. Back corona testing showed that it was no longer present.

At 1715 hours, May 22, 1992, #24 cyclone was unplugged by pulsing the stirring air.

During the early morning hours on May 23, 1992, the 43% inlet guide vane gas turbine tests were run (additional LPT blade stress testing).

The bed level was increased to 141 inches, with a bed temperature of 1535°F. The HPT disc temperature reached 840°F, and bed level was dropped to 135 inches at a bed temperature of 1525°F.

At approximately 0741 hours on May 23, 1992, the combustor and GT were tripped due to failure of the #4 expansion joint in the hot gas clean up system.

<u>Start-Up TD-SU-92-09-01</u>

The #1 cyclone string was effectively blocked off and following other outage work being completed, the combustor was released by the Maintenance Department at 0947 hours on June 7, 1992. Normal gas recirc warming was accomplished on the six internal cyclone ash strings. The vacuum on the secondary ash line was again used.

The gas turbine was rolled at 0515 hours on June 8, 1992, but a high vibration trip was experienced from #1, #3, and #4 bearings before reaching 250 RPM hold speed.

The gas turbine was successfully rolled at 0604 hours, paralleled at 0624 hours, and air flow established through the combustor at 0629 hours.

Start bed level was established with sand and the bed preheater was lit off at 1048 hours on June 8, 1992.

The steam turbine was rolled and paralleled at 1412 hours on June 8, 1992.

A coal fire was established at 1805 hours on June 8, 1992.

Bed level was then increased. The #24 secondary cyclone plugged during start-up, but was successfully pulsed open.

A problem with indicated bed level caused unit control problems. The main steam temperature control station ran into saturation, and main steam temperature was extremely high, which resulted in a combustor trip at 0211 hours on June 9, 1992.

The unit was secured, bed level was lowered to below the paste nozzles, and the paste lines were reversed and clean blown with air.

The bed level was reduced to no indicated differential on bed level taps, and the bed pre-heater was started again at 0950 hours on June 9, 1992.

The steam turbine was rolled and paralleled at 1336 hours.

Coal fire was initiated at 1800 hours.

Bed level was increased and once-through boiler operation was achieved at 0622 hours on June 10, 1992.

Gas turbine inlet guide vane testing was done at 40", 50", 70", 80", 90" and 100" bed levels.

The stack opacity fluctuated around 22% from start bed level to 90", and no improvement could be made with the precipitators.

The #24 cyclone plugged again during this coal fire period. (No. 24 remained plugged for the entire run.)

The gas turbine #1 bearing vertical and #3 and #4 bearing vertical and horizontal vibration were in and out of alarm several times during the start-up and run.

During the entire run, the paste tank level was limited because of agitator amps (due to drier paste which was achieved due to the crusher producing desired fines).

Full load acceptance testing was accomplished on June 12, 13 and 14, 1992, with a bed ash production test being performed on June 16, 1992 (9,200 lbs/hr at 131" bed level).

On June 16, 1992, a failing current transformer (CT) was found on the steam turbine generator "A" winding Phase 2 neutral winding. The temperature of the CT was monitored closely. The loading of the steam turbine generator was limited to approximately 40 MW to limit overheating of this CT.

A dust loading test on the economizer/GT duct was conducted on June 23, 1992. A short bed ash production test was conducted during this dust loading test (9,000 lbs/hr at 115" bed level).

On June 26, 1992, the Phase 2 ST generator "A" winding CT temperature started to increase. The load was reduced on the generator, the steam diverted to the condenser, bed level dropped, and the steam turbine was tripped at 1158 hours. Bed level was reduced to approximately 55 inches, steam flow lowered to 155 kpph, and the boiler circulation pump started. The CT was replaced, and at 0112 hours on June 27, 1992, the steam turbine was paralleled and load backup.

During the run, the performance of the sorbent prep system deteriorated to the point where we could only hold our own at 116" bed level (approximately 18-20 kpph). This was with all material, including the fines going to the storage vessel. The percentage of fines (-60 mesh) was sometimes as high as 40%.

During this run, both of the expansion joints on the sorbent storage vessel outlets failed. The east one was contained very quickly. The west one caused a considerable mess before it was repaired.

