HEALY CLEAN COAL PROJECT

PROJECT PERFORMANCE AND ECONOMICS REPORT
FINAL REPORT: VOLUME 2

APRIL 2001

Alaska Industrial Development and Export Authority
Anchorage, Alaska

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A report on a project conducted jointly under Cooperative Agreement No. DE-FC22-91PC90544 between the United States Department of Energy and the Alaska Industrial Development and Export Authority

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ABSTRACT

The Healy Clean Coal Project (HCCP) is a 50-megawatt (MWe), coal-fired, electric power generating facility at a site near Healy, Alaska. Design, construction, and operation of the facility were in response to the U.S. Department of Energy (DOE) Program Opportunity Notice (PON) issued in May 1989 for the Clean Coal Technology Program. The facility demonstrated the TRW Clean Coal Combustion System and the Babcock & Wilcox/Joy Spray Dryer Absorber (SDA) System, an integrated air pollution control process designed to minimize emissions of oxides of nitrogen (NO_X), sulfur dioxide (SO_2), and particulates while firing a broad range of coals.

The final total estimated project cost is $292,300,000. The DOE's cost share is $117,327,000, with the remaining funds coming from contributions from various project participants and an Alaska Industrial Development and Export Authority (AIDEA) bond sale.

The HCCP Demonstration Test Program (DTP) was conducted from January 1998 through December 1999, accumulating approximately 8,500 hours of coal-fired operation, the equivalent of about 1 year of continuous operation. As part of the DTP, a 90-Day Commercial Operation Test that resulted in the generation of 102,373 MWh of energy at a capacity factor of 94.79 percent was completed in December 1999. The fuel flexibility and corresponding positive economic and waste minimization benefits associated with the new combustor technology were demonstrated by burning 83 percent waste coal, including coal fines, over the 90-Day Commercial Operation Test period. This blend of run-of-mine and waste coal, which had an average daily heating value range of 6,739 Btu/lb to 7,844 Btu/lb, is considered to be fairly representative of coal that would be supplied for the life of the plant. In addition to achieving these results, all generation was achieved within permitted limits for emissions, with the exception of short-term SO_2 and opacity exceedances that occurred during plant startup and equipment repairs.

The HCCP accomplished the objectives set out in the Clean Coal Technology III proposal selected under PON No. DE-PS01-89FE6825. Cost growth of approximately 50 percent occurred during the project, largely as a result of a 2-year delay in environmental permitting, an additional year of demonstration testing, litigation by the power purchaser, and design changes. However, the technology objectives of the program were accomplished.

A 300-MWe, scaled-up version of the HCCP (CC-300) found that the demonstration technologies are a very feasible alternative to Pulverized Coal (PC) and Circulating Fluidized Bed (CFB) power plants. The CC-300 would have competitive capital and operating costs and improved environmental performance. The technologies should be considered an attractive alternative to conventional coal-fired technologies for specific applications.

The results of a study comparing various coal technologies suggest that the coal-fired power generating technology selected for a specific application would depend on the specifics of a particular site because the capital costs and the operating and maintenance costs of the three technologies compared are relatively similar. These "site specifics" would include the

anticipated requirements of environmental emission/discharge permits; the quality, cost, and proximity of the coal supply; the availability and quality of other raw materials (lime, limestone, etc.); and other related factors.

EXECUTIVE SUMMARY

The Healy Clean Coal Project (HCCP) is a 50-megawatt (MWe), coal-fired, electric power generating facility at a site near Healy, Alaska. Design, construction, and operation of the facility were in response to the U.S. Department of Energy (DOE) Program Opportunity Notice (PON) issued in May 1989 for the Clean Coal Technology Program. The facility demonstrated new technologies available to meet power needs in central Alaska in an environmentally acceptable manner.

The HCCP is the first commercial-scale demonstration of the TRW Clean Coal Combustion System and the Babcock & Wilcox/Joy Spray Dryer Absorber (SDA) System, an integrated air pollution control process designed to minimize emissions of oxides of nitrogen (NO_X), sulfur dioxide (SO_2), and particulates while firing a broad range of coals. The emissions of NO_X are reduced in the coal combustion process by the use of a fuel- and air-staged combustor system and a boiler that controls fuel- and thermal-related conditions that inhibit NO_X formation. The slagging combustor and boiler unit also functions as a limestone calciner and first-stage SO_2 removal device in addition to its heat recovery function. A single SDA vessel and a baghouse accomplish secondary and tertiary SO_2 capture, respectively. Ash collection is achieved by removal of molten slag in the coal combustors, removal of bottom ash from the boiler, and removal of fly ash particulates in the baghouse downstream of the SDA.

The final total estimated project cost is $292,300,000. The DOE's cost share is $117,327,000, with the remaining funds coming from contributions from various project participants and an Alaska Industrial Development and Export Authority (AIDEA) bond sale.

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The HCCP Demonstration Test Program (DTP) was conducted from January 1998 through December 1999, accumulating approximately 8,500 hours of coal-fired operation, the equivalent of about 1 year of continuous operation. As part of the DTP, a 90-Day Commercial Operation Test that resulted in generation of 102,373 MWh of energy at a capacity factor of 94.79 percent was completed in December 1999.

All emissions were within permitted limits, with the exception of short-term SO_2 and opacity exceedances that occurred during plant startup and equipment repairs. As part of the DTP air emission compliance demonstration and the state Air Permit requirements, source testing was performed in June 1998 and March 1999 to confirm the validity of the plant's Continuous Emission Monitoring System (CEMS) for NO_X, SO_2, and carbon dioxide (CO_2) and to verify the carbon monoxide (CO) and particulate emissions. The emission monitoring system met all Environmental Protection Agency (EPA) standards for accuracy. As described in this report, the HCCP demonstrated the ability to maintain air emissions at levels below both the state Air

Permit limits and the EPA's applicable New Source Performance Standards (NSPS) limits (40 CFR 60 Subpart Da) and, furthermore, to meet the more stringent DTP emission goals.

- NO_X emissions were monitored continuously by the CEMS. During the DTP, the range of NO_X emissions was 0.208 to 0.278 lb/million Btu, with a typical emission level of 0.245 lb/million Btu (30-day rolling average). During the 90-Day Commercial Operation Test, NO_X emissions averaged 0.275 lb/million Btu (30-day rolling average). The applicable NSPS limit for NO_X for the HCCP is 0.5 lb/million Btu, the Air Permit limit is 0.350 lb/million Btu, and the DTP emission goal is 0.20 to 0.35 lb/million Btu.

- SO_2 emissions were monitored continuously by the CEMS. During the DTP, SO_2 emissions averaged 0.038 lb/million Btu (30-minute average corrected to 3 percent oxygen [O_2]). During the 90-Day Commercial Operation Test, SO_2 emissions averaged approximately 0.060 lb/million Btu. The Air Permit limit is either 0.086 lb/million Btu (annual average) or 0.10 lb/million Btu (3-hour average).

- CO emissions were monitored continuously by a stack O_2/CO analyzer. During the DTP, CO emissions were typically 30 to 40 ppm (30-minute average corrected to 3 percent O_2). During the 90-Day Commercial Operation Test, CO emissions were typically in the 20 to 50 ppm range. The Air Permit limit and the DTP emission goal are 202 and 206 ppm, respectively, corrected to 3 percent O_2.

- Opacity was monitored continuously by the CEMS. The opacity measurements were used as an on-line indication of particulate emissions. During the DTP, typical opacity measurements ranged from 2 percent to 6 percent, based on a 30-minute average. Bag maintenance was higher during 1998 due to premature baghouse filter bag failures caused by poor inlet gas distribution. This problem was corrected in 1999. During the 90-Day Commercial Operation Test, opacity averaged approximately 5.5 percent, which is significantly below the permit limits of 20 percent opacity for a 3-minute average and 27 percent opacity for one 6-minute period per hour. The particulate emission limit, Air Permit limit, and DTP emission goal are 0.03, 0.02, and 0.015 lb/million Btu, respectively.

The 90-Day Commercial Operation Test demonstrated the fuel flexibility and the corresponding positive economic and waste minimization benefits associated with the new combustor technology by burning 17 percent run-of mine (ROM) coal and 83 percent waste coal including coal fines (of which 35 percent was non-fines waste coal) over the 90-day test period. This blend of ROM and waste coal, which had an average daily heating value range of 6,739 Btu/lb to 7,844 Btu/lb, is fairly representative of coal that would be supplied for the life of the plant.

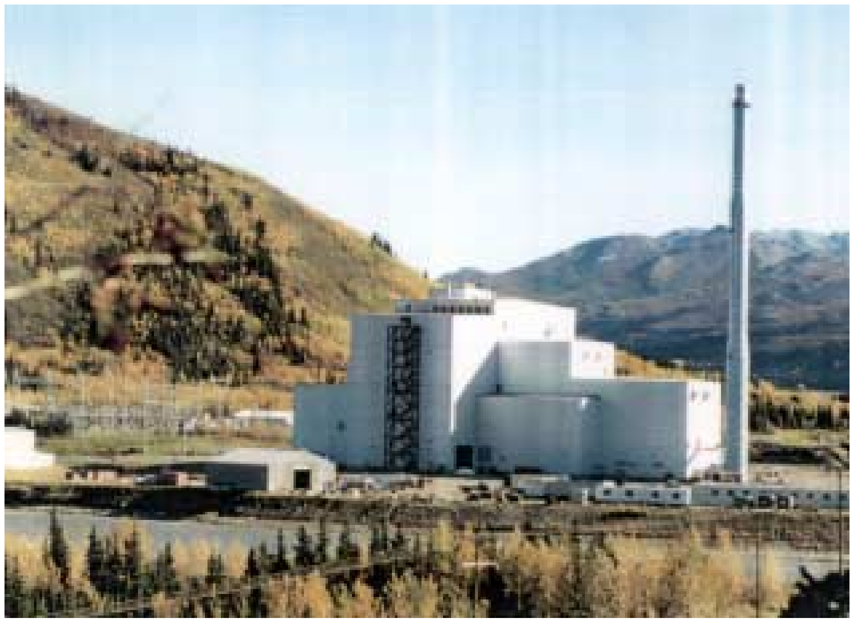
A 300-MWe, scaled-up version of the HCCP (CC-300) found that the demonstration technologies are a very feasible alternative to Pulverized Coal (PC) and Circulating Fluidized Bed (CFB) coal plants. The CC-300 would have competitive capital and operating costs and improved environmental performance. The technologies should be considered an attractive alternative to conventional coal-fired technologies for specific applications.

The results of a study comparing various coal technologies suggest that the coal-fired power generating technology selected for a specific application would depend on the specifics of a particular site because the capital costs and the operating and maintenance costs of the three technologies compared are relatively similar. These “site specifics” would include the anticipated requirements of environmental emission/discharge permits; the quality, cost, and proximity of the coal supply; the availability and quality of other raw materials (lime, limestone, etc.); and other related factors.

1.0 INTRODUCTION

1.1 Purpose of the Project Performance and Economics Report

The purpose of the Project Performance and Economics Report (Final Report: Volume 2) is to consolidate, for the purpose of public use, all relevant non-proprietary information on the project other than that already included in the Public Design Report (Final Report: Volume 1) (AIDEA 2000f).



Although limited to non-proprietary data, it contains sufficient information to provide a technical and economic overview of the project. The report also serves as the primary reference for parties interested in the technology to determine the achievements of the project and to assist them in assessing the technical and economic applicability of the technology to their particular situation.

1.2 Overview of the Project

1.2.1 Background and History of the Project

The Alaska Industrial Development and Export Authority (AIDEA) has designed, constructed, and operated a nominal 50-megawatt (MWe) coal-fired, electric power generating facility at a site near Healy, Alaska. The Healy Clean Coal Project (HCCP) was built in response to the U.S. Department of Energy (DOE) Program Opportunity Notice (PON) issued in May 1989 for the Clean Coal Technology Program. The facility was built to demonstrate new technologies and to meet local power needs in an environmentally acceptable manner. Demonstration of the new technology has been completed and is considered successful; however, design changes are needed to improve wear resistance of the mill exhausters or to replace the mill exhausters with primary air fans, if it is considered commercially viable.

An industrial-scale version of the TRW Clean Coal Combustion System (40 million Btu/hr) was first tested in TRW's Cleveland, Ohio, test facilities, accumulating 10,000 hours of operation burning a wide variety of coal types. In 1990, these tests were conducted using coal from Usibelli Coal Mine, Inc. (UCM) and using limestone to produce and collect flash-calcined material (FCM). In late 1990 and 1991, the FCM was shipped to NIRO's facilities in Sweden, and the material was tested with the NIRO atomizer. These tests were deemed successful. During this time, DOE had selected the Orange & Rockland plant for a retrofit application of the TRW combustors. This project was to be the first full-scale application as a retrofit, but it was subsequently cancelled, which resulted in the HCCP being the first full-size, grass roots application of the technology.

In 1992, AIDEA, TRW, and Stone & Webster Engineering Corporation (Stone & Webster) agreed that, due to spatial limitations, the combustors should bottom-fire the boiler. In 1992, in Ontario, Canada, Foster Wheeler Energy Corporation (Foster Wheeler) conducted flow-model tests on the boiler to determine the optimal tube arrangement considering the proposed bottom firing of the boiler. The TRW Cleveland Test Facility utilized an indirect coal feed system with interim coal storage. After review by TRW, AIDEA, Golden Valley Electric Association, Inc. (GVEA), Foster Wheeler, and Stone & Webster, the TRW coal feed system was changed to a direct feed system. This eliminated a proposed system that included the need to store pulverized coal and resulted in a coal feed system with high pressure at the outlet of the pulverizers and mill exhauster fans to provide the additional pressure required by the changes. The coal feed system was first modeled at the pilot scale in TRW's labs in Redondo Beach, California. This cold test was followed by construction of a full-scale precombustor with a direct coal feed system, which was tested in TRW's Capistrano, California, test facilities using UCM's coal. These tests confirmed the performance of the new technology.

1.2.2 Project Organization

AIDEA was responsible for all aspects of project performance. AIDEA served as Project Manager, as well as authorized representative for the technical and administrative elements of all work performed under the Cooperative Agreement with DOE.

Other project participants, DOE, GVEA, UCM, TRW, Stone & Webster, and Babcock & Wilcox (B&W)/Joy Technologies Inc. (Joy) played important roles in the overall completion of the project. TRW and B&W/Joy provided the demonstration technologies. Foster Wheeler supplied the boiler. Stone & Webster was the design engineer. UCM was the coal supplier and provided coal data for design. GVEA provided some oversight of the design, provided operators during demonstration testing, and is expected to be the operating contractor during subsequent commercial operations. The original organization chart for the project, as presented in the DOE proposal, is shown in Figure 1-1. B&W subsequently purchased all of Joy's assets.

1.2.3 Project Description

The HCCP is a mine-mouth plant located near UCM. UCM coal is a low heating value, low-sulfur, highly volatile coal.

The technology demonstrated in the HCCP combines the TRW Clean Coal Combustion System and the B&W/Joy Spray Dryer Absorber (SDA) System into a single, integrated, combustion/control process. These technologies have been designed to achieve reductions in emission of sulfur dioxide (SO_2), oxides of nitrogen (NO_X), and particulates while meeting

future energy needs from coal-fired generation in an environmentally acceptable manner. A block flow diagram of the new technology is provided in Figure 1-2.
After more than 5 years of planning, design engineering, and permitting activities, the project celebrated its groundbreaking ceremony at Healy, Alaska, on May 30, 1995. Most of the major plant equipment was delivered to the Healy site in 1996. Construction of the plant was completed in November 1997, with startup overlapping construction and commencing in July 1997. Coal-fired operations started in January 1998.

1.2.4 Site

The HCCP is located near Healy, Alaska, 250 miles north of Anchorage and within approximately 7.5 miles of Denali National Park and Preserve. The facility is sited adjacent to the existing Healy Unit No. 1, a 25-MWe, pulverized coal, low-NO_X burner power plant. The combined facilities are on the east bank of the Nenana River where the Healy Spur Highway crosses the Nenana River and adjacent to a railroad spur. The facility is approximately 3 miles from UCM, which minimizes coal transportation costs. These factors contributed to the selection of the HCCP site for the demonstration. The site plan is shown on Figure 1-3. The facility is located within the central region of Alaska and supplies power to the Interior Railbelt and the Fairbanks area.

1.2.5 Project Schedule

Conceptual feasibility studies related to the HCCP and the proposal to DOE began in 1989. In that year, DOE selected the HCCP as part of Round III of the Clean Coal Technology Program. Between 1989 and 1991, AIDEA negotiated and established the project participant roles, established the funding sources for the HCCP, collected environmental background data, negotiated a Power Sales Agreement (PSA) with GVEA, and obtained Alaska Public Utilities Commission approval of the PSA and a Certificate of Public Convenience to operate the facility. The technology suppliers conducted pilot plant programs and developed conceptual designs.

In late 1991, critical contracts with Stone & Webster, Foster Wheeler, TRW, and B&W/Joy were awarded. The Stone & Webster contract was for engineering, the TRW contract was for the combustors and associated ancillary equipment, the Foster Wheeler contract was for the boiler and for boiler and combustor installation, and the B&W/Joy contract was for the SDA System. To minimize any financial risk during this period, AIDEA limited the technology suppliers' work to engineering only, and no fabrication was released. The Environmental Impact Statement (EIS) and the Prevention of Significant Deterioration (PSD) air quality permit were also being prepared at this time.

During 1992 and 1993, the National Park Service (NPS) and the Trustees for Alaska (Trustees) raised considerable objection to the HCCP, particularly regarding potential visibility impacts at the boundary of Denali National Park and Preserve, approximately 7.5 miles from the site. The Trustees filed legal actions to prevent the HCCP from proceeding. To overcome these objections, numerous detailed studies were performed, visibility and air quality monitoring of current conditions was conducted, and conservative elements were included in the design to minimize any impact on the environment. DOE's Final EIS and Record of Decision were issued in December 1993 (DOE 1993). In early 1994, final agreements were reached with all parties, thereby allowing the HCCP to proceed. This action completed Phase 1 of the Cooperative Agreement with DOE. The environmental actions resulted in a 2-year delay in the project and approximately $15 million in additional costs.

Suppliers were released for fabrication in 1994, and the prime construction contract was awarded in late 1994. The prime construction contractor provided much of the small equipment and all of the erection material such as cable, steel, pipe, etc. Groundwork commenced in late spring 1995. Earthworks, substructure, and partial steel construction were completed in 1995. During the winter of 1995-1996, construction was halted due to weather constraints. In 1996 and 1997, equipment and material were installed, with this work completed in November 1997. This completed Phase 2 of the Cooperative Agreement with DOE. Photographs of the HCCP site during construction, at completion of site construction, and at startup are provided in Figures 1-4, 1-5, and 1-6, respectively.

Construction testing and startup commenced in July 1997. With the exception of coal firing, all start-up activities were completed in 1997. Coal firing and startup of the associated combustion equipment was completed in March 1998 as part of the Demonstration Test Program (DTP). The DTP commenced in January 1998 and was completed in December 1999. As part of the DTP and as a requirement of the PSA, a 90-Day Commercial Operation Test was performed during late 1999. An Independent Engineer established the test protocol, observed the testing, and reviewed the test results. The results were deemed inconclusive by the Independent Engineer, primarily due to concerns that the test was performed with a coal having a heating value slightly above the design specification and that excess staffing was on site during the test. This completed Phase 3 of the Cooperative Agreement with DOE, except for submittal of the project reports.

Because of the inconclusive results of the 90-Day Commercial Operation Test and after dispute and some litigation, GVEA and AIDEA agreed on a staged retrofit program. This includes studying the technical, economic, and regulatory feasibility of either a full retrofit to low-NO_X burners and conventional limestone scrubbing or a limited retrofit that would include correction of deficiencies in the new technology identified by the Independent Engineer during the 90-Day Commercial Operation Test. If the full retrofit is not feasible, either GVEA would undertake a limited retrofit or the HCCP would be returned to AIDEA for operation, mothballing, or decommissioning.

1.3 Objectives of the Project

The objectives of the project are as follows.

- To demonstrate a new power plant design that features innovative integration of an advanced combustor and heat recovery system coupled with both high- and low-temperature emission control processes.

- To demonstrate reduced emission levels well below the requirements of Environmental Protection Agency (EPA) New Source Performance Standards (NSPS) (found in 40 CFR 60 Subpart Da) for new utility coal-fired units.
- To meet future energy needs in an environmentally acceptable manner.

There were no changes to the project objectives developed in the original proposal submitted to DOE.

1.4 Significance of the Project

The HCCP is the first commercial-scale demonstration of the TRW Clean Coal Combustion System coupled with the SDA System. The demonstration was considered to be successful. The HCCP accomplished the objectives set out in the proposal to DOE submitted under PON No. DE-PS01-89FE6825. Cost growth of approximately 50 percent occurred during the project as a result of a 2-year delay in environmental permitting, an additional year of demonstration testing, litigation by the power purchaser, and design changes. However, the technology objectives of the program were accomplished.

The commercial use of the HCCP will fulfill future needs for electrical power with less environmental impact than conventional coal-based power systems. The demonstration of the state-of-the-art clean coal technologies of the HCCP will help the electric generation industry by showing that this equipment can be used to produce cost-effective electrical power while reducing SO_2, NO_X, and particulate emissions. Environmental impacts such as transboundary and interstate pollution would be reduced or eliminated.

The State of Alaska views the project as a major step in the development of Alaska's Interior region (Nenana Basin) coal resource for use in producing low cost, environmentally sound electrical power. The base-loaded energy costs from HCCP are currently greater than gas-fired opportunity energy from the Anchorage bowl but, in AIDEA's opinion, are competitive with some other base-loaded facilities in Alaska. If gas prices rise significantly, the HCCP may become commercially and economically superior to other alternatives.

1.5 DOE's Role in the Project

DOE's role is to monitor the participant's progress in developing the project and, to the extent specifically authorized in the Cooperative Agreement, to have a substantial role in project decision-making. DOE has partially financed and facilitated development of the project through its Clean Coal Technology Program, a first-of-its-kind coal technology that offers superior environmental performance.

DOE prepared the EIS and participated in the negotiations necessary to obtain the state Air Permit. AIDEA provided monthly and quarterly progress reports to DOE, and DOE provided comments on the project direction and progress. DOE also participated in most major technical decisions involving the project and provided a comprehensive review of all reports and reporting.

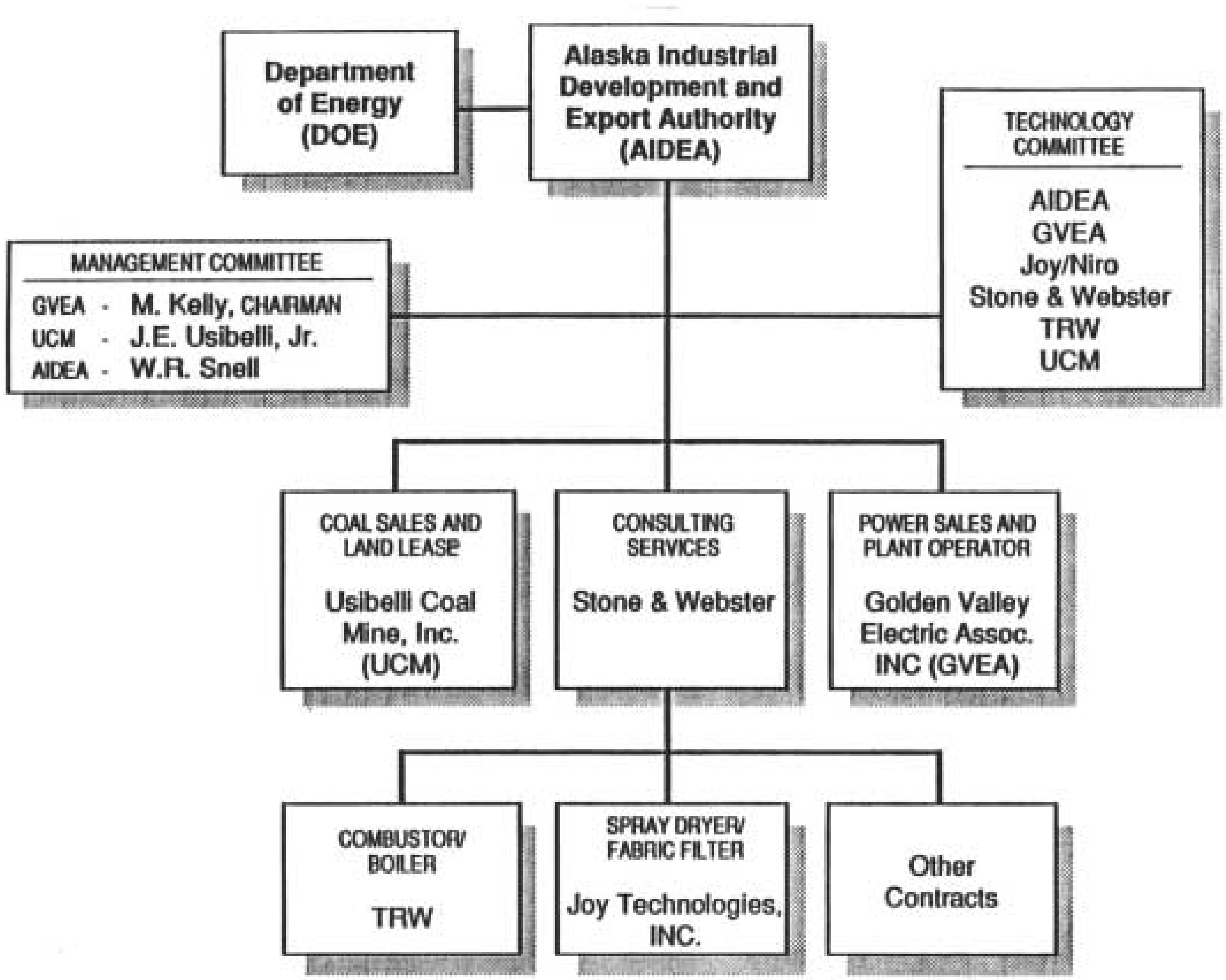


Figure 1-1 Healy Clean Coal Project Organization

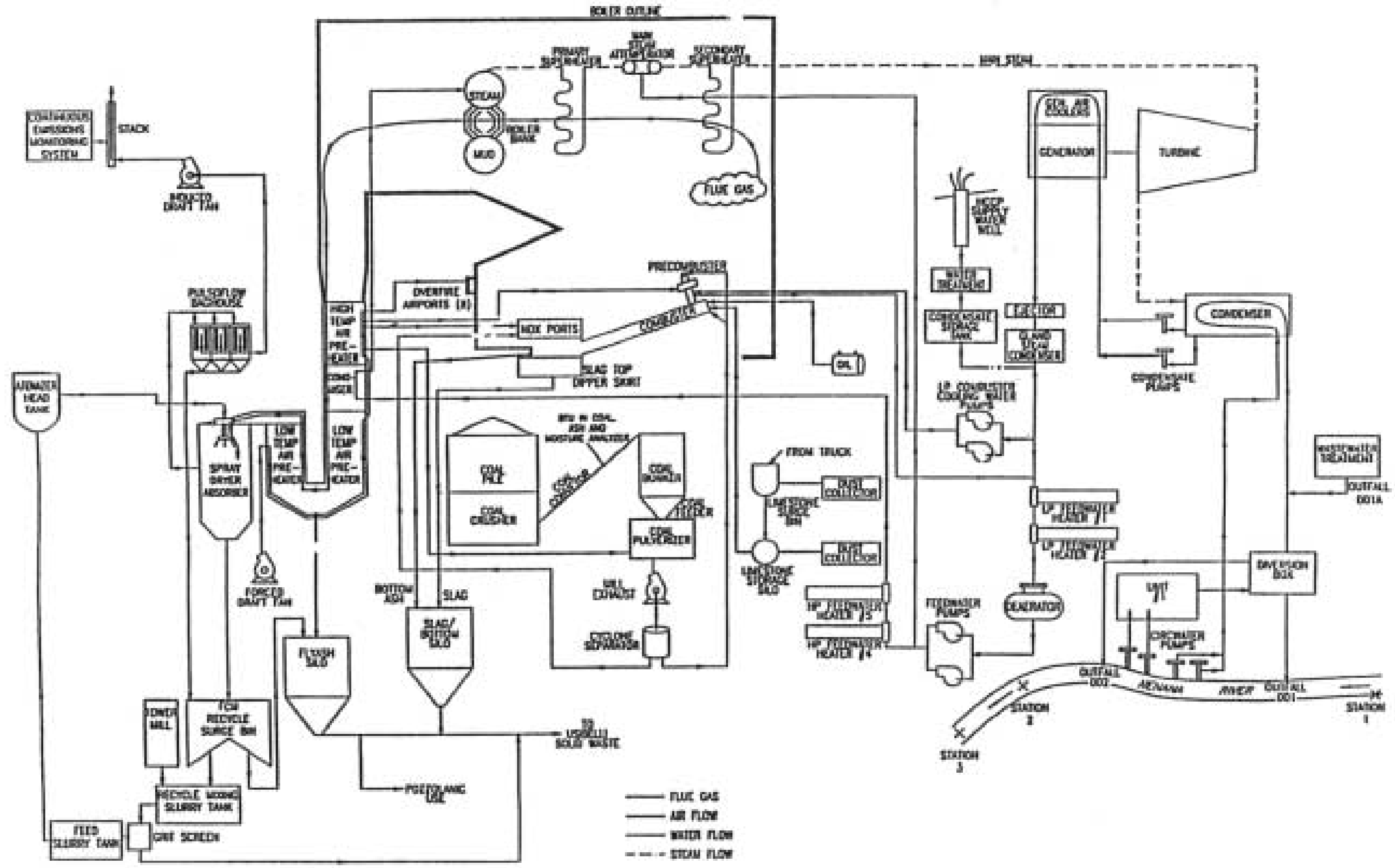


Figure 1-2 Healy Clean Coal Project Process Flow Diagram

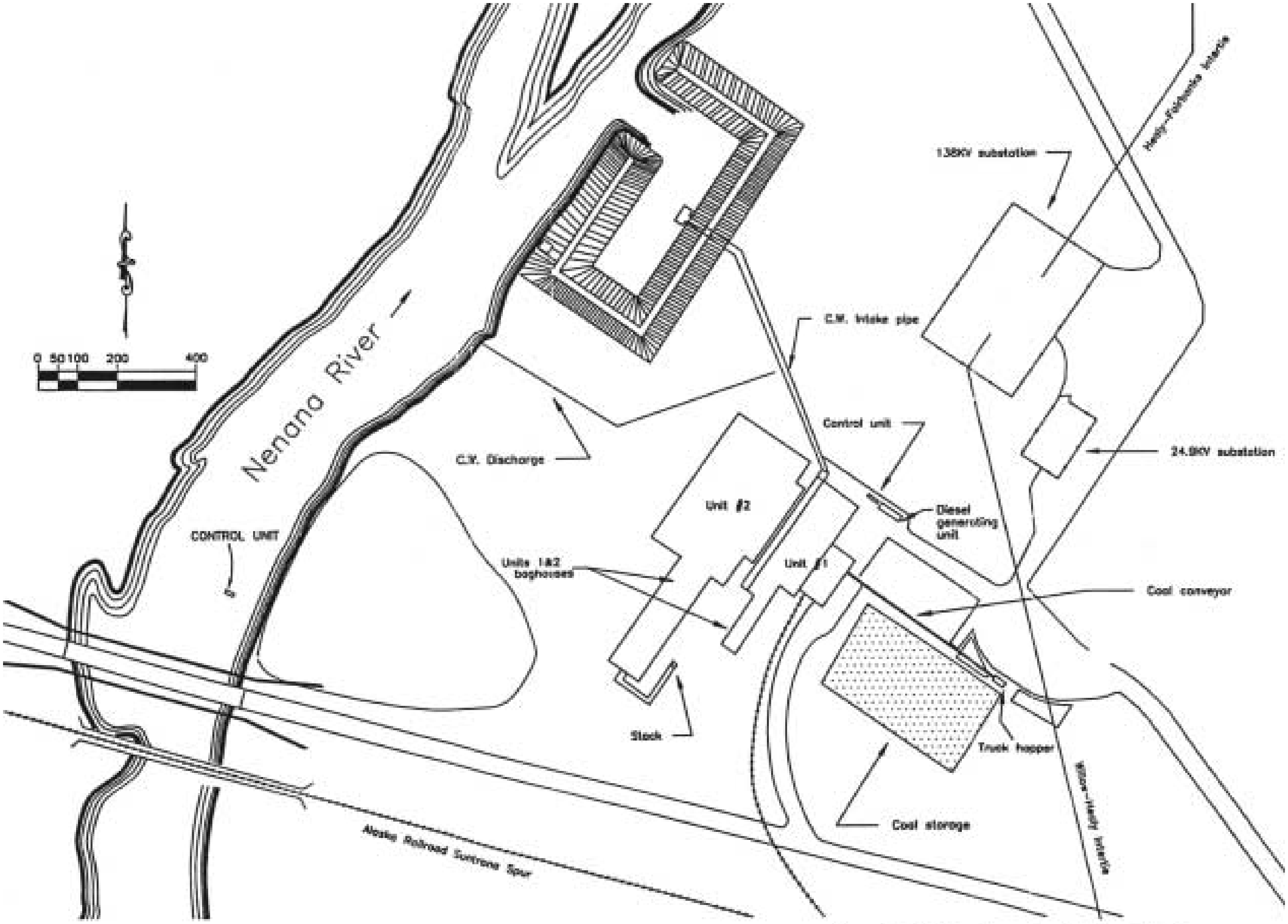


Figure 1-3 Healy Clean Coal Project Site Plan

Figure 1-4 Site Construction Complete – 1997 (side view).

Figure 1-5 Site Construction Complete – 1998 (aerial view).

Figure 1-6 HCCP Complete at Startup.

2.0 TECHNOLOGY DESCRIPTION

2.1 Description of the Demonstration Technology

2.1.1 Combustion Boiler System

The HCCP utilizes a new power plant design that features the integration of advanced coal combustion and emission control processes. The integrated TRW Clean Coal Combustion System and the B&W/Joy SDA are the most important features of the HCCP. The integrated air pollution control process that results from the HCCP configuration of components has been designed to minimize emissions of SO_2, NO_X, and particulates from the facility while firing a broad range of coals.

NO_X emissions are reduced in the coal combustion process by use of the fuel and air-staged combustor system and a boiler that controls fuel and thermal-related conditions that inhibit NO_X formation. In addition to its heat recovery function, the TRW Clean Coal Combustion System, which features a slagging combustor boiler system, also functions as a limestone calciner and first-stage SO_2 removal device. A single SDA vessel and a baghouse accomplish secondary and tertiary SO_2 capture, respectively. Ash collection is achieved by removal of molten slag in the coal combustors, removal of bottom ash from the boiler, and removal of fly ash particulates by the fabric filter system in the baghouse downstream of the SDA.

The TRW Clean Coal Combustion System has been designed for installation on the boiler furnace to provide efficient combustion, maintain effective limestone calcination, and minimize the formation of NO_X emissions. The main combustor components include a precombustor, a main combustor, a slag recovery section, a tertiary air windbox, a pulverized coal and limestone feed system, and a combustion air system. In a unique arrangement, the slagging combustors are bottom-mounted on the boiler hopper because of spatial limitations and cost benefits.

The coal-fired precombustor is used to increase the air inlet temperature to the main combustor for optimum slagging performance. The precombustor burns approximately 25 to 40 percent of the total coal input to the combustor. Combustion is staged to minimize NO_X formation.

The main slagging combustor consists of a water-cooled cylinder, which is sloped toward a slag opening. The remaining coal is injected axially into the combustor, is rapidly entrained by the swirling precombustor gases and additional air flow, and is burned under substoichiometric (fuel-rich) conditions for NO_X control. The ash contained in the burning coal forms drops of molten slag that flows along the water-cooled walls as a result of the centrifugal force resulting from the swirling gas flow. The molten slag is driven by aerodynamic and gravity forces through a slot into the bottom of the slag recovery section where it falls into a water-filled tank and is removed by the slag removal system. Approximately 80 percent of the ash in the coal is removed as molten slag.

The hot gas, which contains carbon dioxide (CO_2), carbon monoxide (CO) and hydrogen (H_2), is then ducted through the hot gas exhaust duct from the slag recovery section to the furnace. To ensure complete combustion in the furnace, additional air is supplied from the tertiary air windbox to NO_X-control ports and to final over-fire air ports located in the furnace.

Pulverized limestone is fed into each combustor for SO_2 control. While passing into the boiler, most of the limestone ($CaCO_3$) is converted to flash-calcined lime (CaO) by the following reaction:

$$CaCO_3 + heat \Rightarrow CaO + CO_2 \qquad \text{[Equation 1]}$$

The mixture of this flash-calcined lime and the ash that was not removed by the combustors is called flash-calcined material (FCM). Some sulfur capture by the entrained CaO also occurs at this time, but the primary SO_2 removal mechanism is through a multiple-step process of spray drying the slurried and activated FCM solids, as described in the next section,.

Using slagging combustor technology and known combustion techniques, NO_X emissions in the boiler were demonstrated at levels significantly below EPA NSPS applicable to the HCCP. The HCCP combustors achieve NO_X control as a combination of the following factors.

- The combustor functions as a well-stirred reactor under substoichiometric conditions for solid fuel combustion by converting the solid fuel components to a hot, partially oxidized fuel gas in an environment conducive to destroying the complex organic fuel-bound nitrogen compounds that could easily be oxidized to NO_X in the presence of excess oxygen.

- The combustor's water-cooled walls absorb approximately 10 to 25 percent of the total available heat input to the combustor.

These two conditions together reduce the potential for combustion temperatures in the furnace to be high enough to decompose molecular nitrogen in the combustion air into forms that can produce thermal NO_X by reacting with excess oxygen.

When the exhaust gases leave the combustor, the coal has already been mixed with approximately 80 to 90 percent of the air theoretically necessary to complete combustion. A portion of the remaining 10 to 20 percent of the air is then allowed to mix slowly with the hot fuel gases exiting the combustor and entering the furnace. The hot gases radiate their heat to the furnace walls at rates faster than combustion is allowed to occur so that gas temperatures slowly decay from those at the furnace entrance. After the furnace gases have cooled sufficiently, a second, and possibly a third, stage of furnace combustion air injection occurs as necessary to complete the coal combustion process in a controlled oxidizing atmosphere so that combustion gas temperatures are maintained below the thermal NO_X floor where significant NO_X formation begins. This contrasts with a traditional coal-fired furnace where pulverized coal is burned in suspension at high excess air rates. Resulting gas temperatures from pulverized coal furnaces typically rise significantly above the 2,800° F temperature maintained in the furnace. In the traditional furnace, the pulverized coal is relatively poorly mixed with low-NO_X wall burner/suspension firing techniques, and local areas of combustion in the presence of stoichiometric oxygen create hot zones within the flame. These hot, turbulent stoichiometric zones can produce significant NO_X levels in the area of the burner throats. This tendency for high, localized NO_X formation is minimized with the demonstration technology's slagging combustor through slow, controlled mixing of furnace combustion air with the partially cooled, well-mixed fuel gases discharging from the combustor into the lower furnace NO_X-control zone.

The HCCP also demonstrated other NO_X reduction techniques, including furnace NO_X ports and over-fire air injection.

2.1.2 SDA System

Once FCM is produced in the furnace via Equation [1], it is removed in the fabric filter system. A portion of the material is transported to disposal. Most of the material, however, is conveyed to a mixing tank, where it is mixed with water to form a 45 percent FCM solids slurry. The lime-rich FCM is slaked by agitation of the suspended slurry. A portion of the slurry from the mixing tank passes directly through a screen to the feed tank, where the slurry is continuously agitated. The remainder of the slurry leaving the mixing tank is pumped to a grinding mill, where the suspension is further mechanically activated by abrasive grinding.

By grinding the slurry in a mill, the FCM is activated by mechanical processes whereby the overall surface area of available lime is increased and coarse lime particle formation is avoided. Thus, the mill enhances the slaking condition of the FCM and increases the surface area for optimal SO_2 absorption. FCM slurry leaving the tower mill is transported through the screen to the feed tank.

Feed slurry is pumped from the feed tank to the SDA, where it is atomized via rotary atomization using B&W/Joy dry scrubbing technology. The SO_2 in the flue gas reacts with the FCM slurry as water is simultaneously evaporated. The dry reaction product is removed via the SDA hopper or baghouse catch. The SO_2 is further removed from the flue gas by reacting with the dry FCM on the baghouse filter bags. The system is designed to include steam heat activation of the slurry.

2.2 Other Process Systems

The demonstration technology of the integrated advanced coal combustion and emission control processes provided by the TRW Clean Coal Combustion System and the B&W/Joy SDA are described in Section 2.1. The other major process systems used in the HCCP include the following.

Boiler

Steam to drive the turbine-generator is generated in the boiler that is fired by the TRW Clean Coal Combustion System. The steam generated in the boiler flows to the turbine and then, after releasing its energy to generate electricity, condenses and returns to the boiler as feedwater to be reboiled and again superheated in the boiler, thus completing the steam cycle.

Turbine

The turbine-generator, condenser, condensate pumps, boiler feed pumps, feedwater heaters, and other equipment are required to convert the high-pressure, high-temperature steam energy into electrical energy. The turbine-generator converts the energy in high-temperature, high-pressure steam (950° F, 1,250 psig) to electrical energy. The electricity is transmitted to the main transformer and then to the substation for regional distribution.

Baghouse

The baghouse removes particulates, including solid sulfur compounds, from the flue gas before it is exhausted to the stack.

Ash/Limestone Area

Ash silos are located in the ash/limestone area. Bottom ash and flyash are loaded from the storage silos into trucks for disposal at the UCM site. Limestone for the SO_2 removal system is unloaded from trucks in this area.

2.3 Proprietary Information

TRW, Incorporated (TRW) is a corporation organized and existing under the laws of the State of Ohio. TRW is acting on behalf of its combustion business unit which has principal offices located at 2111 Rosecrans Avenue, El Segundo, California 90245. TRW holds the patent and associated rights to develop the Clean Coal Combustion System.

Joy Technologies Inc. (Joy) was a U.S. corporation headquartered in Pittsburgh, Pennsylvania, acting on behalf of its Environmental Systems Group, with offices located in Monrovia, California. Joy held the exclusive license from A/S NIRO Atomizer of Copenhagen, Denmark, to supply the atomizers to be used in spray dryer absorber systems for acid gas removal in the North American market. Joy and A/S NIRO jointly owned the patent and associated rights to develop spray drying absorber and baghouse technology that integrate with the clean coal combustion technology developed by TRW. B&W has purchased all assets of Joy.

2.4 Simplified Process Flow Diagram

Figure 1-2 is an overall process block flow diagram of the HCCP process. All major process elements are shown on the diagram. There have been no significant changes from this design since the start of the demonstration testing.

2.5 Stream Data

Complete heat, material, and water balance data are provided in the Public Design Report (Final Report: Volume 1). The balances in that report were calculated for 50 percent and 65 percent waste coal blended with run-of-mine (ROM) coal. Because the HCCP is a base-load facility, the information is provided for full load only.

2.6 Process and Instrumentation Diagrams

Process and instrument diagrams for the HCCP design are not being provided because they can not be reproduced legibly in the required size. The process and instrument diagrams are also too detailed and complex to be of much value without more detailed knowledge of plant design and operation. The process flow diagrams in Section 4.0 of the Public Design Report (Final Report: Volume 1) adequately describe each system.

3.0 PUBLIC DESIGN REPORT UPDATE

3.1 Design and Equipment Changes

3.1.1 Design Changes

Three major changes in the technology were made during design of the HCCP. These were the conversion of the combustor firing configuration from side firing to bottom firing of the boiler, change of the coal feed system from a semi-direct to a direct feed system, and expanding the slag tap opening of the main combustor.

Bottom firing of the boiler was initiated as a result of limited available space adjacent to the boiler and adequate space beneath the boiler. The original plan had been to side-fire the boiler because it was felt that this configuration would be most applicable to retrofitting an existing boiler. The TRW Cleveland Test Facility included a coal feed system that had coal storage between the coal silos and the combustors. After much study and review of all the applicable fire and safety codes for coal-fired boilers, a conventional coal feed system with no coal storage between the coal silos and the combustors was selected. This system was demonstrated at TRW's Capistrano Test Facility and found to be successful. Finally, as a result of concern about possible bridging across the slag tap opening in the main combustors, the opening was increased, although this change resulted in decreased boiler efficiency. The opening was designed to accept an insert that could be added later to reduce the size of the opening.

A decrease in boiler efficiency of approximately 4.59 percent was predicted, but, according to TRW, the decrease in efficiency was significantly less than this. This better performance was achieved, in part, by inactivating the heat exchanger for the ash water system (which was not required) and by reducing the ash water flow rate.

3.1.2 Demonstration Changes to the Combustor Air Supply

Throughout the TRW Combustion System Characterization Testing, the slagging stage of the combustor performed extremely well and continuously demonstrated the capability to reliably burn ROM and ROM/waste coal blends over a broad range of operating conditions while maintaining a thin molten slag layer over the entire tubewall surface. The precombustor also performed very well with ROM coal but exhibited more variable slagging behavior during the initial tests using ROM/waste coal blends. During 1998 and early 1999, a combination of hardware-configuration and operational changes were made that successfully resolved this problem. The key changes were: 1) relocating the secondary air from the precombustor mix annulus to the head-end of the slagging stage, 2) completely transferring the precombustor mill air to the boiler NO_X ports following boiler warmup, and 3) modifying the precombustor burner air injection configuration in order to improve air/coal mixing characteristics.

These changes eliminated the mixing of excess air downstream of the precombustor combustion chamber in order to minimize local slag freezing and increased the precombustor operating temperature in order to provide additional temperature margin. The change had the added benefit of simplifying combustor operation by eliminating the need to monitor and control the coal-laden mill airflow to the precombustor mill air ports during steady-state operation.

Although the precombustor was designed to be operated "non-slagging," ultimately, beginning in 1998, it was operated in a slagging mode. In the initial HCCP design, the combustion process in the precombustor was accomplished in two stages. Coal was burned at a stoichiometric ratio of 0.8 to 1.0 in the primary combustion zone and then entered a mixing section where additional secondary air was added, resulting in a stoichiometric ratio greater than 2.0 (fuel-lean) at the exit of the precombustor. In the new configuration, the precombustor combustion chamber was operated at a stoichiometric ratio of 1.0 to 1.2 (fuel-rich). This change increased the precombustor exit temperature (up to 3,400° F) to provide additional operating margin to ensure slagging conditions when burning high-ash-fusion-temperature waste coals.

The precombustor performance burning ROM/waste coal blends continued to improve during the remainder of demonstration operations in 1999. In particular, following optimization of the precombustor burner configuration and operating conditions in early May 1999, the precombustor slagging behavior was consistent from test to test, and there was no further evidence of localized slag freezing.

3.1.3 Changes to the Precombustor

The precombustor consists of four major sections:

- primary burner and windbox
- combustion chamber with integral baffle
- secondary air mix annulus and windbox
- round to rectangular transition section including swirl damper blades.

The combustion chamber, baffle, and transition section are all tube waterwall components. The gas-side surfaces of these components are covered with three-eighths-inch-diameter studs and a 1-inch to 2-inch sacrificial silicon-carbide refractory layer. These components are all cooled with boiler feedwater nominally at 1400 psig and 585° F.

The water-cooling circuits are designed to be drainable. In the HCCP, the heat absorbed by the cooling water is recovered by directly integrating the combustor cooling water with the water in the steam drum through a separate forced-circulation circuit.

The six 6-inch precombustor mill air ports are integral with the precombustor transition section. Seal boxes filled with castable refractory surround each port.

The swirl damper blades are tube waterwall components fabricated from Grade B pipe. During the DTP, an Inconel 625, 0.10-inch-thick weld overlay was applied along a 1.5-inch-wide surface on the downstream edge of the blades in order to minimize localized particle erosion along this surface. The blades are cooled with water from the low-pressure cooling circuit of the plant condensate system nominally at 350 to 380 psia and 100° F.

For most of the DTP, there were two coal flame scanners and one oil flame scanner on the precombustor. Initially, the oil flame scanner was located along the centerline of the oil ignitor, and the primary coal flame scanner was located on the windbox looking at the flame centerline. Ultimately, the oil flame scanner was moved to the coal flame scanner position looking at the flame centerline, and the primary coal flame scanner was installed farther outboard on the precombustor burner windbox looking at the flame outer boundary. A secondary coal flame scanner was installed on an unused precombustor mill air port downstream of the precombustor combustion chamber. During 1999, an additional flame scanner was installed at the exit of each precombustor just downstream of the swirl dampers.

3.1.4 Changes to the Boiler and Coal Feed System

During 1999, there were several instances of slag falling from the lower part of the boiler into the slag ash and bottom ash hopper, causing some deformation of the hopper. This problem had been anticipated by the flow modeling tests conducted in 1992 in association with bottom firing of the boiler. After evidence of slag buildup was discovered, wall openings were provided in the boiler for the addition of soot blowers, which subsequently minimized slag buildup and slag fall.

During 1998 and 1999, it quickly became evident that the wear rate on the mill exhauster fans was excessive. Two spare fan rotors were purchased, and fan technicians were brought to the site to train maintenance personnel to overhaul the fans. The trained maintenance personnel could change a fan rotor in less than 8 hours while the unit remained at half load. Sacrificial wear plates were also installed on fan blades, which extended the period between fan overhauls. At the end of 1999, a new type of wear plate was installed on high-wear areas on the inside of the fan casing, but the wear plates were not tested due to shutdown of the unit. Additional testing is needed to determine the life of these wear plates.

3.2 Demonstration Plant Capital Cost Update

No significant changes have been made since publication of the Public Design Report (Final Report: Volume 1).

3.3 Demonstration Plant Operating Costs Update

No significant changes have been made since publication of the Public Design Report (Final Report: Volume 1).

4.0 DEMONSTRATION PROGRAM

4.1 Test Plans

The HCCP DTP was initiated in early 1998. The test program comprised several testing activities, including Coal-Firing Trials (Task 1), Compliance Testing (Task 2), TRW Combustion System Characterization Testing (Task 3), B&W/Joy SDA Technology Characterization Testing (Task 4), Boiler Characterization Testing (Task 5), Coal Blend Testing (Task 6), Turbine Performance Guarantee Testing (Task 7), 90 Day-Commercial Operation Test (Task 8), and Long-Term Commercial Operation Demonstration (Task 9).

Overall testing resulted in approximately 8,500 hours of total coal-fired operating time or the equivalent of approximately 1 year of continuous operation.

4.1.1 Short-Term Tests including the 90-Day Commercial Operation Test

The HCCP DTP consisted of the following short-term tests:

- Coal-Firing Trials
- Compliance Testing
- TRW Combustion System Characterization Testing
- B&W/Joy SDA Technology Characterization Testing
- Boiler Characterization Testing
- Coal Blend Testing
- Turbine Performance Guarantee Testing
- 90-Day Commercial Operation Test (90-Day Commercial Operation Test).

The objectives of the short-term tests conducted between January 1998 and June 1999 were to demonstrate the following features of the integrated HCCP combustion and air pollution control systems.

- Demonstrate the capability to control NO_X emissions to the 0.20 to 0.35 lb/million Btu range with low furnace CO levels (less than 200 parts per million [ppm]) while burning ROM/waste coal blends with up to 55 percent waste coal.

- Demonstrate SO_2 removal efficiencies of at least 90 percent at low reagent consumption. The project will demonstrate activation and utilization of combustor-generated FCM waste for SO_2 removal in the SDA System. In most SO_2 control processes, the calcium-based product from the particulate collection equipment is sent to disposal. In this innovative process, the product is recycled to provide additional SO_2 removal in the SDA System. The successful demonstration of this combined process helped to promote the use of the TRW-B&W/Joy integrated system in areas where a minimum 90 percent reduction is required and to effectively compete with other high removal efficiency processes that are more costly.

- Demonstrate SO_2 reduction in the furnace by limestone injection into the exit of the combustor. The HCCP test program provided for a demonstration of in-furnace SO_2 reduction for extremely low sulfur coals. For high sulfur coals, SO_2 removal efficiencies of 50 to 70 percent within the furnace have already been demonstrated using an industrial-scale TRW Clean Coal Combustion System and furnace.

- Control overall particulate matter and the portion of particulate matter typically below 10 microns in size (PM_{10}) to levels below current NSPS requirements applicable to the HCCP.

- Accomplish low-cost waste disposal or reuse. Waste disposal would be made easier by the production of a vitreous slag waste from the combustors and a dry powdery waste from the SDA System that will set up into a high strength, stable waste material that can be easily disposed of in a conventional landfill operation or potentially used in commercial applications such as road base material.

These tests represented a broad range of conditions that fully evaluated all aspects of HCCP operation. The tests occurred during the following timeframes and under the following conditions.

- The first 4 months of the HCCP DTP were dedicated to coal-firing start-up operations and focused on slowly bringing all plant systems on line while burning ROM coal at part-load operation. The plant reached full load for the first time in March 1998.

- During 1998, approximately 5,000 hours of plant thermal operation were accumulated, with approximately 4,500 hours of coal-fired operating time. Both ROM and ROM/waste coal blends were tested in the combustion system. Typically, the ROM/waste coal blends had caloric heating values ranging from 6,200 to 7,500 Btu/lb, ash contents ranging from 10 to 24 percent, and ash fluid temperatures ranging from 2,300° F to 2,900° F.

- During January through June 1999, approximately 2,200 hours of plant thermal operation were accumulated, with approximately 2,000 hours of coal-fired operating time. Almost all testing was performed with ROM/waste coal blends. During 1999, the ROM/waste coal blends had caloric heating values ranging from 6,766 to 7,826 Btu/lb, ash contents ranging from 8.02 to 19.08 percent, and ash fluid temperatures ranging from 2,275° F to 2,852° F. Efforts during 1999 focused on completing the TRW Combustion System Characterization Testing matrix, optimizing the precombustor burner configuration and operating conditions, and evaluating integrated system performance during longer-duration, steady-state tests.

- Overall, during January 1998 through June 1999, approximately 7,200 hours of plant thermal operation were accumulated, with approximately 6,500 hours of coal-fired operating time. Both ROM and ROM/waste coal blends were tested in the combustion system. Typically, the ROM/waste coal blends had caloric heating values ranging from 6,196 to 8,271 Btu/lb, ash contents ranging from 5.7 to 24.0 percent, and ash fluid temperatures ranging from 2,270° F to 2,900° F.

- The HCCP 90-Day Commercial Operation Test occurred during a 90-day period in August through December 1999. The test results are described in the "Healy Clean Coal Project, Topical Report: 90-Day Commercial Operation Test and Sustained Operations Report: A Participant Perspective, May 2000" (AIDEA 2000e). During that test, approximately 2,000 hours of additional coal-fired operating time were accumulated, bringing the total coal-fired operating/testing time to approximately 8,500 hours, the equivalent of about 1 year of continuous operation. During this test, a ROM/waste coal blend (35 percent waste coal excluding coal fines) that included a high percentage of waste fines and had an average caloric heating value of 7,194 Btu/lb was used. This coal was considered to be representative of fuel that would be supplied over the life of the HCCP.

- B&W SDA Technology Characterization Testing and Turbine Performance Guarantee Testing were conducted during the 90-Day Commercial Operation Test. Coal Blend Testing was integrated into the B&W SDA Technology Characterization Testing. Turbine Performance Guarantee Testing was deleted from the DTP because it is not related to the new technology, and a separate report was prepared. Boiler Performance Guarantee Testing and Boiler Characterization Testing were conducted during the TRW Combustion System Characterization Testing.

4.1.2 Long-Term Tests

The Long-Term Commercial Operation Demonstration (beyond the 90-Day Commercial Operation Test) was not performed.

4.2 Operating Procedures

The major systems required for operating the plant are described in Appendix B.

4.2.1 Instrumentation and Data Acquisition

The plant control, instrumentation, and data acquisition systems are described in Appendix B.

4.2.2 Test Methods

Test methods are described in the individual topical reports and in Section 4.4 and Appendix C of this report.

4.3 Analyses of Feedstocks, Products, and Reagents

4.3.1 Coal and Ash Characteristics

The coals to be fired in the HCCP combustion system are low-sulfur, high-moisture, low-heating-value fuels from the nearby UCM. Table 4-1 provides coal and ash characteristics for ROM coal, waste coal, and performance coal. ROM coal is run-of-mine coal, where care is taken in the mining operation to minimize the amount of overburden and non-coal strata included with the coal. Waste coal is not subject to this selective separation process and, hence, has a lower heating value and a higher ash content. Performance coal is a hypothetical blend of 50 percent ROM coal and 50 percent waste coal, each with distinct coal properties.

The heating value of coal delivered to the plant depends on a number of factors. The seam being mined, the coal mining technique, and the specific location within the seam being mined can all cause ROM and waste coal heating values to vary on a daily, monthly, and yearly basis. For example, waste coal may be coal from a low-grade seam, or it may be is ROM coal that has been contaminated with overburden or interburden and, as a result, has a lower heating value, i.e., approximately 5,000 to 7,500 Btu/lb. ROM coal has a heating value greater than 7,500 Btu/lb.

Some ROM coal is ground into fines so that the mine can use it for other markets. A large quantity of excess fines that had been ground too fine to be burned in conventional boilers was used during the 90-Day Commercial Operation Test at HCCP. The heating value of the fines waste is similar to ROM coal but tends to vary more (typically 6,500 to 9,000 Btu/lb) as a result of having gone through the grinding process.

4.3.2 Limestone Characteristics

Tables 4-2 and 4-3 provide the chemical analysis and particle size distribution, respectively, of the limestone used during the 90-Day Commercial Operation Test.

4.4 Data Methodology

Key test parameters and methods used for the B&W SDA Technology Characterization Testing are listed in Table 4-4. Additional test parameters (a continuation of this table) and methods are listed in Appendix C.

All references to the American Society for Testing and Materials (ASTM) Standard Specification, American Society of Mechanical Engineers (ASME) methods, EPA Reference

Methods and to other similar standard publications are to the latest issue of each as of the date of Contract No. HCCP-007 between AIDEA and Joy Manufacturing Company (now B&W) unless specifically stated otherwise.

4.5 Data Summary

The Public Design Report (Final Report: Volume 1) consolidates and summarizes key data associated with this project. Additional data are summarized in this Project Performance and Economics Report (Final Report: Volume 2). More detailed information can be found in the individual topical reports. Highlights of the data are summarized as follows.

4.5.1 Emissions

The DTP was conducted from January 1998 through June 1999. All emissions were within permitted limits, with the exception of short-term SO_2 and opacity exceedances that occurred during plant startup and equipment repairs. As part of the DTP air emission compliance demonstration and the Air Permit requirements, source testing was performed in June 1998 and March 1999 to confirm the validity of the plant's Continuous Emission Monitoring System (CEMS) for NO_X, SO_2, and CO_2 and to verify the CO and particulate emissions. The emission monitoring system met all EPA-required standards for accuracy. As described below, the HCCP demonstrated the ability to maintain air emissions at levels below both the Air Permit limits and the applicable EPA NSPS limits and, furthermore, to meet the more stringent DTP emission goals.

- NO_X emissions were monitored continuously by the CEMS. During the DTP, the range of NO_X emissions was 0.208 to 0.278 lb/million Btu, with a typical emission level of 0.245 lb/million Btu (30-day rolling average). During the 90-Day Commercial Operation Test, NO_X emissions averaged 0.275 lb/million Btu (30-day rolling average). The applicable NSPS limit for NO_X for the HCCP is 0.5 lb/million Btu, the Air Permit limit is 0.350 lb/million Btu, and the DTP emission goal is 0.20 to 0.35 lb/million Btu.

- SO_2 emissions were monitored continuously by the CEMS. During the DTP, SO_2 emissions averaged 0.038 lb/million Btu (30-minute average corrected to 3 percent oxygen [O_2]). During the 90-Day Commercial Operation Test, SO_2 emissions averaged approximately 0.060 lb/million Btu. The Air Permit limit is either 0.086 lb/million Btu (annual average) or 0.10 lb/million Btu (3-hour average).

- CO emissions were monitored continuously by a stack O_2/CO analyzer. During the DTP, CO emissions were typically 30 to 40 ppm (30-minute average corrected to 3 percent O_2). During the 90-Day Commercial Operation Test, CO emissions were typically in the 20 to 50 ppm range. The Air Permit limit and the DTP emission goal are 202 and 206 ppm, respectively, corrected to 3 percent O_2.

- Opacity was monitored continuously by the CEMS. The opacity measurements were used as an on-line indication of particulate emissions. During the DTP, typical opacity measurements ranged from 2 percent to 6 percent, based on a 30-minute average. Bag maintenance was higher during 1998 due to premature baghouse filter bag failures caused by poor inlet gas distribution. This problem was corrected in 1999. During the 90-Day Commercial Operation Test, opacity averaged approximately 5.5 percent, which is significantly below the permit limits of 20 percent opacity for a 3-minute average and 27 percent opacity for one 6-minute period per hour. The particulate emission limit, Air Permit limit, and DTP emission goal are 0.03, 0.02, and 0.015 lb/million Btu, respectively.

4.5.2 Combustor Performance

Overall, the combustor operation and performance demonstrated during the TRW Combustion System Characterization Testing and the 90-Day Commercial Operation Test were quite encouraging given that this was the first utility-scale demonstration of this promising new technology. The overall system met or exceeded all goals for achieving low NO_X and SO_2 emissions at the stack, with extremely low CO levels in the furnace, very high carbon burnout, and removal of the majority of ash prior to entering the furnace. These results were achieved while burning both ROM and ROM/waste coal blends. The ability to control precombustor slagging behavior while burning ROM/waste coal blends was demonstrated, although improvements in precombustor burner configuration and operating conditions were required to achieve this control.

Based on the results of prior testing and on the 90-Day Commercial Operation Test, most project participants agree that demonstration of the combustor technology is successful on a non-site-specific basis. The Harris Group Inc. (the Harris Group) has confirmed that the new technology would be capable of sustained operations using coal with a heating value as low as 7,000 Btu/lb. TRW has noted that only "minor operational changes, rather than design changes, will be required for sustained operation with coals significantly below 7,000 Btu/lb." This comment and additional details regarding the combustor performance during this extended test period are provided in the "Healy Clean Coal Project, Topical Report: 90-Day Commercial Operation Test and Sustained Operations Report: A Participant Perspective, May 2000" (AIDEA 2000e).

4.5.3 Boiler Performance

Foster Wheeler's Boiler Performance Guarantee Testing for the HCCP was executed on March 29 and 30, 1999, in accordance with Contract No. HCP-009 between Foster Wheeler and AIDEA, requirements of the DOE Demonstration Test Program, and the Foster Wheeler "Boiler Performance Guarantee Test Program and Procedures" provided in Appendix A of the "Healy Clean Coal Project, Topical Report: Boiler Performance Testing, March 2000" (AIDEA 2000b).

The boiler test was conducted by Foster Wheeler and witnessed by Stone & Webster. As noted in the Boiler Performance Topical Report, Stone & Webster's judgment regarding the test was that " . . . the boiler guarantees as presented in Table 1 were satisfactorily met . . . ." Key boiler performance test results are provided below in Table 4-5. More detailed boiler performance test results are presented in Appendix A of the Boiler Performance Topical Report (Stone & Webster 1999).

Stone & Webster, the witnessing engineer, and Foster Wheeler, the test engineer, believe that the analysis employed, the results obtained, and the conclusions drawn are valid.

4.5.4 SDA Performance

Formal SDA Performance Guarantee Testing, as required by Contract No. HCCP-007 between AIDEA and B&W, was conducted between June 7 and June 11, 1999. A total of nine tests were conducted, eight of which were considered acceptable. The test results are summarized in Table 4-6. For comparison, the contractually guaranteed values are also included. From the test results, it is concluded that the SDA System at the HCCP has met all performance guarantee requirements of Contract No. HCCP-007 between AIDEA and B&W.

4.6 Operation and Reliability

Overall, HCCP equipment has performed well during various test programs. In general, the plant operates similar to other plants of its size and is undergoing the normal problems associated with bringing on a new plant. Specific problems encountered and solutions to eliminate those problems are described in the following sections. This information can also be found in the operations reports for 1998 and 1999 (AIDEA 1998, AIDEA 1999). All problems have been adequately resolved, or plans were developed to solve them in the future. All of the solutions are applicable to commercial-scale installations using the technology.

For a detailed description of system and equipment problems encountered in 1998 and 1999 refer to Appendix D.

4.6.1 Critical Component Failure Analysis

Slagging or Plugging Problems in the Slagging Combustors when Using Low Heating Value Coal

After completing the 90-Day Commercial Operation Test, some slagging or plugging problems were observed in TRW precombustor ‘B’ when using coal quality below 7,000 Btu/lb. However, based on the performance in precombustor ‘A,’ there does not appear to be excess slagging or plugging using coal heating values between 6,800 and 7,000 Btu/lb. Only minor operational changes, rather than design changes, may be required for sustained operation with coals significantly below 7,000 Btu/lb.

During the early part of the 90-Day Commercial Operation Test, there was a small conflagration in pulverizer ‘B,’ that caused damage to splitter ‘B’ coal flow dampers. This caused precombustor ‘B’ to receive nearly twice the required coal flow, resulting in precombustor ‘B’ being more sensitive to coal quality. Therefore, the performance of precombustor ‘B’ after the conflagration should not be taken as normal. Equipment on the ‘B’ side remained operational even in a damaged condition, which demonstrated the operational flexibility of the system.

During the 90-Day Commercial Operation Test, the unit ran on coal with heating values less than 7,000 Btu/lb a number of times without problems in emissions, load, or ash-handling capacity. From October 26 through October 30, 1999, low-heating-value coal was burned in both combustors, and precombustor ‘A’ performed normally and did not require rodding out.
In the “Healy Clean Coal Project, Topical Report: 90-Day Commercial Operation Test and Sustained Operations Report: A Participant Perspective, May 2000” (AIDEA 2000e), TRW, the combustor manufacturer, stated the following: “ . . . based on the performance in ‘A’ combustor, there does not appear to be any indication of excess slagging or plugging problems during operation with coal heating value between 6,800 and 7,000 Btu/lb.” TRW also added in the same report that “Based on the experience gained during the PC [precombustor] Burner Characterization Tests performed during March/April 1999, it is likely that minor operational changes rather than design changes will be required for sustained operation with coals significantly below 7,000 Btu/lb. This would possibly include reduction in the PC coal split as well as tuning of PC and SC [slagging combustor] stoichiometry for lower coal heating value. The PC and SC stoichiometry could then be automated to track with inferred coal heating value.”

Potential Future Modifications to the Coal Transport System

After the 90-Day Commercial Operation Test, the exhauster fans in the coal feed system showed significant wear. As a result, the coal transport system may need to be modified between the feeder outlet and the combustor inlet. Remediation options are placing one or more primary air fans in a segregated air path upstream or downstream of the tubular primary air preheaters and upstream of the pulverizers, using eductors instead of fans to provide coal transport air to the combustors, adding two small pulverizers, improving the durability of exhauster fan materials, reducing the fan blade tip speed, adjusting the air flow rates, or simply changing out the exhauster fans on a regular basis, as needed.

Modification of the coal transport system is also under evaluation as a result of the conflagration that occurred in pulverizer ‘B’ on September 6, 1999. On that date, an explosion occurred in the fuel preparation and transport system. The pulverizer ‘B’ inlet air duct was ruptured at the mill inlet connection, its mill exhauster casing was partially deformed, and its mill feeder sustained internal damage. According to Foster Wheeler, who investigated the incident and documented results in an AIDEA internal memo, “ . . . it is believed that the explosion occurred as a result of a spontaneous combustion of fuel and volatile gases, which accumulated during the mill shut-down cycle.” Control modifications recommended by Foster Wheeler were implemented to mitigate future occurrences.

Table 4-1 Coal and Ash Characteristics.

Characteristics	ROM Coal	Waste Coal	Performance Coal
PROXIMATE ANALYSIS (percent by weight, as-received basis)			
Moisture	26.35	23.87	25.11
Ash	8.20	25.00	16.60
Volatile	34.56	27.00	30.78
Fixed Carbon	30.89	24.13	27.51
Total	100.00	100.00	100.00
ULTIMATE ANALYSIS (percent by weight, as-received basis)			
Moisture	26.35	23.87	25.11
Ash	8.20	25.00	16.60
Carbon	45.55	35.59	40.57
Hydrogen	3.45	2.70	3.07
Nitrogen	0.59	0.46	0.53
Sulfur	0.17	0.13	0.15
Oxygen	15.66	12.23	13.94
Chlorine	0.03	0.02	0.03
Total	100.00	100.00	100.00
ELEMENTAL ASH ANALYSIS (percent by weight, as-received basis)	38.61	74.58	65.59
Silicon Dioxide	16.97	9.16	11.09
Aluminum Oxide	0.81	0.43	0.52
Titanium Dioxide	7.12	4.18	4.90
Ferric Oxide	23.75	6.32	10.62
Calcium oxide	4.54	1.32	1.87
Potassium Oxide	1.02	1.21	1.16
Sodium Oxide	0.66	0.65	0.65
Sulfur Trioxide	5.07	1.36	2.28
Phosphorus Pentoxide	0.48	0.24	0.30
Strontium Oxide	0.23	0.07	0.11
Barium Oxide	0.44	0.15	0.22
Manganese Oxide	0.06	0.05	0.04
Undetermined	1.24	0.29	0.55
Total	100.00	100.00	100.00

Table 4-2 Limestone Chemical Analysis.

Chemical Constituent (percent dry basis)	Sample Number				
	1 (06/08/99 08:00 hr)	2 (06/09/99 04:00 hr)	3 (06/09/99 18:00 hr)	4 (06/10/99 04:00 hr)	5 (06/10/99 14:00 hr)
Calcium (Ca)	38.93	39.59	39.80	39.70	39.58
Carbonate (CO_3)	59.22	59.13	58.70	58.85	59.15
Magnesium (Mg)	0.42	0.30	0.34	0.35	0.33
Inerts	1.19	0.60	0.55	0.54	0.53

Table 4-3 Limestone Particle Size Distribution.

Particle Size (percent by weight)	Sample Number							
	1 (06/08/99 08:00 hr)	2 (06/08/99 12:00 hr)	3 (06/09/99 04:00 hr)	4 (06/09/99 18:00 hr)	5 (06/10/99 04:00 hr)	6 (06/10/99 14:00 hr)	7 (06/11/99 04:00 hr)	8 (06/11/99 14:00 hr)
on 80 Mesh	0.08	0.11	0.20	0.17	0.11	0.16	0.02	0.14
on 100 Mesh	1.05	0.99	1.06	1.07	1.08	1.00	0.79	0.98
on 140 Mesh	3.06	3.12	3.31	3.13	3.52	3.19	2.98	3.44
on 200 Mesh	8.10	8.40	8.76	8.09	10.86	8.41	8.36	9.29
on 270 Mesh	60.94	63.12	60.91	59.64	63.02	56.53	53.60	59.63
on 325 Mesh	0.13	0.09	0.11	0.09	0.11	13.54	3.12	3.99
through 325 Mesh	26.64	24.17	25.65	27.81	21.30	17.17	31.13	22.53
Total	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00

Table 4-4 Key Test Parameters and Methods.

Test Parameter	Method	Comments
SO_2 Emissions	EPA Method 6C	SO_2 emissions are measured at the Continuous Emission Monitoring System (CEMS) location in the stack, and the system removal efficiency is determined by using the calculated uncontrolled and the measured controlled SO_2 emission.
Particulate Matter Emissions	EPA Method 5B	The flue gas flow rate, particulate matter, and moisture content in the exit gas are measured immediately downstream of the baghouse outlet at the CEMS location in the stack. The measured value for particulate matter emissions excludes condensables and sulfuric acid mist as defined by EPA Test Method 5B. Particulate samples from each test are saved for analysis.
Opacity	Plant Opacity Monitor	The opacity reading of the opacity meter at the CEMS location in the stack is recorded and used.

Table 4-5 Boiler Performance Test Results and Performance Guarantees.

Parameter	Guarantee or Predicted	Actual
Maximum Steam Flow	490,000 lb/hr	493,865 lb/hr
Pulverizer Power	330 kW	213.6 and 204.4 kW
Forced Draft Fan Power	3,150 kW	1,492 kW
Steam Pressure	1,300 psig	1,308 psig
Steam Temperature	955° F	957° F
Boiler Efficiency	79.15 percent	82.2 percent

Table 4-6 SDA Performance Test Results and Performance Guarantees.

Parameter	Parameter Values								
	Guarantee	**Test 1**	**Test 3**	**Test 4**	**Test 5**	**Test 6**	**Test 7**	**Test 8**	**Test 9**
SO_2 Emission (lb/hr maximum)	79.6	<2.01	<2.07	<2.13	<2.15	<2.10	<2.13	<2.13	<2.15
Particulate Loading (lb/million Btu maximum)	0.015	0.0023	0.0042	0.0052	0.0040	0.0027	0.0030	0.0014	0.0034
Opacity (percent)	Maximum of 20 percent for a maximum of 3 minutes in an hour, and during the 3 minutes a maximum of 27 percent	Range: 1.3-1.5 Max: 1.5	1.3-1.7 1.7	1.5-1.7 1.7	1.5-1.7 1.7	1.1-1.4 1.4	1.0-2.0 2.0	1.3-1.5 1.5	1.3-1.5 1.5
System Pressure Drop (in. WG)	13	10.0	10.5	9.6	9.7	9.8	9.9	9.8	9.9
System Power Consumption (kW)	550.5	334	330	324	331	333	333	328	340

5.0 TECHNICAL PERFORMANCE

The technical performance of the HCCP is described in the "Healy Clean Coal Project Demonstration Test Program, Topical Report: Combustion System Operation Final Report, March 2000" (AIDEA 2000c), the "Spray Dryer Absorber System Demonstration Test Report for Healy Clean Coal Project, November 2000" (AIDEA 2000g), and the 1998 and 1999 operations reports (AIDEA 1998, AIDEA 1999). The results described in these reports and the detailed analysis of process variables are provided in this section.

5.1 Combustor System

Combustor system demonstration tests were conducted throughout 1998 and 1999. The results are described in the report entitled "Healy Clean Coal Project Demonstration Test Program, Topical Report: Combustion System Operation Final Report, March 2000" (AIDEA 2000c). The results of the combustor system demonstration tests and comparison with Cleveland Test Facility pilot tests include the following.

- Low NO_X emissions (0.20 to 0.30 lb/million Btu) were demonstrated with ROM/waste coal blends. These results were achieved with very low O_2 levels (3 to 5 percent) simultaneously with extremely low CO emissions (20 to 50 ppm).

- Slagging behavior in the precombustor was more variable with ROM/waste coal than with ROM coal.

- The coal feed system, excluding the mill exhauster fans, operated reliably and was capable of varying the splits to the precombustor, the combustor, and the NO_X ports.

- Combustor performance correlated with analytical model performance, thus validating the Cleveland Test Facility pilot test and the scaling of these results.

Potential future changes to the combustor system may result in NO_X emissions of approximately 0.20 lb/million Btu. This would require further reduction in combustor stoichiometry, a reduction in furnace O_2, and an increase in furnace air staging. TRW believes levels around 0.10 lb/million Btu NO_X could be achieved with ammonia injection into the combustor.

Overall, the combustor system operated extremely well and performed well on all grades of coal tested, with daily average coal heating values ranging from approximately 6,800 to 7,900 Btu/lb. High combustor availability was achieved throughout the tests.

5.2 SDA System

SDA performance tests were conducted between June 7 and June 11, 1999, and SDA System demonstration tests were conducted between November 3 and November 15, 1999. The results of these tests are provided in the topical reports entitled "Spray Dryer Absorber System Performance Test Report for Healy Clean Coal Project, February 2000" (AIDEA 2000a) and "Spray Dryer Absorber System Demonstration Test Report for Healy Clean Coal Project, November 2000" (AIDEA 2000g).

The results of these demonstration tests include the following.

- High sulfur removal efficiencies in excess of 90 percent can be achieved on a long-term basis with low sulfur coals on the order of 0.15 percent sulfur.

- Approach of the flue gas saturation temperature can be in the 30° F to 40° F range and achieve high efficiencies. Original design criteria considered that the flue gas saturation temperature might have to be as low as 18° F.

- Heat activation of the feed slurry appears to provide significant enhancement in SO_2 removal. The economics will depend on the costs of limestone and steam. However, heat activation could be used to handle swings in sulfur content of coal, i.e., burn higher sulfur coal at higher heats.

The most important variables in order of significance are:

- approach to saturation temperature
- heat activation of the SDA feed slurry
- reagent stoichiometry.

The SDA performance tests were conducted as requirements of the AIDEA/B&W contract HCP-007 and the DTP. These tests were conducted burning coal with approximately 11.4 percent ash and a sulfur content of approximately 0.2 percent. The tests indicated that, under the test conditions, SO_2 emissions were around 2 lb/hr, which is significantly below the contract guarantee of 79.6 lb/hr (see Table 4-6).

5.3 Process Variables

An analysis of process variables has been conducted for the period covering the 90-Day Commercial Operation Test, which is considered to be most representative of steady-state conditions. Data gathered during the balance of the test period, when operating conditions were being adjusted to facilitate the demonstration tests on the new technology or to improve operations, are not included.

5.3.1 Coal Heating Value

Figure 5-1 shows NO_X emissions as a function of coal heating value. The data indicate that NO_X emissions are independent of coal heating value of the coals burned to date. This is a significant result because it shows that the new technology can achieve low NO_X emissions while burning coals varying from ROM to low-grade waste coal. This is an operational and economic advantage because it allows flexibility in the coal quality being burned, allows the use of low-cost waste coal, and reduces waste disposal problems and costs. These data from the 90-Day Commercial Operation Test are consistent with trends observed during the DTP, when it was observed that NO_X emissions were not a function of coal heating value, low NO_X emissions being achieved with both ROM and waste coal blends. During May 1998, a 14-day test was conducted, with ROM coal being burned for the first 10 days and a waste coal blend being burned for the next 4 days. The NO_X emissions were constant over the entire 14-day test period, indicating that NO_X emissions were relatively independent of coal heating value.

Figure 5-2 shows CO emissions as a function of coal heating value. The data show minimal variation in CO emissions as a function of coal heating value. This is also a significant result because it shows that the new technology can achieve very low CO emissions concurrent with low NO_X emissions when burning coals varying from ROM to waste coal blend. This indicates that the combustion system has a high combustion efficiency burning coal with heating values ranging from 6,600 to 7,800 Btu/lb, thus providing operational and economic advantages.

Capacity factor for each day of the 90-Day Commercial Operation Test is plotted as a function of coal heating value in Figure 5-3. There appears to be a minimal reduction in capacity factor with waste fuel, which would allow greater use of low heating value waste coal. It should be noted that the majority of the data points at reduced capacity were due to the deliberate reduction of load during the SDA performance characterization tests conducted in conjunction with the 90-Day Commercial Operation Test.

5.3.2 Coal Sulfur Content

The data in Figure 5-4 show only a slight dependency of sulfur removal efficiency on sulfur content in the coal. This trend is unique, since typical low sulfur limestone scrubbing shows a greater decrease in efficiency with very low sulfur coal. The high level of overall sulfur removal efficiency for the low sulfur coal is noteworthy. It appears that the staged sulfur removal of this technology provides higher sulfur removal than conventional spray drying.

5.3.3 Limestone Feed Rate

Figure 5-5 shows sulfur removal efficiency as a function of limestone injection rate, and Figure 5-6 shows sulfur removal efficiency as a function of calcium to sulfur ratio (Ca/S). Both figures indicate little variation in sulfur removal efficiency over a range of variables. The design limestone feed rate is approximately 13 tons per day. A higher-than-design amount of limestone was injected during most of the 90-Day Commercial Operation Test to ensure SO_2 emission compliance. Nominal sulfur removal efficiency was 85 to 90 percent at Ca/S ratios ranging from 1.8 to 6.0. The test data indicate that there is not any benefit to higher limestone injection rates and that there is little gain in efficiency at Ca/S levels greater than 3. This implies that there is some limiting factor in the system, possibly conversion of limestone to calcium oxide, residence time in the SDA, or removal efficiency of the baghouse (i.e., limited surface area).

5.3.4 Excess Air (O_2)

Figure 5-7 shows that CO emissions are not a function of excess air. This trend indicates that high combustion efficiency is being achieved. Carbon monoxide is a regulated air pollutant. The absolute level of CO emissions, 25 ppm, is significantly below the regulated permit level of 200 ppm.

5.3.5 Ash Content of Coal

As shown in Figure 5-8, 90-Day Commercial Operation Test data indicate a decrease in baghouse removal efficiency, as indicated by percent opacity, with higher ash content in the coal. Since the baghouse is a constant-efficiency device for a given particle size, this trend would be logical if the particle size tended towards very small particles. Based on experience and tests with the HCCP coal, the ash does tend to form very small particles. Alternatively, there may have been a leak developing in the baghouse material, allowing bypass of small particles.

5.3.6 Gross Power Output

Figure 5-9 shows NO_X emissions as a function of unit load. Included in the plot are NO_X emission data during: 1) start-up operations including oil-only firing conditions (load less then 20 MWe), 2) coal firing on one combustor with oil firing on the other combustor (load approximately 35 MWe), and 3) operation of one combustor only at high thermal input (30 MWe). The remaining data points describe coal-fired operation at part load. Although part-load operation was limited during the 90-Day Commercial Operation Test, the data indicate that NO_X emissions at part load are similar to those at full load and are below the Air Permit limit of 0.35 lb/million Btu. Conventional boilers typically have increased NO_X emissions at lower loads.

Figure 5-10 plots net heat rate versus unit load. As anticipated for most conventional units, heat rate increases as load is reduced. The HCCP shows an increase of 16 percent in heat rate at approximately 50 percent load. This trend is typical of all coal-fired units.

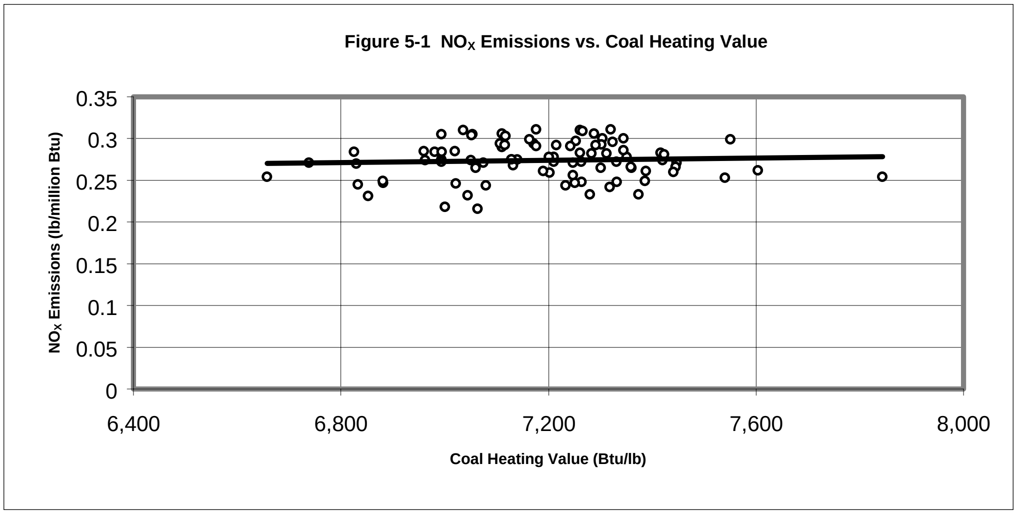


Figure 5-1 NOX Emissions vs. Coal Heating Value
0.35
0.3
0.25
0.2
0.15
0.1
0.05
0
6,400
6,800
7,200
7,600
8,000
NOX Emissions (lb/million Btu)
Coal Heating Value (Btu/lb)

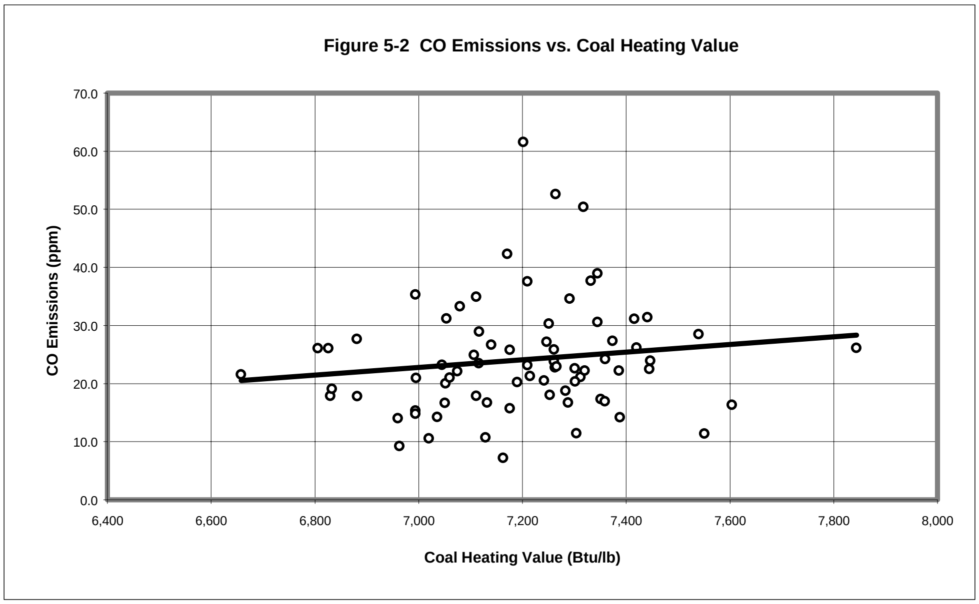


Figure 5-2 CO Emissions vs. Coal Heating Value
70.0
60.0
50.0
40.0
30.0
20.0
10.0
0.0
6,400
6,600
6,800
7,000
7,200
7,400
7,600
7,800
8,000
CO Emissions (ppm)
Coal Heating Value (Btu/lb)

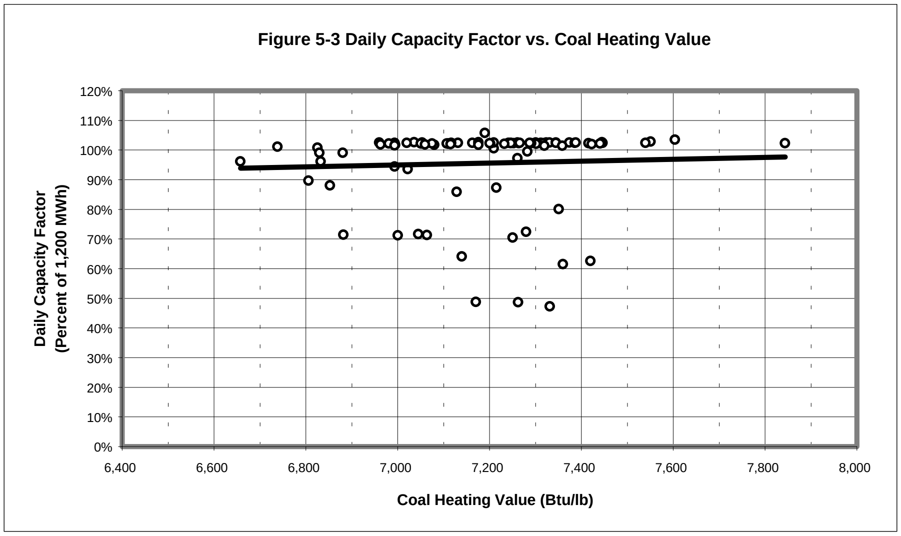


Figure 5-3 Daily Capacity Factor vs. Coal Heating Value
Daily Capacity Factor
(Percent of 1,200 MWh)
120%
110%
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
6,400
6,600
6,800
7,000
7,200
7,400
7,600
7,800
8,000
Coal Heating Value (Btu/lb)

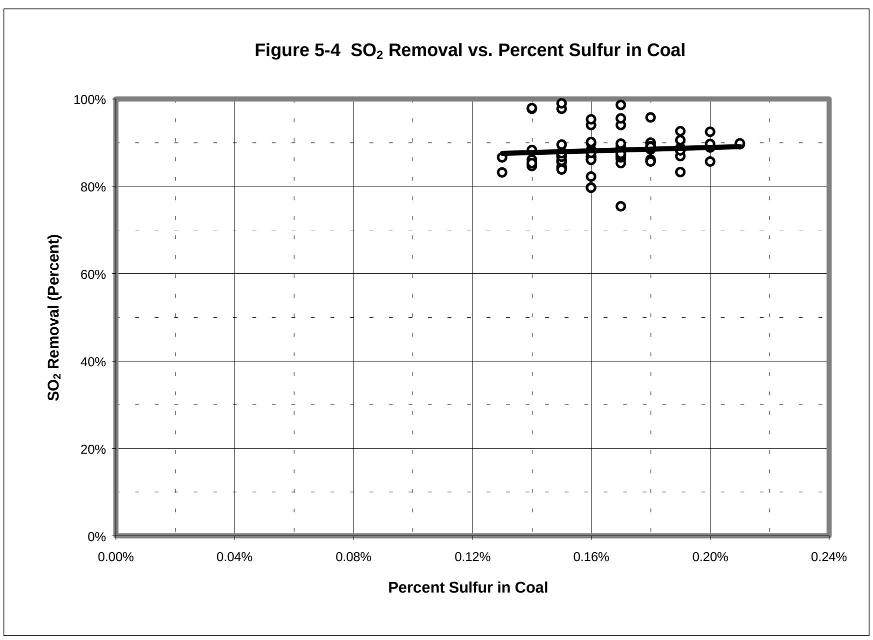


Figure 5-4 SO_2 Removal vs. Percent Sulfur in Coal
SO_2 Removal (Percent)
100%
80%
60%
40%
20%
0%
0.00%
0.04%
0.08%
0.12%
0.16%
0.20%
0.24%
Percent Sulfur in Coal

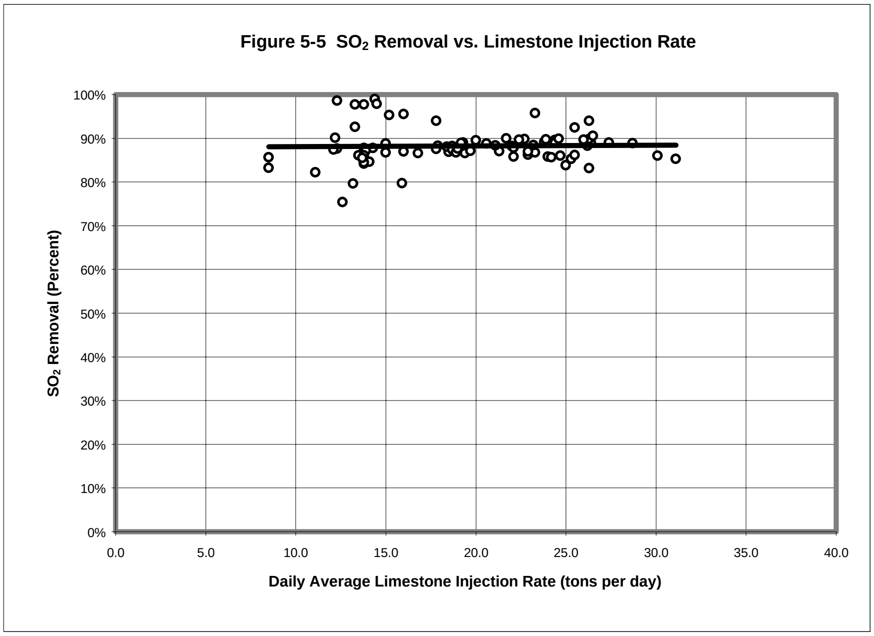


Figure 5-5 SO2 Removal vs. Limestone Injection Rate
SO2 Removal (Percent)
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0.0
5.0
10.0
15.0
20.0
25.0
30.0
35.0
40.0
Daily Average Limestone Injection Rate (tons per day)

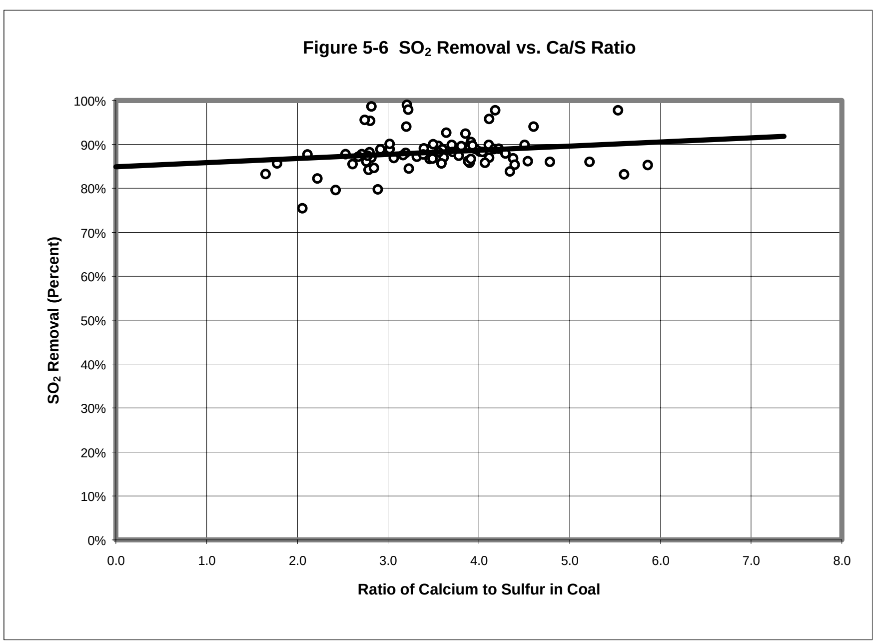


Figure 5-6 SO2 Removal vs. Ca/S Ratio
SO2 Removal (Percent)
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0.0
1.0
2.0
3.0
4.0
5.0
6.0
7.0
8.0
Ratio of Calcium to Sulfur in Coal

Figure 5-7 CO Emissions vs. Excess O_2

(CO Permit Limit = 200 PPM)

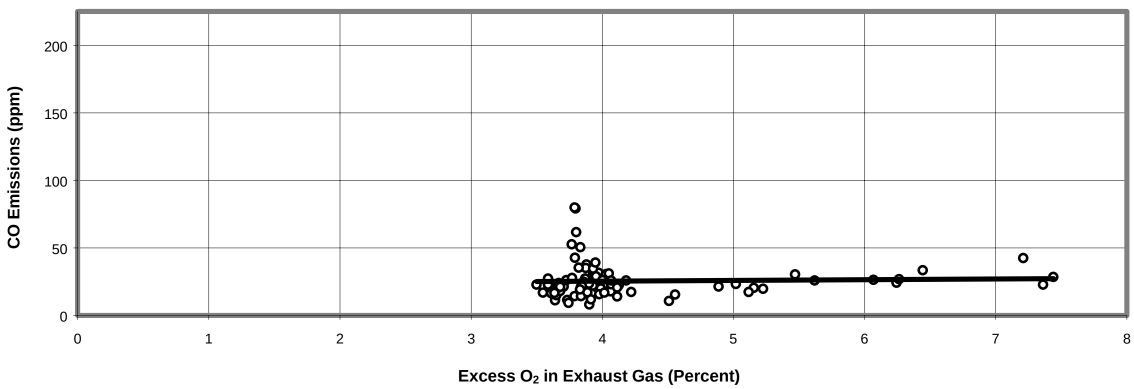
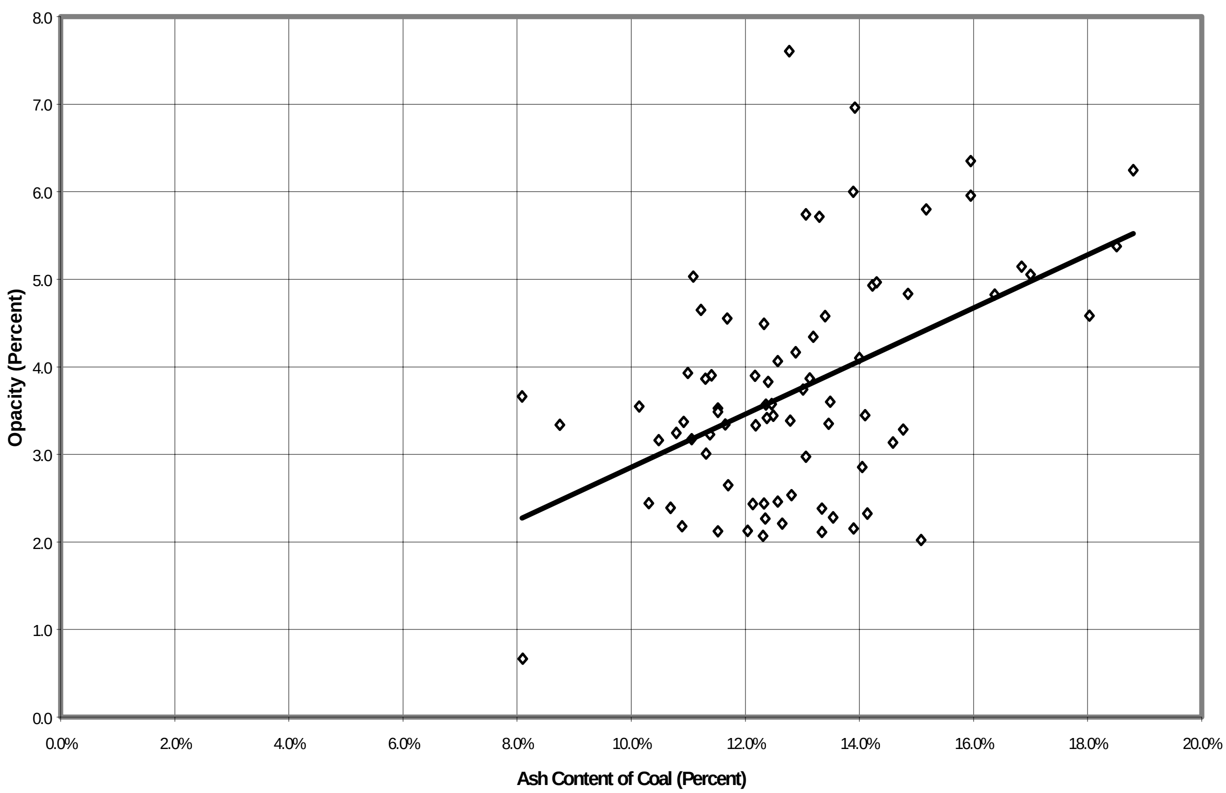


Figure 5-8 Opacity vs. Ash Content of Coal



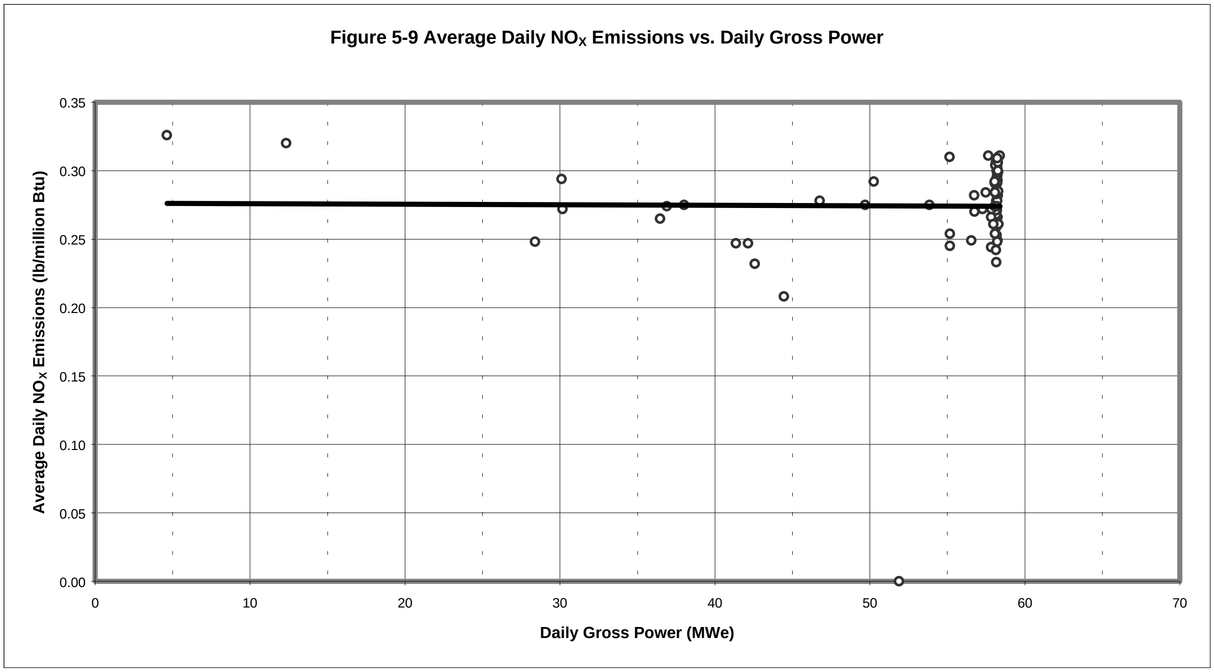


Figure 5-9 Average Daily NO_X Emissions vs. Daily Gross Power
Average Daily NO_X Emissions (lb/million Btu)
0.35
0.30
0.25
0.20
0.15
0.10
0.05
0.00
0
10
20
30
40
50
60
70
Daily Gross Power (MWe)

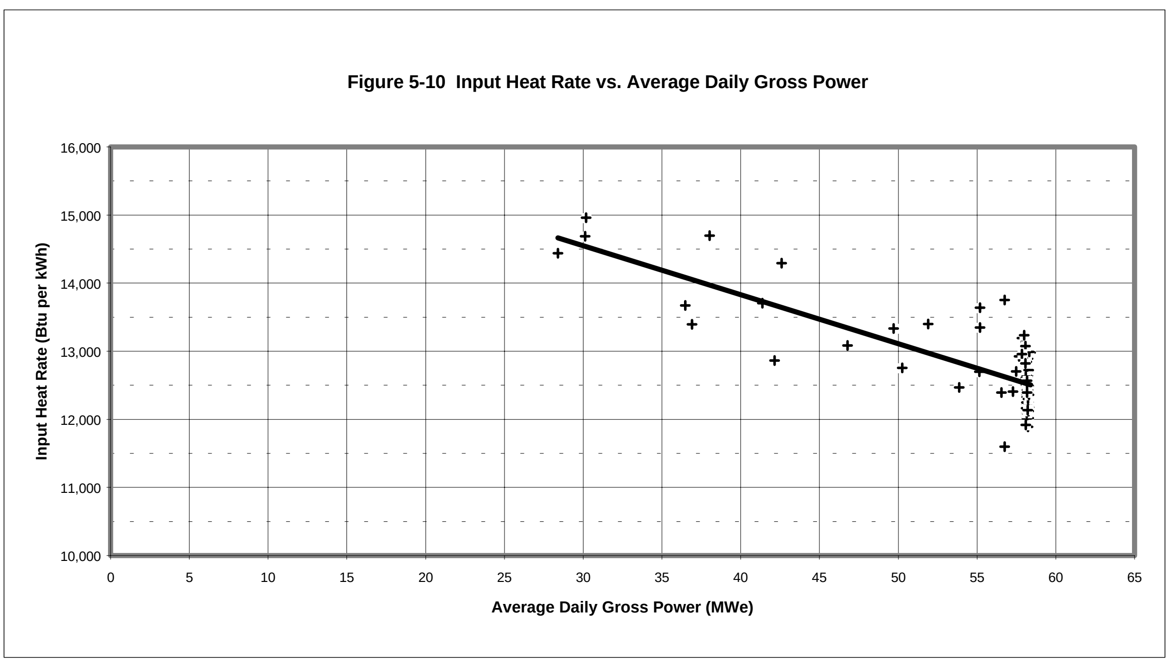


Figure 5-10 Input Heat Rate vs. Average Daily Gross Power
Input Heat Rate (Btu per kWh)
16,000
15,000
14,000
13,000
12,000
11,000
10,000
0
5
10
15
20
25
30
35
40
45
50
55
60
65
Average Daily Gross Power (MWe)

6.0 ENVIRONMENTAL PERFORMANCE

The technology demonstrated significant environmental benefits. In this particular application, the plant is located very near a pristine wilderness area and a heavily visited national park and, therefore, ambient and visibility monitoring have been of great concern. The low NO_X, SO_2, and particulate emissions resulted in no noticeable impacts to the National Park Visitors' Center or the surrounding area. Emissions resulted in no significant impacts on regional haze.