During this run, one of the LPT speed pickups failed. The spare one was connected.

The #2 precipitator TR field shorted to ground, tripped, and could not be reset. (During the outage inspection, a broken wire was found.) Also, the #3 TR set tripped several times on low D.C. voltage, causing several opacity exceedances. Opacity was a continuing problem throughout the run. The fields seemed to "saturate" with ash and would not clear unless they were de-energized.

Several control systems were tuned during the run, including the bed mass controller and the combustion master.

Start-Up TD-SU-92-09-01

During the scheduled shutdown July 10, 1992, a test was performed by taking the freeboard mixing system out of service. Ash loading changed, but not significantly. Excess air on #2 cyclone went even lower than it was previously. The O_2 readings on #4 and #7 cyclone strings increased. The system was returned to service for better distribution in the freeboard.

A test was also conducted to determine if the secondary ash could be removed by a baghouse. (Duct opacity did not drop during this test.)

The bed level was lowered to approximately 95", and at 1400 hours on July 10, 1992, the combustor was tripped. A steam turbine trip followed at 1403 hours.

After the trip, the paste nozzles were reversed while the bed level was still above the nozzles, using LP nitrogen for the splitting air supply. This appeared to have worked very well.

The gas turbine was tripped at 2025 hours on July 10, 1992. Air cooling and feedwater circulation was continued in preparation for maintenance outage activities.

Full load acceptance testing, a 30-day reliability run, and 740 hours of continuous coal fire were accomplished during the run.

Start-Up TD-SU-92-10-01

The combustor was released by Maintenance at 1500 hours on July 25, 1992. Gas recirculation warming began at 1235 hours on July 26, 1992.

The gas turbine was rolled at 2111 hours and paralleled at 2127 hours on July 26, 1992. Intercept and bypass valves were opened at 2137 hours.

Problems were experienced while attempting to light the bed preheater. After the initial light-off, when the temperature control valve was released to go to minimum fire position, the flame became unstable and the preheater tripped on loss of flame. After trying several solutions for correcting the problem, the bed preheater was successfully lit at 0405 hours on July 27, 1992, by not allowing the control valve to go to minimum fire position.

The #24 cyclone showed signs of being plugged as soon as temperatures in the boiler began increasing. (Number 24 cyclone remained plugged for the entire run.)

At 0903 hours, the steam turbine was rolled and paralleled.

The duct opacity was high the entire time while bringing the bed to start level. Fine bed ash material carryover limited the rate of bed level increase that was possible because of primary cyclone ash flow and pressure limitations. While increasing the bed level with 274 System, the south reinjection vessel outlet "L" valve plugged. All attempts at unplugging it failed.

At 1247 hours on July 27, 1992, coal fire was initiated with a bed level of 24".

As bed temperature increased to the point where the controls for fuel master and bed temperature are pulsed to auto, the temperatures began to decrease. (It was determined later that the bed temperature station had been mistakenly left in manual with a zero output.) Bed temperatures were not able to be brought back up quickly enough and at 1300 hours, the combustor was manually tripped. The steam turbine tripped at 1032 hours. The unit was secured following the trip. Because of the plugged reinjection vessel, there was not enough bed material available for another start-up. It was then decided to cool and open the combustor to unplug the south bed ash reinjection vessel, as well as #24 secondary cyclone.

<u>Start-Up TD-SU-92-11-01</u>

The combustor was released by Maintenance at 1025 hours on August 1, 1992. Gas recirculation warming was started at 1940 hours.

The gas turbine was rolled and paralleled at 0219 hours on August 2, 1992, with the valves being opened at 0224 hours.

The bed preheater again had flame-out when the temperature control valve was ordered to the minimum fire position. The minimum fire position was increased and the preheater fire established at 0852 hours.

Again, #24 cyclone showed no signs of any ash flow.

The steam turbine was rolled and paralleled at 1353 hours on August 2.

Duct opacity was high throughout bed level increase, as was ash loading in the primary cyclone ash system.

A coal fire was initiated at 1954 hours, but was ordered off because #4 coal nozzle was plugged. Attempts to clean it were unsuccessful and at 2245 hours, the combustor was tripped. At 2335 hours, the gas turbine was tripped. The Maintenance Department was issued a clearance to allow mechanical removal and cleaning of #4 coal nozzle. (The #1 coal nozzle was also removed and cleaned.)