Replication and commercial implementation of the technology elsewhere could result in additional environmental benefits by contributing significantly to the reduction of acid rain, which is of great concern in the east coast of the United States, Canada, and other industrialized areas.

The technology also provides another significant environmental benefit - waste minimization. The combustors are capable of burning waste coals, which can be a by-product of ROM coals and, in some cases, would have to be disposed of at an additional cost. A "market" is created for what could otherwise be an unuseable product.

The HCCP Final Environmental Impact Statement (Final EIS) provides a discussion of the anticipated environmental performance of the HCCP (DOE 1993). The Final EIS provides evaluations of the HCCP Demonstration Test Program, which was the first phase of the HCCP testing the clean coal technology, and of the commercial operation of the plant. Several project participants evaluated the actual environmental performance of the HCCP during the DTP. Commercial operation of the HCCP has not commenced.

This section of the Project Performance and Economics Report compares the environmental performance predicted in the Final EIS with the actual environmental performance measured during the HCCP DTP. Several operating parameters were chosen for this evaluation, including raw material usage (coal, limestone, and cooling water), air emissions (SO_2, NO_X, PM/opacity, and CO), water discharges (wastewater and cooling water), and solid wastes (ash waste and limestone waste). These data were obtained from the HCCP Distributed Control System (DCS), permit compliance reports, and reports prepared by project participants including AIDEA, GVEA, TRW, and Stone & Webster. Most of the data used here are from the HCCP 90-Day Commercial Operation Test because that period of HCCP operation was most representative of steady-state conditions and because a substantial amount of data was collected during the test.

The 90-Day Commercial Operation Test was performed from August 17 through November 15, 1999, near the end of the 2-year-long DTP.

This section also provides a discussion of the predicted environmental performance of a hypothetical 300-MWe scale-up of the HCCP facility that would be constructed in Wyoming. This hypothetical facility, termed the "CC-300," would utilize the same technology as the HCCP with some minor design changes. These design changes include the addition of six precombustor/slagging combustor units (four units on each side of the boiler instead of two units on one side), the replacement of forced-circulation combustor cooling by natural-circulation combustor cooling, and the replacement of the once-through cooling system by a cooling tower. Other design changes are discussed in Section 7.0. Some of the changes were made because the characteristics of facilities constructed in the "Lower 48" differ from those located in Alaska due to differences in climate, regulatory requirements, resource availability, and many other factors. Once the design changes were incorporated, environmental performance of the CC-300 was estimated using evaluations of actual data from the HCCP and data from other testing facilities. Several operating parameters are used here to define the CC-300 environmental performance, including raw material usage, air emissions, water discharges, and solid wastes. Additional design information for the CC-300 is provided in Section 7.0.

6.1 Anticipated Environmental Performance of the HCCP

The HCCP Final EIS was issued in December 1993. The EIS was prepared by DOE to define the potential environmental impacts of the HCCP during demonstration of the clean coal technologies (the DTP) and during commercial operation. Overall, the anticipated environmental impacts of the HCCP were "minor for most resource areas," with major concerns being potential impacts of air emissions on air quality and visibility in the HCCP area (DOE 1993). These potential impacts were primarily based on the fact that the HCCP would be located just a few miles north of the Denali National Park and Preserve (DNPP).

Table 2.1.2 of the Final EIS provides a summary of several major HCCP operating characteristics related to environmental performance. Values of operating characteristics in Table 2.1.2 of the Final EIS are those anticipated for operation of the HCCP within the "demonstration case" (which meets the DTP goals) and at a capacity factor of 85 percent. Table 6-1 is a summary of portions of Table 2.1.2 of the Final EIS that are applicable to this analysis, as well as additional parameters that are useful for this analysis, such as heat input and coal heating value.

6.1.1 Anticipated Raw Material Usage

The raw material usage rates evaluated in this section include those for coal, limestone, and cooling water. As shown in Table 6-1, the Final EIS predicts that 344,600 tons of coal and 5,600 tons of limestone would be required per year of HCCP operation at a capacity factor of 85 percent. The prediction of coal usage was made during the design process by evaluating the required heat input for the combustion system, the heating value of the coal, the desired facility output, and other parameters. The coal sulfur content, the efficiency of the SO_2 removal systems, the emission requirements, the properties of the limestone, and other engineering parameters were used to predict the limestone usage rate. About 12,500 million gal/year (24,000 gpm) of cooling water would also be required for the HCCP. The determination of the cooling water flow rate was based on the temperature of the water supply (the Nenana River), the design details of the condenser system, and the NPDES thermal discharge requirements.

6.1.2 Anticipated Air Emissions

Anticipated HCCP air emissions were provided primarily by the developers of the integrated clean coal technologies. TRW, B&W/Joy, and Foster Wheeler estimated emission rates by reviewing the results of several pilot-scale tests of the technologies, by evaluating other facilities that contained portions of the HCCP clean coal technology, and by engineering analyses. Earlier sections of this report provide additional information on the development of the technologies, the pilot- and full-scale tests, and the implementation of the HCCP technologies.

The predicted emission rates presented in the Final EIS were used in part to develop emission limits for the Air Quality Permit to Operate No. 9431-AA001 (Air Permit). The Alaska Department of Environmental Conservation (ADEC) issued the Air Permit, which also covers Healy Unit No. 1, in 1994. The Air Permit contains emission limits that are less stringent than the clean coal technology program goals developed by DOE and presented in the Final EIS but are more stringent than the applicable EPA NSPS (provided in 40 CFR 60 Subpart Da) for certain new electric power-generating facilities. The rigorous air emission goals in the Final EIS were not used as Air Permit emission limits because the clean coal technology was considered to be experimental and some operational details were still unknown. However, the Air Permit did state that the permitted emission limits would be lowered if the technology demonstrated the ability to meet the program goals. Until a decision is made regarding the future of the plant, no permit changes will be proposed.

The HCCP Demonstration Test Program Report (Stone & Webster and Steigers Corporation 1998) contains a set of emission goals that are essentially the same as those presented by DOE in the Final EIS (DOE 1993). However, the goal for NO_X emissions in the DTP was 0.20 to 0.35 lb/million Btu, which is less stringent than the NO_X emission goal in the Final EIS of 0.20 lb/million Btu. The Air Permit emission limits, the applicable NSPS requirements, and the program emission goals (both DTP and Final EIS) are given in Table 6-2.

6.1.3 Anticipated Water Discharges

The HCCP was designed to discharge treated wastewater and once-through condenser cooling water to the Nenana River under a National Pollution Discharge Elimination System (NPDES) Permit. The treated wastewater consists primarily of boiler blowdown and demineralizer regenerant wastewater. The treatment system was designed to utilize sedimentation, clarification, and neutralization processes. The discharge rate was estimated using data related to the quality of the incoming water, the wastewater treatment system capability, the boiler specifications, and other plant specifications. The Final EIS estimated the treated wastewater discharge flow rate to be approximately 233,536 gal/day when the plant is operating. The wastewater would be discharged via the HCCP Nenana River discharge outfall.

The once-through condenser cooling water used by the HCCP originates from the Nenana River, is transported through the condenser system to cool the power generating equipment, and does not undergo any water treatment. The Final EIS estimated that the once-through cooling water would be discharged to the Nenana River at a rate of approximately 40,000,000 gal/day. The condenser system was designed to have a temperature increase across the condenser system of approximately 27.5° F, which would result in the Nenana River experiencing a temperature increase of about 9.3° F above ambient at a distance of 30 feet downstream of the HCCP discharge outfall. The 9.3° F increase was estimated by thermal modeling performed for the Final EIS, and that temperature increase was later used to establish a mixing zone for the NPDES Permit Application. The NPDES Permit allowed the mixing zone, provided that the discharge temperature was not greater than about 89° F and the Nenana River temperature at a distance of 650 feet downstream from the HCCP discharge outfall was no greater than 59° F. The NPDES Permit did not provide for a temperature monitoring point at 30 feet downstream of the outfall for verification of the 9.3° F increase in river temperature at that location predicted by the Final EIS.

6.1.4 Anticipated Solid Wastes

Solid wastes included in this evaluation are slag/bottom ash, fly ash, and limestone waste, all of which are nonhazardous wastes. The proportions of slag/bottom ash and fly ash were expected to be approximately 80 percent and 20 percent, respectively. This ash breakdown is significantly different than the ash breakdown for other more conventional coal-fired facilities, which generate mostly fly ash. The Final EIS states that approximately 45,750 tons/year of slag/bottom ash and 11,450 tons/year of fly ash waste would be generated by the HCCP at an 85 percent capacity factor. The bottom ash would be collected at the bottom of the boiler hopper and routed into a silo. The fly ash would be collected in the SDA and in the baghouse, and, from there, it would be routed with the limestone waste to a silo. The amount of limestone waste generated by the HCCP at an 85 percent capacity factor was estimated to be approximately 5,550 tons/year. All three of these solid wastes would be transported via truck to the adjacent UCM for disposal.

Although the EPA does not regulate slag/bottom ash, fly ash, or limestone waste as hazardous wastes (40 CFR Part 261, Regulatory Determination on Wastes from the Combustion of Fossil Fuels; FR Volume 65, No. 99, Final Rules, May 22, 2000, pp. 32214-32235), the Final EIS contains documentation relating to the toxicity of these wastes. Toxicity tests were performed on the slag/bottom ash and fly ash using the Toxicity Characteristic Leaching Procedure (TCLP). None of the metals contained in the ash leached at concentrations exceeding the respective TCLP limits given in 40 CFR 261.24 (DOE 1993). Based on the composition of limestone, the Final EIS stated that the limestone waste would consist mainly of calcium sulfate with little or no toxic metals, and TCLPs were not performed (DOE 1993). Therefore, the wastes would not be “characteristic” hazardous wastes and would not need to be handled as such. It should be noted, however, that the EPA plans to establish national regulations for non-hazardous wastes under the Resource Conservation and Recovery Act (RCRA) that will be applicable to fossil fuel combustion by-products at some time in the future.

6.2 Actual Environmental Performance of the HCCP during the DTP

As stated above, the performance data used for comparison with the performance estimates of the Final EIS are primarily the data generated under the 90-Day Commercial Operation Test rather than under the entire 2-year-long DTP because that period of HCCP operations was most representative of steady-state conditions and because a substantial amount of data was accumulated during the test. The 90-Day Commercial Operation Test data used here are DCS data provided by TRW, the Harris Group, and AIDEA. Some operating parameters, such as cooling water flow rates, were not contained in the DCS data, and, therefore, compliance reports completed by GVEA and other DTP reports were used to supplement the DCS data. A summary of the operating parameters chosen to define actual environmental performance is given in Table 6-3. Values of environmental performance parameters that were anticipated, to the extent that they are available, are also included in Table 6-3.

6.2.1 Actual Raw Material Usage

During the 90-Day Commercial Operation Test, approximately 88,800 tons of coal and 1,700 tons of limestone were utilized according to the DCS data. The capacity factor during the 90-Day Commercial Operation Test was about 94.79 percent. These total raw material usage rates equate to yearly usages of 327,697 tons/year and 6,023 tons/year of coal and limestone, respectively, at the capacity factor used in the Final EIS, which was 85 percent. The usage rate for coal was about 5 percent lower than predicted; however, the heating value was about 3 percent higher and the ash content was about 23 percent lower than predicted. The limestone usage rate was about 8 percent higher than predicted in the Final EIS. The sulfur content of the coal utilized in the 90-Day Commercial Operation Test was about 13 percent higher than predicted.

The cooling water requirement during approximately 6 months of the DTP at times when the plant was presumed to be running at nearly full capacity averaged 12,500 million gal/year. The adjusted flow rate for an approximate capacity factor of 85 percent would have been about 10,640 million gal/year. The actual cooling water usage was about 15 percent lower than the EIS-predicted usage of 12,500 million gal/year.

6.2.2 Actual Air Emissions

Air emissions from the HCCP were measured continuously during the DTP. Part of the HCCP DCS includes a CEMS that measures NO_X, SO_2, and CO_2 emissions and opacity at the stack. The CEMS is required by the EPA NSPS and by the Air Permit. Although the CEMS is not required for CO emissions, CO is measured by a CO/O_2 instrument located in the furnace, with the data recorded on the DCS. In addition to requiring a CEMS, the EPA NSPS and the Air Permit require that stack tests be performed to evaluate the accuracy of the CEMS. In June 1998 and March 1999, stack tests were performed at the HCCP. The March 1999 test was a re-test for PM emissions because equipment malfunctions had caused an exceedance of the PM emission limit during the June 1998 test.

TRW also evaluated emissions during the DTP and provided "typical" emissions in its "Healy Clean Coal Project Demonstration Test Program, Topical Report: Combustion System Operation Final Report, March 2000" (AIDEA 2000c). TRW's "typical" emissions were similar to those measured during the 90-Day Commercial Operation Test. Typical SO_2 emissions were 0.038 lb/million Btu, typical NO_X emissions were 0.245 lb/million Btu, typical opacity was 5.5 percent in the early portion of the DTP and 2.3 percent during later portions of the DTP, and CO emissions were typically 30 to 40 ppm.

All of the Air Permit emission limits and applicable EPA NSPS requirements were met by the HCCP during the DTP, with the exception of intermittent exceedances caused by equipment malfunctions, plant startup, and plant shutdown. CO emissions were much lower than permitted limits. Such low CO emissions are not generally characteristic of conventional coal-fired facilities, especially when NO_X emissions also remain low. The HCCP also met or approached all of the DTP air emission goals presented in the Final EIS. The NO_X emission goal presented in the Final EIS was 0.20 lb/million Btu, and actual NO_X emissions range from about 0.24 to 0.27 lb/million Btu. These NO_X emission levels were achieved without any optimization of the slagging combustor and furnace operating parameters. The NO_X emission goal presented in the HCCP Demonstration Test Program Report (AIDEA 2000d) and in the performance guarantees from the technology providers was 0.20 to 0.35 lb/million Btu. The HCCP consistently met the DTP NO_X goals. All other parameters were measured at emission rates below the DTP air emission goals. Actual results from the DTP and from the 90-Day Commercial Operation Test are included in Table 6-2 for comparison with the Air Permit emission limits, the applicable NSPS requirements, and the program emission goals.

6.2.3 Actual Water Discharges

The HCCP operated within the limits of the NPDES Permit for the discharge of treated wastewater and once-through condenser cooling water during the 90-Day Commercial Operation Test (AIDEA 2000e). For this analysis, the data used to complete the NPDES reports were reviewed for the months of June, July, August, September, October, November, and December 1999.

The actual discharge flow rate of treated wastewater averaged less than 1 million gal/year, which was much lower than the 72.5 million gal/year predicted in the Final EIS. Furthermore, HCCP treats some of the wastewater generated by Healy Unit No. 1, so the actual discharge flow rate of HCCP treated wastewater may be even lower. The HCCP wastewater treatment system operated in a manner that allowed virtually all of the treated wastewater to be recycled. Treated wastewater was primarily reused in other processes such as HCCP flue gas desulfurization.

The average once-through condenser cooling water discharge rate for the days that the HCCP was operating at about full capacity was about 12,510 million gal/year, which equates to an actual discharge rate of about 10,640 million gal/year at a capacity factor of 85 percent. The Final EIS predicted a cooling water discharge rate of 12,500 million gal/year for an 85 percent capacity factor. Therefore, the actual cooling water usage was about 15 percent lower than predicted. The cooling water temperature increase (delta T) across the condenser during operation of the HCCP at full capacity was about 31.5° F during the time period evaluated, which was about 4° F degrees higher than the 27.5° F predicted in the Final EIS based on the design data for the condenser. The higher delta T was probably due to the lower flow rate, with more heat being absorbed per unit volume of water. The Final EIS also predicted that the temperature of the Nenana River would increase 9.3° F above ambient at a distance of 30 feet downstream from the HCCP outfall. However, temperature was not measured at 30 feet from the outfall during the DTP, and, thus, this specific Final EIS prediction could not be evaluated.

The NPDES Permit defines limits for discharge temperature and delta T in the Nenana River. The discharge temperature limit is 89° F, and the Nenana River temperature limit at a distance of 650 feet downstream (Station 2) is 59° F. The HCCP operated well within these limits during the time period evaluated. The Discharge Monitoring Reports (DMRs) indicate a maximum discharge temperature of about 78° F (average of 74° F) and the average Station 2 temperature of about 50° F. The delta T for Station 2 averaged about 3.5° F.

6.2.4 Actual Solid Wastes

The actual amounts of solid wastes generated by the HCCP were obtained from the DCS data from the 90-Day Commercial Operation Test. Slag/bottom ash, fly ash, and limestone waste were generated at average rates of approximately 233,070 lb/day, 58,270 lb/day, and 30,720 lb/day, respectively. These solid wastes would be generated at rates of approximately 36,154 tons/year, and 9,039 tons/year, and 4,766 tons/year, respectively, if the capacity factor were 85 percent. The actual amounts of slag/bottom ash and fly ash were about 21 percent lower than predicted in the Final EIS. The actual amount of limestone waste generated was about 14 percent lower than predicted in the Final EIS. As stated previously, the coal used in the 90-Day Commercial Operation Test contained about 23 percent less ash and about 13 percent more sulfur than predicted. Due to HCCP's remote location from any major markets, no economic application for reuse of any of the waste products has been identified at this time.

6.3 Anticipated Environmental Performance of the 300-MWe Facility

Data accumulated during the operation of the HCCP were extrapolated to evaluate a larger facility using the same integrated clean coal technology as the HCCP. This hypothetical facility, the CC-300, would be a 300-MWe power plant installed in Wyoming. The Harris Group extrapolated the HCCP data using fundamental engineering principles, with assistance from the providers of the various components of the integrated clean coal technology. Several relatively minor changes to the technology needed to be applied in the anticipated design of the CC-300, such as the elimination of once-through cooling and modification of the coal handling process. These changes were incorporated primarily because the facility would be located in the "Lower 48" states rather than in Alaska. These minor design changes affected environmental performance somewhat, as described below. The same Anticipated Values for Operating Parameters (Table 6-1) and the same Air Emission Limits and Goals (Table 6-2) were used for the evaluation of environmental performance. More information on the CC-300 is provided in Sections 7.0 and 8.0.

6.3.1 Anticipated Raw Material Usage

At a 65 percent capacity factor, the usage of coal for the CC-300 would be about 1,246,000 tons/year. The source of coal would be Powder River Basin coal with a heating value of about 8,175 Btu/lb, an ash content of 4 to 5 percent, and a sulfur content of about 0.37 percent. Additional information on Powder River Basin coal is provided in Section 7.0. The limestone usage rate would be about 42,671 tons/year at a capacity factor of 65 percent.

The cooling water requirements for the CC-300 and the HCCP cannot be directly compared because CC-300 would not utilize once-through cooling. The HCCP was able to utilize once-through cooling (with no consumptive use of cooling water) primarily because the HCCP is located in Alaska and a discharge with a thermal mixing zone was approved by EPA. For the CC-300, the recirculated cooling water flow rate would be about 251,900 gpm for operation at full load. On a daily basis, about 1.4 percent of the recirculating cooling water would need to be provided as make-up water due to evaporative losses and cooling tower blowdown. The water source would be a nearby surface water body containing less than 600 mg/L total dissolved solids, 500 ppm total hardness ($CaCO_3$), and 10 ppm silica. Other raw water requirements are provided in Section 7.0. Although water usage can be a problem in Wyoming, it was assumed that sufficient water is available for this plant.

6.3.2 Anticipated Air Emissions

The Harris Group, with assistance from the clean coal technology developers, concluded that the CC-300 would have the same emissions, in units of mass per heat input, as the HCCP. However, the emission rates (mass per time) would differ because the heat input (and the power output) of the CC-300 would be greater than that of the HCCP. The expected CC-300 emissions would be approximately 366 tons/year of SO_2 (0.0359 lb/million Btu), 2,648 tons/year of NO_X (0.26 lb/million Btu), and 214 tons/year of PM_{10} (0.021 lb/million Btu). The CC-300 is described more thoroughly in Section 7.0.

Since the heat input for the CC-300 would exceed 250 million Btu/hr, the CC-300 would be a "PSD Major Stationary Source" because emissions of more than one regulated pollutant would be greater than 100 tons/year (40 CFR 52.21 (b)(1)(i)(a)). The stringency of the air emission limitations for the CC-300 would be determined by a Best Available Control Technology (BACT) analysis. The BACT analysis would be performed for each pollutant emitted in excess of the quantities provided in 40 CFR 52.21 (b)(23)(j). The chosen control technology would need to perform to standards at least as stringent as the NSPS emission limits, which are described below. Furthermore, if computer modeling determined that CC-300 air emissions would exceed the allowable PSD "increments," more stringent air emission limits may be imposed, as described below.

The PSD program requires major stationary sources constructed in areas that meet the National Ambient Air Quality Standards (NAAQS) for criteria pollutants to obtain PSD permits (40 CFR 51.24) and to limit emissions to certain "increments" of pollution. "Increments" are the increases allowed above the baseline concentrations in an area. As stated above, computer modeling of the current air quality and the expected CC-300 stack emissions would be needed to determine the impact of the CC-300 emissions on the NAAQS and the PSD increments.

The EPA NSPS emission limits for PM_{10}, SO_2, and NO_X contained in 40 CFR 60 Subpart Da would apply to the CC-300. Except for NO_X, the NSPS requirements for the CC-300 would be the same as those for the HCCP, i.e., 0.03 lb/million Btu for PM and 70 percent removal for SO_2. However, because the NSPS Subpart Da have been revised for projects constructed after July 9, 1997, the CC-300 would be subject to a new NO_X emission limit of 0.15 lb/million Btu, which is more stringent than the HCCP's applicable limit of 0.50 lb/million Btu. Additional requirements in 40 CFR 60 Subpart Da would also have to be met by the CC-300. These include the installation of CEMS, stack testing, and other requirements.

In addition to the above-described air emission requirements, facilities constructed in the "Lower 48" states must comply with the Title IV requirements (Acid Rain Program) of the Clean Air Act. These requirements apply to SO_2 and NO_X acid deposition and do not apply to facilities in Alaska. The requirements of the Acid Rain Program would apply to the CC-300, as stated in 40 CFR 72(c). The CC-300 facility will be required to obtain an Acid Rain Permit, which in turn may require even more stringent SO_2 and/or NO_X emission limits.

6.3.3 Anticipated Water Discharges

As stated above, the circulating cooling water flow rate for the CC-300 would be approximately 251,900 gpm. However, none of this cooling water would be discharged to surface water bodies as is the case with once-through cooling systems. Therefore, the CC-300 would not require an NPDES Permit for cooling water discharge. About 1.4 percent of the CC-300 cooling water would have to be replaced by make-up water on a daily basis, mostly due to evaporative losses and partially due to cooling tower blowdown. The cooling tower blowdown would be discharged to an on-site pond system. Some of the pond water would be routed through a lime softener and become lime slurry water for the flue gas desulfurization process, and the rest would evaporate.

6.3.4 Anticipated Solid Wastes

The CC-300 would generate about 49,293 tons/year of slag/bottom ash, about 8,709 tons/year of fly ash, and about 33,962 tons/year of limestone waste. Since solid waste from coal combustion is currently exempt under Section 3001 of RCRA, the approximately 92,000 tons/year of CC-300 solid wastes would not need to be managed as hazardous wastes (see Section 6.1.4). The waste would be landfilled according to all applicable federal, state, and local regulations or, if possible, sold for use in commercial applications such as road base material.

Section 7.0 provides additional information on the CC-300, including detailed design parameters, performance information, and an economic analysis. Section 8.0 provides supplementary information on the CC-300, as well as information on competing technologies of the same capacity.

Table 6-1 Anticipated Values for Operating Parameters from the HCCP Final EIS.

Operating Parameter	Anticipated Value
Capacity (MWe)	50
Capacity Factor (%)	85
Heat Input (million Btu/hr)	644
Coal Consumption (tons/year)	344,600
Coal Heating Value (Btu/lb)	6,960
Coal Ash Content (% by weight)	17
Coal Sulfur Content (% by weight)	0.15
Limestone Consumption (tons/year)	5,600
Cooling Water Usage (million gal/year)	12,500
SO_2 Emissions (tons/year)	103
SO_2 Emissions (lb/million Btu)	0.043
NO_X Emissions (tons/year)	480
NO_X Emissions (lb/million Btu)	0.20
PM Emissions (tons/year)	36
PM Emissions (lb/million Btu)	0.015
Opacity (% for 3-minute period)	20
CO Emissions (ppm at 3.5 % O_2)	200
CO Emissions (tons/year)	480
CO_2 Emissions (tons/year)	511,600
Wastewater Discharge (million gal/year)	72.5
Cooling Water Discharge (million gal/year)	12,500
Heat Rejection - Temperature Increase 30 feet Downstream (°F)	9.3
Design Temperature Increase Across Condenser (°F)	27.5
NPDES Discharge Limit (°F)	89.6
Slag/Bottom Ash (tons/year)	45,750
Fly Ash (tons/year)	11,450
Limestone Waste (tons/year)	5,550

Source: DOE 1993

Notes for Table 6-1:

1. *Abbreviations: MWe = megawatts, million gal = 10^6 gallons, Btu = British thermal unit, lb = pounds, ppm = parts per million, CO = carbon monoxide, CO_2 = carbon dioxide, NO_X = oxides of nitrogen, PM = particulate matter, SO_2 = sulfur dioxide, NPDES = National Pollution Discharge Elimination System.*
2. *Capacity, capacity factor, coal usage, limestone usage, cooling water usage, air emissions (except opacity), wastewater and cooling water discharge flow rates, heat rejection, and solid wastes are provided in Table 2.1.2 of the Final EIS.*
3. *The heat value, the ash content, and the coal sulfur content of performance coal are provided on Page 2-15 of the Final EIS.*

4. *The hourly heat input was calculated using the coal usage and the coal heating value provided in the Final EIS.*
5. *The opacity is given in Table 1 of the "Healy Clean Coal Project Demonstration Test Program, Topical Report: Combustion System Operation Final Report, March 2000." (AIDEA 2000c).*
6. *Although the NO_X emission goal in the Final EIS is 0.20 lb/million Btu, the NO_X emission goal in other HCCP documents is 0.20 to 0.35 lb/million Btu.*
7. *The design temperature increase across the condenser is provided on Page 4-16 of the Final EIS.*
8. *The NPDES discharge temperature limit is provided in the HCCP and Healy Unit No. 1 NPDES Permit (EPA 1994).*

Table 6-2 Air Emission Limits and Emission Goals for the HCCP.

Opacity	PM Emissions	NO_X Emissions	SO_2 Emissions	CO Emissions
Air Quality Permit to Operate No. 9431-AA001 Emission Limits				
• 20% opacity (3-minute average) • 27% opacity (one 6-minute period per hour)	• 0.020 lb/million Btu (hourly average) • 13.2 lb/hr (hourly average) • 58 tons/yr (full load)	• 0.350 lb/million Btu (30-day rolling average) • 1,010 tons/yr (full load)	• 0.086 lb/million Btu (annual average) • 0.10 lb/million Btu (3-hour average) • 65.8 lb/hr (3-hour average) • 248 tons/yr (full load)	• 0.20 lb/million Btu (hourly average) • 202 ppm at 3.0% O_2 • 132 lb/hr • 577 tons/yr (full load)
NSPS Emission Limits (40 CFR 60 Subpart Da)				
• 20% opacity (6-minute average)	• 0.03 lb/million Btu (hourly average) • 99% reduction	• 0.50 lb/million Btu	• 70% removal when emissions are less than 0.60 lb/million Btu	• Dependent on HCCP ambient CO levels (no requirements listed in 40 CFR 60 Subpart Da)
EIS and DTP Emission Goals				
• 20% opacity (3-minute average)	• 0.015 lb/million Btu (hourly average)	• 0.20 lb/million Btu (Final EIS) • 0.20 to 0.35 lb/million Btu (DTP)	• 70% removal • 79.6 lb/hr maximum (= 0.13 lb/million Btu at actual HCCP heat input of 608 million Btu/hr – see Table 6-3)	• 200 ppm (dry basis) at 3.5% O_2 • 206 ppm at 3.0% O_2
Actual Results from the DTP				
• 2% to 6% (30-minute average)	• Not measured (source test March 1999 measured 0.0047 lb/million Btu)	• 0.208 to 0.278 lb/million Btu, 0.245 lb/million Btu (30-day rolling average)	• 0.038 lb/million Btu (30-minute average)	• 30 to 40 ppm (30-minute average)
Actual Results from the 90-Day Commercial Operation Test				
• approximately 5.5% (average)	• Not measured	• 0.275 lb/million Btu (30-day rolling average)	• 0.060 lb/million Btu (average)	• approximately 20 to 50 ppm

Sources: AIDEA 2000e, Harris Group 1999, Stone & Webster and Steigers Corporation 1998

Table 6-3 Actual Values for HCCP Operating Parameters.

Operating Parameter	Anticipated Value	Actual Value
Capacity (MWe)	50	50
Capacity Factor (%)	85	95
Availability (%)	85	96
Heat Input (million Btu/hr)	644	608
Heat Input (million Btu/year)	5,359,368	5,059,776
Coal Consumption (tons/year)	344,600	327,697
Coal Heating Value (Btu/lb)	6,960	7,187
Coal Ash Content (%)	17	13.13
Coal Sulfur Content (%)	0.15	0.17
Limestone Consumption (tons/year)	5,600	6,023
Cooling Water Usage (million gal/year)	12,500	10,640
SO_2 Emissions (tons/year)	103	95
SO_2 Emissions (lb/million Btu)	0.043	0.042
NO_X Emissions (tons/year)	480	616
NO_X Emissions (lb/million Btu)	0.20	0.272
PM Emissions (lb/million Btu)	0.015	0.0047
Opacity (%)	20	3.9
CO Emissions (ppm)	200	25.9
CO_2 Emissions (tons/year)	511,600	459,000
Wastewater Discharge (million gal/year)	72.5	< 1
Cooling Water Discharge (million gal/year)	12,500	10,640
Heat Rejection - Temperature Increase at 650 feet Downstream (°F)	No Value	3.5
Condenser Temperature Increase (°F)	27.5	31
Average Discharge Temperature (°F)	89.6	74
Slag/Bottom Ash (tons/year)	45,750	36,154
Fly Ash (tons/year)	11,450	9,039
Limestone Waste (tons/year)	5,550	4,766

Sources: HCCP DCS data, NPDES DMR data, Am Test 1998, HMH 1999
Notes for Table 6-3:

1. *Capacity factor, availability, coal usage, coal ash content, coal sulfur content, limestone usage, air emissions (except particulate and CO, and CO_2 emissions in units of tons per year), and solid wastes were calculated using the HCCP DCS data for the 90-Day Commercial Operation Test. The DCS data used for emissions were 30-minute readings of air emissions. The remaining DCS data were daily averages.*
2. *The values in the table were modified so that they would represent an 85 percent capacity factor rather than the 95.57 percent capacity (during coal-fired days) that was encountered in the 90-Day Commercial Operation Test (the availability during the 90-Day Commercial Operation Test was 93.45 percent).*

3. *The flow rates for cooling water and wastewater, the heat rejection, the temperature increase across the condenser, and the discharge temperature were estimated using spreadsheets utilized to complete the Discharge Monitoring Reports (DMRs) for the NPDES Permit for the months of June, July, August, October, November, and December 1999. Healy Unit No. 1 wastewater is treated by HCCP's treatment system. Therefore, the discharge is a combination of the wastewater for the two facilities, and the value shown in the table includes the discharge for both facilities.*

7.0 ECONOMICS

Two variations of the HCCP clean coal technology are evaluated in this section to illustrate the commercial potential of the technology. The first variation of the HCCP, called the CC-50, is a plant of the same capacity (50 MWe) utilizing the same technology as the HCCP. However, rather than being located near Healy, Alaska, the CC-50 would be located in Wyoming. In addition, it is assumed that the technology is fully developed. The second variation of the HCCP, called the CC-300, is a scaled-up version of the HCCP (nominal capacity 300 MWe) also located in Wyoming.

Wyoming was selected as the hypothetical site in the "Lower 48" states based on availability of low-cost, low-sulfur coal. Site selection is generally dependent on transmission capacity, water supply, and coal supply, in that order of precedence. Because a site with all three conditions is most likely not available, coal is railed to a site with transmission capacity and water supply.

Adjustments were made because of inherent differences in development, construction, and operation of a plant in the "Lower 48" states from those of a plant in Alaska. These inherent differences are described later in this section.

Other adjustments were made to the HCCP data to remove costs of that project due to:

- excessive redundancy of a demonstration plant
- excessive costs of a Rural Electric Association approach to design.

This analysis was performed using HCCP data obtained primarily during the 90-Day Commercial Operation Test. The Harris Group also utilized its comprehensive experience with power plants to determine the expected characteristics of these two HCCP variations. Sufficient details are provided to enable interested parties to use this analysis as a preliminary assessment of the cost of applying these integrated clean coal technologies to their particular situations.

7.1 Economic Parameters

The economic parameters utilized to estimate the cost of the CC-300 are provided in the Pittsburgh Energy Technology Center (PETC) General Guidelines (PETC 1993). The economic parameters used in the PETC General Guidelines are presented here in Table 7-1 and have been given typical values used in recent studies of clean coal technology at the National

Energy Technology Laboratory. The PETC General Guidelines suggest that calculations be done using a 65 percent capacity factor. However, since these would be independent power projects hypothetically constructed in the year 2000, a 90 percent capacity factor was used.

7.2 Estimated Capital Costs

This section discusses the estimated capital costs for the CC-50 and the CC-300 and the assumptions made in developing these estimates.

In order to determine the cost of the HCCP if it had been built in the "Lower 48" states (CC-50), the following adjustments were made to the HCCP final cost report provided in Section 5.0 of the Public Design Report. Note that it has been assumed that the CC-50 is a commercial facility. The design was modified to reflect what an independent power producer would build in the year 2000.

- Transportation Costs – A 4 percent reduction in the capital cost of equipment was applied to the cost analysis because the average equipment shipping cost to the HCCP was approximately 8 percent and our estimate for shipping to a Wyoming site is about 4 percent. This reduction in capital cost was applied to all equipment.

- Construction Costs – The average cost of construction of the HCCP was approximately 1.3 times the capital cost of the equipment. Estimated costs for construction in Wyoming are 0.95 times the capital cost of equipment. The construction cost adjustment includes reduction of HCCP costs attributable to the following items: the 6-month winter shutdown required at Healy, $9 million in temporary construction camp costs, Alaskan labor, and reduced seismic requirements. This adjustment was made to all plant categories.

- Engineering and Home Office Costs – A 4 percent factor was utilized to cover engineering and 4 percent factor was used for home office support. The adjustment eliminated GVEA oversight for the project and excess AIDEA site engineering required at Healy due to the development aspects of the project.

- Construction Management Costs – Construction management was about 7 percent of the total construction account at HCCP. This ratio was adjusted on the assumption that the specific work performed because the HCCP project was a DOE project is not required at the "Lower 48" states site.

Design details for the HCCP provided in Section 3.0 of the Public Design Report were used for the preliminary design of CC-300. However, before evaluating the CC-300 cost, design changes suggested by operation of the HCCP were incorporated. A list of the CC-300 design changes is provided below.

- Natural circulation rather than forced circulation is provided for combustor cooling.

- Dedicated coal mills are provided for the pre-combustors and the slagging combustors to eliminate the external coal classifier in the coal feed system. Two coal mills feed coal to four pre-combustors, and two coal mills feed coal to four slagging combustors.

- Primary air fans replace the exhausters in the coal feed system.

- The larger plant takes advantage of reheat to the steam turbine generator (STG).

- A mechanical-draft cooling tower replaces the once-through circulating water for cycle heat rejection.

- Slag and bottom ash are sluiced and dewatered in ash ponds every 6 months rather than being transported by mechanical conveyors to a silo and trucked when the silo is full. Direct transport of slag and bottom ash is expected to be permitted in Wyoming and would result in a project cost savings.

- Coal is transported via railcar rather than by truck.

- Raw water is stored in a pond rather than in tanks.

- There would be no process wastewater discharge. Cooling tower blowdown is softened for lime slurry make-up water. Process wastewater is utilized for scrubber slurry, and wastewater is trucked to the landfill to condition ash to meet landfill requirements. A small amount of non-reclaimable wastewater is evaporated.

Other design criteria for the CC-300 include the following.

- The plant generates 319,000 kW net output.

- Site elevation is 5,000 feet above sea level, with four seasons including periods below freezing.

- 80 acres of relatively flat acreage is available for the fenced site. Roadwork consists only of on-site roads.

- Powder River Basin coal is delivered by unit train to a spur near the site and dumped, then conveyed either to covered storage or to a 60-day storage pile.

- Crushed limestone is railed to the site and pneumatically unloaded into storage silos.

- The site is located near transmission capacity and near a river capable of supplying approximately 3,400 gpm for mechanical evaporative cooling of cycle heat rejection.

- Raw water is river water with total hardness not greater than 500 ppm ($CaCO_3$) and silica concentration not greater than 10 ppm.

- Fly ash is dry-loaded from under a drive-through silo and trucked to a landfill where it is mixed with wastewater to produce a non-leachable fill. Bottom ash is sluiced to settling ponds and eventually trucked to a landfill.

- Coal storage pile storm drainage is collected and treated before release to natural drainage off site. Open channels are routed to a low point at the site boundary, which forms a single storm drainage point.

- Auxiliaries with stand-by equipment to support an expected availability of from 65 to 92 percent support a single boiler and single STG.

- The STG is designed for 345,000 kW and has a maximum continuous rating equivalent to valves wide open and throttle conditions of 2,400 psig and 1,000° F, which corresponds with the maximum continuous rating of the steam generator.

- The turbine steam/water cycle consists of seven feedwater heaters including the deaerator. Note that the cycle design is very dependent on fuel costs and may be very different for other situations.

- The electrical interface is at the high-side bushings of the generator step-up transformer. The auxiliary transformers receive power from the same utility substation to which generated power is connected. The auxiliary transformers provide power to the plant when the unit is generating.

In order to allow interested parties to assess the cost of applying this new technology to suit their interests in the integrated clean coal technologies, the CC-300 was assumed to be a "greenfield" project.

Site conditions such as raw water storage, coal supply, and ash disposal were included as appropriate for the Wyoming site. The cost provided here includes the civil/structural and architectural estimates to support a complete Engineering/Procurement/Construction (EPC) cost estimate.

Table 7-2 provides the estimated capital costs for the CC-300. Note that the engineer's methodology includes General Facilities costs (line item B) and Engineering costs (line item C) in the costs for each Total Installed Equipment Cost “area.” Contingency is 0. These items are not listed as separate line items.

Cost breakdowns for the HCCP, CC-50, and CC-300 plants are presented in Table 7-3. The capital cost of a CC-300 plant is about five times the cost of a CC-50 plant. Economies of scale provide a lower cost per kilowatt for the CC-300. This is especially true for major equipment such as the boiler, turbine generator, and fuel handling equipment. The cost per kW for the 300-MWe-plant is $1,318, and the cost per kW for a 50-MWe plant is $1,645.

7.3 Projected Operating and Maintenance Costs

Operating and maintenance (O&M) costs were also projected for the CC-300. These costs are provided in Table 7-4. The O&M costs are divided between fixed and variable costs, as specified in the PETC General Guidelines.

7.4 Summary of Performance and Economics

The PETC General Guidelines were used as the basis for estimating the performance and economics of the "scaled-up" HCCP technology. Table 7-5 provides an overall summary of the performance and economics of the CC-300 per the PETC General Guidelines. This summary includes a summary of air emissions as well as cost data. The emission concentrations provided in the table were determined based on concentrations demonstrated by the HCCP. The "emission limits" contained in Table 7-5 are those that would be expected as air permit limits for facilities constructed in Wyoming. The levelized costs of power and the levelized costs on an SO_2/NO_X emission basis are presented on both current and constant dollar bases.

7.5 Effect of Variables on Economics

Parametric calculations were performed to determine the effect on economics of certain variables, including size of the unit, sulfur content of the coal feed, capacity factor, and book life. The results of these calculations are provided in Tables 7-6a through 7-6d and Figures 7-1a through 7-1d and are summarized as follows.

- Additional plant sizes evaluated were 532 MWe, 957 MWe, and 1,276 MWe net. Fixed operating costs per plant capacity were lower for the larger units.

- Coal feed sulfur contents were selected at 1 percent, 2 percent, and 3 percent. Variable costs were higher for higher sulfur-content coal because of higher sorbent costs.

- Capacity factors for capacity factor sensitivity were selected at 65 percent, 75 percent, 85 percent, and 90 percent. Power costs were lower for higher capacity factors because of higher annual net outputs.

- Debt periods for book life sensitivity were selected at 20 years, 25 years, and 30 years. The sale price for electricity was set to yield a 1.25 minimum debt coverage ratio for the base case (15-year debt period). This price was held constant for the three other cases to illustrate the improved economics resulting from longer debt periods.

Table 7-1 Economic Parameters Used in PETC General Guidelines.

Item	Units	Value
Cost of Debt	%	8.5
Dividend Rate for Preferred Stock (pre-tax)	%	7.0
Dividend Rate for Common Stock (pre-tax)	%	7.5
Debt/Total Capital	%	50.0
Preferred Stock/Total Capital	%	15.0
Common Stock/Total Capital	%	35.0
Income Tax Rate	%	38.8
Investment Tax Credit	%	0.0
Property Taxes and Insurance	%	3.0
Inflation Rate	%	4.0
Discount Rate (with inflation)	%	7.925
Discount Rate (without inflation)	%	3.744
Escalation of Raw Materials above Inflation	%	0.0
Construction Period	years	1
Allowance for Funds during Construction	%	0.0
Construction Downtime	days	90
Remaining Life of Power Plant	years	15
Year for Cost Presented in this Report	------	1993
Royalty Allowance (based on total process capital)	%	0.5
Capital Charge Factor (current dollars)	-----	0.160
Capital Charge Factor (constant dollars)	-----	0.124
O&M Cost Levelization Factor (current dollars)	-----	1.314
O&M Cost Levelization Factor (constant dollars)	-----	1.000
Power Plant Capacity Factor*	%	90
Sales Tax Rate	%	5.0
Cost of Freight for Process Equipment	%	2.0
General Facilities/Total Process Capital	%	**0.0
Engineering and Home Office Fees/Total Process Capital	%	**0.0

* A capacity factor of 90 percent was used instead of the 65 percent specified in the PETC General Guidelines.

** The engineer's methodology includes these items in the Total Installed Equipment Cost line items in Tables 7-2, 7-3, 8-5, 8-6, 8-7, and 8-14.

Table 7-2 Estimated Capital Requirements for the CC-300.

Area	Total Installed Equipment Cost	$10^6	$/kW*
100	Coal Unloading and Handling	6.9	19.90
200	Sorbent Unloading and Handling	3.4	9.95
400	Combustion/Steam Generation	201.4	583.65
700	Power Generation	170.5	494.15
800	SO_2 Removal	15.5	44.89
1000	Particulate Removal	11.8	34.18
1400	Ash Collection and Removal	5.2	15.05
1500	Civil/Structural/Architectural	36.0	104.32
(A)	Total Process Capital	450.6	1,306.08
(B)	General Facilities (10% of A)	included	included
(C)	Engineering (10% of A)	included	included
(D)	Project Contingency	0.0	0.0
(E)	Total Plant Cost (A+B+C+D)	450.6	1,306.08
(F)	Allowance for Funds During Construction (0% of E)	0.0	0.0
(G)	Total Plant Investment (E+F)	450.6	1,306.08
(H)	Royalty Allowance (0.5% of A)	2.2	6.50
(I)	Preproduction Costs (3 months of startup)	1.0	2.90
(J)	Inventory Capital	1.0	2.90
(K)	Initial Chemicals	0.1	0.0
(L)	Subtotal Capital (G+H+I+J+K)	454.9	1,318.38
(M)	Cost of Construction Downtime	0.0	0.0
(N)	Total Capital Requirement (L+M)	454.9	1,318.38

* Based on 345 MWe gross capacity

Table 7-3 Cost Breakdown for Three Clean Coal Plants.

Item	Process Area	Installed Costs ($$10^6$)		
		50-MWe HCCP	**50-MWe CC-50**	**300-MWe CC-300**
2.1	Main Boiler(s)	17.312	13.800	85.500
2.2	Combustors	30.730	4.400	14.100
2.3	FGD (including Baghouses)*	7.534	5.400	30.700
2.4	Materials Handling	1.382	1.100	3.500
2.5	Ash Handling	3.591	3.000	2.600
2.6	Pre/Post Combustion Air	0.885	0.800	4.800
2.7	STG and Steam	11.147	8.400	31.900
2.8	Condensate/Feedwater	1.671	1.400	8.800
2.9	Circulating Water	0.208	0.200	1.100
2.10	Water and Wastewater	1.485	1.200	1.000
2.11	Fire Protection	0.067	0.100	0.400
2.12	Plant Controls	2.636	2.200	0.900
2.13	Electrical	2.251	1.900	14.300
2.14	Balance of Plant	11.463	9.300	63.700
3.1	Installation/Contractor Supplied Equip	106.905	37.400	187.400
3.4	Total Process Plant Installed	199.267	90.600	450.700
4.0	Engineering and Home Office	33.679	included	included
	Contingency	0	0	0
4.3	Construction Management	7.121	included	included
	Total EPC Costs**	240.067	90.600	450.700

* Flue Gas Desulfurization

** Engineering/Procurement/Construction

Table 7-4 Operating and Maintenance Costs for the CC-300.

	Units	Quantity	$/Unit	$$10^6$/Year
FIXED O&M COSTS				
Operating Labor	man-hour /hr	9	21.00	1.656
Maintenance Labor				2.100
Maintenance Material				3.200
Administration/Support Labor				0.200
Subtotal Fixed Costs				7.156
VARIABLE OPERATING COSTS				
Fuels				
Coal	tons/hr	217.09	*14.00	23.962
No. 2 Fuel Oil	gal/hr	57.1	2.00	0.900
Sorbent				
Limestone	tons/hr	7.91	20.00	1.247
Regen Chemicals				
Acid	gal/hr	1.4819	1.070	0.01250
Caustic	gal/hr	2.112	2.140	0.03562
Utilities				
Steam	10^3lb/hr	1.2	3.50	0.033
Condensate	10^3lb/hr	2.2	0.77	0.013
Raw Water	10^3gal/hr	203	0.60	0.960
Cooling Water	10^3gal/hr	included	0.16	0.000
Station Service Electric Power	kWh	38.05	0.05	0.015
By-Product Credits	--	--	--	0
Waste Disposal Charges				
Ash Trucked and Landfilled	tons/hr	16.15	9.29	1.183
Subtotal Variable Costs				28.361
Total O&M Cost (Fixed + Variable)				35.517

* Source: FERC 1999

Table 7-5 Summary of Performance and Costs for the CC-300.

POWER PLANT ATTRIBUTES	**Units**	**Value**		
Plant Capacity, net	MWe	319		
Power Produced, net	10^9 kWh/year	2.51		
Capacity Factor*	%	90		
Plant Life	years	15		
Coal Feed	10^6 tons/year	1.712		
Sulfur in Coal	% by weight	0.37		
EMISSIONS CONTROL	**Units**	**SO_2**	**NO_X**	**PM_{10}**
Removal Efficiency	%	96	35	99.95
Emissions Standard	lb/10^6 Btu	0.086	0.35	0.020
Emissions w/o Control	lb/10^6 Btu	0.910	0.40	4.19
Emissions w/ Control	lb/10^6 Btu	0.035	0.26	0.0021
Amount Removed	tons/year	12,176	1,959	59,053
LEVELIZED COST OF POWER	**Current Dollars**		**Constant Dollars**	
	Factor	**Mills/kWh**	**Factor**	**Mills/kWh**
Capital Charge	0.160	28.9	0.124	22.4
Fixed O&M Cost	1.314	3.7	1.000	2.8
Variable Operating Cost	1.314	14.9	1.000	11.3
Total Cost		47.5		36.5
LEVELIZED COST - SO_2/NO_X BASIS	**Factor**	**$/Ton Removed**	**Factor**	**$/Ton Removed**
Capital Charge	0.160	5,109	0.124	3,959
Fixed O&M Cost	1.314	660	1.000	502
Variable Operating Cost	1.314	2,633	1.000	2,004
Total Cost		8,402		6,466

* A capacity factor of 90 percent was used instead of the 65 percent specified in the PETC General Guidelines.

Table 7-6a Effects on Economics Resulting from Changes in Plant Size.

POWER PLANT ATTRIBUTES				
Plant Capacity, net (MWe)	***319***	***532***	***957***	***1,276***
Power Produced, net (10^9 kWh/year)	2.51	4.19	7.54	10.06
Capacity Factor (%)	90	90	90	90
Book Life (years)	15	15	15	15
Coal Feed (10^6 tons/year)	1.712	2.875	5.175	6.900
Sulfur in Coal (% by weight)	0.37	0.37	0.37	0.37
LEVELIZED COST OF POWER (Mills/kWh, Constant Dollars)				
Capital Charge	22.4	22.1	21.1	20.2
Fixed O&M Cost	2.8	2.2	1.9	1.7
Variable Operating Cost	11.3	11.2	11.2	11.1
Total Cost	36.5	35.5	34.2	33.0
LEVELIZED COST OF POWER (SO_2/NO_X Basis - $/Ton Removed, Constant Dollars)				
Capital Charge	3,991	3,904	3,733	3,545
Fixed O&M Cost	506	391	327	301
Variable Operating Cost	2,002	1,975	1,968	1,963
Total Cost	6,499	6,270	6,029	5,810
LEVELIZED COST OF POWER (Mills/kWh, Current Dollars)				
Capital Charge	28.9	28.5	27.3	25.9
Fixed O&M Cost	3.7	2.9	2.4	2.2
Variable Operating Cost	14.8	14.7	14.7	14.6
Total Cost	47.4	46.1	44.4	42.7
LEVELIZED COST OF POWER (SO_2/NO_X Basis - $/Ton Removed, Current Dollars)				
Capital Charge	5,149	5,037	4,817	4,574
Fixed O&M Cost	665	514	430	396
Variable Operating Cost	2,631	2,595	2,586	2,580
Total Cost	8,445	8,146	7,833	7,550

Table 7-6b Effects on Economics Resulting from Changes in Sulfur Content.

POWER PLANT ATTRIBUTES				
Plant Capacity, net (MWe)	319	319	319	319
Power Produced, net (10^9 kWh/year)	2.51	2.51	2.51	2.51
Capacity Factor (%)	90	90	90	90
Book Life (years)	15	15	15	15
Coal Feed (10^6 tons/year)	1.712	1.712	1.712	1.712
Sulfur in Coal (% by weight)	**0.37**	**1.00**	**2.00**	**3.00**
LEVELIZED COST OF POWER (Mills/kWh, Constant Dollars)				
Capital Charge	22.4	22.4	22.4	22.4
Fixed O&M Cost	2.8	2.8	2.8	2.8
Variable Operating Cost	11.3	12.3	13.7	14.8
Total Cost	36.5	37.5	38.9	40.0
LEVELIZED COST OF POWER (SO_2/NO_X Basis - $/Ton Removed, Constant Dollars)				
Capital Charge	3,991	1,568	800	537
Fixed O&M Cost	506	199	102	68
Variable Operating Cost	2,002	862	489	354
Total Cost	6,499	2,628	1,391	960
LEVELIZED COST OF POWER (Mills/kWh, Current Dollars)				
Capital Charge	28.9	28.9	28.9	28.9
Fixed O&M Cost	3.7	3.7	3.7	3.7
Variable Operating Cost	14.8	16.2	18.0	19.4
Total Cost	47.4	48.8	50.6	52.0
LEVELIZED COST OF POWER (SO_2/NO_X Basis - $/Ton Removed, Current Dollars)				
Capital Charge	5,149	2,023	1,033	693
Fixed O&M Cost	665	261	133	90
Variable Operating Cost	2,631	1,132	643	466
Total Cost	8,445	3,416	1,809	1,249

Table 7-6c Effects on Economics Resulting from Changes in Capacity Factor.

POWER PLANT ATTRIBUTES				
Plant Capacity, net (MWe)	319	319	319	319
Power Produced, net (10^9 kWh/year)	1.82	2.10	2.38	2.51
Capacity Factor (%)	**65**	**75**	**85**	**90**
Book Life (years)	15	15	15	15
Coal Feed (10^6 tons/year)	1.246	1.438	1.629	1.712
Sulfur in Coal (% by weight)	0.37	0.37	0.37	0.37
LEVELIZED COST OF POWER (Mills/kWh, Constant Dollars)				
Capital Charge	31.1	26.9	23.7	22.4
Fixed O&M Cost	3.9	3.4	3.0	2.8
Variable Operating Cost	11.3	11.3	11.3	11.3
Total Cost	46.3	41.6	38.0	36.5
LEVELIZED COST OF POWER (SO_2/NO_X Basis - $/Ton Removed, Constant Dollars)				
Capital Charge	5,482	4,751	4,192	3,991
Fixed O&M Cost	696	603	532	506
Variable Operating Cost	2,002	2,001	2,001	2,002
Total Cost	8,179	7,355	6,725	6,449
LEVELIZED COST OF POWER (Mills/kWh, Current Dollars)				
Capital Charge	40.1	34.7	30.6	28.9
Fixed O&M Cost	5.2	4.5	4.0	3.7
Variable Operating Cost	14.9	14.9	14.9	14.8
Total Cost	60.2	54.1	49.5	47.4
LEVELIZED COST OF POWER (SO_2/NO_X Basis - $/Ton Removed, Current Dollars)				
Capital Charge	7,074	6,131	5,410	5,149
Fixed O&M Cost	914	792	699	665
Variable Operating Cost	2,630	2,630	2,630	2,631
Total Cost	10,618	9,553	8,739	8,445

Table 7-6d Effects on Economics Resulting from Changes in Book Life.

POWER PLANT ATTRIBUTES				
Plant Capacity, net (MWe)	319	319	319	319
Power Produced, net (10^9 kWh/year)	2.51	2.51	2.51	2.51
Capacity Factor (%)	90	90	90	90
Book Life (years)	**15**	**20**	**25**	**30**
Coal Feed (10^6 tons/year)	1.712	1.712	1.712	1.712
Sulfur in Coal (% by weight)	0.37	0.37	0.37	0.37
LEVELIZED COST OF POWER (Mills/kWh, Constant Dollars)				
Capital Charge	22.4	18.6	17.3	16.8
Fixed O&M Cost	2.8	2.8	2.8	2.8
Variable Operating Cost	11.3	11.3	11.3	11.3
Total Cost	36.5	32.7	31.4	30.9
LEVELIZED COST OF POWER (SO_2/NO_X Basis - $/Ton Removed, Constant Dollars)				
Capital Charge	3,991	3,314	3,082	2,993
Fixed O&M Cost	506	506	506	506
Variable Operating Cost	2,002	2,002	2,002	2,002
Total Cost	6,499	5,822	5,590	5,501
LEVELIZED COST OF POWER (Mills/kWh, Current Dollars)				
Capital Charge	28.9	24.0	22.3	21.7
Fixed O&M Cost	3.7	3.7	3.7	3.7
Variable Operating Cost	14.8	14.8	14.8	14.8
Total Cost	47.4	42.5	40.8	40.2
LEVELIZED COST OF POWER (SO_2/NO_X Basis - $/Ton Removed, Current Dollars)				
Capital Charge	5,149	4,276	3,975	3,862
Fixed O&M Cost	665	665	665	665
Variable Operating Cost	2,631	2,631	2,631	2,631
Total Cost	8,445	7,572	7,271	7,158

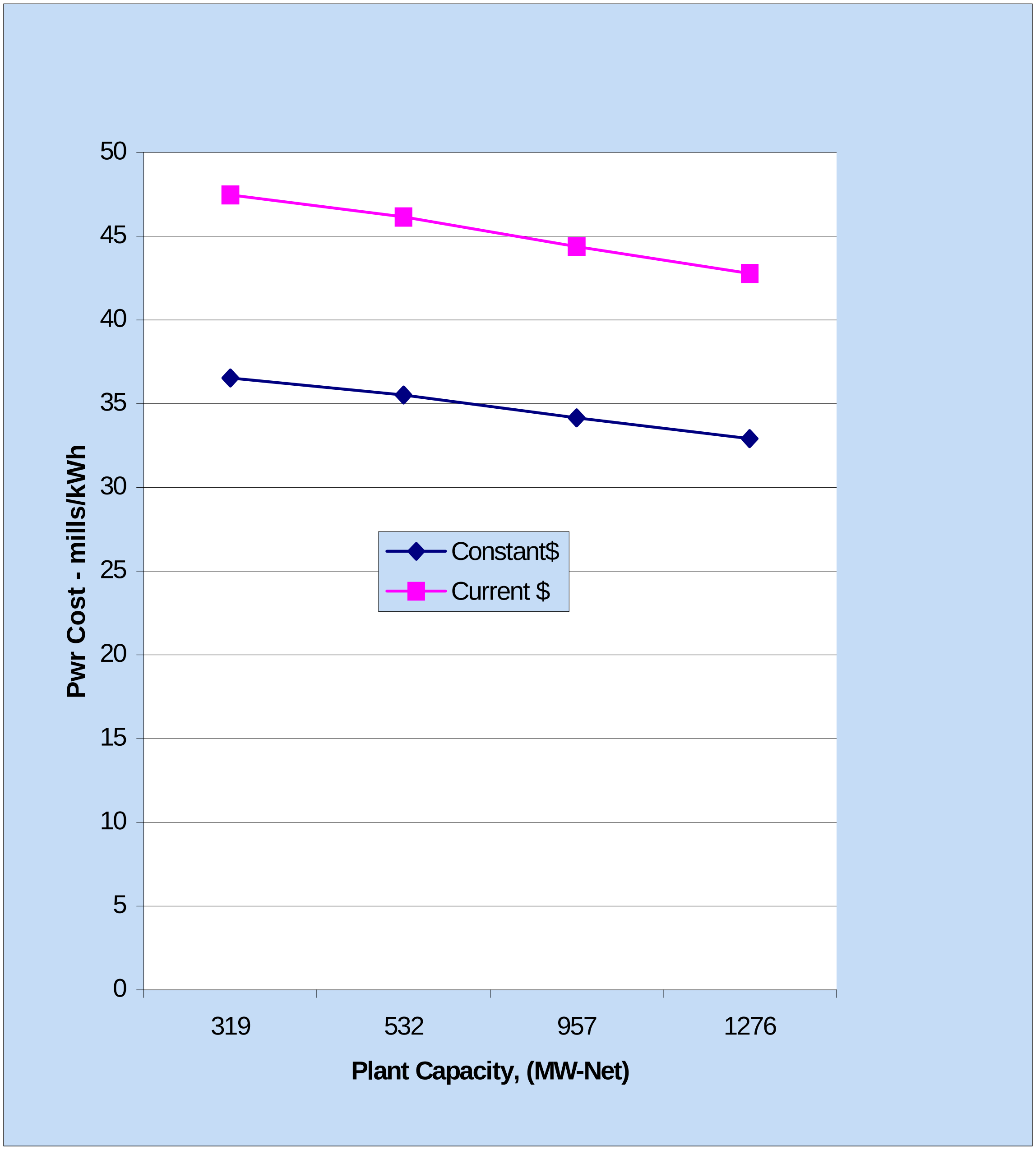


Figure 7-1a Power Cost vs. Plant Capacity.

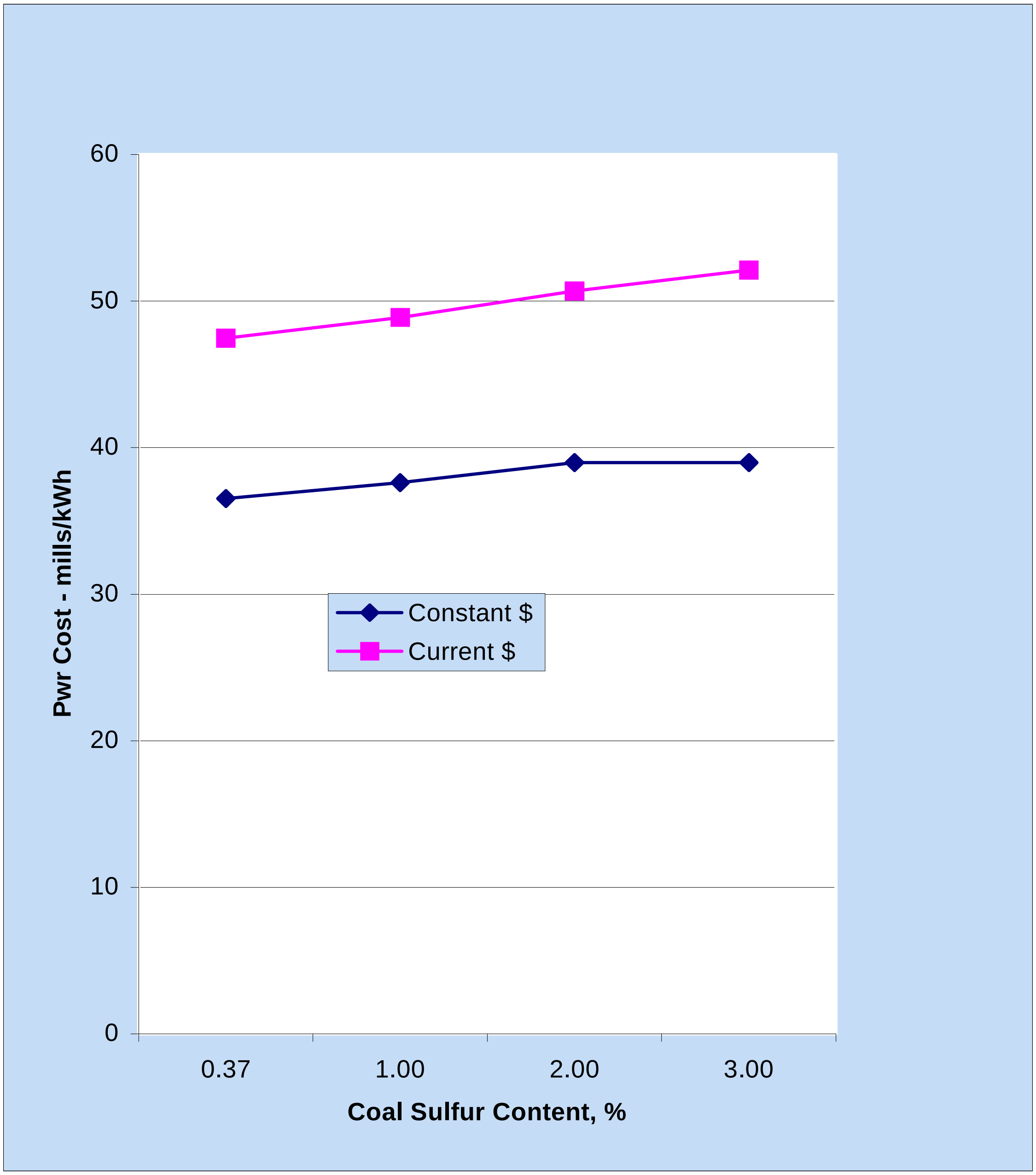


Figure 7-1b Power Cost vs. Sulfur Content.

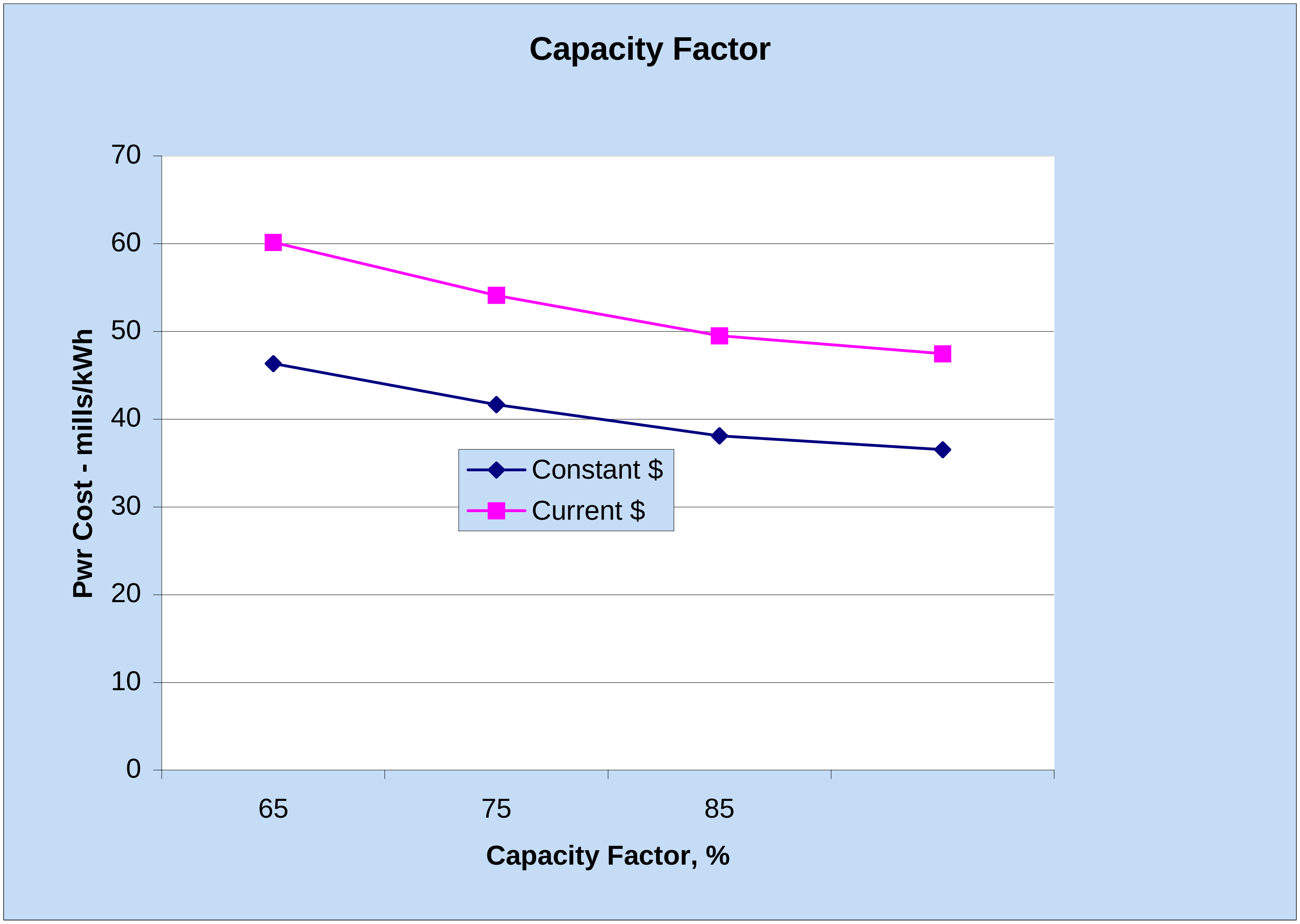


Figure 7-1c Power Cost vs. Capacity Factor.

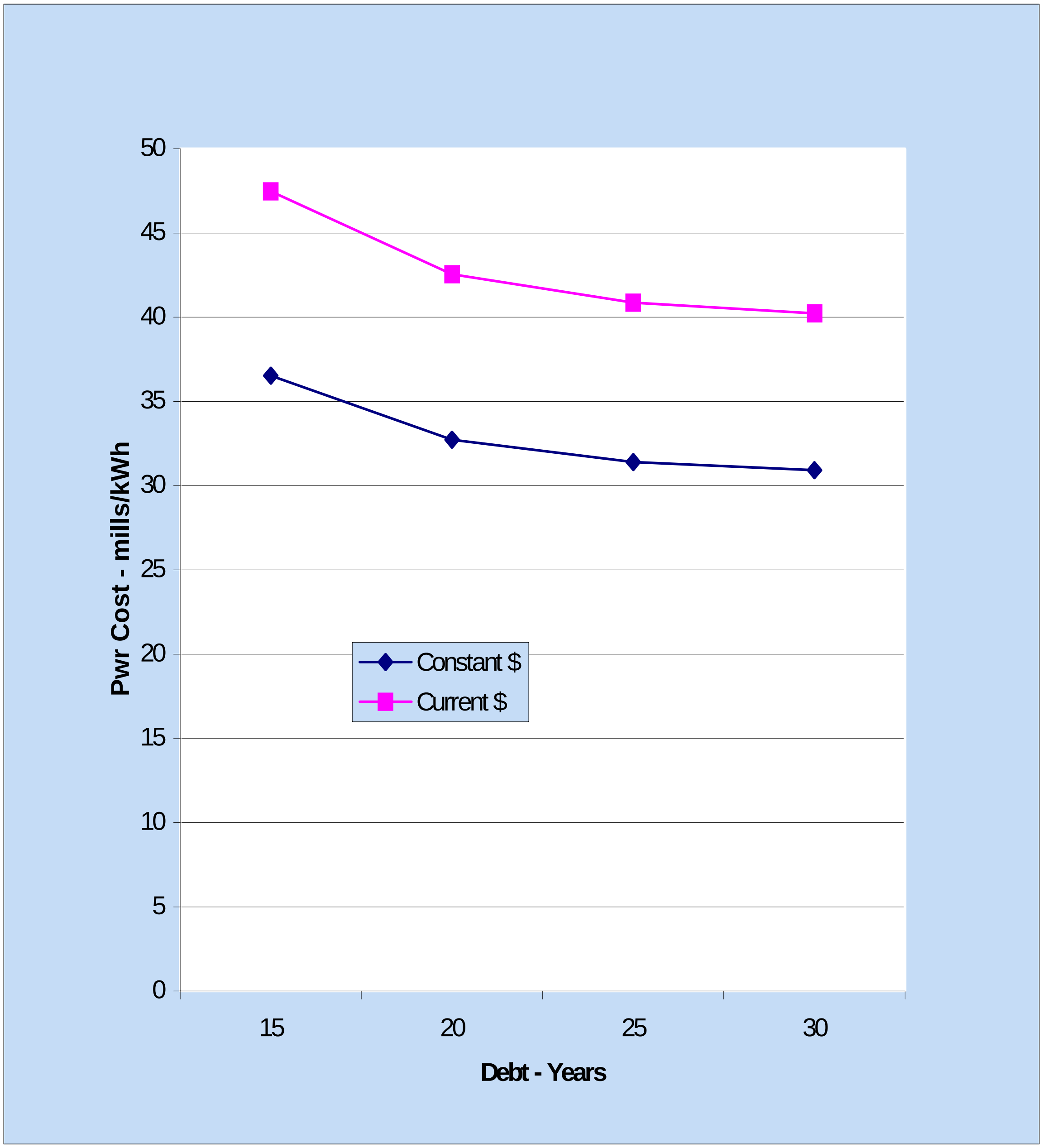


Figure 7-1d Power Cost vs. Book Life.

8.0 COMMERCIALIZATION POTENTIAL AND PLANS

8.1 Market Analysis

8.1.1 Applicability of the Technology

The HCCP consists of the TRW Clean Coal Combustion System and the B&W/Joy SDA and pulse-jet baghouse system. The integrated clean coal technologies demonstrated at the HCCP would be suitable for a wide range of electric power generating facilities, either in the construction of a new plant or in the retrofit of an existing facility. The appropriateness of these technologies to serve a particular electric power generating need would depend primarily on the properties of the coal, the air emission requirements, the location and accessibility of the facility, the availability of limestone, and, if it were for a retrofit application, the configuration, type, and size of the existing boiler system.

TRW's Clean Coal Combustion System is an emerging technology that offers low emissions of NO_X, SO_2, and CO. The technology also provides high carbon burnout (greater than 99 percent) and high ash removal (75 to 85 percent) within the combustion system. The technology provides for the staged combustion of low-grade fuels prior to their entering the furnace. Control of air-fuel mixing and stoichiometric conditions allows for the high combustion efficiency, which results in low CO emissions and low carbon content in the slag and fly ash while minimizing NO_X emissions. Cyclonic confinement of particulates allows for the rejection and removal of most of the incoming coal ash as slag. The limestone injection provides FCM for sulfur capture.

TRW, the Clean Coal Combustion System manufacturer, has claimed the following benefits over other technologies used at coal-fired plants.

- Eliminates the need for oil or gas assist while burning low-grade and low-volatile-content coals, thus decreasing plant fuel costs.

- Increases the boiler combustion efficiency while achieving low emissions of pollutants (SO_2, NO_X, CO, and particulates) concurrently with more than 99 percent carbon burnout in the slag and fly ash. Although the boiler combustion efficiency is increased over conventional technology, the overall plant efficiency is lower due to the greater amount of power required because of heat losses that occur where slag exits the combustor.

- Provides a potentially usable, environmentally neutral, by-product (slag) that contains less than 1 percent carbon. Potential uses are bricks or as a filter medium. No actual uses were demonstrated at the HCCP.

- Provides few waste disposal problems associated with fly ash because the fly ash contains less than 0.5 percent carbon.

- Can be used to retrofit many types and sizes of existing conventional coal-fired boilers.

- TRW predicts up to a 33 percent reduction in boiler and air pollution system equipment sizes for new installations.

- Reduces boiler maintenance and plant downtime because of the technology's high ash removal ability (prior to the boiler) and because the particulates that do enter the boiler are less abrasive. (The HCCP has not been run long enough to fully evaluate this claim.)

- Reduces erosion, slagging, and fouling of the furnace, convective pass tubes, and superheat tubes while burning high-ash coals.

Not all of the manufacturer's claims have been fully demonstrated at HCCP, and some are open to question and/or are cost prohibitive. The benefits of the Clean Coal Combustion System demonstrated at HCCP have been documented throughout this report and in a series of topical reports.

When TRW's Clean Coal Combustion System is combined with a back-end SO_2 and particulate matter removal system, SO_2 removal efficiencies of greater than 90 percent and particulate emissions levels of 0.0047 lb/million Btu have been demonstrated. This back-end SO_2 and particulate removal system is accomplished by the SDA System. The SDA System is a flue-gas-desulfurization system that uses limestone or lime as the sorbent material. The HCCP SDA System utilizes limestone. Unlike most conventional flue-gas-desulfurization systems, the limestone is injected in the HCCP combustors and is converted into FCM. After exiting the boiler, the FCM is transformed into a slurry for use in the SDA. The SO_2 in the flue gas entering the SDA reacts with the FCM slurry and creates a dry reaction product. This dry reaction product, as well as fly ash from the boiler, is then removed in the pulse-jet baghouse. The next step of SO_2 removal is accomplished when the unreacted SO_2 reacts with the FCM on the baghouse filter bags.

The SDA System is applicable to a wide range of electric power generating facilities. While, in itself, it is not a new technology, this is the first time it has been applied in tandem with the TRW Clean Coal Combustion System. A positive attribute of the SDA is that it can use either limestone or lime as the sorbent material, thus offering substantial operating flexibility. A significant savings in operating costs can be accomplished by using limestone because it is less expensive than lime. Furthermore, performance may be enhanced by heating the feed slurry.

Coal Properties

One of the most desirable characteristics of the integrated technologies demonstrated at the HCCP is the adaptability of the technology to a variety of coal types. The technology was specifically developed to burn a low-grade coal, but a wide range of coals can be burned by adjusting the operating temperature and stoichiometry of the combustion system. The coal used by the HCCP, called performance coal, is a 50/50 blend of ROM coal and waste coal supplied by UCM. HCCP performance coal has a low caloric heating value, a high volatile content, a high moisture content, and a high ash-fusion temperature. Approximate properties of performance coal are presented in Table 8-1.

At the other extreme, the operating temperature of the TRW Clean Coal Combustion System can be adjusted to burn coals with high caloric heating value, low ash-fusion temperature, and low ash content and to burn low-volatile anthracitic coals with minimum or no oil assist. Since the TRW Clean Coal Combustion System exploits the slagging of coal ash, the utilization of coals with low ash-fusion temperatures is easily accommodated. Table 8-2 provides a summary of the properties of coals that have been utilized in other demonstrations of the TRW Clean Coal Combustion System.

The TRW Clean Coal Combustion System demonstration projects have provided extensive experience burning coals with a wide variety of properties. There has been success burning coals with heating values from 6,800 Btu/lb to over 13,000 Btu/lb, coal ash levels from less than 5 to 27 percent, and coal ash-fusion temperatures from 2,100° F to 2,900° F. For coals with properties outside these ranges, subscale coal confirmation tests would be recommended during the early stages of the project.

Limestone Properties

A source of limestone would be needed for a new or retrofitted facility utilizing the integrated clean coal technologies demonstrated at the HCCP. Selection of limestone would be site specific and would primarily depend on SO_2 reduction requirements and local availability. The preferred limestone would contain 80 percent $CaCO_3$ and would have a median particle size of 74 microns (70 percent through a 200-mesh grind size). Finer limestone particles (7 to 25 microns) may be used to significantly improve the sulfur capture in the furnace (70 percent capture of sulfur at a Ca/S ratio of 2.5). However, it is often more difficult to feed finer limestone into the system. The limestone feed rate typically depends on the required SO_2 removal rate.

Section 7.0 of this report introduces a hypothetical 319-MWe plant located in Wyoming and utilizing the integrated clean coal technologies demonstrated at the HCCP. It was determined that the facility, the CC-300, would use about 43,000 tons/year of limestone, which is about 20 to 25 percent less than the amount of limestone that would be required for a Circulating Fluidized Bed (CFB) coal-fired plant with the same capacity. An equivalent-sized Pulverized Coal (PC) plant would require less than half the amount of sorbent for control of SO_2 emissions. However, the PC sorbent is pebble lime, which has a unit cost of about four times that of limestone. The crushed limestone used for the hypothetical CC-300 would exhibit the properties listed in Table 8-3.

Other Applicability Factors

Another factor that would affect the potential for using the HCCP clean coal technologies at another facility would be the area required for the facility. However, as described later in this section, it has been determined that the area-related requirements for a HCCP-type facility would be very similar to those for a PC or CFB coal-fired plant with an equivalent capacity. Section 7.0 describes the CC-300, which would be developed on an 80-acre site.

Technology Demonstration Experience

The HCCP demonstration at the utility scale was performed as part of DOE's Clean Coal Technology III Program. It resulted in over 8,000 hours of operation at a 50-MWe capacity. Over 10,000 hours of operation had been demonstrated previously by the industrial-scale system, the Cleveland Test Facility combustor, which had a heat input of 40 million Btu/hr and a power output of 4 MWe. Use of the TRW Clean Coal Combustion System in new or retrofit applications on boiler sizes from approximately 4 MWe to 300 MWe can be accomplished but would be contingent on site-specific conditions such as space available, coal types, boiler configuration, and other design parameters.

Figure 8-1 illustrates the scale of the TRW Clean Coal Combustion Systems that have been built and demonstrated to date. The higher-pressure (5 to 6 atmospheres) combustors (points 3 and 4 on Figure 8-1) have been demonstrated as part of magnetohydrodynamic power projects. These combustors (with some site-specific modifications) can be utilized for gas turbine applications, for integrated combined-cycle power plants, and as solid fuel combustors for emerging advanced cycles. The HCCP (point 6 on Figure 8-1), with a maximum firing rate of 100 MWt and a chamber diameter of approximately 9 feet, represents the maximum size individual combustor demonstrated to date. For a 200-MWe plant, six 100-MWt combustors could be used to provide the required thermal input. Alternatively, if there are space constraints or other boiler integration issues (such as a retrofit application where it may be desirable to retain existing furnace penetration points), eight 75-MWt combustors with a chamber diameter of 7.5 feet could be used. For plants with capacities greater than about 200 MWe, more combustors would be utilized. The industrial-scale Cleveland Test Facility combustor (point 2 on Figure 8-1), with a nominal firing rate of 12 MWt and a chamber diameter of less than 3 feet, represents the minimum practical-sized individual combustor demonstrated to date. On this basis, the minimum boiler rating would be 4 MWe.

The TRW Clean Coal Combustion System is amenable to both bottom-firing and side-firing boiler configurations. The bottom-firing approach was demonstrated in the HCCP utility-scale facility. The side-firing approach was demonstrated in Cleveland Test Facility combustor industrial-scale facility. Typically, retrofitting an existing boiler with TRW slagging combustors is accomplished by combustors that fire into the sidewalls of the boiler because space is generally restricted near the base of the boiler.

General Application

The TRW Clean Coal Combustion System could generally be applied to the following actions.

- Retrofitting existing oil- or natural gas-fired boilers and constructing new coal-fired plants to offer significant savings in fuel costs because of the ability to burn lower-grade coals.

- Retrofitting existing or constructing new coal-fired plants to meet more stringent air emissions control.

- Retrofitting existing or constructing new coal-fired plants where beneficial use of waste products (slag and fly ash) is desirable and/or disposal of waste products is restricted because of the high carbon content of the waste product.

When operated at atmospheric pressure, the TRW Clean Coal Combustion System can be utilized for many applications at electric power generating facilities. When operated at elevated pressures, the TRW Clean Coal Combustion System offers an attractive approach for integrated combined-cycle applications.

The TRW Clean Coal Combustion System addresses many typical problems encountered in coal-fired power plants, including difficulty in burning low-grade, high-ash coals and/or low-volatile coals while meeting stringent emission standards. In many cases, coal-fired plants have had to resort to burning natural gas and/or oil when burning low-grade or low-volatile coals.

In addition, many plants are experiencing problems managing waste products due to restrictions on reuse, resale, or disposal of high-carbon-content waste products. The TRW Clean Coal Combustion System addresses these problems by offering the ability to burn a wide variety of coals (low-grade, high-ash coals, or low-volatile coals) while maintaining a very high combustion efficiency (low CO emissions and low carbon content in the slag and fly ash), achieving low NO_X emissions, and providing the first step in SO_2 removal and high ash removal (75 to 85 percent).

Generally, the SDA System is not considered "new technology," so it is not addressed in this section of the report.

Retrofit Applications

The following are examples of benefits that the manufacturer, TRW, claims can be accomplished by using the Clean Coal Combustion System in a retrofit application.

Retrofitting a boiler would require minimal modifications to the boiler steel and, hence, could be accomplished at a relatively low cost compared with other retrofit technologies that would require the entire boiler island to be replaced.

TRW combustors can easily be added to an existing oil-fired unit that has sufficient space available around the boiler. The boiler would not have to be substantially modified because the TRW technology includes the removal of 75 to 85 percent of the coal ash prior to the combustion products entering the furnace.

The ability of the combustors to remove greater than 80 percent of the coal ash as molten slag upstream of the boiler furnace results in much less ash entering the boiler, and derating is not required even when operating with high-ash coals.

For plants with extremely low CO emission requirements, the combustor offers the benefit of providing low CO emissions simultaneously with low NO_X emissions. The high carbon burnout and low CO emissions are achieved, because the combustion of coal occurs prior to entering the furnace and because any carbon not burned by the combustor has additional residence time in the furnace to further gasify.

For plants where reuse or resale of slag and fly ash is desired, the combustion system offers the benefit of extremely low carbon content in the ash. The molten slag is environmentally neutral and can be utilized as a construction material. However, if disposal of the ash is still required, the disposal requirements are significantly less stringent because of the high carbon burnout.

For plants where less than 70 percent SO_2 removal is acceptable, the TRW technology alone can achieve sufficient removal without any back-end flue gas desulfurization (SDA System) equipment; removal of 50 to 70 percent SO_2 may be accomplished within the furnace simply by installing a limestone feed system to inject limestone into the exit point of the combustor. This is a viable option for many plants outside the U.S. An SDA System could be added at a later date.

For plants where erosion and fouling of the furnace, convective pass, and superheater tubes are exacerbated by high ash and/or highly abrasive ash in the coal, a retrofit using the TRW system would offer substantial benefits. Less ash would enter the boiler, and the ash particles would typically be smaller (less than 10 microns) and would be spherical in shape with smooth surfaces. Therefore, abrasion and erosion damage would be reduced.

Overall, the details of a particular facility should be analyzed to determine the applicability of the TRW Clean Coal Combustion System for either a new facility or a retrofit application. TRW's Clean Coal Combustion System allows the use of lower-grade coal, which reduces operating costs because low-grade coal is less expensive. It also uses limestone as the sorbent for SO_2 control, which is significantly less expensive than lime. An economic value should be established for the reduced maintenance on the boiler due to the lower throughput of coal ash. Furthermore, the economics of a potential after-market opportunity for fly ash should be considered in the evaluation of the technology.

8.1.2 Market Size

Potential United States Market

According to the Energy Information Administration (EIA), which is the independent statistical and analytical agency within the DOE, as of January 1, 1999, there was a planned addition of more than 23,000 MWe of generating capacity (314 generating units) by electric utilities within the United States through the year 2003. Of these, 124 are planned for petroleum fuels, 154 are planned to operate on natural gas, 17 will use conventional hydropower, 8 will be waste heat units, and the remainder (11) will use coal or some renewable fuel. The EIA has withheld specific data on the number of coal-fired units to prevent disclosure of proprietary corporate data. No new nuclear or multiple-fuel units are planned to be added to the domestic inventory through the year 2003 (DOE 1999a).

For non-utility, electric power-generating stations, the EIA reports that there is a planned nationwide addition of 61,000 MWe generating capacity from 443 new units for the same period through 2003. Of these, 278 units are forecast to be gas turbines, 99 units will be mixed petroleum/gas fueled, 17 will be petroleum fired, and 13 are hydro units, and with the remaining 36 units powered by wind, wood, coal, and other sources. There are no plans for additional capacity utilizing geothermal, solar, or nuclear power through the year 2003 (DOE 1999b).

From the discussion presented in Section 8.1.1, the TRW Clean Coal Combustion System is a viable alternative for some of the added capacity described above. The combustion system can serve as a direct replacement for planned PC burning units, and it could also be substituted for petroleum-fired boilers. In looking beyond 2003 through 2020, the EIA forecasts that electric power generation in the United States from both coal and natural gas will increase to meet higher demand and to offset the expected removal of 40 gigawatts of nuclear generating capacity. Considering the lower capital cost of gas turbine plants, natural gas has an advantage over coal use in newly fabricated plants in the near term. However, the lower capital cost advantages of natural gas plants are expected to decline. Furthermore, whereas, natural gas prices are forecast to rise (wellhead price of $1.96 per million Btu in 1998 versus $2.81 per million Btu in 2020), coal shows a continuous price decline ($17.51 per ton in 1998 to $12.54 per ton in 2020) (DOE 1999c). Recent energy price trends suggest a potential for expanded use of coal. These observations indicate a strong potential domestic market for the TRW Clean Coal Combustion System through at least 2020.

New coal-fired plants and many existing coal-fired plants will be candidates for the TRW Clean Coal Combustion System. New PSD major sources and existing PSD sources undergoing major modifications are required to utilize BACT. A determination of what constitutes BACT includes an analysis of the cost of each potential control alternative to determine if the removal cost per ton of pollutant for any alternative will be unjustifiably high.

Regions where the available coal has high sulfur and ash content and is not otherwise marketable or requires blending with low-sulfur coal offer potential markets for the TRW Clean Coal

Combustion System. This includes midwestern and eastern regions that must blend local high-sulfur coals with low-sulfur western coals to meet federal regulations on SO_2 emissions.

Another factor favoring the application of the TRW Clean Coal Combustion System is the Clean Air Act Title IV Acid Rain Program. Effective January 1, 2000, Phase II of the Acid Rain Program instituted more stringent SO_2 and NO_X emission limits. Virtually all electric utility units are now required to reduce their emissions to roughly one-half of 1980 levels. The limit on SO_2 emissions has been reduced from no more than 2.5 lb/million Btu to no more than 1.2 lb/million Btu times their average 1985 through 1987 fuel consumption. This sudden reduction in allowable SO_2 emissions will further expand the market for the TRW Clean Coal Combustion System now that more facilities are required to reduce SO_2 emissions to avoid exceedances of their reduced allowances. The limit on NO_X emissions from Group 2 boilers (including cyclone boilers) is 0.86 lb/million Btu of heat input on an annual average basis (40 CFR 76.6).

The most commonly used alternative for reducing SO_2 emissions to satisfy Acid Rain Program requirements is to switch to a lower-sulfur coal. These coals, however, have an inherently lower heating value. Greater quantities of coal must be burned to generate the same power, causing emissions of pollutants, such as particulate matter, to increase due to the increased coal consumption. The TRW Clean Coal Combustion System will provide an attractive alternative at the power plants currently using the lower-sulfur, lower-Btu coal because of its particulate matter control capabilities.

International Markets

The world market for clean energy technologies is expanding at an unprecedented rate. Global demand for power generating technologies and services is anticipated to create a $480 billion export market over the next three decades and to support more than 600,000 jobs in the U.S. power-equipment industry. Electrification in developing nations, modernization of outdated energy facilities in newly emerging nations, and economic expansion in much of the Pacific Rim are creating enormous opportunities for U.S. companies to export equipment and coal-based fuel products that enhance efficiency and environmental performance.

The TRW Clean Coal Combustion System, developed at the Healy Clean Coal Project, is helping to open new markets for Alaska's abundant coal resources. Regional markets of interest include the Far East (China, India, Korea, and Japan) and North America. A thorough analysis of the International Energy Markets through 2020 was recently published by the EIA (DOE 2000). In the International Energy Outlook 2000, the EIA forecasts that the use of coal worldwide will increase by 2.3 billion short tons by 2020 (to 7.6 billion short tons) compared with the 1997 worldwide consumption of 5.3 billion short tons of coal. This includes all coal types. The EIA reports that virtually all of this increased production will be used for electric power generation. However, in both Europe (western and eastern) and in the former Soviet Union, coal use for electric power generation will decrease, largely due to large increases in the use of natural gas as a preferred fuel source.

According to the EIA, by far the largest growth in the use of coal for electric power generation will be in China, followed by increased coal consumption in India. China is forecast to add some 600 power-generating units of 300 MWe each through 2020 (this represents 180 gigawatts of electric power-generating capacity for China alone). For India, the EIA forecasts an additional

50 gigawatts of capacity (167 plants at 300 MWe each) through 2020. These two markets alone more than make up for the decline in coal use for electric power generation in the remainder of the world. India has mostly bituminous and anthracite coal, whereas China's recoverable reserves are split almost evenly between lignite/subbituminous coal and bituminous/anthracite coal (DOE 2000).

Despite the substantial bituminous coal trade market in the Pacific Rim, it has been repeatedly shown that the coal derating issue is a major barrier to the export of Alaskan subbituminous coal. With the availability of the TRW Clean Coal Combustion System, regions in the Pacific Rim can make broader use of Alaska’s coal resources, particularly where oil and gas are not a readily available alternative. The market size for bituminous coal and the potential for conversion of heavy oil units to coal-utilizing slagging combustors suggest a significant market potential for bundled coal/combustor conversions.

8.1.3 Market Barriers

There is a natural reluctance among power plant operators to adopt a new power generation technology. Consequently, new entrants such as the TRW Clean Coal Combustion System generally face a considerable array of entry barriers. In order to commercialize any technology, potential barriers to implementing that technology must be identified, analyzed, and thoroughly understood. For any new coal combustion technology, the primary barriers to market penetration are: 1) risk aversion (i.e., the general hesitation to incur the risk associated with implementation of an “unproven” technology), 2) environmental and regulatory concerns, 3) economic concerns, and 4) technological concerns. Each of these areas will be discussed briefly below.

Risk Aversion

The incorporation of innovative technologies into mature industries is generally met with skepticism with regard to claims of improved performance and/or cost savings. There is perceived risk associated with removing a proven technology and replacing it with a relatively new and less proven technology. Advocates of the TRW Clean Coal Combustion System will have to compete with the following well-established technologies and emission control alternatives:

- switching to a low-sulfur coal to reduce SO_2 emissions
- flue gas scrubbing or SDA using lime
- Atmospheric Fluidized Bed Combustion (AFBC)
- Pressurized Fluidized Bed Combustion (PFBC)
- Integrated Gasification Combined-Cycle (IGCC) Repowering Project
- early retirement
- sorbent and chemical injection.

The perceived risk could be any combination of performance, reliability, cost, and safety. Generally, vendor claims in these areas must be substantiated with operational data - presumably generated in an actual demonstration if an emerging technology is being considered. However, in many cases, historical operating data must be presented in order to convince a decision-maker to incorporate something new into an otherwise mature process. Because of this, long-term, large-scale demonstration may be the only way to generate such data. Also, when considering a specific application of an innovative product, at least some sort of pilot testing would almost certainly be required.

Environmental and Regulatory Concerns

The major environmental concerns related to the continued use of coal combustion for electric power generation are acid rain resulting mainly from SO_2 emissions, global climate change due to CO_2 and NO_X emissions, and to a far lesser extent, particulate matter emissions (EPA's $PM_{2.5}$ proposed provision from the NAAQS). Within the U.S., SO_2 and NO_X emissions are regulated under the Clean Air Act Amendments of 1990. Since Phase II of the Acid Rain Program began on January 1, 2000, coal-fired generating stations have come under even greater pressure to maintain compliance with Phase II's more stringent SO_2 and NO_X emission limits.

The Kyoto Protocol on Climate Change (Kyoto Protocol) is an international treaty that was developed in December 1997 in Kyoto, Japan, at the third meeting of the Conference of the Parties to the 1992 Framework Convention on Climate Change. The intent of the Kyoto Protocol is to lessen the effects of man-made greenhouse gases on global climate change by forcing the reduction of emissions of greenhouse gases worldwide. Opened for signature in 1998, the Kyoto Protocol established CO_2 emissions requirements. It will enter into force 90 days after 55 countries ratify the accord.

As of January 13, 2000, the United Nations Framework Convention on Climate Change stated that 84 countries had signed the Kyoto accords, and 22 had ratified or accessed the accord. The accord commits developed countries to reduce their collective emissions of six key greenhouse gases by at least 5 percent by 2008 through 2012. At the April 2000 meeting of the Group of Eight industrialized countries (G-8) in Otsu, Japan, environment ministers failed to agree on a deadline to ratify the Kyoto Protocol. The European Union and Japan wanted a commitment to the accord by 2002, but the U.S. and Canada resisted a specific time frame for ratification. Because of the reluctance of some developing countries (China, for example) to commit to the accord, the U.S. President will not ask the Senate to debate on the accord. The United States cannot be bound to the agreement without Senate approval.

An analysis of the situation by the EIA indicated that, should the United States be bound to the agreement, coal use for electric power generation could see a reduction of up to 78 percent by 2010 and could "nearly disappear" by 2020. This reduction in the use of coal would be due to "carbon price" provisions, which are additional fuel costs resulting from requirements to purchase carbon permits from other nations and increased costs resulting from new technology applied to the reduction of carbon emissions.

Economic Concerns

Increasingly, natural gas-fired turbines are gaining popularity both within the United States and internationally. Western Europe has seen a 37 percent decline in the use of coal between 1989 and 1997, while the use of gas turbines has increased significantly due to lower capital cost of gas turbine plants combined with the availability of cheap liquefied natural gas from northern Africa and Libya. Within the U.S., coal use will increase through 2020, and, if the domestic gas prices increase and delivered coal prices decrease as predicted, coal-fired units could become more attractive economically than gas-fired turbines. Today, however, they are not cost competitive. Cost competition with petroleum-fired units will not be considered here, due to the high volatility of the international oil markets. According to the EIA, coal has a fuel price cost advantage over gas through the period to 2020, but, through 2010, gas-fired plants maintain a cost advantage when "capital, operating, and fuel costs are considered."

Other economic barriers include alternative fuels, lack of brand identification, substantial capital investment requirements, locked-up distribution channels, and the need for a project approach in the international marketplace. Alternative fuels are a continual competitive threat to the coal-based combustion industry. In many applications, depressed oil and gas prices create and perpetuate a reluctance to switch to coal or to purchase new coal-fired systems. Liquids and gases derived from coal also provide competition to coal-fired systems. Other solids that are tied to tax incentives, such as peat, wood wastes, and garbage, are capturing a part of the market.

In addition to the widespread availability of alternative fuels, coal supplies can be destabilized by a variety of forces beyond the control of the facility operator. Strikes by coal miners and railroad workers can cut off or sharply curtail coal supplies. Actions that government agencies are compelled to take or consider essential to ensure compliance with the applicable regulations present more potential interruptions of the coal supply.