Start-Up TD-SU-92-11-02

The mechanical cleaning of the paste nozzles was completed by the Maintenance Department and the gas turbine was rolled and paralleled at 0511 hours on August 3, 1992. Combustor air flow was established at 0518 hours; oil fire was initiated at 0558 hours.

The #24 cyclone was still plugged.

The steam turbine was rolled and paralleled at 0911 hours.

The duct opacity again was high while establishing start bed level, and also the primary ash loading in the transport piping. This limited the rate of bed level increase.

A coal fire was initiated at 1231 hours, but was ordered off when the #4 coal paste pump did not pump through the nozzle. Attempts at clearing it were unsuccessful. A successful coal fire with five pumps was established at 1617 hours on August 3, 1992.

After increasing air flow and pressure vessel pressure, the #24 cyclone was pulsed and showed signs of at least some ash flow. (Later it plugged again.)

Sorbent injection was initiated with the east line at 1850 hours.

Bed level was increased to approximately 40 inches and bed material inventory was built to enable increase to once-through operation. Throughout this period, adjustments were made to the precipitator TRs to optimize the dust collection. The opacity was never reduced below approximately 45% during the entire period.

At 0743 hours on August 4, 1992, several indications pointed to a tube leak on the outside of the boiler (inside the combustor). The combustor was tripped at 0821 hours in order to avoid further damage from the suspected leak. Outage inspection revealed a leak in a drain connection weld on the boiler bottom header.

The gas turbine was tripped from the MCS at 1154 hours on August 4, 1992.

Start-Up TD-SU-92-12-01

The combustor was released by the Maintenance Department at 1435 hours on August 8, 1992. Gas recirculation warming was initiated at 1745 hours.

The gas turbine was rolled at 2337 hours, paralleled at 2356 hours, and the turbine valves were opened at 0001 hours on August 9, 1992.

The bed preheater was lit off at 0558 hours on August 9, 1992. Increased minimum firing set point was again used.

The bed level was increased using bed ash reinjection. The steam turbine was rolled and paralleled at 1254 hours, with a coal fire being initiated at 1349 hours.

Sorbent injection was started at 1616 hours with the east line.

Bed level was increased to approximately 50 inches and maintained to build bed ash inventory.

The stack opacity was unusually high from the time bed material was started into the bed until a bed level of approximately 80 inches was attained. Tests were conducted on the precipitator TR sets and it was determined that "back corona" existed and was preventing collection of the ash. ("Power off" rapping of each field for approximately 45 minutes cured the problem and the stack opacity was maintained at 10% in energy management mode for the remainder of the run.)

During the lower bed level condition, a total of seven dust loading tests on the precipitator inlet duct were conducted. At 0117 hours on August 10, 1992, the #4 paste pump tripped due to low splitting air flow. Manual reversing cleared the splitting air tube, but the nozzle was still plugged. Several hours later, after many unsuccessful attempts, the nozzle was cleared and the pump was returned to service at 0849 hours.

While increasing air flow, the low pressure turbine speed was quickly brought through the critical speed range of 4550 - 4610 RPM by closing the LPC inlet guide vane and increasing the air flow demand.

During the next several days, problems were experienced with #4, #5, and #6 paste pumps pumping inconsistently. The problem was, once again, caused by poor distribution of paste in the tanks.

At 0310 hours on August 13, the sorbent prep system vibrating screen motor bearings failed. Bed level was lowered to reduce sorbent usage while repairs were made. The motor was repaired and at 1514 hours, sorbent prep was started and bed level was increased.

Problems were experienced very early in the start-up with the coal prep system crusher. Skewing was a problem and the recycle rate could not be operated high enough to obtain a good product (fines) and to keep the throughput high enough to support the needed firing rate. On August 14, 1992, the screws were reinstalled above the crusher and both throughput and an acceptable coal paste were achieved.

Prepared sorbent mixing with the coal paste was tested during the week of August 17. A 50% rate was tested from August 17 through August 19, 1992, and a 100% rate was tested from August 19 through August 21, 1992.