Retrofit candidates must be evaluated on a case-by-case basis to determine the appropriate retrofitted combustor size. Given the emphasis currently placed on cash flow in the power industry, the capital cost to install the TRW Clean Coal Combustion System will present another barrier to its entry into the marketplace. Cost would be higher to retrofit the entrained combustor into a conventional PC, but the overall cost would still be significantly less capital intensive than competing retrofit technologies. The time estimated to recover the capital cost of the TRW Clean Coal Combustion System is 3 to 4 years. Less capital-intensive systems, such as low-NO_X burners with sorbent injection systems using hydrated lime, would be more attractive for peak or intermediate load applications for small plant sizes.

International trade and investment barriers, such as tariffs and trade restrictions, will further restrict the marketability of the TRW Clean Coal Combustion System. These barriers exist in varying degrees in all energy-use markets (residential and commercial buildings, transportation, and industry). They include:

- trade tariffs
- restrictions on trade

- inadequate market information and incentives
- lack of accessible financing
- inappropriately regulated markets
- fragmented technology and service markets.

The continued presence of these barriers to trade will inhibit the growth of the TRW Clean Coal Combustion System in the international marketplace and will significantly limit the ability of nations to build power plants featuring this technology.

Technological Concerns

The ability to take advantage of lower fuel cost by burning lower-quality or waste coal would be limited by the slagging temperature of the coal ash. Subbituminous coals generally have lower slagging temperatures and have better ability to maintain acceptable slagging temperatures when contaminated with waste material, which typically are high in silica. Bituminous coals with higher slagging temperatures would be able to tolerate less contamination, even though their heating value would be much higher than subbituminous coal. This would tend to limit applicability for the technology as a means to use bituminous waste coal with a slagging temperature above 2,900° F.

The most significant market barrier that is apparent from the demonstration plant is related to the size (space requirements) and cost of the combustors. The combustors take up a significant amount of space, which would be a limiting factor in many plants. Though the raw base cost of the combustors may not be a major barrier to retrofit, if major modifications to basic plant layout are needed, the cost of retrofit would likely be prohibitive.

Size (space requirements) and cost issues would also seem to be a barrier to retrofitting the SDA System. Again, if retrofit to the SDA System required major plant modifications to gain space, then it seems probable that just adding more limestone in the system to achieve target sulfur capture levels would be the more technologically feasible solution.

8.1.4 Economic Comparison with Competing Technologies

Because one of the major objectives of the Clean Coal Technology Program is to bring the demonstrated technology to commercial readiness, an analysis was performed on competing technologies. The most likely competing technologies are PC and CFB technologies with low-NO_X burners. The CC-300, described in Section 7.0, was compared to a 300-MWe PC plant and a 300-MWe CFB coal plant.

This evaluation was performed using the power plant design and consulting experience of the Harris Group, which has recently been involved with PC and CFB plants in the "Lower 48" states and was able to utilize data from those facilities for this analysis.

All three facilities would be constructed in Wyoming and would burn Powder River Basin coal. A summary of input data, including capacity information, coal data, boiler information,

limestone/lime data, and ash data is provided in Table 8-4. Data for the HCCP are also included in the table for comparative purposes. The boiler efficiencies were calculated by dividing the heat out by the heat in. The dry gas and moisture losses are calculated, but the combustibles in the ash were taken from measurements made for other boiler tests. The remaining content is determined to be other unmeasured and uncalculated losses, including radiation, ash-sensible heat, fan compression, limestone calcination, and heat gained from sulfation.
The CC-300, PC, and CFB plants are each furnished with four coal mills and two baghouses. The CC-300 and PC units are furnished with SDA for sulfur collection, and sulfur collection by the CFB is accomplished in the CFB beds with limestone injection. The PC unit utilizes pebble lime as a sorbent. Limestone is introduced into the CFB bed for bed material augmentation and to be used as a sorbent. Both the CC-300 and CFB units calcine the limestone during the combustion process. Sorbent use is primarily a function of operating economics, and the costs of pebble lime and limestone are highly variable and primarily dependent upon transportation costs.

The design criteria for the CC-300 plant are presented in Appendix E. Design criteria that are different for the PC and CFB plants are provided in Appendix F and Appendix G, respectively.

Capital costs are provided in Tables 8-5, 8-6, and 8-7 for the CC-300, PC, and CFB, respectively. These capital costs were determined using information from other plants with which the Harris Group was involved. Operation and maintenance costs for the three plants are presented in Tables 8-8, 8-9, and 8-10. These costs were determined by comparison with plants of similar size within the Harris Group's database.

The CC-300 emission rates were taken from the HCCP performance data. Emission rates for the PC and CFB are not expected to differ from smaller plants utilizing the same technologies because concentrations are not a function of plant size.

A summary of performance and cost is provided in Tables 8-11, 8-12, and 8-13. These tables include general plant attributes, air emission information, levelized costs for power generation, and levelized costs for emissions. Levelized costs are presented on a SO_2/NO_X basis, with NO_X emissions from the CFB and the PC units as the basis for comparison of emissions from the CC-300.

The overall result of this analysis of competing technologies for coal-fired power generation is that the three power plants have relatively similar capital costs and O&M costs. The majority of the equipment is identical. The small differences in costs are attributable to the difference in combustion technology, which includes the downstream pollution control equipment. Table 8-14 provides a summary of the cost of the major components of each plant.

The PC plant has the lowest capital cost because the combustion technology equipment is less expensive. The PC plant also has the lowest O&M cost because its boiler efficiency is the highest, thereby resulting in lower fuel costs. In addition, sorbent costs are less for the PC plant.

It should be noted that operating personnel are assumed to be the same for all plants and that the three technologies also have similar maintenance costs.

The CC-300 has the best environmental performance because:

- NO_X generation is slightly lower in the CC-300 technology
- CO emissions are significantly lower
- up to 50 percent SO_2 reduction is achieved within the boiler during combustion.

The amount of fly ash generated in the CC-300 technology is only 25 percent of that generated by the other technologies because most of the ash is slag and bottom ash. Therefore, the baghouse handles and emits much less particulate matter.

Based on the Harris Group's experience, the technology selected for specific applications will depend on site emission permits, cost of fuel (for example, waste versus commercial coal), size of plant, and overall project economics.

8.2 Plans for Commercialization

TRW continues to work toward the commercialization of its entrained slagging combustion system. At this time, TRW is actively studying the domestic and international market potential for this patent-protected technology, focusing on applicability, profitability, and leveraging of TRW's global reach. Also, because of the inherent environmental benefits of the combustion system, its application in countries without regulations as stringent as those in the U.S. is being vigorously investigated. This would give countries with large coal reserves a head start on producing electricity while lowering emissions compared with using conventional PC units. These plants can then add back-end clean-up equipment using the revenue generated from the first several years of operation of the plant.

TRW's current strategy for commercialization of the TRW Clean Coal Combustion System includes:

- assessment of potential worldwide market size
- investigation of options for partnering with other firms to ensure maximum profitability to TRW while ensuring delivery of high quality systems to customers
- consideration of licensing the technology to others to market
- investigation of options for further demonstration of the system's capabilities, perhaps in China or India (the largest perceived potential markets for the technology) or possibly the U.S.

Table 8-1 Properties of Coal Used for the HCCP Utility-Scale Demonstration.

Coal Property	Performance Coal
Proximate Analysis	
Heating Value (Btu/lb)	6,960
Moisture (%)	25.11
Ash (%)	16.60
Volatile (%)	30.78
Fixed Carbon (%)	27.51
Ultimate Analysis	100.00
Moisture (%)	27.19
Ash (%)	13.27
Carbon (%)	42.58
Hydrogen (%)	3.22
Sulfur (%)	0.16
Oxygen (%)	13.03
Nitrogen (%)	0.55

Source: AIDEA 2000e

Table 8-2 Properties of Coals Used in TRW Clean Coal Combustion System Demonstration Projects.

Coal Type	Moisture (%)	Ash (%)	Volatiles (%)*	Nitrogen (%)*	Sulfur (%)*	Heating Value (Btu/lb)	Coal Ash-Fusion Temperature (° F)
Ohio # 6	3.64	8.37	40.9	1.55	2.00	13,061	2,460
Ohio # 6 CWS	31.70	4.39	36.3	1.71	1.50	9,462	2,631
Wyoming	9.17	7.01	45.7	1.60	0.73	11,484	2,118
Pittsburgh # 8	2.34	10.10	43.1	1.61	3.05	12,975	2,475
Upper Freeport	3.18	11.99	38.8	1.54	2.06	12,948	2,695
Upper Freeport CWS	31.45	6.43	35.6	1.82	1.77	9,310	2,550
Blacksville	5.35	12.07	41.4	1.36	3.70	12,458	2,320
Montana Rosebud	22.60	12.22	46.2	0.95	1.23	8,503	2,509
Illinois # 6	8.42	12.53	44.7	1.30	4.59	11,245	2,410
West Virginia	1.36	7.82	37.5	1.74	0.73	13,641	2,900
Kentucky	10.76	9.58	42.4	1.90	2.10	11,188	2,610
Balcke-Durr (German)	8.00	7.90	10.6	1.66	1.07	13,024	2,700
Healy Two Bull Ridge	9.82	27.32	60.8	1.21	0.57	7,358	2,876
Healy Run-of-Mine	26.40	8.2	34.6	0.59	0.17	7,815	2,228
Healy Specification Waste Blends	25.00	12 to 18	30.6	0.52	0.18	6,800 to 7,200	2,600

* Dried, ash-free

Source: AIDEA 2000c

Table 8-3 Properties of Limestone for Clean Coal Technology Facilities.

Limestone Property	Value (%)
$CaCO_3$	90 to 97
$MgCO_3$	0.8 to 1.2
Inerts	3 to 8
Moisture	0 to 0.4

Source: Harris Group 1999 in AIDEA 2000e

Table 8-4 Plant Summary Data.

	HCCP	CC- 300	PC	CFB
CAPACITY DATA				
Gross Plant Output (kW)		345,000	345,000	345,000
Auxiliary Power (kW)		26,000	26,000	26,000
Auxiliary Power (% of Gross)		7.5	7.5	7.5
Net Plant Output (kW)		319,000	319,000	319,000
Net Plant Heat Rate (Btu/kWh)		11,127	10,838	10,947
Gross Plant Heat Rate (Btu/kWh)		10,288	10,021	10,122
COAL DATA (as-received ultimate coal analysis)				
Carbon (%)	42.58	48.44	48.44	48.44
Ash (%)	13.27	4.66	4.66	4.66
Moisture (%)	27.19	30.47	30.47	30.47
Sulfur (%)	0.16	0.37	0.37	0.37
Hydrogen (%)	3.22	3.22	3.22	3.22
Nitrogen (%)	0.55	0.64	0.64	0.64
Oxygen (%)	13.03	12.20	12.20	12.20
Total (%)	100.00	100.00	100.00	100.00
Higher Heating Value (Btu/lb)	7,187	8,175	8,175	8,175
BOILER INFORMATION				
Excess Air (% of stoichometric)	22	20	20	20
Air Heater Gas Out Temperature (°F)	325	300	300	300
Heat Losses:				
• Dry Flue Gas (%)	9.9	8.8	8.8	8.8
• H_2O in Fuel/Air/H_2 Combination (%)	8.1	7.5	7.5	7.5
• Combustibles in Ash (%)	*0.3 - 0.8	0.1	0.1	0.2
• Other (%)	4.3	4.3	2.3	3.0
• Total (%)	23.1	20.7	18.7	19.5
Boiler Efficiency (%)	76.9 - 77.5	79.4	81.3	80.5
Boiler Heat Out (million Btu/hr)	468.195	2,811.187	2,811.187	2,811.187
Coal Flow (lb/hr)	84,058 - 84,700	434,187	422,900	427,175
Plant Availability (%)		90	90	90
Coal Flow (million tons/year)		1.725	1.667	1.684

• Percent of heat input lost to this parameter

* Although the actual amount of combustibles in the HCCP ash ranged from 0.3 to 0.8 percent, the majority of this was carried over in pyrites from the pulverizers due to rocks in the waste coal. It

is our opinion, that with run-of-mine coal, the combustibles in the ash would be consistent with or slightly higher than those of a PC unit.

Table 8-4 Plant Summary Data (continued).

	HCCP	CC- 300	PC	CFB
LIMESTONE AND LIME DATA				
Limestone				
Ca (%)	39.5			
$CaCO_3$ (%)		96.0		96.0
$MgCO_3$ (%)		1.0		1.0
Inerts (%)		3.0		3.0
Pebble Lime				
CaO (%)			90.0	
MgO (%)			5.0	
Inerts (%)			5.0	
Ca/S	3.6	3.0	1.9	3.8
Sulfur Collection Efficiency (%)	86.4	90.0	90.0	90.0
Limestone Flow, lb/hr	1,564	14,988		19,551
Limestone Flow, tons/year		42,671		55,662
Pebble Lime Flow, lb/hr			5,781	
Pebble Lime Flow, tons/year			16,459	
ASH DATA				
Flyash (%)	15	15	20	50
Coal Ash Flow (lb/hr)		20,393	19,708	19,906
Coal Flyash Flow (lb/hr)		3,059	15,766	9,953
Lime Loss on Ignition (%)	40	40	1	40
Limestone Wastes Flow (lb/hr)		11,929	8,050	14,279
Total Flyash Flow (lb/hr)		14,988	23,817	24,232
Total Flyash Flow (tons/year)		42,671	67,807	68,989
Bottom Ash Flow (lb/hr)		17,314	3,942	9,953
Bottom Ash Flow (tons/year)		49,293	11,223	28,336
Total Ash Disposal (tons/year)		91,964	79,030	97,325

Table 8-5 Estimated Capital Requirements for the CC-300.

Area	Total Installed Equipment Cost	$\$10^6$	$/kW*
100	Coal Unloading and Handling	6.9	19.90
200	Sorbent Unloading and Handling	3.4	9.95
400	Combustion/Steam Generation	201.4	583.65
700	Power Generation	170.5	494.15
800	SO_2 Removal	15.5	44.89
1000	Particulate Removal	11.8	34.18
1400	Ash Collection and Removal	5.2	15.05
1500	Civil/Structural/Architectural	36.0	104.32
(A)	Total Process Capital	450.6	1,306.08
(B)	General Facilities (10% of A)	included	included
(C)	Engineering (10% of A)	included	included
(D)	Project Contingency	0.0	0.0
(E)	Total Plant Cost (A+B+C+D)	450.6	1,306.08
(F)	Allowance for Funds During Construction (0% of E)	0.0	0.0
(G)	Total Plant Investment (E+F)	450.6	1,306.08
(H)	Royalty Allowance (0.5% of A)	2.2	6.50
(I)	Preproduction Costs (3 months of startup)	1.0	2.90
(J)	Inventory Capital	1.0	2.90
(K)	Initial Chemicals	0.1	0.0
(L)	Subtotal Capital (G+H+I+J+K)	454.9	1,318.38
(M)	Cost of Construction Downtime	0.0	0.0
(N)	Total Capital Requirement (L+M)	454.9	1,318.38

Table 8-6 Estimated Capital Requirements for the PC.

Area	Total Installed Equipment Cost	$10^6	$/kW*
100	Coal Unloading and Handling	6.9	19.90
200	Sorbent Unloading and Handling	3.4	9.95
400	Combustion/Steam Generation	198.5	575.23
700	Power Generation	170.5	494.15
800	SO_2 Removal	15.5	44.89
1000	Particulate Removal	11.8	34.18
1400	Ash Collection and Removal	5.2	15.05
1500	Civil/Structural/Architectural	36.0	104.32
(A)	Total Process Capital	447.7	1,297.66
(B)	General Facilities (10% of A)	included	included
(C)	Engineering (10% of A)	included	included
(D)	Project Contingency	0.0	0.00
(E)	Total Plant Cost (A+B+C+D)	447.7	1,297.66
(F)	Allowance for Funds During Construction (0% of E)	0.0	0.00
(G)	Total Plant Investment (E+F)	447.7	1,297.66
(H)	Royalty Allowance (0.5% of A)	0.0	0.00
(I)	Preproduction Costs (3 months of startup)	1.0	2.90
(J)	Inventory Capital	1.0	2.90
(K)	Initial Chemicals	0.1	0.00
(L)	Subtotal Capital (G+H+I+J+K)	449.8	1,303.46
(M)	Cost of Construction Downtime	0.0	0.00
(N)	Total Capital Requirement (L+M)	449.8	1,303.46

Table 8-7 Estimated Capital Requirements for the CFB.

Area	Total Installed Equipment Cost	$\$10^6$	$/kW
100	Coal Unloading and Handling	6.9	19.90
200	Sorbent Unloading and Handling	3.4	9.95
400	Combustion/Steam Generation	238.5	691.43
700	Power Generation	170.5	494.15
800	SO_2 Removal	0.0	0.00
1000	Particulate Removal	11.8	34.18
1400	Ash Collection and Removal	5.2	15.05
1500	Civil/Structural/Architectural	36.0	104.32
(A)	Total Process Capital	472.3	1,368.97
(B)	General Facilities (10% of A)	included	included
(C)	Engineering (10% of A)	included	included
(D)	Project Contingency	0.0	0.0
(E)	Total Plant Cost (A+B+C+D)	472.3	1,368.97
(F)	Allowance for Funds During Construction (0% of E)	0.0	0.0
(G)	Total Plant Investment (E+F)	472.3	1,268.97
(H)	Royalty Allowance (0.5% of A)	0.0	0.00
(I)	Preproduction Costs (3 months of startup)	1.0	2.9
(J)	Inventory Capital	1.0	2.9
(K)	Initial Chemicals	0.1	0.00
(L)	Subtotal Capital (G+H+I+J+K)	474.4	1,274.77
(M)	Cost of Construction Downtime	0.0	0.0
(N)	Total Capital Requirement (L+M)	474.4	1,274.77

Table 8-8 Operating and Maintenance Costs for the CC-300.

	Units	Quantity	$/Unit	$$10^6$/Year
FIXED O&M COSTS				
Operating Labor	man-hour /hr	9	21.00	1.656
Maintenance Labor				2.100
Maintenance Material				3.200
Administration/Support Labor				0.200
Subtotal Fixed Costs				7.156
VARIABLE OPERATING COSTS				
Fuels				
Coal	tons/hr	217.09	*14.00	23.962
No. 2 Fuel Oil	gal/hr	57.1	2.00	0.900
Sorbent				
Limestone	tons/hr	7.91	20.00	1.247
Regen Chemicals				
Acid	gal/hr	1.4819	1.070	0.01250
Caustic	gal/hr	2.112	2.140	0.03562
Utilities				
Steam	10^3lb/ hr	1.2	3.50	0.033
Condensate	10^3lb/hr	2.2	0.77	0.013
Raw Water	10^3gal/hr	203	0.60	0.960
Cooling Water	10^3gal/hr	included	0.16	0.000
Station Service Electric Power	kWh	38.05	0.05	0.015
By-Product Credits	--	--	--	0
Waste Disposal Charges				
Ash Trucked and Landfilled	tons/hr	16.15	9.29	1.183
Subtotal Variable Costs				28.361
Total O&M Cost (Fixed + Variable)				35.517

* Source: FERC 1999

Table 8-9 Operating and Maintenance Costs for the PC.

	Units	Quantity	$/Unit	$$10^6$/Year
FIXED O&M COSTS				
Operating Labor	man-hour /hr	9	21.00	1.656
Maintenance Labor				2.100
Maintenance Material				3.200
Administration/Support Labor				0.200
Subtotal Fixed Costs				7.156
VARIABLE OPERATING COSTS				
Fuels				
Coal	tons/hr	211.46	*14.00	23.340
No. 2 Fuel Oil	gal/hr	79.0	2.00	0.900
Sorbent				
Lime	tons/hr	2.89	85.00	1.937
Regen Chemicals				
Acid	gal/hr	1.4819	1.070	0.01250
Caustic	gal/hr	2.112	2.140	0.03562
Utilities				
Steam	10^3lb/ hr	1.2	3.50	0.033
Condensate	10^3lb/ hr	2.2	0.77	0.019
Raw Water	10^3gal/ hr	203	0.60	0.960
Cooling Water	10^3gal/ hr	included	0.16	0.000
Station Service Electric Power	kWh	52.7	0.05	0.015
Waste Disposal Charges				
Ash Trucked and Landfilled	tons/hr	13.88	9.29	1.017
Subtotal Variable Costs				28.269
Total O&M Cost (Fixed + Variable)				35.425

* Source: FERC 1999

Table 8-10 Operating and Maintenance Costs for the CFB.

	Units	Quantity	$/Unit	$$10^6$/Year
FIXED O&M COSTS				
Operating Labor	man-hour /hr	9	21.00	1.656
Maintenance Labor				2.100
Maintenance Material				3.200
Administration/Support Labor				0.200
Subtotal Fixed Costs				7.156
VARIABLE OPERATING COSTS				
Fuels				
Coal	tons/hr	213.58	*14.00	23.575
No. 2 Fuel Oil	gal/hr	79.0	2.00	0.900
Sorbent				
Limestone	tons/hr	9.78	20.00	1.514
Regen Chemicals				
Acid	gal/hr	1.4819	1.070	0.01250
Caustic	gal/hr	2.112	2.140	0.03562
Utilities				
Steam	10^3lb/ hr	1.2	3.50	0.033
Condensate	10^3lb/ hr	2.2	0.77	0.019
Raw Water	10^3gal/ hr	203	0.60	0.960
Cooling Water	10^3gal/ hr	included	0.16	0.000
Station Service Electric Power	kWh	52.7	0.05	0.015
Waste Disposal Charges				
Ash Trucked and Landfilled	tons/ hr	17.09	9.29	1.252
Subtotal Variable Costs				28.297
Total O&M Cost (Fixed + Variable)				35.453

* FERC 1999

Table 8-11 Summary of Performance and Costs for the CC-300.

POWER PLANT ATTRIBUTES	**Units**	**Value**		
Plant Capacity, net	MWe	319		
Power Produced, net	10^9 kWh/year	2.51		
Capacity Factor*	%	90		
Plant Life	years	15		
Coal Feed	10^6 tons/year	1.712		
Sulfur in Coal	% by weight	0.37		
EMISSIONS CONTROL	**Units**	**SO_2**	**NO_X**	**PM_{10}**
Removal Efficiency	%	96	35	99.95
Emissions Standard	lb/10^6 Btu	0.086	0.35	0.020
Emissions w/o Control	lb/10^6 Btu	0.910	0.40	4.19
Emissions w/ Control	lb/10^6 Btu	0.035	0.26	0.0021
Amount Removed	tons/year	12,176	1,959	59,053
LEVELIZED COST OF POWER	**Current Dollars**		**Constant Dollars**	
	Factor	**Mills/kWh**	**Factor**	**Mills/kWh**
Capital Charge	0.160	28.9	0.124	22.4
Fixed O&M Cost	1.314	3.7	1.000	2.8
Variable Operating Cost	1.314	14.9	1.000	11.3
Total Cost		47.5		36.5
LEVELIZED COST - SO_2/NO_X BASIS	**Factor**	**$/Ton Removed**	**Factor**	**$/Ton Removed**
Capital Charge	0.160	5,149	0.124	3,991
Fixed O&M Cost	1.314	665	1.000	506
Variable Operating Cost	1.314	2,631	1.000	2,002
Total Cost		8,445		6,499

* A capacity factor of 90 percent was used instead of the 65 percent specified in the PETC General Guidelines.

Table 8-12 Summary of Performance and Costs for the PC.

POWER PLANT ATTRIBUTES	Units	Value		
Plant Capacity, net	MWe	319		
Power Produced, net	10^9 kWh/year	2.51		
Capacity Factor*	%	90		
Plant Life	years	15		
Coal Feed	10^6 tons/year	1.667		
Sulfur in Coal	% by weight	0.37		
EMISSIONS CONTROL	**Units**	**SO_2**	**NO_X**	**PM_{10}**
Removal Efficiency	%	85	0	99.95
Emissions Standard	lb/10^6 Btu	0.300	0.3	0.020
Emissions w/o Control	lb/10^6 Btu	0.910	0.3	6.89
Emissions w/ Control	lb/10^6 Btu	0.136	0.3	0.0035
Amount Removed	tons/year	10,483	0	93,840
LEVELIZED COST OF POWER	**Current Dollars**		**Constant Dollars**	
	Factor	**Mills/kWh**	**Factor**	**Mills/kWh**
Capital Charge	0.160	28.6	0.124	22.2
Fixed O&M Cost	1.314	3.7	1.000	2.8
Variable Operating Cost	1.314	14.7	1.000	11.2
Total Cost		47.0		36.2
LEVELIZED COST - SO_2/NO_X BASIS	**Factor**	**$/Ton Removed**	**Factor**	**$/Ton Removed**
Capital Charge	0.160	6,865	0.124	5,320
Fixed O&M Cost	1.314	897	1.000	683
Variable Operating Cost	1.314	3,537	1.000	2,692
Total Cost		11,299		8,695

Table 8-13 Summary of Performance and Costs for the CFB.

POWER PLANT ATTRIBUTES	**Units**	**Value**		
Plant Capacity, net	MWe	319		
Power Produced, net	109 kWh/year	2.51		
Capacity Factor*	%	90		
Plant Life	years	15		
Coal Feed	106 tons/year	1.684		
Sulfur in Coal	% by weight	0.37		
EMISSIONS CONTROL	**Units**	**SO_2**	**NO_X**	**PM_{10}**
Removal Efficiency	%	85	----	99.95
Emissions Standard	$lb/10^6$ Btu	0.300	0.3	0.020
Emissions w/o Control	$lb/10^6$ Btu	0.910	0.3	6.94
Emissions w/ Control	$lb/10^6$ Btu	0.136	----	0.0035
Amount Removed	tons/year	10,589	0	95,475
LEVELIZED COST OF POWER	**Current Dollars**		**Constant Dollars**	
	Factor	**Mills/kWh**	**Factor**	**Mills/kWh**
Capital Charge	0.160	30.2	0.124	23.4
Fixed O&M Cost	1.314	3.7	1.000	2.8
Variable Operating Cost	1.314	14.8	1.000	11.3
Total Cost		48.7		37.5
LEVELIZED COST - SO_2/NO_X BASIS	**Factor**	**$/Ton Removed**	**Factor**	**$/Ton Removed**
Capital Charge	0.160	7,168	0.124	5,555
Fixed O&M Cost	1.314	888	1.000	676
Variable Operating Cost	1.314	3,511	1.000	2,672
Total Cost		11,568		8,903

Table 8-14 Cost Breakdown for Three Technologies.

Item	Process Area	Installed Costs ($\$10^6$)		
		300-MWe CC-300	**300-MWe PC**	**300-MWe CFB**
2.1	Main Boiler(s)	85.500	98.900	119.500
2.2	Combustors	14.100	0	0
2.3	FGD (including Baghouses)*	30.700	30.700	11.800
2.4	Materials Handling	3.500	3.500	3.500
2.5	Ash Handling	2.600	2.600	2.600
2.6	Pre/Post Combustion Air	4.800	4.800	4.800
2.7	STG and Steam	31.900	31.900	31.900
2.8	Condensate/Feedwater	8.800	8.800	8.800
2.9	Circulating Water	1.100	1.100	1.100
2.10	Water and Wastewater	1.000	1.000	1.000
2.11	Fire Protection	0.400	0.400	0.400
2.12	Plant Controls	0.900	0.900	0.900
2.13	Electrical	14.300	14.300	14.300
2.14	Balance of Plant	63.700	63.700	63.700
3.1	Installation/Contractor Supplied Equip	187.400	185.100	208.000
3.4	Total Process Plant Installed	450.700	447.700	472.300
4.0	Engineering and Home Office	included	included	included
	Contingency	0	0	0
4.3	Construction Management	included	included	included
	Total EPC Costs**	450.700	447.700	472.300

* Flue Gas Desulfurization

** Engineering/Procurement/Construction

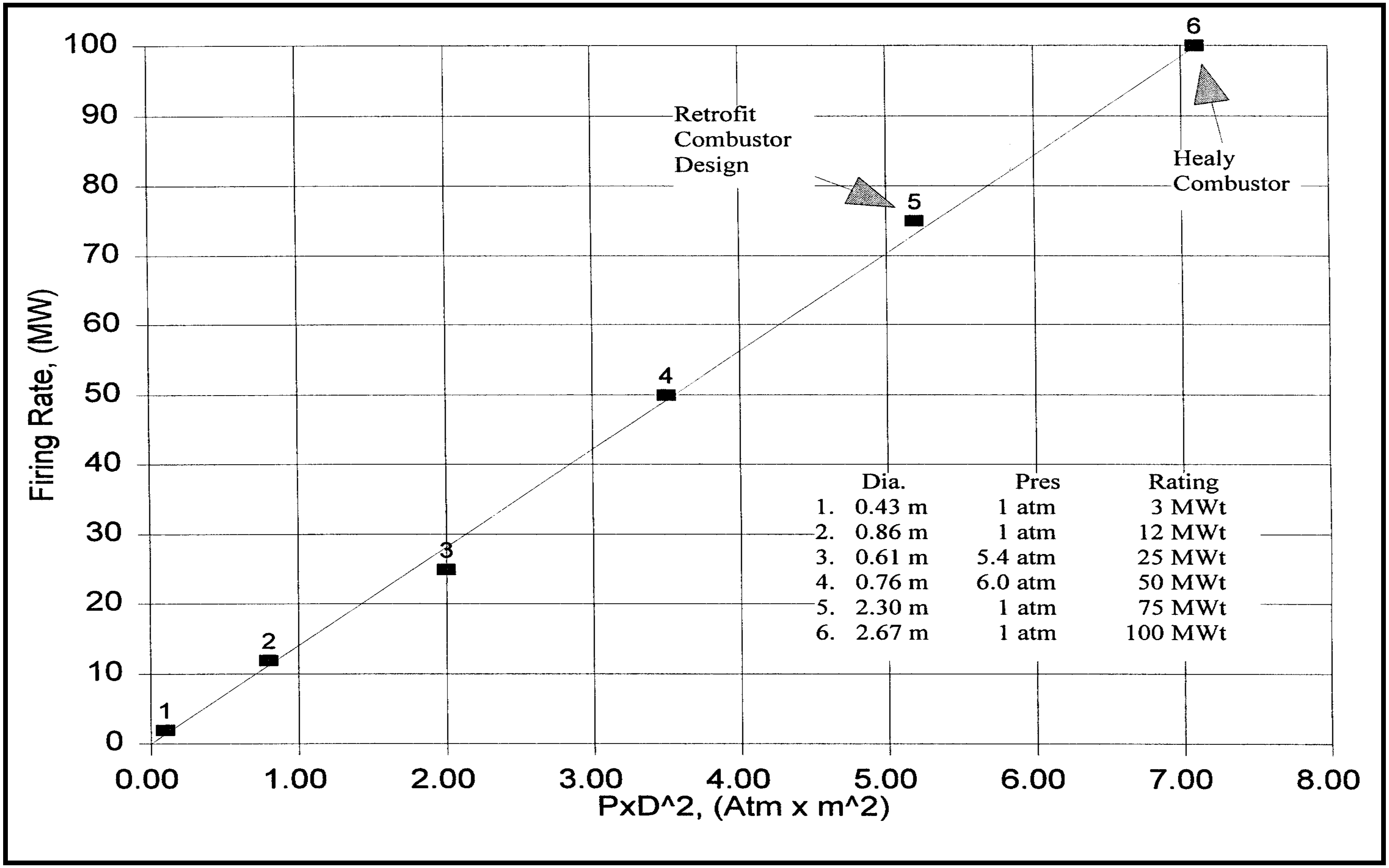


Figure 8-1 Scale of TRW Clean Coal Combustion Systems Demonstrated to Date.

Source: AIDEA 2000e

9.0 CONCLUSIONS AND RECOMMENDATIONS

9.1 Major Technical Findings

The Healy Clean Coal Project accomplished the objectives set out in the Clean Coal Technology proposal submitted to and selected under PON No. DE-PS01-89FE6825. Cost growth of approximately 50 percent occurred during the project as a result of a 2-year delay in environmental permitting, an additional year of demonstration testing, litigation by the power purchaser, and design changes. However, the technology objectives of the program were accomplished.

The combustors demonstrated the ability to burn low-sulfur Alaska coal varying in heating value from 6,000 Btu/lb (100 percent waste coal) to 7,800 Btu/lb (100 percent ROM coal) while maintaining reduced NO_X, SO_2, particulate, and CO emissions. During the 90-Day Commercial Operation Test, reduced emissions were achieved while generating 102,373 MWh of electricity at a capacity factor of approximately 95 percent.

During the 2-year demonstration, the system operation was not fully optimized. The emphasis was on completing the 90-Day Commercial Operation Test required by the PSA between AIDEA and GVEA. The emissions sustained during the 90-Day Commercial Operation Test are typical of long-term operation but are not necessarily the emissions achievable after optimization or additional testing of the applicability of the technology using other coals.

During the 90-Day Commercial Operation Test, NO_X emissions averaged 0.275 lb/million Btu. Sulfur dioxide emissions while burning coal with 0.15 percent sulfur averaged around 0.06 lb/million Btu. Opacity was well below the 20 percent regulatory limit, and particulates were below the 0.01 lb/million Btu limit. CO emissions averaged 25 ppm during the test, about one-eighth of the CO emission limit.

The 90-Day Commercial Operation Test also proved that a high percentage of ash removal (typically 75 to 85 percent) occurred as slag bottom ash. Bottom ash is much easier to handle and is more acceptable environmentally than fly ash. In some cases, it can be used as a filler for construction materials. Furthermore, bottom ash removal reduces the particulate load on the boiler and the baghouse.

9.2 Commercialization Potential

Commercialization of the new technology depends on continued additional development, proven applications, the need for coal in the near-term in the power generation industry, continued emphasis on reduction of coal plant emissions, and the competitiveness of the new technology.

One of the obvious applications of the technology is to retrofit existing boilers currently burning oil. A retrofit can be accomplished without derating the unit. Spatial limitations, emission limits, and coal quality are the variables that limit applications specific to a retrofit. Another application is retrofit of existing coal-fired boilers without SO_2 removal capabilities and without stringent SO_2 limits. These units might be able to use the combustor technology without the SDA System. Sulfur removal in the combustor and furnace alone may approach 70 percent.

New plant capital costs are competitive with PC units with low-NO_X burners and with CFB boilers. The TRW Clean Coal Combustion System technology would best compete with low-NO_X burners on coal retrofit units. In addition, there are many existing oil-fired units in the Pacific Rim that might be suitable candidates for the technology retrofit application if coal sources were available at competitive prices. The new technology competes favorably on new units with CFB boilers.

An intensive effort in the U.S. toward reduction of greenhouse gases would also enhance the commercialization of the new technology based on the low emissions demonstrated at the HCCP.

9.3 Process Limitations

At the HCCP, there is a unique site-specific process limitation: the life expectancy of the mill exhauster fans. Three HCCP-specific design issues drove the use of mill exhauster fans.

- A decision was made that there should be only one pulverizer for each combustor. This required a high-pressure coal feed splitter system to divide the coal between the precombustor and the slagging combustor.

- A decision was made that the coal feed system should not allow for storage of the coal due to concerns about fires as a result of the high volatility of the Alaska coal.

- The pulverizer supplier initially felt that the mill could not be pressurized to the required coal splitter inlet pressure, so the fan needed to be installed on the dirty side rather than the clean side of the mill.

Based on these three HCCP-specific issues, exhauster fans were added to the downstream side of the mill. There are numerous alternative design solutions to this problem, including redesign of the coal feed system. An alternative approach, such as primary air fans or interchangeable wear plates on the mill exhausters, would be recommended for any new application that has similar design constraints.

On the HCCP, one option to consider is continued use of the fans while working to develop new fan materials and coatings with greater life expectancy. A mill exhauster fan can be changed out in an 8-hour shift while operating the plant at half load, and the fan can be rebuilt on site. In addition, new fan rotors cost $75,000. These factors indicate that, for the existing unit, an operations and maintenance solution may be a workable option if only limited capital resources are available.

The use of bottom firing is also unique to the HCCP design requirements. This approach is only suitable for boilers with no space limitations under the boiler. Side firing is probably more practical in most applications; however, in a retrofit application, spatial limitations are a major consideration. Almost all other applications would use a traditional side-firing approach. Additional focus on "packaging" of the combustor and boiler would be desirable to reduce the relatively large space requirements for the new technology.

Heat loss through the combustor slag opening is also a major limitation due to the loss in efficiency that results from the slag tap opening in the main combustor.

The test results at HCCP are limited to the Alaska coal burned during the demonstration tests. The coal is soft, highly volatile, of low sulfur content, and prone to fire and explosions. It contains numerous abrasive components. Extrapolations of the HCCP results to other low-grade coals will be difficult due to the unique nature of the Alaska coal. Although testing of the TRW technology was conducted using other coals as noted in Table 8-2, additional testing on a broader range of coals is necessary.

9.4 Additional Process Development

Additional process development, which is required to enhance the application of the new technology, includes firing of other low-grade coals to verify the HCCP test results. An application with side firing of the boiler would greatly assist in extrapolation of the HCCP results to retrofit applications. In addition, while 50 MWe was the next logical step in the process development, the technology needs to be demonstrated on a commercial-size 300-MWe unit before being used by most existing utilities.

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ABBREVIATIONS, ACRONYMS, UNITS, AND TERMS

Acid Rain Program	Title IV of the Clean Air Act
AIDEA	Alaska Industrial Development and Export Authority
ADEC	Alaska Department of Environmental Conservation
AFBC	Atmospheric Fluidized Bed Combustion
Air Permit	Air Quality Permit to Operate No. 9431-AA001
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
BACT	Best Available Control Technology
B&W	Babcock & Wilcox
Btu	British thermal unit
Btu/lb	British thermal units per pound
Ca/S	calcium to sulfur ratio
CaO	flash-calcined lime
$CaCO_3$	limestone
CC-50	50-MWe Clean Coal Technology plant hypothetically constructed in Wyoming
CC-300	300-MWe Clean Coal Technology plant hypothetically constructed in Wyoming
CEMS	Continuous Emission Monitoring System
CFB	Circulating Fluidized Bed
CFR	Code of Federal Regulations
CO	carbon monoxide
CO_2	carbon dioxide
DCS	Distributed Control System
delta T	temperature increase
DMR	Discharge Monitoring Report
DNPP	Denali National Park and Preserve
DOE	U.S. Department of Energy
DTP	Demonstration Test Program
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EPA	U.S. Environmental Protection Agency
EPC	Engineering/Procurement/Construction
FCM	flash-calcined material
FGD	flue gas desulfurization
Foster Wheeler	Foster Wheeler Energy Corporation
GVEA	Golden Valley Electric Association
H_2	hydrogen
Harris Group	The Harris Group Inc.
HMH	Haas, Morgan & Hudson
HCCP	Healy Clean Coal Project
IGCC	Integrated Gasification Combined-Cycle
in. WG	inches of water gauge

Joy	Joy Technologies Inc.
Kyoto Protocol	Kyoto Protocol on Climate Change
lb/million Btu	pounds per million British thermal units
million gal/year	million gallons per year
million Btu	million British thermal units
MWe	megawatt of electricity
MWh	megawatt-hours
NAAQS	National Ambient Air Quality Standards
NO_X	oxides of nitrogen
NSPS	New Source Performance Standards
NPDES	National Pollution Discharge Elimination System
NPS	National Park Service
O_2	oxygen
O&M	operation and maintenance
PC	Pulverized Coal
PETC	Pittsburgh Energy Technology Center (now National Energy Technology Laboratory)
PFBC	Pressurized Fluidized Bed Combustion
PM	particulate matter
PM_{10}	particulate matter less than 10 microns in diameter
PON	Program Opportunity Notice
ppm	parts per million
PSA	Power Sales Agreement
PSD	Potential for Significant Deterioration
RCRA	Resource Conservation and Recovery Act
ROM	run-of-mine
SDA	Spray Dryer Absorber
SO_2	sulfur dioxide
STG	steam turbine generator
Stone & Webster	Stone & Webster Engineering Corporation
TCLP	Toxicity Characteristic Leaching Procedure
TRW	TRW, Incorporated
tons/year	tons per year
Trustees	Trustees for Alaska
UCM	Usibelli Coal Mine, Inc.

APPENDICES

Appendix A	**Start-up and Shut-down Procedures and Information**
Appendix B	**Operating Procedures and Plant Control**
Appendix C	**Miscellaneous Test Parameters and Methods**
Appendix D	**System and Equipment Problems in 1998 and 1999**
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Appendix A
Start-up and Shut-down Procedures and Information

Start-up

Before beginning a plant start-up, a review should be made of each of all systems to ensure that they are in good operating condition. This should include, as a minimum, a review of all currently active alarm conditions and of recent shift logs and maintenance reports prior to and during the last shutdown.

If any maintenance repair or overhaul work has been done, a visual check should be made of the equipment and it should be verified that all tags have been removed. Valve lineups for system start-up should be verified. The equipment manufacturer's recommendations should be followed regarding any initial start-up checks or limitations, which may be required.

Water levels should be checked in the boiler drum, condenser hotwell and deaerator and they should be filled, if necessary, using the procedures outlined in the associated turnover packages. Acceptable levels should also be verified in the condensate, demineralized water and well water storage tanks.

Minimum operational levels should be verified in the coal and limestone silos and fuel oil storage tank. These should be filled if required.

If the boiler or a combustor was tripped with coal still in the pulverizer, this coal must be removed, using the coal grind out procedure listed in the coal feed system turnover package.

The circulating water system should be filled, if required, using the service water pumps. The intake screens should be checked and cleaned, if necessary.

The slag ash hopper should be filled, if necessary, using the ash recirculation pumps and the level verified, in both the slag ash and bottom ash hoppers. Pump 1B should be used first to empty the surge tank to a level of 3.3 ft, then switch to pump 1A.

The makeup water treatment and waste water systems should be functioning and the chemical feed tanks should have adequate levels.

Start-up Procedure

This procedure assumes that the plant is in a cold shutdown condition, with auxiliary electrical power available and the plant control system operational. If the plant was recently shutdown with some of the systems left in operation, the associated steps may be skipped. The order of some steps may be altered at the operator's discretion. If system alarms are encountered during the start-up, they should be investigated and corrected prior to continuing.

Auxiliary Steam System
If necessary, auxiliary boiler should be started to supply the auxiliary steam header.
Note: This system is normally left in continuous operation, supplied from either Unit 1 or the auxiliary boiler, in order to maintain building heat and other services.

Plant Air System
- Two of the plant air compressors should be started and the third one placed in the auto standby mode.
- Verify that the receiver air pressure is between 95 and 110 psig.
- Verify that the air dryer is operating and that the inlet and outlet filter differentials are below alarm limits and that the dew point is below - 40° C/° F.

Plant Water Systems
The plant water treatment and waste water systems are normally operated by PLC in the automatic mode.

- The demineralized water system and waste water system should be placed in the automatic mode.
- Place both demineralized water pumps in the auto mode.

Note: The sampling system and boiler chemical injection systems should be placed into automatic operation, in accordance with the manufacturer's instructions, after the boiler is operational.

Circulating Water System
- Place both vacuum priming pumps into auto mode to evacuate air from the circulating water system.
- Start both circulating water pumps.

Note: A minimum two minute interval between pump starts should be maintained. The pump discharge valves will be automatically sequenced open with the pump start.

- Start the circulating water booster pump.

Service Water System
- Start one service water pump.

Note: If river silt levels are high, filtered plant water may be used in place of service water.

Component Cooling Water System
- Verify normal water level in the pump suction head tank.
- Start one component cooling water pump and place the second one in the auto standby mode.

- Place the system temperature control valve, pressure control valve and lube oil temperature control valve in auto.

Condensate System

- Verify normal water level in the condenser hotwell.
- Start one condensate pump and place the second pump into the auto standby mode.
- Place the deaerator level control valve and hotwell level control valves in auto mode, if vessels are at normal operating levels.
- Place LP combustor cooling pump recirculation control valve and both combustor LP cooling flow control valves in auto mode.
- Start one low pressure combustor cooling pump and place the second one in auto standby.
- Put boiler vent and drain valves into start-up positions.
- Check steam drum level.
- Fill, if required, to +15” using the cross-tie valve.
- Open combustor three inch natural circulation bypass warm-up valves.
- Close both combustor natural circulation valves.
- Start one high pressure combustor cooling water pump.
- Refill drum to +4” and then start the second high pressure combustor cooling pump. Place boiler start-up blowdown and drain valves into auto.

Note: Initial firing of the boiler, with ignitors, should be made with the cross-tie valve open, supplying boiler feedwater with the condensate pumps. Drum pressure should reach at least 100 psig, before starting the boiler feed pumps.

Combustion Air and Flue Gas Systems

Prior to starting the system, the following dampers should be opened or verified open.

- ID and FD fan inlet and outlet dampers
- NO_x port clean air dampers
- Mix annulus secondary air dampers
- Precombustor secondary air dampers
- Overfire air control dampers
- Baghouse bypass damper (bypass position)

When ambient temperature is below 40° F, one glycol air preheater system should be placed in service by starting one glycol circulating pump and placing the second one in auto standby. The steam temperature control valve to the associated heat exchanger should then be placed into auto mode. The following sequence should then be followed:

- Close ID fan inlet damper.
- Start ID fan.
- Note: ID fan inlet vanes will automatically be released for control after fan is started.
- Place furnace pressure control into auto mode.
- Close FD fan inlet damper.
- Start FD fan.

- Note: FD fan inlet vanes will automatically be released for control after fan is started.
- Increase FD fan inlet vane position in manual mode, until total air flow is greater than 30%.

Note: The economizer bypass damper will automatically open to maximize flue gas exit temperatures during start-up. It will gradually close as the temperature increases.
The CEMS should be verified to be in operation. Insert the furnace temperature probe.
When the Purge Ready indicator is present, a five minute boiler and combustor purge can be initiated. The Purge Complete indicator will be present after this interval.

Fuel Oil and Ignitor System

- Start one fuel oil transfer pump, if not already in operation, and place the second pump in auto standby mode.
- Verify fuel oil heater is in operation.
- Verify that the fuel oil header pressure is normal (160 psig).
- Set the precombustor (PC) stoichiometry to 1.3 and the slagging combustor (SC) stoichiometry to 1.48.
- Set the PC coal percent at 0.38 and the BTu value at 8227 BTu/lb. or last known value.
- When ready to begin lightoff, select the Prelight Mode.

Note: This will begin a ten minute time interval during which an ignitor flame must be established or else another purge cycle must be initiated.

- Depress the black master fuel trip reset button on the control console.
- Select one combustor and manually position the swirl dampers to the retracted position. Position precombustor secondary air damper for 25Klb/hr of air flow and mix annulus damper for 30Klb/hr.
- Open the precombustor cold air flame stabilization valve (the hot cooling air valve closes simultaneously).
- Reset the Ignitor Trip indicator and the Ignitor Start Ready indicator will display.
- Set the precombustor and mix annulus air dampers to auto/cascade mode.
- Start the ignitor (the ignitor automatically extends before lighting).
- Verify Ignitor in Service indicator.
- Boiler should be warmed up and pressurized with the ignitors following the manufacturer’s procedures.

Note: The gas temperature measured by the furnace probe should be kept below 900° F, until adequate steam flow is established in the superheater (20% MCR minimum).

- Repeat ignitor lightoff sequence for slagging combustor ignitor.
- Lightoff ignitors for second combustor, when desired.

Feedwater System

- Verify that the deaerator water level is in normal range and deaerator pressure is around 5 psig from pegging steam.
- Verify that the pump casing temperature is within 75° F of the deaerator temperature.
- Verify that boiler drum pressure is at least 100 psig.
- Start one boiler feed pump and place the second pump in auto standby mode.

Note: The lube oil pumping system will be automatically started and the pump discharge isolation valve sequenced open, when the pump is started.

- The lube oil system for the standby pump will, also, be started.
- Place the start-up (single element) drum level control valve into auto mode.

Turbine Generator & Auxiliaries

Note: The turbine generator should be started up and placed on-line in strict accordance with the manufacturer's recommendations and procedures. Note: The control fluid warming pump should be started at least one hour prior to beginning the turbine start-up.

- Start one turbine main oil pump and tank vapor extractor.
- Place the second oil pump in auto standby.
- Check that the DC oil pump is ready for service.
- Start one hydraulic control fluid pump and place the second pump in auto standby.
- Check casing displacement readings and protective device operation, in accordance with manufacturer's procedures.
- Start jacking oil pump.
- Start turning gear operation.
- Crack open the main steam isolation valve and warm steam line with all drain valves open (if boiler is pressurized).
- Open main steam isolation valve completely.
- Start gland steam condenser exhaust fan and place gland seal pressure regulating and desuperheater valves into auto mode.
- Close condenser vacuum breaker valve.
- Open steam supply valve to condenser vacuum ejectors and begin hogging condenser (with one set of holding jets and the hogging ejector).
- When steam inlet conditions are in accordance with the manufacturer's recommended start-up curve and condenser vacuum is greater than 11.86 psig vacuum, the turbine may be rolled, in accordance with manufacturer's procedures.
- Select cold, warm or hot start at the turbine panel and position the load limiter to 100%. Open main turbine stop valve and place turbine controls into automatic ramp up mode. Turn on generator excitation system and adjust voltage regulator to rated voltage.
- Turn on semi-automatic synchronizer.

- When generator voltage and frequency are synchronized with the line, close the generator circuit breaker.
- Increase turbine load to approximately 5 MWE, adjusting oil firing rate as required to maintain main steam pressure.
- Close main steam, turbine and gland steam drain valves.
- The extraction line isolation valves will open automatically, when the turbine load reaches 25%.

Ash Handling System

Place bottom ash/slag handling system into service, in accordance with the manufacturer's recommended procedures.

Coal Feed System

Note: Pulverizer lube oil pump should be started at least four hours prior to starting the pulverizer.