At 1320 hours on August 21, 1992, the return roller bearing on conveyor #2 failed. Bed level was reduced to conserve coal. The bearing was replaced and on August 22, 1992, the bed level was again increased for testing of sorbent fines.

The sorbent fines mixed with the coal paste test was conducted August 24 through August 26, 1992.

After completion of the sorbent-in-paste testing and sample collection, the unit was shut down for tube bundle inspection. The combustor was tripped at 0341 hours on August 27, 1992, the unit was cooled and secured in the normal manner. The gas turbine tripped at 1028 hours. The combustor continued to be cooled for maintenance outage work.

Start-Up TD-SU-92-13-01

The combustor was released by the Maintenance Department at 1053 hours on September 13, 1992. Gas recirculation was started at 1536 hours; and vacuum was applied to the secondary ash line prior to starting the gas recirculation.

The gas turbine was rolled at 2251 hours and was paralleled at 2311 hours. The valves were reset and air heating of the combustor began at 2316 hours.

All secondary cyclone dip legs evidenced signs of being plugged, except for Numbers 22 and 24.

Bed level was increased and the steam turbine was rolled and paralleled at 1906 hours. During this time, the #24 secondary cyclone plugged.

Coal fire was ordered on at 0127 hours on September 15, 1992. The #3 paste pump failed to start and the function group was ordered off. The pump was run in recirculation locally and then was stopped. The function group was ordered on again at 0132 hours. Bed temperatures rose at an extremely fast rate. O_2 levels dropped rapidly, the boiler water circuits entered into a large swing, and the boiler circulation flow went low enough to trip the combustor at 0136 hours.

After securing the unit, the paste pumps were reversed. All indications were that the reverse sequence was acceptable.

The bed preheater was lit off at 0208 hours. The steam turbine was rolled and paralleled at 0443 hours.

At 0538 hours, a coal fire was ordered on, but the #3 coal paste pump again did not start. The function group was ordered off. It was recirculated again locally, then returned to automatic. At 0546 hours, a coal fire was again ordered on, but No. 5 paste pump was the only one which did not have an over hydraulic problem. Unsuccessful attempts were made to unplug the nozzles, and the combustor tripped at 1115 hours. The gas turbine tripped at 1257 hours.

The unit was then released to the Maintenance Department to clean the paste nozzles and the secondary cyclones.

Start-Up TD-SU-92-14-01

The gas turbine was rolled at 1332 hours on September 20, 1992, and was paralleled at 1349 hours. The valves were reset and air heating of the combustor began at 1400 hours.

The LPC was cleaned with Carboblast injection during the warming period.

The bed preheater was lit at 1922 hours. Bed level was increased. The steam turbine was rolled and paralleled at 1906 hours.

At 0121 hours on September 21, 1992, a coal fire was initiated. Bed temperatures rose very fast. Fuel master was cut, but the combustor tripped at 0128 hours on two bed temperature thermocouples greater than 1670°F.

After paste line reversing, the #2 and #3 nozzles were still plugged. The bed was taken back up into the reinjection vessels, and plans were made to remove the gas turbine from service to clean the fuel nozzles from outside of the combustor. At 0543 hours, the gas turbine tripped because of fictive disc temperature differential.

Start-Up TD-SU-14-02

After the cleaning of all six paste nozzles from the outside of the combustor, the gas turbine was rolled at 2107 hours on September 21, 1992, and was paralleled at 1349 hours. The valves were reset at 1400 hours.

The paste nozzles were checked for flow with LP nitrogen. The #1 nozzle did not show a clean flow of nitrogen. The bed level was lowered to six inches, and a reverse sequence attempted. This also failed to show good flow. It was determined that the isolation valve, HCV-B711, was not seating. The gas turbine was removed from service at 0139 hours on September 22, 1992, the valve was disassembled, and the seat repaired. The angle valve used for clean blowing was also replaced because of leakage and opening problems.

Start-Up TD-SU-92-14-03

Following the repair to the #1 paste line isolation valve, the gas turbine was rolled at 1001 hours on September 22, 1992. Parallel was at 1018 hours and the valves were opened at 1029 hours.

The bed preheater was lit at 1242 hours. Bed level was increased and the steam turbine rolled and paralleled at 1553 hours.