- Open steam inerting and soot blower supply valves at the boiler drum.
- Transfer FD fan inlet vane control to auto and verify discharge pressure is above 20" water column (wg).
- Select a combustor with ignitors in service and open coal feeder seal air damper. Note: This will also position the primary air capacity damper and temperature control dampers to their lightoff positions.
- Inert the pulverizer.
- Open primary air shutoff damper (PASO), after high flow inert period is complete (two minutes).
- Inert coal feed system.
- Open the coal burner shutoff valves (BSO) after inert is complete (three minutes).
- Manually set the cyclone blowdown damper at 15% open and verify that the PC NO_x port damper opens 100%.
- Start mill exhauster fan.
- Verify discharge pressure is greater than 60" wg.
- Open cyclone blowdown damper to 75%.
- Open the precombustor fire valve.
- Open the slagging combustor fire valve.
- Manually adjust the primary air (PA) capacity damper to approximately 86-90Klb/hr air flow.
- Put blowdown damper in auto.
- Ramp up precombustor and slagging combustor ignitors to maximum, at least 125 psig and 80 psig respectively.
- Verify that the burner combustion air temperature has been above 300° F for at least 2 minutes (Boiler Warm-up Complete).
- Set PC stoichiometry to 1.14 and SC stoichiometry to 1.48.

- Start pulverizer. Close combustor cooling bypass warm-up valves.
- Start feeder at minimum speed.
- Verify that the combustor coal flame is established, after preset time interval.
- Verify flue gas O_2 level is > 6%.
- Set PC stoichiometry at 0.86 and SC stoichiometry at 1.32.
- Adjust pulverizer coal/air outlet temperature to approximately 135^0 F and transfer station to auto at this setpoint.
- Transfer primary air capacity damper to auto.
- Manually set boiler NO_x port balance damper to 5% open.
- Slowly increase coal flow rate (in 2Klb/hr steps) up to 19Klb/hr while decreasing oil firing rate to minimum and adjusting stoichiometry ratios.
- Boiler NO_x port shutoff damper will open automatically at 17Klb/hr.
- Adjust boiler NO_x port balance damper, until the precombustor cyclone injection port flow rate is 12.7Klb/hr for cooling the coupling.
- Increase coal flow rate to 30Klb/hr.
- Open hot flame stabilization air to SC and cold flame stabilization air to PC
- Completely transfer PC NO_x port air flow to the boiler NO_x ports and open manual purge valve above the closed PC NO_x damper.
-
- Slowly increase coal flow to achieve desired load while adjusting stoichiometry ratios.
- Check that boiler oxygen is > 3% and transfer O_2 trim controller to auto.
- Transfer fuel master control station to auto.

Note: The second combustor may be started up using the same procedure, at any time after firing has stabilized in the first combustor (firing rate greater than 50%).

Limestone Feed System

Note: The limestone feed system should be started, when the boiler load reaches 25%. Based on which combustors are in service, one or both feed systems should be started.

- Open carrier air blower discharge valves and combustor isolation valves.
- Start carrier air blower(s).
- Start rotary valve.
- Position diverter gate.
- Start weigh belt feeder.
- Start bin activator.
- Open silo discharge gate.
- Place feed rate controller (SO_2 control) into auto.

Flue Gas Desulfurization System and Baghouse

Place spray dryer absorber and baghouse into service, in accordance with manufacturer's recommended procedure after ignitors are shut down.

Normal Operation

After start-up is complete, the unit should be gradually brought up to the desired load and maintained there, to the greatest extent possible. Conditions in the slagging combustors should be monitored closely and any alarms or abnormal indications should be investigated and resolved immediately. Visual inspection of the slagging conditions, inside the combustors, should be made frequently.

Limestone feed system, baghouse and spray dryer should all be in service, after ignitors have been shut down. Soot blowers should be put into service, when the unit load is above 50%. The slag ash/bottom ash system should be in continuous operation and the fly ash system should be sequenced, as often as, necessary.

Wherever possible, plant control loops should be placed in the auto mode. Unit load control may be operated in boiler follow, turbine follow or coordinated control modes (the normal mode should be turbine follow). The appropriate mode is automatically selected, based on the manual/auto status of the boiler master control station and the turbine governor system.

The boiler continuous blowdown and chemical feed systems should be adjusted to obtain acceptable water quality. Emissions levels should be monitored and adjustments made to the limestone feed rate and/or spray dryer outlet temperature setpoints, if necessary, to stay in compliance. Flue gas O2 levels should be approximately 3%.

Shutdown

A normal shutdown is performed by reducing load and taking one combustor at a time out of service and then tripping the turbine and generator. The turbine load must be reduced in parallel, with the boiler, to maintain normal steam pressure. If the turbine is in inlet pressure control (or turbine follow mode), the turbine load will automatically follow, as the boiler firing rate is reduced.

Combustor Shutdown

- Select one combustor and manually reduce the coal firing rate to approximately 25Klb/hr while adjusting stoichiometry ratios.
- Shut off the limestone feed to the combustor.
- Remove the spray dryer and baghouse from service.
- Start the precombustor and slagging combustor ignitors at minimum rate.
- Transfer Boiler NO_x port flow to the PC NO_x ports while maintaining constant carrier air flow. Close 4 inch manual purge valve above PC NO_x damper.
- Note: Both ignitors should be started before coal flow is reduced below 22Klb/hr.
- Slowly reduce the coal firing rate, until feeder coal flow is less than 15Klb/hr. while adjusting stoichiometry ratios.

- Verify boiler NO_x port shutoff damper closes and manually close the NO_x port balance damper.
- Ramp the ignitors to maximum firing rates, while decreasing coal flow to 9Klb/hr.
- Manually close the mill hot air damper and open the tempering air damper (mill outlet temperature should be less than 105° F).
- Select Normal Coal Feed System Stop.
- Stop the coal feeder.
- .
- Set PC stoichiometry to 1.3 and SC stoichiometry to 1.48.
- After a twenty minute pulverizer sweep interval, stop the pulverizer.
- Wait five minutes and close the primary air capacity damper.
- Manually set the cyclone blowdown damper to 75%.
- Close the precombustor and slagging combustor fire valves.
- Stop the mill exhauster. Verify that the PC NO_x port shutoff valve automatically closes.
- Close the primary air shutoff damper.
- Close the burner shutoff valves.
- Close the feeder seal air damper.
- Start the pulverizer steam inert cycle.
- Shutdown SC and PC ignitors.

The same shutdown process should be repeated for the second combustor. When the last ignitors are shutdown, a master fuel trip (MFT) will occur, requiring a boiler purge before restart.

The turbine and generator may be manually tripped when the load has been reduced to a minimum value or they may be tripped automatically with the MFT. The baghouse, spray dryer and limestone feed system should normally be removed from service, when the boiler load drops below 25% and before the ignitors are placed into service.

The FD and ID fans should be left running for a minimum of ten minutes for a post shutdown purge of the boiler and combustors.

The initiation of the master fuel trip will, in turn, cause the turbine to trip, closing its main steam stop valve, if it has not already been tripped manually. The turbine trip will, in turn, cause the generator breaker and generator field breaker to trip.

The boiler motor operated stop valve should be closed when the drum pressure has decreased below 700 psig and the air removal ejectors isolated.

The drum level control should be in the single element mode. The feedwater pump may be shut down when the drum pressure reaches 100 psig. However, the condensate system must remain in service in order to keep the Low Pressure (LP) and high pressure (HP) combustor cooling water pumps operating long enough to remove residual heat from the slag (at least until the boiler drum pressure is below 25 psig).

The boiler start-up blowdown and drain valves should be placed in manual and closed. Steam drum and superheater vents should be opened when drum pressure reaches 5 psig.

Depending on the intended duration of the shutdown, the remaining plant systems may be either left in operation or shutdown, in the reverse order of start-up.

Operating Interlocks

Both the boiler and turbine generator have protective systems, which will immediately trip them off-line when dangerous conditions develop. These tripping systems are interconnected, so that when one of them trips, they all trip. Unless the trip was due to an electrical fault on the transmission system, the plant house electrical power should remain in service. When such a trip occurs, all of the equipment, which was not, tripped (especially, the ID and FD fans, condensate pumps and feedwater pump) should be left running, until conditions have stabilized and the boiler has been thoroughly purged. A trip will cause many of the control loops to be transferred to the manual mode, so the operator must be aware of boiler air and water conditions and make adjustments accordingly.

After a trip occurs, the plant control system will record the sequence of events, which initiated the trip, so that the originating cause may be determined. When a boiler or combustor trip occurs while firing coal, the pulverizers will have to be emptied of coal, using the grind out procedure, before they can be restarted.

Many of the primary plant systems, including the condensate and feedwater systems, are supplied with redundant standby pumps or equipment. For these systems, the automatic starting of the backup equipment should avoid a plant trip. These failures will be alarmed through the plant control system, however, and the cause should be immediately investigated.

Some systems, such as circulating water, do not have redundant pumps. A trip or failure of an operating pump, in these systems, will require a corresponding reduction in plant load. A load run back will also be required, if one combustor trips while the other is still operating. If the plant load control system is operating in the automatic mode, the necessary load run back will be initiated automatically. However, in the manual mode, the operator must respond by decreasing load as rapidly as boiler and turbine limitations allow, until the operating conditions have stabilized.

Appendix B
Operating Procedures and Plant Control

The major systems, which are required for operating the plant, are:

- Boiler and auxiliary systems
- Combustors and auxiliary systems
- Coal feed system
- Fuel oil and ignitor system
- Combustion air and flue gas systems
- Limestone feed system
- Turbine generator and auxiliary systems
- Main and auxiliary steam systems
- Condensate system
- Feedwater system
- Circulating water system
- Flue gas desulfurization and baghouse system
- Slag and bottom ash handling system
- Fly ash handling system
- Water treatment systems
- Fire protection system
- Component cooling water system
- Instrument and service air system
- Coal handling system
- Electrical distribution system
- Plant control system

The HCCP power plant has several unique features, most of which are centered around operation of the two slagging coal combustors. These combustors are designed to capture the slag created from burning low-grade coals, before it reaches the furnace and causes deposits and operational problems. It is also designed to produce low levels of NO_x emissions through the staged combustion process and to assist in the reduction of SO_2 emissions by the injection of limestone into the combustors during firing.

Proper operation of the combustors requires that both the coal feed and the combustion air be split up into multiple streams, which are controlled independently and introduced into the combustor at precise locations and in controlled ratios to achieve the desired combustion profile. This results in numerous control loops and sequences, which are not present on an ordinary pulverized coal boiler.

The HCCP plant is controlled through the plant control system (PCS). This is composed primarily of a microprocessor-based distributed control system. This system has three operator consoles (plus one slave console) located in the main control room.

After normal pre-operational checks of valve line-ups, equipment condition, etc., all of the operator actions required for normal start-up and shutdown of the plant can be performed from these consoles. They also have all of the system monitoring, alarming, trending, etc., required for normal operation. Emergency shutdowns can be accomplished through the PCS or alternatively by a set of hard wired master fuel trip and ignitor fuel trip push-buttons located on the auxiliary panel located next to the consoles. Generator synchronization is also done with hard-wired indicators and switches on this panel.

The specific operating sequence is as follows and involves the following systems:

- Start-up
- Preparation for Start-up
- Start-up Procedure
- Auxiliary Steam System
- Plant Air System
- Plant Water Systems
- Circulating Water System
- Service Water System
- Component Cooling Water System
- Condensate System
- Combustion Air and Flue Gas Systems
- Fuel Oil and Ignitor System
- Feedwater System
- Turbine Generator and Auxiliaries
- Ash Handling System
- Coal Feed System
- Limestone Feed System
- Flue Gas Desulfurization and Baghouse

A sequence for each system is described in detail in the Appendix A Start-up and Shutdown Procedures and Information. Start-up and shutdown procedures were eventually automated in order to simplify operations. This appendix also includes information on operating interlocks. HCCP systems turnover packages can be referenced to find additional information.

Plant Control System

The purpose of the Plant Control System (PCS) is to provide a reliable and flexible means of controlling and monitoring all of the various plant systems and equipment from a centralized location in the plant control room. It provides the control room operator with both overview and detailed information on the status of the plant from graphic type consoles and allows the operator to start or stop equipment and adjust operating setpoints from these same consoles. It also performs continuous automatic regulation of pressures, temperatures, levels, flow rates, etc., in the various plant systems and provides automated start-up or shut down sequences and automatic starting of standby equipment.

Other functions performed by the PCS include:

- Trending and historical recording of important plant process variables
- Generating alarms to alert operators of abnormal or dangerous operating conditions
- Producing logs and reports of process conditions, events, and operator actions
- Executing on-line performance and heat rate calculations for the major process equipment
- Producing time sequence of event logs during plant trip situations to help diagnose the cause of the trip
- Providing communication interfaces to vendor furnished subsystems having their own stand alone programmable controllers (PLC)
- Performing self diagnostic and trouble shooting routines to assist in maintenance

The PCS interfaces with the instrumentation and control devices of virtually all of the other plant systems.

The PCS is a microprocessor-based distributed control system, which has local process control units (PCU) located at strategic locations throughout the plant. Each of these local processing units contains one or more multifunction processors (MFP). The MFP's are the brains of the systems and perform all of the control strategy and data processing functions. The MFP's are supported by a variety of other types of processing modules which perform specialized functions such as field input and output signal processing and communications with other processors.

The system also has three main graphic CRT-type operator interface stations (OIS) located in the main control room and a slave OIS located in the engineering work room. These stations also contain processors which perform such functions as generating graphic displays for the CRT screens, managing and updating the real time process variable data base, and storing and retrieving historical data such as trends and logs.

These major components are all tied together with a fully redundant communication data highway (Infi-Net) which forms a loop.

Other peripheral equipment which form a part of the control system include three engineering work stations (EWS) which are used to develop or modify the control strategy configurations, databases, graphic screens, etc., for the rest of the system. There are also three control room printers which are used for reports and logs, as well as, copies of display screens. An optical disk data storage device is used for long-term storage of plant historical data and a high speed sequence of events recorder is used to capture and time stamp events related to plant trips. A separate computer (DEC VS4000) is used to collect data and perform calculations related to

plant performance and heat rate, emissions, and other test program data analysis. The system also has a timing system and an antenna which provides synchronization of the internal system clocks with the international universal time standard via satellite link.

Each of the PCU's is a stand-alone controller, which will continue to function independently of the rest of the system. They consist of input and output modules, the multifunction processors, communications processors, power supplies, and the cabinets and racks in which they are mounted. There are six main PCU's which make up the control system. Three of these are located in the relay room adjacent to the main control room while the other three are attached to motor control centers in the plant area. In addition, there are five remote Input/Output (I/O) units associated with these main PCU's. These are attached to other motor control centers (MCC) in remote areas of plant.

The three PCU's located in the relay room primarily handle logic and control functions associated with the boiler, combustors, fuel, air, and feedwater systems. They also perform supervisory control functions for the flue gas desulfurization and water treatment systems and contain communication interfaces with the PLC's which directly control these systems. The sequence of events recorder and time synchronization clock is also located in these cabinets.

The other three PCU's generally perform control logic functions associated with the motors and equipment which are fed from the MCC's that they are attached to. The remote I/O units do not have multifunction control processors but only provide I/O interfaces with the MCC and other nearby devices.

The multifunction processors, data highway communications processors, and power supplies within the PCU's are all redundant, so that if a failure occurs in one of them, the backup will take over with no loss of control functions.

The three OIS consoles are located in the main control room and provide the operator with a real time view of process conditions throughout the plant. They each consist of a 19" CRT screen, a special function operator keyboard, a custom alarm panel, and a DEC VAX computer with hard disk drive for data storage. A fourth operator interface console is located in the engineering work room adjacent to the main control room. It is not an independent console, but operates as a slave to one of the other three consoles utilizing that console's computer, database, and graphics files. There is also a common optical disk storage unit for archiving of historical plant data for later review or comparison. Two black and white, continuous type printers are used for printing of alarms, shift logs, daily reports, etc. A third color printer is used for printing copies of graphic screens.

Each of the OIS consoles contains a database of all the plant process variables and information which is collected by the PCU's. This database is continuously updated over the data highway so that it always contains a current snapshot of conditions throughout the plant. Each of the stations also contains a large number of preprogrammed graphic screen displays which depict flow diagrams or representations of the various plant systems. The current information from the database is superimposed on these graphic screen displays to give the operator a real time view of plant conditions.

From the console, the operator can directly control plant equipment through face plate displays which resemble push button stations or analog controller stations. Alarm conditions are indicated by a horn as well as a change of color and flashing of the displayed variable on the screen. All alarms may also be logged for future reference. A customizable alarm push button panel beside the CRT allows the operator to transfer directly to the appropriate screen with a single touch for critical alarms.

Trend displays are available for all important process variables in the plant. These displays can graphically trend up to four variables on the same chart and have expandable time scales or ranges to allow close-up views of areas of interest. They also allow panning backward in time using stored historical data.

Special tuning displays are available for on-line tuning of analog feedback control loops. System troubleshooting displays are also provided which indicate the status of all the modules connected to the system and can pinpoint any failure. Displays which are used for changing the basic control system configuration parameters are protected by passwords to prevent unauthorized changes.

An EWS is provided to perform tasks such as development or updating of the control strategy programs in the PCU's, development or updating of the operator console databases or graphic screens and testing and troubleshooting of system problems. It consists of a personal computer and dedicated printer connected directly to the data highway through an interface module. Two additional stand alone EWS' are provided which are not connected to the data highway. These can be used for off-line program development.

The engineering workstation contains graphics-based software packages, called CAD/Text and SLDG, which are used off-line to work on the PCU or operator station configurations. Because of the redundancy built into the PCU processors, it is possible to upload the operating configuration from a PCU into the EWS, modify it and then down load the new configuration back to the PCU without any interruption of plant control.

These packages contain tools for monitoring, tuning, and troubleshooting the system operations while on line. They are also self-documenting so that when changes are made the system documentation can easily be kept up to date.

The plant performance computer is a separate DEC VAX computer connected to the data highway through an interface module. This computer utilizes a software package called open data management server (ODMS) to continuously collect data from the control system and store it in a database which can then be accessed by a variety of different performance calculations, emissions calculations, or data trending and reporting programs. After a thirty-day period, the data is transferred onto a tape storage unit for archiving purposes.

PCU04, located in the relay room, contains communication interfaces to the flue gas desulfurization (FGD) system PLC and to the water treatment system PLC. These interfaces allow two-way communication with these PLC's. They are used primarily to collect data from the PLC's, so that it can be displayed on the operator consoles. In the case of the FGD system, however, the analog control of the spray dryer equipment is performed in the PCS and the resulting control outputs are transferred back over the interface.

The plant control system also interfaces with the turbine generator control system, the fly ash pugmill control system, the continuous emissions monitoring system (CEMS), and the utility remote load dispatch system. The data transfer signals with these systems are carried over hardwired input/output points.

The plant control systems successfully maintained process operation with minimum maintenance.

Continuous Emission Monitoring System

The purpose of the HCCP CEMS is to analyze flue gas emissions on a continuous basis in a form compliant with the EPA and Alaska Department of Environmental Conservation (ADEC) permit requirements. The CEMS also provides real time emission compliance alarms.

The continuous emission monitoring system interfaces with the following systems:

- Flue gas
- Instrument air system
- Low voltage critical Alternating Current (AC) power
- Plant control system

The CEMS basically performs two types of analysis; flue gas limited chemical content via an in-stack-dilution type sampling probe and flue gas opacity. The flue gas chemical content analysis is limited to SO_2, NO_x, and CO_2.

The CEMS is comprised of several components or subsystems; flue gas sampling, flue gas opacity, and data acquisition. The basic system operation consists of the flue gas sampling subsystem continuously capturing a dilute flue gas sample via the in-stack probe and delivering this sample to the chemical analyzers via the heated sample transport umbilical. Dilution air is supplied to the probe from filtered and conditioned instrument air. The flue gas chemical analysis is performed continuously on the sample flue gas while the unit is not in calibration. During automatic or manually initiated calibration, the probe is flooded by calibration gases, resulting in calibration gas transport to the chemical analyzers via the sample transport umbilical. The control of the chemical analyzers and associated support

equipment is performed by the sampling subsystem programmable logic controller (PLC).

The flue gas opacity is determined via an optical density instrument.

The chemical analysis and opacity are captured by the data acquisition system and stored for subsequent EPA and ADEC report generation, data analysis, and data archival. The data acquisition system consists of a computer located in the water treatment control room which runs the required database and reporting software packages. This computer is also used for emissions reporting for the adjacent Healy Unit No. 1.

The CEM system is designed to run automatically by the PLC with scheduled preventive maintenance. The automatic operation provides EPA and ADEC compliant unit calibration, data acquisition, and data archival. The system provides external real time analysis values as well as calculated values and general alarms to the PCS, through hard wired PLC outputs. These values are monitored, recorded, and alarmed by the PCS and the SO_2 value is used as a control feedback input to the FGD sulfur removal control system.

The unit operator as well as the CEMS technician have access to the CEMS data via the plant control system and/or the CEM data acquisition subsystem.

Control action of the flue gas sampling subsystem is performed at the flue gas sampling subsystem analyzer enclosure or limited functions may be performed at the data acquisition computer console.

Several CEMS flue gas analysis values and alarms are displayed on the PCS graphics. No control functions can be performed on the CEMS via the PCS. Refer to the following PCS graphic for the primary display of the CEMS data on the PCS.

Refer to Figure 4.18 in the Public Design Report (Final Report:Volume 1) for a diagram of the HCCP Plant Control System.

Appendix C
Miscellaneous Test Parameters and Methods

Table 4-4 continued from main body of the report

#	Test Parameter and/or Variable	Test Codes and/or Method	Comments
4	System Pressure Drop	U-tube manometer measurement at SDA inlet and baghouse outlet as per Contract.	Flue gas flow rate, oxygen content, temperature and moisture content were determined at CEMS location in the stack. Oxygen content and moisture content of flue gas at SDA inlet are also measured. Flue gas flow at SDA inlet was calculated from the gas flow rate at the CEMS location and the oxygen content at CEMS location and SDA inlet. This was done should there be any need to correct the pressure drop for difference in gas flow rate between the guaranteed condition and the test condition.
5	Average Electric Power Consumption	At FGD System feed circuit breakers using plant or test company-supplied instruments.	Averaged over the time period of particulate emission tests.
6	Boiler Heat Input from Fuel (Million-BTU/hr)	Calculated based on coal feeder totalizer and average analysis of coal samples taken.	Coal Sampling Frequency: Every hour. Sample Size: Minimum 2 lb (each sample). Sampling Location: Coal belt feeder discharge (from Feeder A and Feeder B). Other: Samples are collected in plastic bags, properly identified and sealed immediately after sampling and stored indoors at room condition for future analysis.
7	Uncontrolled SO_2 Emissions	Calculated based on coal feeder totalizer and average analysis of coal samples taken during the tests.	Same as Item 6 above.

#	Test Parameter and/or Variable	Test Codes and/or Method	Comments
8	Total Particulate Flow into SDA (lb/hr)	EPA Method 17, Method 1, and Method 2	The FGD System inlet flue gas, particulate matter flow, and moisture content are measured upstream of the SDA inlet. The measured value for particulate matter excludes condensable. Particulate samples are saved for analysis, should it be required.
9	Limestone Sorbent Flow Rate (lb/hr)	Limestone feeder weigh cell and flow totalizer or separate measurements during the tests at limestone feeder discharge.	Time averaged over the test period.
10	Limestone Conversion to Reactive CaO (%)	Analysis of samples collected for Item 8 at SDA inlet.	This parameter is very difficult to determine. The parameter was not determined since SO_2 emission and removal efficiency far exceeded the guarantee requirements.
11	Flue Gas Temp., SDA Inlet, (^{0}F)	From Item 8 measurement.	
12	Flue Gas Flow into SDA (lb/hr)	From Item 8 measurement and Flue Gas Analysis	See Item 4.
13	Flue Gas O_2 at SDA Inlet (% vol. dry)	Electronic O_2 analyzer at SDA inlet	
14	Flue Gas Moisture at SDA Inlet (% vol.)	Method 4 at SDA inlet.	

#	Test Parameter and/or Variable	Test Codes and/or Method	Comments
15	Coal Sample	Grab samples	See Item 6
16	Coal Analysis	ASTM D3176, D3180, D2015	
17	Limestone	Grab samples	Sampling Frequency: Same as coal sampling frequency (see Item 6). Sample Size: 2 lb minimum (each sample). Sampling Location: Limestone feeder discharge. Other: Samples are collected in plastic bags, properly identified and sealed immediately after sampling and stored indoors at room condition. Analysis Required: As per Contract No. HCCP-007 between Alaska Industrial Development and Export Authority (AIDEA) and Joy Manufacturing Company (now B&W).

All references to the American Society for Testing and Materials (ASTM) Standard Specification, American Society of Mechanical Engineers (ASME), EPA Reference Methods and to other similar standard publications are to the latest issue of each as of the date of Contract No. HCCP-007 between AIDEA and Joy Manufacturing Company (now B&W) unless specifically stated otherwise.

Appendix D
System and Equipment Problems in 1998 and 1999

1998

The resolution or status of the following system and equipment major problems that occurred in 1998 are discussed in this section.

- Condensate Pump A Failure
- Steam Drum Level and Level Control
- Boiler Feed Pump Problems
- Furnace Pressure Excursions When Initiating Coal Flow
- Precombustor NO_x Port Piping Overheating
- Precombustor Slagging
- Flame Scanner Slagging
- Swirl Damper Immobility
- Coal Quality Management
- Pulverized Coal and Coal Transport Air
- Mill Exhauster Fan Seal Leakage
- Mill Exhauster Fan Blade Erosion
- Erroneous Coal Cyclone Vent to Precombustor Flow Measurement
- Precombustor Mill Air Port Leakage
- Recycle Surge Bin Inventory Management
- Recycle and Feed Slurry Pump Seal Leakage
- Recycle Slurry Pump Suction Pluggage
- Restricted Atomizer Spray Flow
- Atomizer High Vibration
- Baghouse Filter Wear
- Plugged Line on Outlet from Rotary Feeder to Recycle Mix Tank
- Fly Ash Pugmill Plugging
- Slag Ash Removal
- Slag Drag Chain Overloading
- Inclined Slag Transfer Drag Chain Problems
- Bucket Elevator Plugging
- Waste Water
- Restricted Flow through Multi-Media Waste Water Filters (MMWEWF's)

Condensate Pump 1A Failure
It appeared that the shaft on Condensate Pump 1A failed as the result of improper adjustment after renewal of packing. The necessary replacement pump components were provided and installed. The pump is now performing reliably.

Steam Drum Level and Level Control
At times, the level in the drum was not the same at both ends and, in particular, when the drum level changed significantly. When the steam drum level changed abruptly, the level indicated by the level transmitters on the control board and the level shown simultaneously on the electro-eye were not the same. Sometimes the operator effectively intervened by placing the feedwater flow control valve in manual and then controlling the feedwater flow based on the level indicator believed to be most accurate. If the level was not maintained or (because of erroneous indications) appeared not to be maintained by the system logic within predetermined drum high and low level limits, the unit tripped. Specifically, the boiler circulating pumps tripped because a level transmitter provided an incorrect level indication. Therefore, a level switch was incorporated and is now used instead of the level transmitter by system logic to trip the pumps. Also, an interval drum level indicator equalization line was installed. Drum level control stability is now acceptable.

Boiler Feed Pump Problems
The following boiler feed pump problems occurred:

Boiler feed pump suction line water hammer
Multiple boiler feed pump trips
Boiler feed pump seal leakage
Boiler feed pump lube oil pump trips

The boiler feed pump trips were probably caused by high vibration created from a suction line water hammer. It is also believed that seal leakage was either caused or exacerbated by the suction line water hammer. Therefore, the root cause of items one through three is believed to be the suction line water hammer.

The cause of the suction line water hammer is not clearly known; however, the automatic boiler feed pump recirculation valve did stick open. Thus, recirculation flow (back to the deaerator) may have occurred when it was not desired and, perhaps, even though stuck open, the valve may not have provided sufficient recirculation flow. Thus, insufficient recirculation flow may have caused high temperature water to be discharged from the operating boiler feed pump so that this warmer feedwater was fed back through the non-operating boiler feed pump and into its suction line. This warmer water may have flowed upward into the suction leg of the non-operating pump so that, if flashed into steam at some elevation above the boiler feed pump (yet below the vertex of the inverted "Y" from the deaerator to the two boiler feed pumps), it would result in a steam bubble rising in the warm leg of the unused boiler feed pump until it reached the colder leg of the running boiler feed pump, thereby collapsing and causing a water hammer.

This scenario does not necessarily explain any or all of the incidents of water hammers that occurred; however, after rebuilding automatic recirculation valve components, the problems with items one through three diminished.

Item four was independent of items one through three and was caused by lube oil pump motor failures. The motors were not sized for the power requirements and were replaced with heavier duty motors to eliminate this problem.

Furnace Pressure Excursions When Initiating Coal Flow
Furnace pressure excursions occurred when initiating coal flow as a result of opening the fire valves too quickly. This problem has not reoccurred since the instrument air supply was throttled to slowly open the fire valves.

Precombustor NO_x Port Overheating
The overheating was believed to have resulted from a pressure difference between the precombustor NO_x ports, causing a circulation pattern from one or more higher pressure precombustor NO_x ports through the supply piping to one or more lower pressure precombustor NO_x ports. This circulation was noted to have occurred while firing oil during start-up of the unit, when there is little or no air flow from the pulverizers through the coal cyclone vents. In addition, a similar condition existed after the transfer was made of cyclone vent air from the precombustor cyclone NO_x ports to the boiler NO_x ports. This transfer occurs at a coal flow rate of approximately 17,000 pounds per hour (per combustor coal flow). In order to prevent the circulation pattern from occurring, during 1998 test operations, approximately 35,000 pounds per hour of the 110,000 pounds per hour total primary air was maintained at all times to the precombustor NO_x ports. This leaves approximately 35,000 pounds per hour of carrier air (air which transports coal from the cyclone coal outlets to the precombustor and slagging combustor) and 40,000 pounds per hour of cyclone vent air to the boiler NO_x ports. Maintaining this air to the precombustor NO_x ports eliminates circulation of combustion gas through the NO_x port piping which is believed to have caused a fire in the cyclone vent piping.

During 1999, the precombustor NO_x port flow was eliminated, in order to minimize the potential for improper slagging when waste coal is fired and additional modifications to the precombustor NO_x ports were required in order to eliminate circulation of combustion air.

Precombustor Slagging
Slagging, although not initially supposed to occur in the precombustor, did occur. Potential causes identified for this unpredicted slagging are:

a) The local effects of injecting the relatively cold cyclone vent air (134^0 F) and 750^0 F secondary air into the precombustor can exit gas stream. The precombustor can refers to the inner portion of the air flow relative to the annular flow from the precombustor mix annulus.

b) Stoichiometry not adjusted relative to the temperature at which coal ash becomes slag, so that the condition required to achieve slagging temperature is not reached in the precombustor. As such, precombustor slagging could be caused by failing to adjust for varying heating value and/or slagging temperature of the coal because of varying coal and ash properties.

c) Inadequate mixing just downstream of the mix annulus causing slag to form and be cooled and frozen by secondary air from the mix annulus.

Following the December 1998 test series, there was not any indication of localized slag freezing within the precombustors. However, there had been occasional oil firing during this test series due to pluggage of frozen coal within the coal silos and, therefore, it was uncertain if the local slag freezing phenomena had fully been resolved.

Flame Scanner Slagging

Many flame scanner positions were tried in an attempt to find locations allowing reliable flame detection in 1998. The flame detector ports were often obstructed by slag. The problem was substantially resolved by 1999; however, minor additional changes were implemented. There is currently one oil flame scanner on each precombustor and on each slagging combustor. An oil flame scanner is located in the air pipe to the oil gun in each slagging combustor. The oil flame scanner for each precombustor is located in the head of the precombustor between the outside of the coal injector and the windbox inner register secondary flow baffle. There are three precombustor coal flame scanners in each precombustor. ‘A’ Precombustor head-end coal flame scanner is located in the main flame detector pipe and views the coal from the annular area of the precombustor windbox outer register air path.

A horizontal radial precombustor coal flame scanner is located on the east side of each precombustor through a rodding/view port in the coal cyclone vent air injection ports. The third precombustor coal flame scanner is horizontal and located on the west side of the precombustor through a rodding port downstream of the west swirl damper. On the head end of each slagging combustor there are also three coal flame scanners. Two are located in 3:00 and 9:00 positions of the six outer ring secondary air injection ports. Coal is currently injected into the inner ring of ports except for the 11:00 port on Combustor A and the 1:00 port on Combustor B where the third coal flame scanner is located in this seventh secondary air injection port. No trips due to loss of flame detection occurred after March 1998 Sometimes the required cleaning frequency was higher than desired, because of concern that scanners could slag over and cause a unit trip before they could be cleaned. However, this never occurred and did not continue to be a major or frequent problem.

Swirl Damper Immobility

The swirl dampers were originally designed to beinserted and retracted into the outlet gas flow from the precombustor to control the velocity of the gas from the precombustor as it discharges tangentially into the slagging combustor. The motor drives for the swirl dampers were not designed for the ambient temperatures experienced and were not capable of sustaining the loads required to insert and retract the dampers through the slag which forms in the precombustors. New drives utilizing metal rather than plastic gearing and a roller and track arrangement were designed and installed. The required force to insert the dampers was not achieved. However, since HCCP is to be a base loaded unit, the dampers were effectively set to a fixed position associated with the full-load firing rate of each combustor and were not adjusted from that setting.

Coal Quality Management

Certain ROM coal, particularly Seam 6 coal, is difficult to grind. Suspended particles not ground to a fineness sufficient to be swept through the mill classifiers accumulate in the pulverizer creating considerable coal inventory between the coal feeders and the combustors. This was characterized by the high differential pressures experienced across the mills when using Seam 6 coal. As a result, the actual instantaneous (recognizing there must always be some time delay between coal leaving the feeder and entering combustors) coal feed rate to the combustors is not identical to the feeder feed rate because of changing coal inventory in the pulverizers. The buildup of coal in the pulverizers is believed to have caused at least one pulverizer trip. In addition, if coal inventory in the mill suddenly decreases, the firing rate suddenly increases, causing load swings and difficulty in maintaining steam drum level. This was resolved by future blending of Seam 6 coal with other coal.

The unit undergoes large load swings when the coal heating value is inconsistent. Large variations in coal heating value occurred, even in fuels that were supposed to be of consistent heating value. Separate ROM and waste coal piles sourced two separate hoppers each with controllable outlet feeder speeds. Feeder speeds were automatically varied from the two separate waste and ROM hoppers to maintain a constant heating value based on the online ash, moisture and estimated heating value of the fuel analyzer on the HCCP and Unit 1 common conveyor, which is downstream of the two variable speed feeders. Unfortunately, there were times when coal from the waste hopper had a higher heating value than the ROM coal, so increasing the feeder speed from the waste coal hopper, which was supposed to have a lower heating value than ROM coal, was obviously unsuccessful. The most successful method of achieving a blend of waste and ROM coal, with a relatively uniform heating value, was to provide a layered pile with alternating layers of waste and ROM coal. A front end loader was used to lift through a vertical wall at the edge of the pile, thereby gathering a mixture of the layers. In addition to the mixing which occurred in the coal pile, both hoppers were fed so that their respective feeders would provide a mix from each hopper. Then the coal feed into the two plant silos, one silo for each of the two combustors, was alternated via automatic flop gates. These were alternated approximately once per every fifty tons loaded, thereby providing a more uniform heating value to the combustors at any given time.

Mill Exhauster Fan Seal Leakage

The inboard (motor side) and outboard mill exhauster seals on both mill exhausters have leaked coal dust from the positive pressure which occurs at the fan casing/shaft interface to the atmosphere. Mill exhauster seal leakage was mitigated by providing a field applied silicon seal to the outside of the two shaft seals at each fan casing shaft penetration. The space between the inner and outer seals was purged using sufficient plant compressed air to create a higher pressure between the seals than the adjacent pressure inside the fan casing.

Erroneous Coal Cyclone Vent to Precombustor Flow Measurement

Flow measurements in the line to the precombustor mill vent air ports, which are used to adjust flow between the precombustor NO_x ports and the boiler NO_x ports were erroneous. The purge air valves, which provide compressed air to blow coal dust out of the static pressure and total pressure measurement orifices, leaked. The leaking valves were replaced. This mitigated problems with flow measurement errors; however, it did not eliminate them. Alternative flow measuring methods are being investigated including the possibility of eliminating the need to measure the flow or eliminating the flow itself.

Precombustor Mill Air Port Leakage

The precombustor NO_x ports (where a portion of the coal cyclone vent air is vented to the precombustor) leaked coal dust from the positive pressure inside the combustor through the grooved-end mechanical joint victaulic coupling gaskets. This type of joint was provided to allow for the thermal growth of the precombustor nozzles relative to the connecting piping. High gas temperatures were not anticipated in this area and the gaskets failed due to exposure to temperatures exceeding the coupling gasket design temperature. The victaulic couplings were replaced with butt-welded metal bellow expansion joints designed for much higher temperatures. Subsequent precombustor mill air port leaks were caused by poor welds at the interface between the mill vent piping and its connection to the seal box on the precombustor. The welds were repaired and there were no more leaks.

Fly Ash Recycle Surge Bin Inventory Management

A limestone feed rate of less than twice the desired amount could not be achieved with the original equipment; consequently a new gear drive was installed on the limestone feeder so that the feeder speed was halved. There is a significant time delay (several hours) between the time limestone is injected into the combustors and when it is actually utilized for SO_2 removal (in the spray dryer absorber system). This delay results from the limestone having been flash calcined, collected in the baghouse hoppers (along with some previously reacted FCM and inert fly ash), passed through the recycle bin, mixed in the recycle mix tank, ground in the tower mill, flowed to the feed slurry tank, and pumped through the atomizer. The fly ash recycle bin is filled via the fly ash drag chain. Filling is initiated when there is a high level in either one of the rear baghouse hoppers (where more material is collected than any of the other hoppers) or upon high levels in any other two baghouse hoppers. Once the fly ash drag chains begin to operate, they continue operating until all high levels have cleared unless a high-high level occurs in the recycle surge bin. A high-high surge bin level causes the fly ash drag chains to stop until the high-high level clears. The recycle surge bin outlet rotary valve speed is controlled to maintain the setpoint of recycle mix tank solids concentration. The recycle surge bin outlet rotary valve discharges to the fly ash transport line on high level. It runs until there is a low level in the bin. This problem was not resolved in 1998 and another speed reducing gear was installed later.

Recycle and Feed Slurry Pump Seal Leakage
Leakage in the recycle slurry pump and feed slurry pump seal was attributed to a buildup of solids between the rotating shaft seal assembly and the stationary seal flange of the flushless mechanical seals. This buildup is believed to have caused a slight separation of the rotating and stationary mechanical seal surfaces, leading to seal failure. Holes were drilled through the stationary seal flange to provide approximately three gallons per minute of relatively clean filtered waste water to purge any buildup of solids from the sealing surfaces. Seal leakage problems appear to have been eliminated since this modification.

9.0

Recycle Slurry Pump Suction Pluggage
Recycle slurry pump pluggage was attributed primarily to chunks of agglomerated ash (originating from wet ash deposits which eventually dried and flaked off from the upper walls of the SDA) being fed via the rotary feeder from the recycle surge bin into the recycle mix tank. These chunks then became lodged at the inlet to the pump impeller. The short term and long term solutions to this problem are listed below.

Short-term solutions:

- The affected pump discharge valve was closed, the pump suction line was back flushed using filtered waste water, and then the pump was restored to its normal operating configuration.
- The pumps were switched, suction piping disassembled, and the blockage cleared on the original pump.
- When the SDA drag chain carried chunks, they were removed, so the chunks didn't reach the recycle mix tank.

Long-term solution:

- The formation of the chunks in the SDA was eliminated. These chunks resulted from wet deposits on the upper walls of the SDA caused by excessive atomizer spray flow based on slurry solids concentration and the approach to saturation temperature in the SDA. Slurry solids concentration was increased from approximately thirty to forty percent solids. Spray flow was limited, while flushing the atomizer, and the spray flow was reduced as solids concentration decreased.

Restricted Atomizer Spray Flow
Restricted atomizer spray flow was attributed to the agglomeration of particles somewhere between the atomizer and the head tank outlet strainer. This agglomeration either built up and gradually constricted flow or released a chunk, which then was caught

downstream, where it suddenly restricted flow. The frequency of plugging appeared to be related to the level of unreacted calcium (as calcium oxide and calcium hydroxide) in the fly ash. Flushing the atomizer with filtered waste water (approximately once every twelve hours) appeared to mitigate restriction of atomizer spray flow. In addition, providing coal from a pre-blended pile improved the ability to operate with consistently lower levels of unreacted calcium compounds in the slurry. Various logic changes in the control system alleviated the problem, but it was not fully solved.

Atomizer High Vibration

High vibration levels in the SDA atomizer have been attributed to the formation and release of an agglomeration of particles larger than approximately 3/16 inch. These particles are believed to eventually block off or inhibit flow from one of more of the nozzles in the atomizer wheel, creating vibration. Flushing the atomizer with relatively clean filtered waste water has decreased vibration.

Baghouse Filter Wear

Excessive fabric filter wear, especially adjacent to compartment walls opposite the compartment inlet ducts, caused increased stack opacity. Poor inlet gas distribution caused the filters to rub against the compartment side walls and against each other, resulting in holes in the fabric. Flow distribution baffles were installed in early 1999 to mitigate fabric filter wear.

10.0

Plugged Line on Outlet from Rotary Feeder to Recycle Mix Tank

Plugging of the pipe, which feeds powdered FCM into the recycle mix tank, was attributed to poor tank level control and vent scrubber plugging. Both are believed to cause the inside of the feed pipe to become wet, resulting in the powder sticking to the inside wall of the pipe. Poor tank level control may have caused alternating rising and lowering tank levels to wet the inside surface of the pipe, thereby creating a plug. Vent scrubber plugging sometimes caused malfunctioning of the level indicator/controller. When the vent scrubber plugs, excessive dust in the moist, warm environment above the slurry surface in the tank is believed to cake dust on the level indicator/controller and on the inside of the FCM feed pipe. If the water level drops below the bottom of the feed pipe, splashing water may wet the inside of the pipe, which also causes caking. This issue has not been resolved.

Fly Ash Pugmill Plugging

Pugmill plugging was caused by:

Improper ratio of dust suppression water to fly ash during unloading

Failure to clean out the pugmill after completing unloading operations, causing the wet fly ash to set-up into a cement-like mixture

Excessive CaO concentration in the fly ash

Items one and two were corrected, as operators became more proficient at unloading fly ash from the silo to the dump trucks. Item three was avoided by pre-blending the coal in the coal yard. This provided a blended coal with sulfur and ash contents that deviated less from well mixed (or average) values. Therefore, it was not necessary to provide an incrementally higher limestone flow to compensate for larger deviations resulting in excess CaO concentration in the fly ash.

Slag Drag Chain Overloading

When low heating value, high ash coal was encountered, the tension at the head end of the slag drag chain increased causing the flights to lift off the dewatering ramp. Therefore, material slid back down the dewatering ramp. Eventually, the slag drag chain could not remove the slag as fast as it was produced, resulting in excess hydraulic pressure and shutdown. The increased chain tension also caused damage to the sprocket teeth and hydraulic motor support at the head end of the slag drag chain as well as bending the flights.

The bent flights were straightened, the hydraulic drive motor support was replaced, the interfering flanges of the breaker beams were trimmed and modifications were performed near the head end idlers and sprocket to keep the flights centered and to keep them down onto the slag tank outlet ramp. In addition, a larger hydraulic drive was provided to increase the speed of flights removing slag and support the modifications that were performed on the configuration of the some of the flights in an attempt to remove more material per flight.

Extension plates, parallel to the dewatering table, were welded onto the bottom of each flight, so that, when the drag chain lifted off the dewatering table, the material laid on top of the parallel plates rather than sliding back down the ramp. In addition, small drain holes were added to the flights, resulting in better dewatering, which also helped to minimize loss of slag material from the flights as they traveled up the dewatering ramp. The slag drag chain has operated reliably since the modifications.

11.0

Inclined Slag Transfer Drag Chain Problems

The slag transfer drag chain failed as a result of material being caught between the chain and the head end and tail end sprockets and pulleys. There was also a buildup of material at the tail end, which resulted in the chain breaking. The under side of the tail end was provided with an opening for any excess material carried around the head pulley to drop out into a small hopper which is emptied by an eductor discharging to the slag ash drag chain reservoir. The head end of the conveyor was first modified to wipe material away from the chain before it passed over the head sprocket and the tail end was provided with an idler sprocket rather than the initial idler pulley. This prevents the chains from getting out of alignment with each other. The table on which the top strand of chain and flights is dragged across was removed and the direction of the transfer drag chain conveyor was reversed so that material fell directly to its bottom table to be dragged by the bottom strand of chain and flights. Any material dribbling from the head pulley discharge also fell to the bottom table where it was dragged up toward the head end rather than down toward the tail end of the conveyor. The transfer drag chain operated more reliably since the modifications; however, further modification to the slag transfer drag chain was required to minimize and dispose of tail end material dribble and to reduce drag chain wear.

Bucket Elevator Plugging

The slag bucket elevator discharges to the bottom/slag ash silo via a transition chute. The transition chute had a reduced cross section through which the material flowed. The reduced cross section caused material to backup into the discharge chute and eventually caused the material to be carried over the head sprocket which clogged the tail end of the bucket elevator. The discharge chute transition piece was first modified to provide a more gradual cross section reduction. This improved the situation but did not eliminate pluggage. As a further measure to assist material movement, a vibrator was added to the chute work and no pluggage has occurred since.

Restricted Flow through Multi-Media Waste Water Filters (MMWEWF's)

Restricted flow through the MMWEWF's was attributed to the highly turbid, highly alkaline slag drag chain circulation water used as make-up to the filtered waste water system, via the dirty waste water tank and the MMWEWF's. Using water directly from the slag ash drag chain as backwash for these filters also contributed to the problem. The quality of this water was degraded further when FGD sump water, resulting from recycle slurry tank and/or feed slurry tank overflow or (during preparation for shutting the plant down) drainage, was pumped to the slag drag chain.

The high turbidity of the slag drag chain circulation water caused the MMWEWF's to plug. The FGD slurry water, in particular, tended to plug these filters quickly. The high alkalinity of this water also caused the filtered waste water to be transferred to a neutralization tank. Then neutralized water from the neutralization tank returned to the dirty waste water tank and passed through the MMWEWF's again, before flowing to the filtered waste water tank (if its pH was low enough) or returning to the neutralization tank again (if recontaminated with too much additional high alkaline make-up water).

The slag ash drag make-up source to the dirty waste water tank was replaced with river water.

1999

The resolution or status of the following system and equipment problems that occurred in 1999 is discussed in this section.

- Fuel Coal System
  - Modifications to Isolate Coal Cyclone Vent Air from the Precombustor
  - Precombustor Rodding Port and Cyclone Vent Air Port Overheating
  - Mill Exhauster Abrasion
- Ash Systems

    - Water Lances to Remove Slag Accumulation on Sloped Furnace Hopper
    - Inclined Slag Drag Chain
    - Accumulation of Solids in the Ash Water Surge Tank
    - Excessive Fabric Filter Bag Wear
- Boiler Steam and Water
    - Unstable Turbine Throttle Valve Operation
    - Poor Pressure Regulation of Steam Jet Air Ejector Motive Steam
    - Boiler/Combustor Water Chemistry and Tube Metallurgy
    - Slag Tap Dipper Skirt Shield Tube Heat Exchanger Vent and Drain Piping Leaks
- Miscellaneous Systems
    - Induced Draft Fan Noise
    - Restricted Flow Through Multi-Media Waste Water Filters (MMWEWF's)
    - CO_2 Fire Protection System Test Failures

Mill Exhauster Fan Blade Erosion
The abrasive HCCP coal eroded the mill exhauster fan blades. The blades were rebuilt onsite using tungsten carbide, but eroded again between October and December. New rotors with blades of Barberite™, a more erosion resistant material, were installed in December for testing in 2000.

Modifications to Isolate Coal Cyclone Vent Air From the Precombustor
During start-up, coal cyclone vent fines must be directed into the precombustor in the immediate vicinity of the oil flame to ensure proper combustion of this dust. Then, after reaching a higher load, these fines can be transferred to the boiler NO_x ports for combustion, because sufficient flame intensity exists in the NO_x ports at higher loads. It is advantageous to transfer this source of cold air away from the precombustor to avoid slag accumulation. However, there is a vertical leg above the isolation valve on the cyclone vent line to the precombustor. A purge line was cross-tied into this vertical cyclone vent line so that the fine coal dust would not form a pile on top of the cyclone vent isolation valve to the precombustor.

This purge line was effective at preventing the accumulation of coal dust on top of the closed cyclone vent air isolation valve. This configuration requires manual operation and it is important to close the purge air valve, because whenever the cyclone vent air to the boiler NO_x ports is throttled, the discharge pressure from the mill exhauster fan increases and could eventually overcome the discharge pressure of the purge air (provided from the pulverizer tempering air duct) where purge air normally flows into the coal feed system piping. This could cause coal dust in the cyclone vent air to be fed into some of the flame scanner purge air ports and, possibly, to other places in the purge air system where coal dust would be undesirable. There may also be a risk that the precombustor ports that accept cyclone vent air could become slagged over. If this occurred, coal dust could pile up over a slagged-over port creating a potentially dangerous situation when coal fines in the cyclone vent air are directed to the precombustor cyclone vent ports.

One method of eliminating the complications and potential problems associated with above method of eliminating vent air from the precombustor would be to provide oil burners at the current furnace NO_x ports so that fines could be reliably incinerated with a sufficiently intense flame during start-up. Such a proposal was received in February, 2000 in response to a request by AIDEA for the design and supply of oil igniter equipment and waterwall tubing to modify the boiler NO_x ports, and to provide the NO_x port windbox. Plans were made to carry out this modification during the year 2000.

Precombustor Rodding Port and Cyclone Vent Air Port Overheating

Purge air (provided from pulverizer tempering air) flow valves had reportedly been left closed, causing overheating of the rodding ports on top of the tangential entry of the precombustor into the slagging combustor. However, there was some concern that, even with the purge air flow valves open, these ports could slag over and block the flow of purge air, thereby shutting off a needed supply of air to cool the rodding ports. Therefore, cooling air for these ports was provided with compressed air from the plant service air system, which operates at a minimum pressure of 90 psi. This source of air is presumed to be capable of overcoming any slag layer so as to prevent the plugging off of the cooling/purge air flow. The one-inch lines providing service air to these rodding ports, if left wide open, could significantly contribute to the overloading of the service air compressors and could potentially depressurize the vital instrument air system. Consequently, orifices were provided to ensure that the flow would not be excessive.

There were also instances when the six-inch cyclone vent air connections to the precombustor became overheated. These connections had also been fitted with purge air connections when the operating configuration, which completely isolated the cyclone vent air from the precombustors at a designated total coal flow rate, was incorporated. Non-orificed, one-inch valved service air lines were provided to each of these six connections (per precombustor) to provide the extra flow and pressure, as required to protect the connections from overheating.

Mill Exhauster Abrasion

Mill Exhauster A achieved its longest continuous run starting with the ninety-day test and continuing through the additional seventeen days operation in December. During this period there was no internal maintenance done to the exhauster's wear surfaces. There were occasions when coal abraded completely through the outer casing and the resulting coal leaks were repaired online with an external patch plate lined with ceramic tile.

HCCP mill exhauster wear rate exceeds normal levels for two primary reasons:

1. The mill exhauster rotor tip speed (approximately 24,000 feet per minute) is very high and

2. The coal and contaminants in it (sandstone and other constituents from overburden and interburden) are very abrasive.

Both exhauster rotors rotate in the same direction. Therefore, since Mill Exhauster A discharges to the north and Mill Exhauster B discharges to the south, the discharge from Mill Exhauster A is from the bottom of its casing and Mill Exhauster B discharges from the top of its casing. The ceramic tile, which was utilized as an internal casing wear overlay, tended to wear excessively.

During the outage that took place after the December 16 shutdown, the worn ceramic tile lining inside the mill exhauster casings was replaced and an additional one-half inch thick overlay material was placed on the ceramic tiles located in the high wear zones.

Water Lances to Remove Slag Accumulation on Sloped Furnace Hopper

Water lances were selected instead of steam or air devices to remove slag from the sloped furnace hopper, because of the ability of a water jet to more effectively wash slag from waterwall surfaces at distances up to twenty feet. Steam or air cleaning devices clean effectively only up to distances of approximately three or four feet.

Two water lances are required to cover the total north to south span across the sloped tube wall of the furnace hopper. The lance to the north is the longer of the two at approximately twenty-nine feet (overall length), because there is much more open space between the north (front) waterwall and the deaerator for the lance in its retracted position. The south lance covers the distance uncovered by the north lance and is approximately eleven feet (overall length). These lances are mounted on the north (front) and south (rear) waterwalls and are configured very similarly to the standard retractable superheater steam soot blowers on the upper west (left) furnace waterwall.

Each lance has four nozzles, two of which direct straight streams to the area of the sloped hopper being washed and the other two provide diffuse streams for thrust balancing to prevent the lance from being moved around by an unbalanced radial thrust. The lance rotates in a circle as it advances (or retracts) axially. Thus, its spray pattern is a helix. The speed at which the lance advances is variable and is controlled by a programmable controller so that the velocity of the wash point on the washed surface is constant. Water flow is maintained for cooling at all times while the lance is inserted into the furnace. Two solenoid operated valves provide water pressure control so that high pressure water is only provided to the lance nozzles when the straight stream nozzles are directed to the surface areas to be washed. The rest of the time, water flow is provided to maintain cooling as required for the inserted lance.

Inclined Slag Drag Chain

The tail end of the slag transfer drag chain was fitted with a pyramidal hopper with an eductor at its base. The eductor is provided with motive water from the pyrites sluicing system and operates in a manner similar to the eductors used for removing pyrites from the pulverizers. The system discharges to the submerged drag chain reservoir and has functioned well.

Removal of the top table and reversal of the direction of the inclined drag chain (as discussed in the 1998 Operations Topical Report) also worked well. However, removing the top table caused the chain to wear. Particles of slag acted as a grinding compound because of sliding contact between the drag chain and the plate under it. This plate was completely removed and the drag chain was supported by the rolling idlers. This essentially eliminated chain wear from sliding contact. There was some wear to the rollers, especially at the head end of the conveyor where chain tension is greatest because of the head end sprocket drive. Head-end rollers of hardened steel have greatly reduced idler wear at this point and the rate of wear elsewhere appears to be acceptably low.

Accumulation of Solids in the Ash Water Surge Tank
Large quantities of flow from the ash water recycle pumps to the drag chain reservoirs and, subsequently, over their overflow weirs caused solids to be entrained in the overflow water. The ash water surge tank acted as a settling basin for the entrained solids.

During normal operation, the ash water system, as designed, used recycle pumps to circulate ash water from the ash water surge tank through the ash water heat exchangers to reject waste heat to the once-through type circulating water system, which is water from the Nenana River. This cooled ash water was to flow to the slag ash and bottom ash drag chain reservoirs, where heat is rejected from the slag to the ash water. The ash water flowed over weirs and returned via piped weir drains back to the ash water surge tank to be recirculated through the cycle. Because of the submergence of the slag tap dipper skirt and the finned tube heat exchanger that serves as its heat shield, these heat exchangers provided enough heat exchange capability to render the ash water heat exchangers, for rejecting heat to the circulating water system, unnecessary. Consequently, the ash water heat exchangers were valved out of service and bypassed. The heat rejected to the ash water from the slag and slag tap losses (other than evaporation and ambient losses) was incorporated as part of the heat duty of the slag tap dipper skirt shield tubes and was recovered into the condensate system.

Since operating experience showed that a high volume of recirculation flow was unnecessary, weir overflow was minimized. This reduced the amount of suspended solids and, therefore, substantially reduced the solids accumulation in the ash water surge water tank.

Excessive Fabric Filter Bag Wear
Review of the 1998 baghouse fabric filter replacement records indicated that excessive bag wear in the pulse jet baghouse was occurring. Bag failures were much more frequent on bags along the walls opposite the flue gas entrance duct. This wear was attributed to turbulent flow conditions external to the bags, causing the bag filter inner support cages, which hang from the top tube sheet support, to sway. This swaying caused the fabric filter bags around the outside of the support cage to rub on the adjacent wall and on other bags.

In January 1999, full width turning vanes were installed, which significantly reduced the number of bag failures.

Unstable Turbine Throttle Valve Operation
The turbine throttle valve failed to move smoothly in response to normal control parameter variations, causing the unit to trip. This problem was attributed to thyristor damage, which may have been caused by a transmission system voltage surge as the result of a Unit #1 trip. The turbine manufacturer engineers replaced the damaged thyristors and a defective throttle valve control cable. The unstable turbine throttle operation did not recur.

Poor Pressure Regulation of Steam Jet Air Ejector Motive Steam
It was necessary to operate the control valve that maintains 300 psig motive steam to the condenser air ejectors with its inlet isolation valve throttled. Otherwise, the control valve operated at near zero percent open. The control valve seat and plug were replaced to provide a smaller trim with the proper valve flow coefficient for normal operating conditions. The valve now operates at approximately fifty to sixty percent open with its isolation valves fully open.

Boiler/Combustor Water Chemistry and Tube Metallurgy
Various concerns, primarily as the result of operation with alleged low pH for very short periods of time during early 1998 and high silica levels following a dipper skirt shield leak in February, 1999, led to a decision to obtain and analyze material samples from potentially damaged or compromised areas of the combustors and the boiler.

Four waterwall tube samples and two combustor tube samples were taken in December 1999. Two of the waterwall samples were taken from the right and left side waterwalls (one each) and two waterwall samples were taken from the nose of the boiler. The two combustor samples were taken from the slagging combustor baffle inner tubes where the highest heat flux exists. This location was chosen because it is considered to be the area most sensitive to water chemistry.

The boiler tubes are three inch (outside diameter) by 0.165 inch (minimum wall), SA-178 Grade C material. The combustor tubes are one and a half inch (outside diameter) by 0.180 inch (minimum wall).

The laboratory analysis of the submitted samples indicated that:

- Each of the waterwall samples was in good condition and contained a thin deposit on the inside surface. After the deposit was removed, the inside surface exhibited shallow pitting, indicating that the low pH conditions, which occurred during the initial operation of the unit, had no detrimental effects.
- Both combustor tube samples contained circumferentially oriented cracks that initiated at the shield fin-to-tube welds, primarily in the welds that attached the fins to the top (or concave) half of the tube. The morphology of the cracks indicated that they developed from an oxidation fatigue mechanism and appeared to be still propagating at the time the samples were removed. In the four sections evaluated from one of the samples, the deepest crack had not yet reached the midpoint of the tube wall.

- Aside from the cracks, the combustor tubes displayed no additional distress. The wall thickness measurements were still above minimum wall thickness, the inside surface contained a thin deposit and the microstructure exhibited no evidence of significant overheating.

Based on the above results, the combustor designer determined that the original shield fin design should have been of a different configuration to withstand thermal cycling. Therefore, spare tube material at the HCCP site was sent to a tube bender so that a better shield fin and weld stud configuration could be incorporated. The original inner baffle tubes were removed and replaced with inner baffle tubes with the improved design.

Slag Tap Dipper Skirt Shield Tube Heat Exchanger Vent and Drain Piping Leaks
Problems occurred in the small bore vent and drain piping of the slag tap dipper skirt shield tubes. In February, the drain piping leaked from a drain valve, which apparently opened during operation. One possible cause is that falling slag opened the ball valve handle on the drain valve. Then, in September, a drain valve was severed from the bottom dipper skirt shield tube heat exchanger header. As a result, all of these drain valves were removed and replaced with a pipe cap.

Small bore (one inch or smaller) vent piping was provided on the upper headers of the dipper skirt shield tube heat exchangers. On several occasions, this piping developed small leaks at the connection to the header pipe it vented. To prevent future vent piping leaks, the vent piping was removed and the connections were plugged. The basis for this was that the average flow velocity (greater than 2 ft/sec) within the four-inch horizontal header pipe would likely sweep sufficient air through the horizontal top header of the shield tube heat exchangers to maintain the water level up to the elevation of the vent connection on the header without a vent. No further problems occurred after these modifications.

Induced Draft Fan Noise
The induced draft (ID) fan at HCCP is audible from locations near the plant, as well as from various locations within the local community. In January, an ID fan inlet silencer was installed into the breeching duct between the ID fan and the stack to reduce the noise levels. The silencer consists of two side by side baffles. The silencer substantially reduced tonal noise.

Restricted Flow through Multi-Media Waste Water Filters (MMWEWF's)
Use of river water, instead of slag ash water, as the makeup source to the dirty waste water tank greatly reduced the rate at which MMWEWF flow became restricted; however, backwash water from the ash water sluice pumps continued to contaminate these filters.

Filtered waste water was adopted as a backwash source. This water is relatively free of silt, since it is the clean product from the MMWEWF's and its pH is already at an acceptable level, as a result of river water being used as the makeup source to the dirty waste water tank.

CO_2 Fire Protection System Test Failures

Multiple full discharge CO_2 tests were attempted on the switchgear room (Zone 13) and the relay (Zone 16) room, during the construction and start-up phases of HCCP. These tests failed to meet the requirements of NFPA 12, which requires the following CO_2 concentrations in these two zones during and after a full discharge of CO_2:

CO_2 Concentration	Time After Discharge
Thirty percent	Three minutes
Fifty percent	Seven minutes
Fifty percent	Twenty minutes

The contractor had attempted to better seal the rooms; however, in subsequent full discharge tests, the required fifty percent concentration was still not maintained in Zone 16 and fifty percent concentration was not achieved in time nor maintained in Zone 13.

In order to pass the test, the following modifications were implemented:

1. Three additional cylinders were headered into the existing bank of cylinders, so that they would only discharge if Zone 13 discharged. A loop header was provided from the three additional cylinders to tie into the discharge end of the original header from the CO_2 cylinder bank to Zone 13. This new loop header significantly reduced head loss between the CO_2 cylinders and the discharge piping in Zone 13. Consequently, nozzle discharge pressure increased, resulting in a more rapid injection of CO_2 into Zone 13 to obtain the required thirty percent concentration within three minutes.
2. Four additional cylinders were headered together to flow through a single orifice sized to provide CO_2 from those cylinders for approximately twenty minutes. The header downstream of the orifice was tied into the existing header piping so that the four additional cylinders would be discharged whenever either Zone 13 or Zone 16 was activated. This extended CO_2 discharge compensated for any leakage of air into the two zones (and the leakage of CO_2 from those zones) after the non-orificed bottles stopped discharging CO_2.
3. Additional sealant was applied to the cable tray penetrations, magnetic sealant strips were installed on the doors, and the cinder block walls were coated with a sealant to better seal the rooms.

Following these changes, full discharge tests were conducted on Zones 13 and 16 and the required concentrations were achieved and maintained for the required amount of time.

Appendix E
HCCP Plant Design Criteria

CONTENTS

<u>SectionTitle</u>

1.0 General Plant Design Criteria

The HCCP combustion technology has been scaled up from 50 to 300 MWe net and is referred to as the Clean Coal (CC) unit. The scaled-up plant is compared economically with competing combustion technologies. A site is selected in the western US at 5,000 ft ASL with four seasons including periods below freezing. The site is located near transmission capacity and a river to take approximately 3,400 gpm for mechanical evaporative cooling of cycle heat rejection. Coal is railed to the site.

1.1 Powder River Basin coal is selected with an ultimate, as-received analysis of:

1.2

	Design	Range
Moisture	30.47 %	21-33%
Carbon	48.44 %	35-50%
Hydrogen	3.22 %	3-4%
Nitrogen	0.64 %	0.5-0.7%
Sulfur	0.37 %	0.2-1.5%
Ash	4.66 %	4-15%
Oxygen	12.20 %	
Total	100.00 %	
HHV	8,175 BTU/lb	7,600 - 8,800

lbs SO_2/million-BTu	0.90
Chlorine mg/kg	625
Hardgrove Index	82.7 @ 30% H2O
Process Density	70 lb/cuft
Structural Density	100 lb/cuft

1.2 Coal is railed to a spur near the site and is dumped then conveyed either to covered storage or to a 60-day storage pile.

1.3 Crushed limestone is railed to the site and pneumatically unloaded into storage silos. Performance limestone as delivered is:

$CaCO_3$	96% average	90-97% range
$MgCO_3$	1%	0.8 - 1.2% range
Inerts	3%	3 - 8% range
Moisture	0.12%	0 - 0.4% range
Total	100%	

Expected lime size distribution - fines definition throughout the range of 95% retained on US sieve 200 mesh through 95% passing US sieve 10 mesh.

1.4 Raw water analysis is river water with total hardness not greater than 500 ppm ($CaCO_3$) and silica concentration not greater than 10 ppm.

1.5 No 2 Fuel oil characteristics are:

Parameter	Units	Minimum	Maximum
Gravity	API deg @ 60 F	30.0	42.0
Viscosity	Kinematic CTS @ 100 F	2.3	5.8
Water & Sediment	% by vol		0.1
Flash Point	deg F, PMCT	125	
Sulfur	% by wt		0.15
Ash	ppm by wt		50
Pour Point	deg F		15
Sodium + Potassium	ppm by wt		1.0
Vanadium	ppm by wt		0.5
Calcium	ppm by wt		2.0
Higher Heating Value	BTu/gal @ 60 F	134,293	
Distillation Temp	90% Point, deg F		650
Carbon Residue	% by wt (10% bottoms)		1.0

Particulates	mg/100 ml		4
Cetane Index		40	
Color			2
Cetane Number		40	
Lead	ppm by wt		1.0
Fuel Bound Nitrogen	% by wt	0.01	0.1

1.6 Process waste water is utilized for scrubber slurry and water is trucked to the landfill to condition ash to meet the landfill requirements. The plant is designed for no process waste water discharge. Cooling tower blowdown is softened for lime slurry makeup water. A small amount of non-reclaimable waste water is evaporated.

1.7 Fly ash is dry-loaded from under a drive-through silo and trucked to a landfill where waste water is mixed with it at the land fill to produce a non-leachable fill. Typical ash characteristics from mineral analyses are:

Constituent, %wt	Typical, %
SiO_2	41.1
AlO	15.1
TiO2	0.6
FeO	5.6
CaO	28.2
MgO	3.0
K2O	1.2
NaO	0.5
SO3	3.2
PO5	0.3
StO	0.2
BaO	0.4
MnO	0.2
Undetermined	0.4
Total	100.0

1.8 Expected fly ash size distribution is: (US Sieve) Cumulative Results

Passing	Retained On	%wt	% Retained	% Passing
----------	20 mesh	0.31	0.31	99.69
20 mesh	40 mesh	2.73	3.04	96.96

40 mesh	60 mesh	14.15	17.19	82.81
60 mesh	100 mesh	18.09	35.28	64.72

100 mesh	200 mesh	24.37	59.65	40.35
200 mesh	325 mesh	34.50	94.14	5.86
325 mesh	pan	5.86	100.00	0.00

1.9 Fly ash density for process design is 35 lb/cuft
Fly ash density for structural design is 100 lb/cuft
Fly ash density for mechanical drive design is 60 lb/cuft
Expected maximum fly ash carbon content is up to 3% by wt

1.10 Bottom ash is sluiced to settling ponds and eventually trucked to a land fill.

1.11 Expected bottom ash size distribution is: (US Sieve)

			Cumulative Results	
Passing	Retained On	%wt	% Retained	% Passing
----------	½ inch	2.55	2.55	97.45
½ inch	4 mesh	35.95	38.50	61.50
4 mesh	10 mesh	27.73	66.23	33.77
10 mesh	20 mesh	18.75	84.98	15.02
20 mesh	40 mesh	8.46	93.45	6.55
40 mesh	60 mesh	2.93	96.38	3.62
60 mesh	100 mesh	1.42	97.80	2.20
100 mesh	200 mesh	1.09	98.89	1.11
200 mesh	pan	1.11	100.00	0.00

1.12 Bottom ash density for process design is 45 lb/cuft
Bottom ash density for structural design is 100 lb/cuft
Expected maximum bottom ash carbon content is up to 3% by wt

1.13 The electrical interface is at the high side bushings of the Generator Step-Up Transformer. The Auxiliary Transformers receive power from the same utility substation as generated power is connected. The Auxiliary Transformers provide power to the plant when the unit is generating.

1.14 80 acres of a relatively flat acreage is available for the fenced sites. Road work consists only of on-site roads.

1.15 The results of dispersion modeling for the actual plant will determine the chimney height. For the purposes of this comparison, the stack height is 460 ft.

1.16 Coal storage pile storm drainage is collected and treated before released to natural drainage off site. A single storm drainage point is formed by grading open channels routed to a low point at the site boundary.

1.17 The following are specifically excluded

Raw water supply and pre-treatment facilities

Landscaping

Security design

Start-up, construction and temporary services

Switchyard design

Details of the Administration Building, maintenance areas, laboratories, warehouse and parking lot

Solid and liquid process waste treatment and disposal and sewage treatment

Site access roads

Truck scales

Railroad to unloading points

SIZE AND TYPE OF PLANT

1.18 The plant generates nominally 300,000 kW net output fired with Powder River Basin coal delivered by unit train. The steam turbine generator (STG) is designed for 345,000 kW, and has a maximum continuous rating equivalent to valves wide open and throttle conditions of 2,400 psig and 1,000 F which corresponds with the MCR rating of the Steam Generators.

1.19 The turbine steam/water cycle consists of seven (7) feedwater heaters including the Deaerator as represented by the Process Flow Diagram - Design Case. Solids and water balances have generated for the design case.

1.20 A single boiler and single STG are supported by auxiliaries with stand-by equipment to support an expected availability of from 65 to 92%.

DESIGN CHANGES

1.21 Design changes made from HCCP to the 300 MWe clean coal plant include:

- Natural circulation for combustor cooling rather than forced circirculation
- Dedicated coal mills for the pre-combustors and slag combustors to eliminate the external coal splitter in the coal feed system
- Primary air fans to replace the exhausters in the coal feed system
- The larger plant takes advantage of reheat to the STG
- Mechanical draft cooling tower to replace the once-through circulating water for cycle heat rejection
- Slag and bottom ash is sluiced and de-watered in ash ponds every 6 months rather than transported by mechanical conveyors to a silo and trucked when the silo is full
- Coal transport via railcar rather than by truck
- Raw water stored in pond rather than in tanks
- No process waste water discharge

1.22 The birds-eye view of all three plants is the same since the differences are inside the Power Building.

LAYOUT CONSIDERATIONS

1.24 The Turbine-Generator in this arrangement has an unit supported steam chest and internally located generator stator coolers. Other available turbine-generators will fit in the same space envelope with minimum adjustments.

1.25 The largest battery load during an emergency is the Emergency Bearing Oil Pump. The Battery Room is located in the turbine lube oil reservoir area.

1.26 The Plant Air Compressors are located in a clean air area so that inlet filter and compressor maintenance is minimized.

1.27 Coal Bunkers and Coal Mills are located on the boiler front and contained in one area to maximize dust control.

1.28 Isles, stairs and an elevator provide the necessary space for operation and life safety. A continuous ground floor drive through the Power Building is provided for equipment access.

1.29 The Control Room with the DCS equipment is located on the operating level above the Electrical Room to minimize wiring between the DCS cabinets and the motor control centers.

1.30 Switchgear is located on the mezzanine for bottom and top entry into cabinets.

1.31 The Auxiliary Boiler and Emergency Diesel Generator are located on the Boiler side of the Power Building and are enclosed separately for safety. Combustion air is conveniently available for both through an outside wall. Fuel oil piping is minimized by location of the tank outside, but near this equipment.

1.32 Lunch and conference rooms, offices, showers, restrooms and water lab are all located within the finished portion of the Power Building and adjacent to the Control Room.

1.33 The Administration Building provides reception, offices, restrooms, warehouse, and mechanical, electrical and instrument maintenance areas.

1.34 A rail spur supplies both coal and lime deliveries. Handling systems are adjacent and can be utilized simultaneously. Coal storage areas and the Crusher Tower are located to accommodate comfortable rises for belt conveyors.

1.35 The direction of the transmission line leaving the site is on the Switchyard side of the plant.

1.36 The direction of the raw water source entering the site is near the Raw Water Reservoir.

1.37 The direction of the off-site land fill for ash disposal is near the Ash Ponds.

1.38 The High Quality, Intermediate Quality and Evaporation Ponds are adjacent to each other to minimize overflow distances.

1.39 The cooling tower is located on the opposite side of the plant from the Switchyard to avoid plume interference with high voltage bushings.

1.40 The cooling tower is located in-line with the Condenser to minimize underground pipe pressure losses.

1.41 The Boiler Makeup Water Treatment area and Condensate Storage Tanks are located to accommodate reagent truck delivery.

1.42 Nitrogen, hydrogen, carbon dioxide, fuel oil, lube oil and fly ash storage areas are located to accommodate easy truck deliveries and pickups.

1.43 Space is allocated on the operating floor for laydown of high pressure shell halves and generator rotor removal.

1.44 Flue gas flow is straight from the boiler through the SDA and Baghouses to the Stack to minimize pressure drops and duct size.

2.0 Steam Generator

2.1 The Steam Generator (Boiler) is fired with pulverized coal and with No 2 fuel oil for ignition and flame stabilization at low loads. Four (4) 33% capacity coal feed trains provide coal to the 16 combustors. Two feed trains feed 8 pre-combustors and two trains feed 8 slag combustors.

COAL FEED

2.2 Coal gravity feeds from its associated coal bunker to a gravimetric belt coal feeder. The bunker is located in the boiler structure and is sized for 12 hours full load operation. The feeder meters coal to its associated pulverizer as signaled by the combustion control system. A pair of nuclear (gamma ray) coal flow monitors are located in the coal chute to detect a loss of the seal above the feeder and to activate a vibrator on the cone bottom of the Coal Bunker to re-establish coal flow.

PULVERIZERS (MILLS)

2.3 Coal is pulverized and dried in four (4) 33% capacity, bowl or ball and race-type Pulverizers. Primary and tempering air provides the transport medium for coal flow to the combustors. Flow and temperature of the coal-air mixture leaving the Pulverizer is controlled by hot air and tempering air dampers. Pyrites and tramp iron are rejected by the Pulverizer and discharged to the wet ash system. The top of the coal mill is equipped with a mechanical, centrifugal classifier adjusted for the desired coal particle size distribution. Each coal mill is equipped with a forced circulation, lube oil conditioning package.

COAL/AIR PIPING AND COMBUSTORS

2.4 The coal-air mixture from each Pulverizer is transport through pipes to the combustors. An isolation gate in the coal-air pipe provides shutoff of the coal.

Combustor location in the furnace walls is clean coal-specific in the side walls with 4 pre and 4 slag combustors per side. Each Pulverizer supplies coal equally to provide balanced firing when bringing Pulverizers into or out of service. The combustor mixes the primary air - coal mixture with secondary air from the burner windbox. Secondary air is introduced in stages by clean coal-specific techniques to reduce maximum flame temperatures thereby reducing the formation of nitrous oxides.

OIL BURNERS AND IGNITERS

2.5 Each oil burner is furnished with an oil igniter which is ignited by a high-energy spark. Warmup oil guns are included to maintain flame stability at low loads. Insert/retract mechanisms are provided to prevent thermal damage to the guns when not in use. Oil is supplied from the fuel oil system. The number of oil burners are the same as the number of Pulverizers.

FURNACE

2.6 The furnace walls consist of water-cooled steam generating tubes. The furnace is designed to accommodate mixing and sufficient resident time for the coal to combust to ash at a higher temperature than its fusion temperature to minimize tube fouling. Water circulates upward through the steam generating tubes into the steam drum and either by natural or forced (pump assisted) circulation through external "downcomers" to the lower water header and back into the steam generating tubes. Saturated steam is mechanically separated in the top of the steam drum and passed into the primary superheater. Ash falls into a wet bottom hopper and discharges to the wet ash system.

SUPERHEATERS

2.7 The primary and secondary superheaters heat the saturated steam to $1,005^0$ F. Superheater tubes are located in the backpass area of the flue gas path in temperature zones for optimum heat transfer. Radiant superheater platens may be located in the top of the furnace to cool flue gas by radiation, however, the majority of the tubes are arranged in banks in the horizontal and vertical convection passes of the unit. Spray attemperators are located in connecting pipe between the primary and secondary superheaters to lower steam temperature as necessary. Auxiliary steam and sootblowing steam is supplied from the primary superheater outlet header. Spray water is supplied from boiler feedwater pump discharge.

REHEATER

2.8 To improve plant efficiency, a bank of reheater tubes is located in the top of the furnace. Cold reheat steam from the last stage of the high pressure turbine passes through the reheater to raise the steam temperature to $1{,}005^0$ F as hot reheat steam, and as the source of steam to the intermediate pressure turbine stages. A spray water attemperator is located in the cold reheat piping to lower steam temperature as necessary. Spray water is supplied from an interstage tap on the feedwater pumps.

ECONOMIZER

2.9 The Economizer removes heat from the flue gas downstream of the superheaters and raises the feedwater temperature leaving the last high pressure feedwater heater before entering the steam drum. Ash collected in the economizer ash hopper discharges into the wet ash system.

COMBUSTION AIR FANS (PAF A, PAF B, FDF A and FDF B)

2.10 Secondary combustion air is furnished by two (2) 50% capacity, variable pitch, axial flow FD Fans and primary combustion air is furnished by two (2) 50% capacity centrifugal PA Fans with inlet vanes for air flow control. The axial fan inlet ducts are equipped with modulating, louvered, reversed bladed dampers to improve the resolution of fan flow control. Each fan inlet is equipped with a silencer and fan outlet with a louvered, isolation damper. Each axial flow fan is equipped with a forced lubrication bearing oil conditioning and hydraulic control package.

GLYCOL-AIR HEATERS

2.11 Combustion air is preheated in three (3) stages as needed to prevent cold-end flue gas duct corrosion due to acid gas precipitation. The degree of heating is dependent upon the sulfur content of the coal. First stage combustion air heating occurs in the glycol air heaters which are finned-tube and wall-mounted in the boiler enclosure walls.

2.12 The heat transfer fluid is generally Dowtherm J or Therminol T-44 which is heated in a steam/glycol, shell and tube heat exchanger. Four (4) 25% capacity heaters are supplied for subfreezing ambient air temperatures and are operated up to 40^0 F. All four heaters heat air to the fan room. The heat exchanger is designed to run dry on the steam side. Heat exchanger discharge air temperature is controlled by steam flow to the heat exchanger. To protect the condensate system from glycol contamination due to tube leakage, condensate is routed to a plant drain when contamination is detected.

2.13 The Glycol Storage Tank and the Glycol Expansion Tank are horizontal, cylinder shell, unfired pressure vessels. The storage tank holds 110% of the contents of the system to accommodate component maintenance. The expansion tank accommodates fluid expansion from minimum ambient air temperature to operating temperature. The expansion tank is designed to allow separation and removal of water from the fluid. Each tank is furnished with a nitrogen blanket to prevent air contact and subsequent oxidation breakdown of the fluid.

2.14 One (1) 100% positive displacement Glycol Transfer Pump fills the system and three (3) 50% single stage, horizontal, centrifugal Glycol Circ Pumps circulate the fluid. All four (4) pumps are furnished with mechanical seals to minimize fluid leakage. Centrifugal pump minimum flow protection is provided with continuous recirculation back to the expansion tank. The transfer pump is furnished with an internal discharge-to-suction relief for pump and system protection.

2.15 Two (2) circ pumps are required for circulating fluid at ambient air temperatures below 10^0 F and one at temperatures above 10^0 F.

2.16 Without second stage air heating the glycol system sufficiently pre-heats air at ambient temperatures above 20^0 F

STEAM COIL HEATERS (PASCH A, PASCH B, SASCH A, SASCH B)

2.17 Second stage combustion air heating occurs in the air steam coil heaters (ASCH) located downstream of each FD and PA Fan for ambient air temperatures between 40^0 and 80^0 F.

2.18 The ASCH is a self-draining, finned tube heat exchanger. Heating steam is supplied either from the auxiliary steam system during start-up or from extraction steam during normal operation. Steam is supplied when the ambient air temperature is lower than 80^0 F. A minimum of 15 psig is maintained in the ASCH system to minimize the potential of freeze damage in case of loss of first stage heating.

2.19 Each ASCH drains to its associated condensate receiver and from there to the drain receiver common to the four (4) ASCHs. Condensate is normally pumped to the Deaerator (DA) from the common receiver by one of two (2) 100% capacity multi-stage, vertical can pumps. On DA high level the condensate is diverted to the main condenser. Condensate may also be routed to the Auxiliary Boiler DA or the Condensate Storage Tanks.

2.20 Set point level is maintained in the common receiver by a control valve on the pump discharge. The individual receivers are vented to the common receiver and the common receiver is pressure set-point controlled through a control valve venting to atmosphere. The common receiver pressure is set-point controlled 5 psig lower than the steam system to allow flow into the receiver. The individual receivers are level controlled to provide a water seal and separate the two different pressure systems.

2.21 Pump minimum flow protection is provided with continuous recirculation back to the common receiver. A water seal is provided to the pump stuffing box to prevent air leakage into the condensate system.

2.22 Without first stage air heating, the ASCH sufficiently pre-heats air at ambient temperatures above -20^0 F. The ASCH must be first placed into service before a fan is started to prevent freezing.

AIR PREHEATERS (PAH A, PAH B, SAH A and SAH B)

2.23 The third stage of combustion air preheating occurs in a Ljungstrom-type, vertical shaft regenerative air heater. These are 100% capacity units and are located downstream of each steam coil air heater and transfer heat from flue gas downstream of the Economizer. This heater rotates horizontally passing first under the flue gas duct to transfer heat to the finned baskets and then above the air duct to transfer the heat to the air. The heater is equipped with a constant speed, electric motor, gear drive and a bearing lubrication system. Ports are furnished into the heater housing for off-line water washing. Heat transfer is entirely dependent upon unit load and basket cleanliness.

PRIMARY AIR

2.24 Primary air transports coal from the mill to the combustors. Both the air and gas sides of the air preheaters are provided with cross-over ducts and motorized gates so that either PA Fan may be used with either air preheater. Outside air passes through the glycol air heaters into the common enclosed FD/PA fan room. Mill tempering air is ducted to each set of two (2) coal mills from PA Fan discharge through a louvered control damper at the mill for transport air temperature control.

SECONDARY AIR

2.25 Combustion air is comprised mostly of secondary air which is admitted at the coal combustors from windboxes and generated by the FD Fans. Both the air and gas sides of the air preheaters are provided with cross-over ducts and motorized gates so that either FD Fan may be used with either air preheater.

INDUCED DRAFT FAN (IDFA and IDFB)

2.26 Two (2) 60% capacity variable pitch, axial flow ID Fans are located downstream of the Baghouse and provide a balanced draft in the furnace. The fan inlet ducts are equipped with modulating, louvered, reversed bladed dampers to improve the resolution of fan flow control. Each fan inlet is equipped with a silencer and fan outlet with a louvered, isolation damper. Each fan is equipped with a forced lubrication bearing oil conditioning and hydraulic control package.

FLUE GAS PATH

2.27 The four (4) absorber vessels are arranged between inlet and outlet plenums with isolation gates so that any one of two on each of the two sets maybe operated.

SOOT BLOWERS

2.28 Soot blowers are furnished to clean fouled tube surfaces. These consist of wall blowers in the furnace, retractable blowers in the radiant and convective reheater, superheater and economizer tube banks and stationary blowers in the air preheaters. Auxiliary steam is the blowing medium. Blowers are electric-motor, gear driven and are programmed to operate sequentially.

COOLING BLOWERS

2.29 Blowers are provided for cooling air to flame scanners and oil burner combustion air, if required.

SLAG AND BOTTOM ASH HOPPERS

2.30 Slag and bottom ash falling into the furnace bottom is collected in wet ash hoppers. The hoppers are supported at grade and the boiler is top supported. Tramp air entry is prevented by a water seal trough, which accommodates the thermal growth differences between the hopper and boiler. The hopper and trough water levels are maintained with raw or process waste water to makeup for losses in evaporation and transport with the slag and ash.

FLY ASH HOPPERS

2.31 Fly ash is collected in hoppers located in the downstream flue gas path and generally at low points in the ducting under the economizer and/or air preheaters. The hoppers are sized for 200% of the expected total ash loading. Fly ash hoppers are insulated and provided with thermostatically controlled electric heaters, vibrators, hammer anvils, air fluidizing pads and poke holes to insure that the flue gas moisture does not precipitate into the ash and that ash that bridges the hopper may be removed on-line.

STEAM TEMPERATURE CONTROL

2.32 Steam temperature control is manufacturer-specific and in addition to spray water attemperation, tilting burners or gas recirculation may be used.

FURNACE SAFETY AND FUEL AUTOMATION

2.33 The control system includes interlocks and permits required by code for safe start-up, operation and shut-down of feeders, mills and coal and oil burners. Start-up and shutdown sequences are manually or automatically supervised. This system is configured in hardware and software compatible with the Distributed Control System (DCS).

3.0 Spray Dryer Absorber

The Spray Dryer Absorber (SDA) description boundaries are:

The discharge end of the expansion joint from the air preheater outlet duct

The discharge end of the expansion joint from the absorber vessel outlet duct

The receivers on top of the Limestone Day Tanks

Water supply to the slurry mixing tanks and saturation water tank

Inlet flanges of the Recycle Bins

Major equipment includes:

4 SDA Vessels

4 SDA Atomizers

4 Absorber Head Tanks

2 Limestone Day Tanks

2 Limestone Day Tank Fluidizing Blowers

2 Limestone Dust Collector Systems

4 Furnace Feeders

2 Recycle Bins

2 FCM Disposal Ejectors

2 FCM Grit Screens

2 Mix Tank Feeders

2 Limestone Weigh Belt Feeders

2 Slurry Mixing Tanks

4 Recycle Slurry Pumps

2 Slurry Feed Tanks

4 Slurry Feed Pumps

1 Saturation Water Tank

2 Saturated Water Pumps

2 Lime Makeup Water Heaters

2 Tower Mills

3.1 The Spray Dryer Absorber is provided to meet the requirements of the air permit in removing acid gases. Atomized FCM slurry mixed with the flue gas in the absorber vessel provides contact, chemical reaction and precipitation of the dry products of reaction into the vessel's hopper. To lower limestone consumption the SDA is provided with recycle of the dry reaction products.

3.2 Four (4) 25% capacity vessel/atomizer trains are furnished so that maintenance can be performed on one train without unit shutdown.

3.3 The limestone handling, FCM preparation systems and SDA are designed to handle coal with up to 1.0 % sulfur content.

LIMESTONE INJECTION AND FCM PREPARATION

3.4 Two (2) 100 % capacity, centrifugal, positive-pressure Limestone Day Tank Blowers provide transport air for the two transfer systems to the two limestone day tanks located in the FCM preparation area. Automatic, air-operated slide-gates are furnished to route lime from either transfer system to either day tank. Each day tank is furnished with a bin vent filter to vent the transport air to atmosphere, pressure safety relief, manway, access ladder and platform, discharge hopper, discharge slide-gate, bin activator, rotary-valve feeder, level indicator and nozzle on the top for manual sounding of tank level.

3.5 Crushed limestone is discharged from the day tank by means of rotary valve feeder, variable-speed, gravimetric belt feeder and pneumatic ejector and introduced into the furnace for calcination.

3.6 FCM is collected by fly ash handling equipment and conveyed to the Recycle Bins. FCM is metered into the Slurry Mixing Tank, pumped to the Tower Mill, passed through a grit screen into the Slurry Feed Tank. A 45% slurry is pumped by the Slurry Feed Pump to the Atomizer Head Tank which feeds slurry to the Atomizer.

3.7 Two (2) 100% capacity slurry preparation trains are provided. Each tower mill is equipped with a classifier (grit screen) and an agitated Slurry Feed Tank with pumps. The grit screen recycles oversized FCM back into the mill.

3.6 Makeup water for FCM preparation is heated with auxiliary steam to maintain 190^0 F temperature. Slurry with the desired particle size gravity flows into the Slurry Feed Tanks and then pumped to the Atomizer Head Tanks. Four (4) 60% capacity horizontal, centrifugal Recycle Slurry Pumps and four (4) 60% capacity Slurry Feed Pumps are provided.

3.7 Each SDA is equipped with an Absorber Head Tank.

3.8 Slurry feed tank level and FCM concentration controls the input of concentrated slurry and dilution water dependent upon the rates of head tank return slurry and recycle solids. Slurry is batch controlled into the Slurry Feed Tank so that the Tower Mill operates at a constant full flow for optimum operation. Level in the Slurry Mixing Tank controls the rate of FCM from the Recycle Bin.

3.9 A dust collector system is provided for the Limestone Day Tanks.

ABSORBER VESSELS AND ATOMIZERS

3.10 The four (4) absorber vessels are arranged between inlet and outlet plenums with isolation gates so that any one of two on each of the two sets maybe operated. Each vessel is equipped with a high-speed atomizer with disc, motor, gear and lubrication system. Layout area, monorail and hoist are provided in the atomizer area to accommodate disc replacement.

3.11 The Absorber Head Tank provides a uniform pressure for flow control of slurry into the atomizer. Head tank level is controlled with excess slurry draining back to the slurry tank.

3.12 The slurry is centrifugally accelerated by disc rotation of about 35,000 rpm and releases the slurry into the swirling flue gas within the absorber vessel. The vessel inlet scroll imparts swirling to the flue gas. The intense energy given to the slurry causes it to separate into many small droplets, exposing a large surface area for flue gas and slurry contact. The sulfur oxides are preferentially absorbed on the surfaces of the droplets to form calcium sulfite and calcium sulfate solids. An excess of slurry is supplied to drive the reaction of sulfur dioxide with calcium hydroxide to form solid calcium sulfite and calcium sulfate. The unreacted calcium oxide is recycled to lower the lime consumption rate.

3.13 Water is also added to the atomizer stream to control SDA flue gas discharge set-point temperature at 30 degrees above saturation. The flow of slurry is controlled by a feed forward from unit load and trimmed by stack SO_2 to a set-point comfortably within the emission limit. If excessive quench water drives the flue gas temperature below adiabatic saturation, the SDA ash hopper diverter dumps ash to waste to avoid plugging the downstream conveyors.

3.14 This design offers no reheat capability. High ambient summer temperature conditions and/or permits with narrow emission limits may require the addition of reheat or an increase in sulfur removal efficiency subject to rigorous dispersion modeling.

3.15 Water from the Saturation Water Tank is pumped through spray nozzles in the vessel to protect the baghouse bags from thermal damage on failure of the air preheater. The pump power is connected to the Emergency Motor Control Center which source is the Diesel-engine Generator.

3.16 Excessive water in the vessel hopper is diverted to waste to prevent the recycle conveyor from plugging with wet reaction products.

4.0 Baghouse

The Baghouse description boundaries are:

Downstream expansion joint flange from the spray dryer absorber ducting

Upstream expansion joint flange to the ID Fans inlet ducting

Major equipment includes:

2 Baghouses

1 Set of Baghouse Ash Hoppers

4.1 The Baghouse provides particulate control to meet the air permit requirements. A baghouse is preferred to an electro-static precipitator for this application and for its high particulate removal efficiency, low power requirements and with operation using relatively low sulfur content coal.

4.2 Two (2) 50% Baghouses are located downstream of the spray dryer absorber and are provided to filter fly ash, spray dryer absorber reaction product and excess FCM using filter bags which are cleaned by the pulse-jet technique. Each baghouse consists of multiple compartments and is equipped with pulse air equipment, poppet valves and controls for bag cleaning. Two are provided to increase plant availability.

4.3 An additional compartment is provided in each baghouse to accommodate full load operation when a compartment is being cleaned. Each compartment can be isolated for the cleaning sequence and for bag replacement.

4.4 Some sulfur dioxide is removed in the Baghouse. The total sulfur removal is based upon the sum of that collected in the spray dryer absorber and the baghouses.

4.5 The bags are coated with FCM before operating any extended period on oil firing. The oil adheres to the lime coating and drops with it during cleaning rather that to stick to the bag surface.

BAGS

4.6 Particulate matter is collected on the exterior surfaces of the filter bags and is periodically removed by pulse-jet air flow to shake the ash off and into the hopper. The compartment for cleaning is isolated from the flue gas entering the compartment during cleaning.

The bags are fabricated from a synthetic fabric such as homoacrylic or polyester material and are arranged for a three (3) bag reach.

In case of an air preheater or spray dryer absorber failure and emergency water quench is applied to protect the bags from thermal damage.

FLY ASH HOPPERS

4.8 Fly ash is collected in hoppers located under each compartment. The hoppers are sized for 200% of the expected total ash loading. Hoppers are insulated and provided with thermostatically controlled electric heaters, impactors, hammer anvils, air fluidizing pads and poke holes to insure that the flue gas moisture does not precipitate into the ash and that ash that bridges the hopper may be removed on-line.

ENCLOSURE

4.9 The top of the baghouse is enclosed for rain and snow protection of the air cleaning valves. The bottom of the baghouse is enclosed for fugitive ash control. Monorails, hoists and trolleys are furnished to accommodate maintenance.

CLEANING CONTROLS

4.10 Cleaning controls are initiated either by timer or by high differential pressure across the compartment. Control hardware and software is compatible with the DCS.

5.0 Limestone Handling

The unloading and storage portion of the system includes all equipment for receiving and handling of crushed limestone from railcars to the Limestone Day Tanks which are part of the FCM preparation system procured with the SDA. Unloading and receiving extends from the railcar outlet hopper adaptors located beneath the track through the outlet nozzles of the Limestone Receiving Tank.

Transfer and storage extends from the Limestone Silo Feeders under the receiving tank to the outlet nozzles of the Limestone Silos. Limestone feed extends from the Limestone Day Tank Feeders under the silos to the inlet nozzles of the Limestone Day Tanks.

Major equipment includes:

1 Limestone Receiving Tank

1 Limestone Tank Vent Filter

2 Limestone Unloading Blowers

2 Limestone Silo Blowers

2 Limestone Silo Feeders

4 Limestone Silos

4 Limestone Silo Bin Activators

4 Limestone Silo Vent Filters

2 Limestone Silo Fluidizing Blowers

2 Limestone Day Tank Blowers

4 Limestone Day Tank Feeders

UNLOADING AND RECEIVING

5.1 Two (2) 100 % capacity negative pressure conveying lines are provided for unloading. Each suction nozzle at the railcar hopper is equipped with an air-operated hopper adapter. Flexible hoses are provided for connecting to the vacuum feed headers.

5.2 Limestone flows from the rail car by gravity assisted by vacuum. Each conveying line is full-load controlled to prevent system pluggage. Conveying air is provided by two (2) 100 % capacity, centrifugal, negative-pressure Limestone Unloading Blowers. Limestone is conveyed through the vacuum feed header by air flow at a velocity and negative pressure sufficient for the tonnage required. Limestone is separated from the air stream in the Limestone Receiving Tank which contains a centrifugal separator and a bin vent filter on top. Limestone enters an air-lock which allows the tank to operate at atmosphere. The tank is vented to atmosphere through the bin vent filter. Transport air is dis-entrained in the air-lock, passes through a filter, through the blower and through a silencer to atmosphere. Blower controls are procured with the blowers.

5.3 Only one of the two unloading systems is operated at a time. The conveying line is purged between connections to the rail car hoppers. Unloading is stopped by blower shut down if for any reason the receiving tank is full. The unloading system control is local and located enclosed near the railroad spur.

5.4 The railcar is initially positioned over the intake hopper by the locomotive engineer. Further movement of the car is accomplished by an operator. After spotting, the railcar is vented and a flex hose connected to the railcar hopper. Mechanical assistance for inducing flow from the railcar may be required.

5.5 The connection between the railcar hopper and flex hose is a pneumatically-operated adaptor controlled by the operator. When the adaptor is connected the hopper discharge gate is opened and unloading proceeds after the silo fill sequence is selected and the unloading blower is started.

5.6 The unloading and receiving system is designed on the basis of one 8-hour operating shift per week after initial inventories are established. Each unloading line is sized to convey lime at 50 tph to minimize the required unloading time.

5.7 The Limestone Receiving Tank is sized to provide a minimum of 15 minutes storage with both unloading systems operating a full capacity.

5.8 The receiving tank and unloading blowers are located not further than 200 ft from the railroad spur.

TRANSFER AND STORAGE

5.9 The Limestone Receiving Tank is equipped with two (2) discharge hoppers to support two transfer systems to the four storage silos. Each hopper is furnished with a discharge slide-gate and rotary-valve feeder. Conveying air is provided by two (2) 100 % capacity, centrifugal, positive-pressure Limestone Silo Blowers. Automatic, air-operated slide-gates are furnished to route lime from either of the transfer systems into any one of the four storage silos.

5.10 Each silo is equipped with a bin vent filter to vent the transport air to atmosphere, silo pressure safety relief, manway, access ladder and platform, discharge hopper, discharge slide-gate, bin activator, rotary-valve feeder, level indicator and nozzle on the top for manual sounding of silo level.

5.11 Only one of the two silo feed systems is operated at a time. The conveying line is purged between silo fills. Unloading is stopped by blower shut down if for any reason when all silos are full. The transfer system control is local and incorporated with the unloading control.

5.12 Each transfer-to-storage line is designed to convey line to the silos at 120 tph.

5.13 Each silo is sized to provide a minimum of 7.5 days supply or 30 days total for the four (4) silos based on a maximum lime demand shown below. A five (5) ft freeboard in the silo is not considered as part of the working volume of the silo. This area allows disentrainment of the transport air from the limestone.

5.14 Silos are designed to ensure mass flow. The discharge hopper has a minimum slope of 70 degrees from horizontal and includes stainless steel liners with a polished finish. Bin activators are furnished to aid in mass flow from the hopper.

5.15 Silo fill control is automatic, with silo fill sequence manually selectable. The fill sequence includes purge of the conveying line after a silo is filled.

5.16 The silos are located near the FCM preparation area.

TRANSFER TO PREPARATION AREA

5.17 The limestone feed system controls the unloading of limestone from the storage silos to insure that adequate limestone is automatically transported to the day tanks.

5.18 Two (2) 100 % capacity, centrifugal, positive-pressure Limestone Day Tank Blowers provide transport air for the two transfer systems to the two day tanks located in the lime preparation area. Automatic, air-operated slide-gates are furnished to route lime from either transfer system to either day tank.

5.19 Only one of the two day tank transfer systems is operated at a time. The conveying line is purged between day tank fills. Unloading is stopped by blower shut down when both day tanks are full. Control is local and incorporated with the unloading and silo fill controls.

5.20 Design limestone feed based on performance coal is 190 tpd. The day tank feed system is designed for 15 tph.

Appendix F
PC Plant Design Criteria

CONTENTS

<u>SectionTitle</u>

1.0 Steam Generator

The Steam Generator description boundaries are:

Coal Bunker inlet flanges

Single point of supply to Fuel Oil Burner Pipe Racks

Ash hopper and pyrites discharge flanges

Inlet of the feedwater stop and check valve at the Economizer

Outlet of the final superheater stop and check valve

Outlet of the hot reheat isolation valve

Inlet of the cold reheat isolation valve

Outlet of the superheat and reheat spray water control valves

Discharge of all vent, drain, sample and continuous blowdown valves

Inlet to FD and PA fans Glycol air heaters

Gas discharge flanges of the Primary and Secondary Air Preheaters

Inlet and discharge flanges of water coolers

Discharges of steam safety valve silencers

The Stack inlet flanges

Major equipment includes:

1	Boiler
4	Coal Bunkers
4	Coal Mills
4	Coal Feeders
4	Oil Burners and Igniters
2	Superheaters (Primary and Secondary)
1	Reheater
1	Economizer
2	Primary Air (PA) Fans
2	Forced Draft (FD) Fans
4	Glycol-Air Heaters
1	Glycol Storage Tank
1	Glycol Expansion Tank
1	Glycol Transfer Pump
2	Glycol Heat Exchangers
2	Glycol Heat Exchanger Drain Tanks
3	Glycol Circ Pumps
2	Air Heater Drain Pumps
1	Air Heater Drain Receiver
4	Air Heater Drain Tanks
2	Primary Air Steam Coil Heaters (PASCH)
2	Secondary Air Steam Coil Heaters (SASCH)

2 Primary Air preheaters (PAH)

2 Secondary Air preheaters (SAH)

2 Induced Draft (ID) Fans

1 Set of Soot Blowers

1 Set of Cooling Blowers

1 Bottom Ash Hopper

1 Set of Fly Ash Hoppers

1 Furnace Safety / Fuel Automation Burner Management System (BMS)

1.1 The Steam Generator (Boiler) is fired with pulverized coal and with No 2 fuel oil for ignition and flame stabilization at low loads. Four (4) 33% capacity coal feed trains provide coal at four (4) elevations in the furnace.