Coal ignition was accomplished at 1944 hours. Bed temperatures again increased very rapidly. The fuel master set point was lowered to 10.5%. Air flow was increased to 425 kpph, freeboard mixing was initiated, then sorbent injection with the east line was started at 2035 hours.

Bed level was increased to 45 inches and held there to build bed material inventory.

When sorbent injection swapped to the west line, material would not feed out of the bottom of the injection vessel. The system was operated on single-line operation with the east line. Maintenance worked on the west injection vessel outlet. Wet material was found to be the problem. (This line was returned to service at 1436 hours on September 23, 1992.)

Once-through operation was accomplished at 0740 hours on September 23, 1992, with an indicated bed level of 62 inches.

Increased bed level to the 112 inch tap to hold there for the intended limestone injection test.

Estimates are that the limestone sorbent arrived in the bed at 2200 hours.

At approximately 0200 hours on September 24, 1992, the bed conditions became unstable. Evaporator outlet tube temperatures were increasing into alarm, hot and cool spots were observed in the bed, and some sinters were found in the bed ash removal system.

The splitting air flow was increased and bed level decreased in an attempt to eliminate sintering and to improve the bed dynamics. Conditions did not improve and at 0510 hours, the combustor tripped because of three bed temperature thermocouples less than 1200°F.

All bed material was removed, the gas turbine removed from service at 1014 hours, the combustor was cooled and then released to the Maintenance Department for outage work.

Start-Up TD-SU-92-15-01

The combustor was released by Maintenance at 2000 hours on September 28, 1992.

The combustor warming was accomplished by starting the air circulation, establishing 0 pressure in the freeboard with 741/758 System, then warming the boiler circuits.

The gas turbine was rolled at 0706 hours on September 29, 1992. Parallel was at 0726 hours, and the valves were opened at 0733 hours. Unusual vibration and noise were detected on the LPC housing during the air heating period.

The bed preheater was lit at 1346 hours. The test O_2 analyzer lines were found to have leaks just outside of the combustor. These lines were plugged with high temperature RTV to prevent leaks.

Water mist nozzles were used on the inlet to the precipitator in an attempt to increase the collection of the ash. This appeared to help until after coal fire when the bed level was increased.

Bed level was increased for the steam turbine roll. The steam turbine stop valve trip solenoid coil failed and was replaced. At 2031 hours, the steam turbine was rolled and was paralleled at 2132 hours.

Coal fire was initiated at 2222 hours. The #3 paste pump was pumping much lower flow than the others. The bias was increased to 1.5. This helped, but tuning in logic was required to bring the flow up to what was needed. Bed temperatures increased slowly, and the fuel master set point was increased to 12.5%.

The vibration on #1 and #2 bearings of the gas turbine increased until air flow was increased above 375 kpph. Air flow increase was stopped at

400 kpph, splitting air flow bias set to 1.25, freeboard mixing was initiated, then sorbent injection with the east line was started at 2327 hours. Splitting air flow bias was increased .05% at a time to a bias of 1.55 at a bed level of 45 inches (splitting air flow at this time was 3875 ppm).

Bed level was maintained at 45 inches to build bed inventory.

Once-through operation was accomplished at 0557 hours on September 30, 1992.

At approximately 0800 hours, water was found in the economizer outlet duct drain. The precipitator inlet duct water injection was shut down to determine if this water was coming from that operation. (Outage inspection proved that this was true.)

At 1143 hours, air flow was decreased because of high vibration on the #1 bearing of the gas turbine.

Splitting air flow bias was increased to 1.58 and a flow of 3950 kpph.

Bed level was increased to the 112 inch tap to hold there for the intended limestone injection test.

Some sinters were found in the bed ash removal system and at approximately 2100 hours, the sinter production seemed to be increasing, and evaporator tube temperatures and bed temperatures became erratic. Water was added to the coal paste tank in an effort to cause the paste to split better in the bed. Splitting air flow was increased to try to improve conditions. Nothing appeared to have any significant effect.

The combustor was manually tripped at 0101 hours on October 1, 1992, because of the very poor bed dynamics.

All bed material was removed, the gas turbine removed from service at 0446 hours, and the combustor was cooled and then released to the Maintenance Department for outage work.