COAL FEED

1.2 Coal gravity feeds from its associated coal bunker to a gravimetric belt coal feeder. The bunker is located in the boiler structure and is sized for 12 hours full load operation. The feeder meters coal to its associated pulverizer as signaled by the combustion control system. A pair of nuclear (gamma ray) coal flow monitors are located in the coal chute to detect a loss of the seal above the feeder and to activate a vibrator on the cone bottom of the Coal Bunker to re-establish coal flow.

PULVERIZERS (MILLS)

1.3 Coal is pulverized and dried in four (4) 33% capacity, bowl or ball and race-type Pulverizers. Primary and tempering air provides the transport medium for coal flow into the furnace. Flow and temperature of the coal-air mixture leaving the Pulverizer is controlled by hot air and tempering air dampers. Pyrites and tramp iron are rejected by the Pulverizer and discharged to the wet ash system. The top of the coal mill is equipped with a mechanical, centrifugal classifier adjusted for the desired coal particle size distribution. Each coal mill is equipped with a forced circulation, lube oil conditioning package.

COAL/AIR PIPING AND BURNERS

1.4 The coal-air mixture from each Pulverizer is transported through a pipe to the burner. An isolation gate in the coal-air pipe provides shutoff of the coal to the furnace. Burner location in the furnace walls is manufacturer-specific and is either in the corner for tangential firing or in the front and rear walls for opposed firing. In both arrangements each Pulverizer supplies coal equally at a furnace elevation to provide balanced firing when bringing Pulverizers into or out of service. The Burner mixes the primary air - coal mixture with secondary air from the burner windbox. Secondary air is introduced in stages by manufacturer-specific techniques to reduce maximum flame temperatures thereby reducing the formation of nitrous oxides.

OIL BURNERS AND IGNITERS

1.5 Each oil burner is furnished with an oil igniter which is ignited by a high-energy spark. Warmup oil guns are included to maintain flame stability at low loads. Insert/retract mechanisms are provided to prevent thermal damage to the guns when not in use. Oil is supplied from the fuel oil system. The number of oil burners may be the same as the number of coal burners and in some designs oil burners are shared with coal burner elevations.

FURNACE

1.6 The furnace walls consist of water-cooled steam generating tubes. The furnace is designed to accommodate mixing and sufficient resident time for the coal to combust to ash at a higher temperature than its fusion temperature to minimize tube fouling. Water circulates upward through the steam generating tubes into the steam drum and either by natural or forced (pump assisted) circulation through external "downcomers" to the lower water header and back into the steam generating tubes. Saturated steam is mechanically separated in the top of the steam drum and passed into the primary superheater. Ash falls into a wet bottom hopper and discharges to the wet ash system.

SUPERHEATERS

1.7 The primary and secondary superheaters heat the saturated steam to $1{,}005^{0}$ F. Superheater tubes are located in the backpass area of the flue gas path in temperature zones for optimum heat transfer. Radiant superheater platens may be located in the top of the furnace to cool flue gas by radiation, however, the majority of the tubes are arranged in banks in the horizontal and vertical convection passes of the unit. Spray attemperators are located in connecting pipe between the primary and secondary superheaters to lower steam temperature as necessary. Auxiliary steam and sootblowing steam is supplied from the primary superheater outlet header. Spray water is supplied from boiler feedwater pump discharge.

REHEATER

1.8 To improve plant efficiency, a bank of reheater tubes is located in the top of the furnace. Cold reheat steam from the last stage of the high pressure turbine passes through the reheater to raise the steam temperature to $1{,}005^0$ F as hot reheat steam and as the source of steam to the intermediate pressure turbine stages. A spray water attemperator is located in the cold reheat piping to lower steam temperature as necessary. Spray water is supplied from an interstage tap on the feedwater pumps.

ECONOMIZER

1.9 The Economizer removes heat from the flue gas downstream of the superheaters and raises the feedwater temperature leaving the last high pressure feedwater heater before entering the steam drum. Ash collected in the economizer ash hopper discharges into the wet ash system.

COMBUSTION AIR FANS (PAF A, PAF B, FDF A and FDF B)

1.10 Secondary combustion air is furnished by two (2) 50% capacity, variable pitch, axial flow FD Fans and primary combustion air is furnished by two (2) 50% capacity centrifugal PA Fans with inlet vanes for air flow control. The axial fan inlet ducts are equipped with modulating, louvered, reversed bladed dampers to improve the resolution of fan flow control. Each fan inlet is equipped with a silencer and fan outlet with a louvered, isolation damper. Each axial flow fan is equipped with a forced lubrication bearing oil conditioning and hydraulic control package.

GLYCOL-AIR HEATERS

1.11 Combustion air is preheated in three (3) stages as needed to prevent cold-end flue gas duct corrosion due to acid gas precipitation. The degree of heating is dependent upon the sulfur content of the coal. First stage combustion air heating occurs in the glycol air heaters which are finned-tube and wall-mounted in the boiler enclosure walls.

1.12 The heat transfer fluid is generally Dowtherm J or Therminol T-44 which is heated in a steam/glycol, shell and tube heat exchanger. Four (4) 25% capacity heaters are supplied for subfreezing ambient air temperatures and are operated up to 40^0 F. All four heaters heat air to the fan room. The heat exchanger is designed to run dry on the steam side. Heat exchanger discharge air temperature is controlled by steam flow to the heat exchanger. To protect the condensate system from glycol contamination due to tube leakage, condensate is routed to a plant drain when contamination is detected.

1.13 The Glycol Storage Tank and the Glycol Expansion Tank are horizontal, cylinder shell, unfired pressure vessels. The storage tank holds 110% of the contents of the system to accommodate component maintenance. The expansion tank accommodates fluid expansion from minimum ambient air temperature to operating temperature. The expansion tank is designed to allow separation and removal of water from the fluid. Each tank is furnished with a nitrogen blanket to prevent air contact and subsequent oxidation breakdown of the fluid.

1.14 One (1) 100% positive displacement Glycol Transfer Pump fills the system and three (3) 50% single stage, horizontal, centrifugal Glycol Circ Pumps circulate the fluid. All four (4) pumps are furnished with mechanical seals to minimize fluid leakage. Centrifugal pump minimum flow protection is provided with continuous recirculation back to the expansion tank. The transfer pump is furnished with an internal discharge-to-suction relief for pump and system protection.

1.15 Two (2) circ pumps are required for circulating fluid at ambient air temperatures below 10^0 F and one at temperatures above 10^0 F.

1.16 Without second stage air heating the glycol system sufficiently pre-heats air at ambient temperatures above 20^0 F.

STEAM COIL HEATERS (PASCH A, PASCH B, SASCH A, SASCH B)

1.17 Second stage combustion air heating occurs in the air steam coil heaters (ASCH) located downstream of each FD and PA Fan for ambient air temperatures between 40^0 and 80^0 F.

1.18 The ASCH is a self-draining, finned tube heat exchanger. Heating steam is supplied either from the auxiliary steam system during start-up or from extraction steam during normal operation. Steam is supplied when the ambient air temperature is lower than 80^0 F. A minimum of 15 psig is maintained in the ASCH system to minimize the potential of freeze damage in case of loss of first stage heating.

1.19 Each ASCH drains to its associated condensate receiver and from there to the drain receiver common to the four (4) ASCHs. Condensate is normally pumped to the DA from the common receiver by one of two (2) 100% capacity multi-stage, vertical can pumps. On DA high level the condensate is diverted to the main condenser. Condensate may also be routed to the Auxiliary Boiler DA or the Condensate Storage Tanks.

1.20 Set point level is maintained in the common receiver by a control valve on the pump discharge. The individual receivers are vented to the common receiver and the common receiver is pressure set-point controlled through a control valve venting to atmosphere. The common receiver pressure is set-point controlled 5 psig lower than the steam system to allow flow into the receiver. The individual receivers are level controlled to provide a water seal and separate the two different pressure systems

1.21 Pump minimum flow protection is provided with continuous recirculation back to the common receiver. A water seal is provided to the pump stuffing box to prevent air leakage into the condensate system.

1.22 Without first stage air heating, the ASCH sufficiently pre-heats air at ambient temperatures above -20^0 F. The ASCH must be first placed into service before a fan is started to prevent freezing.

AIR PREHEATERS (PAH A, PAH B, SAH A and SAH B)

1.23 The third stage of combustion air preheating occurs in a Ljungstrom-type, vertical shaft regenerative air heater. These are 100% capacity units and are located downstream of each steam coil air heater and transfer heat from flue gas downstream of the Economizer. This heater rotates horizontally passing first under the flue gas duct to transfer heat to the finned baskets and then above the air duct to transfer the heat to the air. The heater is equipped with a constant speed, electric motor, gear drive and a bearing lubrication system. Ports are furnished into the heater housing for off-line water washing. Heat transfer is entirely dependent upon unit load and basket cleanliness.

PRIMARY AIR

1.24 Primary air transports coal from the mill to the furnace. Both the air and gas sides of the air preheaters are provided with cross-over ducts and motorized gates so that either PA Fan may be used with either air preheater. Outside air passes through the glycol air heaters into the common enclosed FD/PA fan room. Mill tempering air is ducted to each set of two (2) coal mills from PA Fan discharge through a louvered control damper at the mill for transport air temperature control.

SECONDARY AIR

1.25 Combustion air is comprised mostly of secondary air which is admitted at the coal burner from the windbox and generated by the FD Fans. Both the air and gas sides of the air preheaters are provided with cross-over ducts and motorized gates so that either FD Fan may be used with either air preheater.

INDUCED DRAFT FAN (IDFA and IDFB)

1.26 Two (2) 50% capacity variable pitch, axial flow ID Fans are located downstream of the Baghouse and provide a balanced draft in the furnace. The fan inlet ducts are equipped with modulating, louvered, reversed bladed dampers to improve the resolution of fan flow control. Each fan inlet is equipped with a silencer and fan outlet with a louvered, isolation damper. Each fan is equipped with a forced lubrication bearing oil conditioning and hydraulic control package.

FLUE GAS PATH

1.27 The four (4) absorber vessels are arranged between inlet and outlet plenums with isolation gates so that any one of two on each of the two sets maybe operated.

SOOT BLOWERS

1.28 Soot blowers are furnished to clean fouled tube surfaces. These consist of wall blowers in the furnace, retractable blowers in the radiant and convective reheater, superheater and economizer tube banks and stationary blowers in the air preheaters. Auxiliary steam is the blowing medium. Blowers are electric-motor, gear driven and are programmed to operate sequentially.

COOLING BLOWERS

1.29 Blowers are provided for cooling air to flame scanners and oil burner combustion air, if required.

BOTTOM ASH HOPPER

1.30 Ash falling into the furnace bottom is collected in a wet ash hopper. The hopper is supported at grade and the boiler is top supported. Tramp air entry is prevented by a water seal trough which accommodates the thermal growth differences between the hopper and boiler. The hopper and trough water levels are maintained with raw or process waste water to makeup for losses in evaporation and transport with the ash.

FLY ASH HOPPERS

1.31 Fly ash is collected in hoppers located in the downstream flue gas path and generally at low points in the ducting under the economizer and/or air preheaters. The hoppers are sized for 200% of the expected total ash loading. Fly ash hoppers are insulated and provided with thermostatically controlled electric heaters, vibrators, hammer anvils, air fluidizing pads and poke holes to insure that the flue gas moisture does not precipitate into the ash and that ash that bridges the hopper may be removed on-line.

STEAM TEMPERATURE CONTROL

1.32 Steam temperature control is manufacturer-specific and in addition to spray water attemperation, tilting burners or gas recirculation may be used.

FURNACE SAFETY AND FUEL AUTOMATION

1.33 The control system includes interlocks and permits required by code for safe start-up, operation and shutdown of feeders, mills and coal and oil burners. Start-up and shutdown sequences are manually or automatically supervised. This system is configured in hardware and software compatible with the DCS.

2.0 Spray Dryer Absorbers

The Spray Dryer Absorber (SDA) description boundaries are:

The discharge end of the expansion joint from the air preheater outlet duct

The discharge end of the expansion joint from the absorber vessel outlet duct

The receivers on top of the Lime Day Tanks

Water supply to the slakers and saturation water tank

Discharge flange of the ash hopper

Major equipment includes:

4 SDA Vessels

4 SDA Atomizers

4 Absorber Head Tanks

2 Lime Day Tanks

2 Lime Day Tank Fluidizing Blowers

2 Lime Dust Collector Systems

2 Ball Mill Slakers

2 Lime Grit Screens

2 Lime Slaker Feeders

2 Lime Weigh Belt Feeders

2 Lime Concentrate Tanks

2 Lime Concentrate Pumps

2 Lime Slurry Tanks

2 Lime Slurry Pumps

1 Saturation Water Tank

2 Saturated Water Pumps

2 Lime Makeup Water Heaters

2.1 The Spray Dryer Absorber is provided to meet the requirements of the air permit in removing acid gases. Atomized lime slurry mixed with the flue gas in the absorber vessel provides contact, chemical reaction and precipitation of the dry products of reaction into the vessel's hopper. To lower lime consumption the SDA is provided with recycle of the dry reaction products.

2.2 Four (4) 25% capacity vessel/atomizer trains are furnished so that maintenance can be performed on one train without unit shutdown.

2.3 The lime handling and preparation systems and SDA are designed to handle coal with up to 1.0 % sulfur content.

LIME PREPARATION

2.4 Two (2) 100 % capacity, centrifugal, positive-pressure Lime Day Tank Blowers provide transport air for the two transfer systems to the two lime day tanks located in the lime preparation area. Automatic, air-operated slide-gates are furnished to route lime from either transfer system to either day tank. Each day tank is furnished with a bin vent filter to vent the transport air to atmosphere, pressure safety relief, manway, access ladder and platform, discharge hopper, discharge slide-gate, bin activator, rotary-valve feeder, level indicator and nozzle on the top for manual sounding of tank level.

2.5 Pebble lime is discharged from the Lime Day Tanks to a wet ball mill slaker by means of a variable-speed, gravimetric belt feeder. Two (2) 100% capacity ball mill/slakers are provided. Each ball mill is equipped with a classifier (grit screen) and an agitated lime concentrate tank with pumps. The grit screen recycles oversized pebbles back into the ball mill.

2.6 Makeup water to the slaker is heated with auxiliary steam to maintain 190^0 F slaking temperature. Slurry with the desired particle size gravity flows into and Lime Concentrate Tanks and then pumped into a Lime Slurry Tank. Two (2) 100% capacity horizontal, centrifugal Lime Concentrate pumps and two (2) 100% capacity Lime Slurry Tanks are provided.

2.7 The concentrated slurry is diluted with lime softener effluent water and mixed in the Lime Slurry Tank. The slurry is pumped to the top of the absorber vessel into the Absorber Head Tank. Two (2) 100% capacity horizontal, centrifugal Lime Slurry pumps and each SDA is equipped with an Absorber Head Tank.

2.8 Slurry tank level and lime concentration controls the input of concentrated slurry and dilution water dependent upon the rates of head tank return slurry and recycle solids. Slurry is batch controlled into the Lime Slurry Tank so that the slaker operates at a constant full flow for optimum operation. Level in the Concentrated Slurry Tank controls the rate of pebble lime into the mill/slaker.

2.9 A dust collector system is provided for the Lime Day Tanks.

ABSORBER VESSELS AND ATOMIZERS

2.10 The four (4) absorber vessels are arranged between inlet and outlet plenums with isolation gates so that any one of two on each of the two sets maybe operated. Each vessel is equipped with a high-speed atomizer with disc, motor, gear and lubrication system. Layout area, monorail and hoist are provided in the atomizer area to accommodate disc replacement.

2.11 The Absorber Head Tank provides a uniform pressure for flow control of slurry into the atomizer. Head tank level is controlled with excess slurry draining back to the slurry tank.

2.12 The slurry is centrifugally accelerated by disc rotation of about 35,000 rpm and releases the slurry into the swirling flue gas within the absorber vessel. The vessel inlet scroll imparts swirling to the flue gas. The intense energy given to the slurry causes it to separate into many small droplets, exposing a large surface area for flue gas and slurry contact. The sulfur oxides are preferentially absorbed on the surfaces of the droplets to form calcium sulfite and calcium sulfate solids. An excess of slurry is supplied to drive the reaction of sulfur dioxide with calcium hydroxide to form solid calcium sulfite and calcium sulfate. The unreacted calcium oxide is recycled to lower the lime consumption rate.

2.13 Water is also added to the atomizer stream to control SDA flue gas discharge set-point temperature at 30^0 above saturation. The flow of slurry is controlled by a feedforward from unit load and trimmed by stack SO_2 to a set-point comfortably within the emission limit. If excessive quench water drives the flue gas temperature below adiabatic saturation, the SDA ash hopper diverter dumps ash to waste to avoid plugging the downstream equipment.

2.14 This design offers no reheat capability. High ambient summer temperature conditions and/or permits with narrow emission limits may require the addition of reheat or an increase in sulfur removal efficiency subject to rigorous dispersion modeling.

2.15 Water from the Saturation Water Tank is pumped through spray nozzles in the vessel to protect the baghouse bags from thermal damage on failure of the air preheater. The pump power is connected to the Emergency Motor Control Center which source is the Diesel-engine Generator.

2.16 Excessive water in the vessel hopper is diverted to waste to prevent the recycle conveyor from plugging with wet reaction products.

2.17 Pebble lime is railed to the site and pneumatically unloaded into storage silos. Performance lime is ¾ in minus as delivered with:

CaO	90% average	88-94% range
MgO	5%	3 - 5
Inerts	5%	5 - 9
Total	100%	

Expected lime size distribution - fines definition throughout the range of 95% retained on US sieve 200 mesh through 95% passing US sieve 10 mesh.

3.0 Ash Handling

The Ash Handling description boundaries are:

Outlet flange of Bottom and Fly Ash Hoppers

Outlet telescopic chute of Fly Ash Silo

Discharge from Bottom Ash Sluice flexible, floating pipe in the Ash Pond

Inlet of ash recycle water pipe in Ash Pond

Ash Water Tank makeup water inlet nozzle

Major equipment includes:

1 Fly Ash Silo

3 Fly Ash Blowers

2 Ash Receiver/Filters

1 Fly Ash Silo Bin Vent

1 Ash Unloading Dust Blower

1 Ash Unloading Spout

1 Ash Fluidizing Blower

3 Clinker Grinders

3 Ash Jet Pumps

1 Ash Water Tank

2 Ash Water Makeup Pumps

2 Ash Sluice Pumps

2 Ash Water Recirc Pumps

2 Ash Water Sump Pumps

1 Ash Water Settling Tank

2 Ash Settling Sludge Pumps

2 Ash Pond Screens

2 Ash Sluice Strainers

3.1 Ash is defined as the coal ash, unburned carbon, lime inerts and SDA reaction products. Coal fly ash is expected to be 80% of the total coal ash. Fly ash is collected pneumatically by a vacuum system, stored in a 3-day silo and trucked back to the coal mine. It may used as impervious line materials for the on-site ponds. It may also be sold to seal mine shafts, if the mine is underground.

3.2 Bottom ash passes from the hopper through a clinker grinder and is sluiced to the Ash Pond. The sluice water is recycled for water conservation. Two 6 month Ash Ponds are constructed so that while one is settling ash, the other has been emptied and ready for alternate use when the operating pond is full. Bottom ash is trucked back to the coal mine.

3.3 Ash ponds are lined with a two (2) foot depth of mixtures of fly ash, lime and cement to meet permeability requirements of $< / = 10^{-7}$ cm/s.

FLY ASH HANDLING

3.4 Fly ash is transported pneumatically in a dilute phase vacuum system to a storage silo and trucked dry to the minefill.

3.5 Three (3) 50% positive displacement blowers produce the vacuum. The blowers are equipped with inlet and outlet silencers and an inlet filter and are enclosed in an insulated, walk-in enclosure.

3.6 Each collection point is furnished with an air cylinder-operated gate. The ends of each collection line are equipped with air inlet check valves. Conveying pipe elbows are erosion-resistant wearbacks which can be turned around for extended use and easily replaced.

3.7 The Fly Ash Silo is sized for 5 days storage and is elevated for drive-through, dry, top truck loading. A pulse-jet baghouse disentrains transport air from ash and the air is vented to atmosphere. The baghouse is provided at 200% capacity of the expanded transport air. A lock hopper arrangement on top of the silo equalizes the vacuum to ambient air pressure within the silo. The lock hopper gates are air cylinder operated slide-type. The silo is equipped with a bin activator, air cylinder-operated, slide-type, discharge gate and telescopic chute with truck operator pendant unloading controls. A fluidizing system is installed under the silo consisting of two (2) fluidizing stones located inside the silo, two (2) 100% capacity fluidizing blowers, silencers and filters. Fly ash level is monitoring on the DCS and fly ash handling equipment is controlled in the DCS.

BOTTOM ASH HANDLING

3.8 Long-term bottom ash storage for the model was selected primarily for its low capital and operating costs and proven operability. De-watering bins and daily trucking will be considered if site space is limited or if environmental impacts result in prohibiting the use of ash ponds.

3.9 Bottom ash is collected wet, passed through grinders and sluiced to the Ash Pond. Two (2) 100 % redundant systems are furnished from the Bottom Ash Hopper to the Ash Ponds.

3.10 The Bottom Ash Hopper (provided with the Boiler) is refractory insulated and designed for gravity feed through two (2) 100% capacity discharge cones. The hopper is equipped with flush nozzles, pressurized lancing doors, air cylinder-operated discharge gates and a seal trough. The discharge gates are equipped with pressure lancing and access doors. The seal trough is designed to isolate the negative furnace pressure conditions throughout the range of boiler thermal growth.

3.11 Three (3) 200% capacity, double roll-type Clinker Grinders are located on the discharges of the bottom ash hopper to reduce slag size to 2.5 inch minus. Work-hardened, manganese teeth are cast onto the crusher rolls so that when they are worn may be built up to original size at the plant with readily available weld rod. The grinders are equipped with slag discharge openings for material that the grinder can't handle. This material is collected in a bin for manual removal.

3.12 From the discharge of the grinder, ash drops into the Ash Jet Pumps and is sluiced to the Ash Pond with high pressure, high flow ash water. A flexible, floatable line is installed on the sluice line discharge to allow consistent depth placement of ash into the pond.

3.13 The ash ponds are adjacent to each other and are U-shaped to accommodate short runs of both sluice and recycle piping. The ponds are mirror-imaged to accommodate a common wet pit for location of the Ash Water Recirc Pumps. The U-shape also provides maximum retention time for settling between sluice discharge and recirculation water pump suction.

3.14 The ash ponds are diked with excavation material to minimize both fill and disposal requirements.

3.15 To conserve water, sluice, cooling and ash seal water is recycled from the Ash Pond to the Ash Water Settling Tank and then to the Ash Water Tank for reuse.

3.16 Two (2) 100% capacity, horizontal, centrifugal Ash Sluice Pumps take suction from the Ash Water Tank and provide the sluice and seal water supply.

3.17 Two (2) 100% capacity, vertical, centrifugal Ash Makeup Water Pumps located in a wet pit at the ponds provide the head to pump makeup water to the Ash Water Tank and to the bottom ash hopper seal trough. Pump operation is set-point range controlled by level in the Ash Water Tank.

3.18 Two (2) 100% capacity vertical, centrifugal Ash Water Recirc Pumps located in a wet pit at the Ash Pond pump the recycled water back to the Ash Settling Tank. Settled water is decanted and gravity flows into the Ash Water Sump and is pumped into the Ash Water Tank. When a pond is nearly full of ash, recirculating water is pulled from the other pond.

3.19 At the pond settled, near-surface water is decanted into the wet pit through fixed, dual screens. Pump seals are flushed with potable water. The wet pit is designed for sludge removal to prevent plugging the pump suction screens.

3.20 The ash water equipment is located in the Ash Pumphouse.

3.21 Bottom ash conveying is monitored and controlled in the DCS.

3.22 The bottom ash hopper is designed with 3 compartments sloped a minimum of 40 degrees to the horizontal and 18 inches of water above the ash design capacity. The water depth insures that water to cool and shatter ash effectively.

3.23 The bottom ash hopper is a steel, refractory-lined, rectangular, free-standing hopper fitting the shape of the bottom of the furnace. Boiler thermal growth is accommodated in the seal trough filled with water which isolates the slightly negative pressure in the furnace during operation.

3.24 The hopper walls above normal water level are constantly exposed to radiant heat. To minimize refractory spalling, the hopper walls above the water line are constantly cooled by a curtain of water around the hopper perimeter. The seal trough is fabricated in 10 foot sections. Each section is supplied with water separately from the Ash Sump Pumps. The internal side of the trough provides a weir for the seal water to curtain the hopper sides with water at a rate of 2 gpm per lineal foot of hopper wall. Each section is also supplied with a drain nozzle and shutoff valve for use in lengthy maintenance outages.

3.25 All parts of the bottom ash hopper except structural supports are fabricated with stainless steel.

3.26 During pulling of bottom ash, the seal system is given a high flow rate flush of 8 gpm per lineal hopper ft. Flushing is required to avoid buildup of ash in the seal trough/cooling system, which would result in uneven cooling and subsequent refractory spalling.

3.27 The three (3) hopper discharge gates are 2 x 2 ft. As each section of the hopper is emptied the sloped walls are flushed with 100 psig ash water through slope nozzles to move material that failed to fall by gravity.

3.28 The 3 compartments are sequentially emptied either by complete compartment emptying or by maintaining a compartment water level during the emptying process. Both methods have merit and a method would be selected during detailed design. In either case, the sluice line is flushed before and after each compartment emptying process.

3.29 The Ash Water Tank is sized to hold 3 days supply in addition to the system fill volume. For pump protection, dual screens with backwash capability are provided in the tank discharge line. Dependent upon ash chemical composition, acid may be required to be added to minimize pipe scaling or caustic added to minimize pipe corrosion. These chemicals are added into the Ash Water Tank from the chemical teed pumps.

3.30 The sluice system is designed for 100 tph with short operation 3 times a day. This is based on emptying the bottom ash hopper at an ash density of 45 lb/cuft (50 % voids in the ash), 8 fps sluice pipe velocity and a 3-compartment hopper with an ash storage capacity of 12 hours. This results in sluice pump design at 1,950 gpm and 350 psig discharge pressure with the sluice lines less than 1,000 ft in length, 10 inch diameter pipe and a jet-pump efficiency of 35 %.

3.31 Jet-pump minimum throat diameter is 3 times the size of the largest ash particle through the clinker grinder. This minimizes the possibility of wedging ash in the pump throat.

3.32 Sluice piping is routed above ground so that it can be rotated to extend pipe life. Ash flows on the bottom of the sluice pipe and this is where most of the erosion takes place. Pipe can be rotated 3 times. Victolic-type couplings are used to join sections of pipe to accommodate rotation. Erosion-resistant, wear-back fittings are used. Routing is designed to minimize turns. Sluice piping is located in a trench to permit vehicular traffic around the Power Building.

3.33 Sluice pipe material is alloy cast iron. During freezing weather a constant low flow of water is run through the pipe to prevent freezing. The sluice lines flow water continuously to prevent oxidation corrosion. The slide gate at the pond is partially open for freeze prevention flow.

3.34 The settling tank in the ash water recirculation system is designed to settle solids out down to less than 1,000 ppm of suspended solids to minimize pump wear. Sludge is removed continuously during recirculation operation from the settling tank and is pumped back to the pond.

3.35 The settling tank discharge weir is sized for a 2 gpm/sqft of active surface area. The hopper cone is 45 degrees from the horizontal to promote gravity flow of sludge for discharge.

3.36 Abrasion resistant materials are used in all ash water pump applications.

MILL PYRITES

3.37 The rock content of this coal does not justify automatic, sluicing of mill pyrites. Mill pyrites are collected into a wheelbarrow for manual transport to a truck for disposal.

4.0 Pebble Lime Handling

The unloading and storage portion of the system includes all equipment for receiving and handling of dry pebble lime from railcars to the Lime Day Tanks which are part of the lime preparation system procured with the SDA. Unloading and receiving extends from the railcar outlet hopper adaptors located beneath the track through the outlet nozzles of the Lime Receiving Tank. Transfer and storage extends from the Lime Silo Feeders under the receiving tank to the outlet nozzles of the Lime Silos. Lime feed extends from the Lime Day Tank Feeders under the silos to the inlet nozzles of the Lime Day Tanks.

Major equipment includes:

1 Lime Receiving Tank

1 Lime Tank Vent Filter

2 Lime Unloading Blowers

2 Lime Silo Blowers

2 Lime Silo Feeders

4 Lime Silos

4 Lime Silo Bin Activators

4 Lime Silo Vent Filters

2 Lime Silo Fluidizing Blowers

2 Lime Day Tank Blowers

4 Lime Day Tank Feeders

UNLOADING AND RECEIVING

4.1 Two (2) 100 % capacity negative pressure conveying lines are provided for unloading. Each suction nozzle at the railcar hopper is equipped with an air-operated hopper adapter. Flexible hoses are provided for connecting to the vacuum feed headers.

4.2 Lime flows from the rail car by gravity assisted by vacuum. Each conveying line is full-load controlled to prevent system pluggage. Conveying air is provided by two (2) 100 % capacity, centrifugal, negative-pressure Lime Unloading Blowers. Lime is conveyed through the vacuum feed header by air flow at a velocity and negative pressure sufficient for the tonnage required. Lime is separated from the air stream in the Lime Receiving Tank which contains a centrifugal separator and a bin vent filter on top. Lime enters an air-lock which allows the tank to operate at atmosphere. The tank is vented to atmosphere through the bin vent filter. Transport air is dis-entrained in the air-lock, passes through a filter, through the blower and through a silencer to atmosphere. Blower controls are procured with the blowers.

4.3 Only one of the two unloading systems is operated at a time. The conveying line is purged between connections to the rail car hoppers. Unloading is stopped by blower shut down if for any reason the receiving tank is full. The unloading system control is local and located enclosed near the railroad spur.

4.4 The railcar is initially positioned over the intake hopper by the locomotive engineer. Further movement of the car is accomplished by an operator. After spotting, the railcar is vented and a flex hose connected to the railcar hopper. Mechanical assistance for inducing flow from the railcar may be required.

4.5 The connection between the railcar hopper and flex hose is a pneumatically-operated adaptor controlled by the operator. When the adaptor is connected the hopper discharge gate is opened and unloading proceeds after the silo fill sequence is selected and the unloading blower is started.

4.6 The unloading and receiving system is designed on the basis of one 8-hour operating shift per week after initial inventories are established. Each unloading line is sized to convey lime at 50 tph to minimize the required unloading time.

4.7 The Lime Receiving Tank is sized to provide a minimum of 15 minutes storage with both unloading systems operating a full capacity.

4.8 The receiving tank and unloading blowers are located not further than 200 ft from the railroad spur.

TRANSFER AND STORAGE

4.9 The Lime Receiving Tank is equipped with two (2) discharge hoppers to support two transfer systems to the four storage silos. Each hopper is furnished with a discharge slide-gate and rotary-valve feeder. Conveying air is provided by two (2) 100 % capacity, centrifugal, positive-pressure Lime Silo Blowers. Automatic, air-operated slide-gates are furnished to route lime from either of the transfer systems into any one of the four storage silos.

4.10 Each silo is equipped with a bin vent filter to vent the transport air to atmosphere, silo pressure safety relief, manway, access ladder and platform, discharge hopper, discharge slide-gate, bin activator, rotary-valve feeder, level indicator and nozzle on the top for manual sounding of silo level.

4.11 Only one of the two silo feed systems is operated at a time. The conveying line is purged between silo fills. Unloading is stopped by blower shutdown if for any reason when all silos are full. The transfer system control is local and incorporated with the unloading control.

4.12 Each transfer-to-storage line is designed to convey line to the silos at 120 tph.

4.13 Each silo is sized to provide a minimum of 7.5 days supply or 30 days total for the four (4) silos based on a maximum lime demand shown below. A five ft. freeboard in the silo is not considered as part of the working volume of the silo. This area allows disentrainment of the transport air from the lime.

4.14 Silos are designed to ensure mass flow. The discharge hopper has a minimum slope of 70 degrees from horizontal and includes stainless steel liners with a polished finish. Bin activators are furnished to aid in mass flow from the hopper.

4.15 Silo fill control is automatic, with silo fill sequence manually selectable. The fill sequence includes purge of the conveying line after a silo is filled.

4.16 The lime silos are located near the lime preparation area.

TRANSFER TO PREPARATION AREA

4.17 The lime feed system controls the unloading of lime from the storage silos to insure that adequate lime is automatically transported to the day tanks.

4.18 Two (2) 100 % capacity, centrifugal, positive-pressure Lime Day Tank Blowers provide transport air for the two transfer systems to the two lime day tanks located in the lime preparation area. Automatic, air-operated slide-gates are furnished to route lime from either transfer system to either day tank.

4.19 Only one of the two-day tank transfer systems is operated at a time. The conveying line is purged between day tank fills. Unloading is stopped by blower shut down when both day tanks are full. Control are local and incorporated with the unloading and silo fill controls.

4.20 The day tank feed system is designed for 15 tph.

Appendix G
CFB Plant Design Criteria

CONTENTS

<u>SectionTitle</u>

1.0 Steam Generator

The Steam Generator description boundaries are:

Coal Bunker inlet flanges

Single point of supply to Fuel Oil Burner Pipe Racks

Ash hopper and pyrites discharge flanges

Inlet of the feedwater stop and check valve at the Economizer

Outlet of the final superheater stop and check valve

Outlet of the hot reheat isolation valve

Inlet of the cold reheat isolation valve

Outlet of the superheat and reheat spray water control valves

Discharge of all vent, drain, sample and continuous blowdown valves

Inlet to PA, SA and CT fan silencers

Gas discharge flanges of the Primary and Secondary Air Preheaters

Inlet and discharge flanges of water coolers

Discharges of steam safety valve silencers

The Stack inlet flanges

Major equipment includes:

2	Boilers with each consisting of:	
	2	Coal Bunkers
	2	Coal Mills
	2	Coal Feeders
	2	Oil Burners and Igniters
	2	Cyclones
	2	Classifiers
	2	Superheaters (Primary and Secondary)
	1	Reheater
	1	Economizer
	1	Primary Air (PA) Fan
	1	Coal Transport (CT) Fan
	1	Secondary Air (SA) Fan
	2	Fluid Seal Blowers
	1	Primary Air Steam Coil Heater (PASCH)
	1	Coal Transport Steam Coil Heater (CTSCH)
	1	Primary Air preheater (PAH)
	1	Coal Transport Air preheater (CAH)
	1	Induced Draft (ID) Fan
	1	Set of Soot Blowers
	1	Set of Cooling Blowers
	3	Bed Ash Hoppers

1 Set of Fly Ash Hoppers

1 Furnace Safety / Fuel Automation (Burner Management System) (BMS)

4 Glycol-Air Heaters

1 Glycol Storage Tank

1 Glycol Expansion Tank

1 Glycol Transfer Pump

2 Glycol Heat Exchangers

2 Glycol Heat Exchanger Drain Tanks

3 Glycol Circ Pumps

2 Air Heater Drain Pumps

1 Air Heater Drain Receiver

4 Air Heater Drain Tanks

1.1 The Steam Generators (Boilers) are fired with crushed coal (1/4 in minus) and with No. 2 fuel oil for ignition and flame stabilization at low loads. Two (2) 67% capacity coal feed trains provide coal at ports in the furnace front for each unit.

COAL FEED

1.2 Coal gravity feeds from its associated coal bunker to a gravimetric belt coal feeder. The bunker is located in the boiler structure and is sized for 12 hours full load operation. The feeder meters coal to its associated pulverizer as signaled by the combustion control system. A pair of nuclear (gamma ray) coal flow monitors are located in the coal chute to detect a loss of the seal above the feeder and to activate a vibrator on the cone bottom of the Coal Bunker to re-establish coal flow.

COAL MILLS

1.3 For each unit, coal is pulverized and dried in two (4) 67% capacity, bowl or ball and race-type Coal Mills. Coal transport and tempering air provides the transport medium for coal flow into the furnace. Flow and temperature of the coal-air mixture leaving the mill is controlled by hot air and tempering air dampers. Pyrites and tramp iron are rejected by the mill and discharged to the wet ash system. The top of the coal mill is equipped with a mechanical, centrifugal classifier adjusted for the desired coal particle size distribution. Each coal mill is equipped with a forced circulation, lube oil conditioning package.

COAL/AIR PIPING AND BURNERS

1.4 The coal-air mixture from each mill is transported through a pipe to the furnace coal ports. An isolation gate in the coal-air pipe provides shutoff of the coal to the furnace. Coal ports location in the furnace walls is manufacturer-specific and is normally in the front wall. Each coal mill supplies coal equally to the coal ports to provide balanced firing when bringing mills into or out of service. Secondary air is introduced near the top of the bed. In addition to the circulating flow in the cyclones, bed material circulates in the classifiers to improve sulfur capture and to classify bed ash.

OIL BURNERS AND IGNITERS

1.5 Each oil burner is furnished with an oil igniter which is ignited by a high-energy spark. Warmup oil guns are included to maintain flame stability at low loads. Insert/retract mechanisms are provided to prevent thermal damage to the guns when not in use. Oil is supplied from the fuel oil system. The number of oil burners may be the same as the number of coal burners and in some designs oil burners are shared with coal burner elevations.

FURNACE

1.6 The furnace walls consist of water-cooled steam generating tubes. The furnace is designed to accommodate mixing and sufficient resident time for the coal to combust to ash at a higher temperature than its fusion temperature to minimize tube fouling. Water circulates upward through the steam generating tubes into the steam drum and by natural circulation through external "downcomers" to the lower water header and back into the steam generating tubes. Saturated steam is mechanically separated in the top of the steam drum and passed into the primary superheater. Bed ash falls into a wet bottom hopper and discharges to the wet ash system.

SUPERHEATERS

1.7 The primary and secondary superheaters heat the saturated steam to 1005^0 F. Superheater tubes are located in the backpass area of the flue gas path in temperature zones for optimum heat transfer. Radiant superheater platens may be located in the top of the furnace to cool flue gas by radiation, however, the majority of the tubes are arranged in banks in the horizontal and vertical convection passes of the unit. Spray attemperators are located in connecting pipe between the primary and secondary superheaters to lower steam temperature as necessary. Auxiliary steam and sootblowing steam is supplied from the primary superheater outlet header. Spray water is supplied from boiler feedwater pump discharge.

REHEATER

1.8 To improve plant efficiency, a bank of reheater tubes is located in the top of the furnace. Cold reheat steam from the last stage of the high pressure turbine passes through the reheater to raise the steam temperature to 1005^0 F as hot reheat steam and as the source of steam to the intermediate pressure turbine stages. A spray water attemperator is located in the cold reheat piping to lower steam temperature as necessary. Spray water is supplied from an interstage tap on the feedwater pumps.

ECONOMIZER

1.9 The Economizer removes heat from the flue gas downstream of the superheaters and raises the feedwater temperature leaving the last high pressure feedwater heater before entering the steam drum. Ash collected in the economizer ash hopper discharges into the wet ash system.

COMBUSTION AIR FANS (PAF 1, PAF 2, SAF 1 and SAF 2)

1.10 For each unit, primary combustion air is furnished by a 100% capacity, variable pitch, axial flow PA Fan. The PA Fan provides fluidizing air under the bed. The axial fan inlet duct is equipped with a modulating, louvered, reversed bladed damper to improve the resolution of fan flow control. The fan inlet is equipped with a silencer and fan outlet with a louvered, isolation damper. The axial flow fan is equipped with a forced lubrication bearing oil conditioning and hydraulic control package.

1.11 Secondary air is furnished by a 100% capacity centrifugal SA Fan with inlet vanes for airflow control. This air is admitted near the top of the bed.

1.12 Fluid seal blowers are located at the bottom of each cyclone to assist in the circulation of material from the cyclones to the furnace.

COAL TRANSPORT AIR

1.13 For each unit, coal transport air is furnished by a 100% capacity centrifugal CT Fan with inlet vanes for airflow control. Outside air passes through the glycol air heaters into the common enclosed fan room. Mill tempering air is ducted to each set of two (2) coal mills from CT Fan discharge through a louvered control damper at the mill for transport air temperature control.

GLYCOL-AIR HEATERS

1.14 Combustion air is preheated in three (3) stages as needed to prevent cold-end flue gas duct corrosion due to acid gas precipitation. The degree of heating is dependent upon the sulfur content of the coal. First stage combustion air heating occurs in the glycol air heaters, which are finned-tube and wall-mounted in the boiler enclosure walls.

1.15 The heat transfer fluid is generally Dowtherm J or Therminol T-44 which is heated in a steam/glycol, shell and tube heat exchanger. Four (4) 25% capacity heaters are supplied for subfreezing ambient air temperatures and are operated up to 40^0 F. All four heaters heat air to the fan room. The heat exchanger is designed to run dry on the steam side. Heat exchanger discharge air temperature is controlled by steam flow to the heat exchanger. To protect the condensate system from glycol contamination due to tube leakage, condensate is routed to a plant drain when contamination is detected.

1.16 The Glycol Storage Tank and the Glycol Expansion Tank are horizontal, cylinder shell, unfired pressure vessels. The storage tank holds 110% of the contents of the system to accommodate component maintenance. The expansion tank accommodates fluid expansion from minimum ambient air temperature to operating temperature. The expansion tank is designed to allow separation and removal of water from the fluid. Each tank is furnished with a nitrogen blanket to prevent air contact and subsequent oxidation breakdown of the fluid.

1.17 One (1) 100% positive displacement Glycol Transfer Pump fills the system and three (3) 50% single stage, horizontal, centrifugal Glycol Circ Pumps circulate the fluid. All four (4) pumps are furnished with mechanical seals to minimize fluid leakage. Centrifugal pump minimum flow protection is provided with continuous recirculation back to the expansion tank. The transfer pump is furnished with an internal discharge-to-suction relief for pump and system protection.

1.18 Two (2) circ pumps are required for circulating fluid at ambient air temperatures below 10^0 F and one at temperatures above 10^0 F.

1.19 Without second stage air heating the glycol system sufficiently pre-heats air at ambient temperatures above 20^0 F

STEAM COIL HEATERS (PASCH 1, PASCH 2, CTSCH 1, CTSCH 2)

1.20 Second stage combustion air heating occurs in the air steam coil heaters (ASCH) located downstream of each PA and CT Fan for ambient air temperatures between 40^0 and 80^0 F.

1.21 The ASCH is a self-draining, finned tube heat exchanger. Heating steam is supplied either from the auxiliary steam system during start-up or from extraction steam during normal operation. Steam is supplied when the ambient air temperature is lower than 80^0

F. A minimum of 15 psig is maintained in the ASCH system to minimize the potential of freeze damage in case of loss of first stage heating.

1.22 Each ASCH drains to its associated condensate receiver and from there to the drain receiver common to the four (4) ASCHs. Condensate is normally pumped to the DA from the common receiver by one of two (2) 100% capacity multi-stage, vertical can pumps. On DA high level the condensate is diverted to the main condenser. Condensate may also be routed to the Auxiliary Boiler DA or the Condensate Storage Tanks.

1.23 Set point level is maintained in the common receiver by a control valve on the pump discharge. The individual receivers are vented to the common receiver and the common receiver is pressure set-point controlled through a control valve venting to atmosphere. The common receiver pressure is set-point controlled 5 psig lower than the steam system to allow flow into the receiver. The individual receivers are level controlled to provide a water seal and separate the two different pressure systems.

1.24 Pump minimum flow protection is provided with continuous recirculation back to the common receiver. A water seal is provided to the pump stuffing box to prevent air leakage into the condensate system.

1.25 Without first stage air heating, the ASCH sufficiently pre-heats air at ambient temperatures above -20^{0} F. The ASCH must be first placed into service before a fan is started to prevent freezing.

AIR PREHEATERS (PAH 1, PAH 2, CTH 1 and CTH 2)

1.26 The third stage of combustion air preheating occurs in a Ljungstrom-type, vertical shaft regenerative air heater. These are 100% capacity units and are located downstream of each steam coil air heater and transfer heat from flue gas downstream of the Economizer. This heater rotates horizontally passing first under the flue gas duct to transfer heat to the finned baskets and then above the air duct to transfer the heat to the air. The heater is equipped with a constant speed, electric motor, gear drive and a bearing lubrication system. Ports are furnished into the heater housing for off-line water washing. Heat transfer is entirely dependent upon unit load and basket cleanliness.

INDUCED DRAFT FAN (IDF1 and IDF 2)

1.27 For each unit, a 100% capacity variable pitch, axial flow ID Fan is located downstream of the Baghouse and provides a balanced draft in the furnace. The fan inlet duct is equipped with modulating, louvered, reversed bladed damper to improve the resolution of fan flow control. The fan inlet is equipped with a silencer and fan outlet with a louvered, isolation damper. The fan is equipped with a forced lubrication bearing oil conditioning and hydraulic control package.

SOOT BLOWERS

1.28 Soot blowers are furnished to clean fouled tube surfaces. These consist of wall blowers in the furnace, retractable blowers in the radiant and convective reheater, superheater and economizer tube banks and stationary blowers in the air preheaters. Auxiliary steam is the blowing medium. Blowers are electric-motor, gear driven, and are programmed to operate sequentially.

COOLING BLOWERS

1.29 Blowers are provided for cooling air to flame scanners and oil burner combustion air, if required.

BED ASH HOPPERS

1.30 Classified bed ash drains from three (3) ports in bottom of the furnace and is collected in a wet ash hoppers. The hopper is supported at grade and the boiler is top supported. Tramp air entry is prevented by a water seal trough, which accommodates the thermal growth differences between the hopper and boiler. The hopper and trough water levels are maintained with raw or process waste water to makeup for losses in evaporation and transport with the ash.

FLY ASH HOPPERS

1.31 Fly ash is collected in hoppers located in the downstream flue gas path and generally at low points in the ducting under the economizer and/or air preheaters. The hoppers are sized for 200% of the expected total ash loading. Fly ash hoppers are insulated and provided with thermostatically controlled electric heaters, vibrators, hammer anvils, air fluidizing pads and poke holes to insure that the flue gas moisture does not precipitate into the ash and that ash that bridges the hopper may be removed on-line.

STEAM TEMPERATURE CONTROL

1.32 Steam temperature control is manufacturer-specific and in addition to spray water attemperation, tilting burners or gas recirculation may be used.

FURNACE SAFETY AND FUEL AUTOMATION

1.33 The control system includes interlocks and permits required by code for safe start-up, operation and shutdown of feeders, mills, and coal and oil burners. Start-up and shutdown sequences are manually or automatically supervised. This system is configured in hardware and software compatible with the DCS.

2.0 Ash Handling

The Ash Handling description boundaries are:

Outlet flange of Bed and Fly Ash Hoppers

Outlet telescopic chute of Fly Ash Silo

Discharge from Bottom Ash Sluice flexible, floating pipe in the Ash Pond

Inlet of ash recycle water pipe in Ash Pond

Ash Water Tank makeup water inlet nozzle

Major equipment includes:

1	Fly Ash Silo
3	Fly Aash Blowers
2	Ash Receiver/Filters
1	Fly Ash Silo Bin Vent
1	Ash Unloading Dust Blower
1	Ash Unloading Spout
1	Ash Fluidizing Blower
3	Clinker Grinders
3	Ash Jet Pumps
1	Ash Water Tank
2	Ash Water Makeup Pumps
2	Ash Sluice Pumps
2	Ash Water Recirc Pumps
2	Ash Water Sump Pumps
1	Ash Water Settling Tank
2	Ash Settling Sludge Pumps

2 Ash Pond Screens

2 Ash Sluice Strainers

2.1 Ash is defined as the coal ash, unburned carbon, limestone inerts and sulfur reaction products. Coal fly ash is expected to be 50% of the total coal ash. Fly ash is collected pneumatically by a vacuum system, stored in a 3-day silo and trucked back to the coal mine. It may used as impervious line materials for the on-site ponds. It may also be sold to seal mine shafts, if the mine is underground.

2.2 Bed ash passes from the hopper through a clinker grinder and is sluiced to the Ash Pond. The sluice water is recycled for water conservation. Two 6 month Ash Ponds are constructed so that while one is settling ash, the other has been emptied and ready for alternate use when the operating pond is full. Bed ash is trucked back to the coal mine.

2.3 Ash ponds are lined with a two (2) foot depth of mixtures of fly ash, lime and cement to meet permeability requirements of $< / = 10^{-7}$ cm/s.

FLY ASH HANDLING

2.4 Fly ash is transported pneumatically in a dilute phase vacuum system to a storage silo and trucked dry to the minefill.

2.5 Three (3) 50% positive displacement blowers produce the vacuum. The blowers are equipped with inlet and outlet silencers and an inlet filter and are enclosed in an insulated, walk-in enclosure.

2.6 Each collection point is furnished with an air cylinder-operated gate. The ends of each collection line are equipped with air inlet check valves. Conveying pipe elbows are erosion-resistant wearbacks which can be turned around for extended use and easily replaced.

2.7 The Fly Ash Silo is sized for 5 days storage and is elevated for drive-through, dry, top truck loading. A pulse-jet baghouse disentrains transport air from ash and the air is vented to atmosphere. The baghouse is provided at 200% capacity of the expanded transport air. A lock hopper arrangement on top of the silo equalizes the vacuum to ambient air pressure within the silo. The lock hopper gates are air cylinder operated slide-type. The silo is equipped with a bin activator, air cylinder-operated, slide-type, discharge gate and telescopic chute with truck operator pendant unloading controls. A fluidizing system is installed under the silo consisting of two (2) fluidizing stones located inside the silo, two (2) 100% capacity fluidizing blowers, silencers and filters. Fly ash level is monitoring on the DCS and fly ash handling equipment is controlled in the DCS.

BED ASH HANDLING

2.8 Long-term bed ash storage for the model was selected primarily for its low capital and operating costs and proven operability. De-watering bins and daily trucking will be considered if site space is limited or if environmental impacts result in prohibiting the use of ash ponds.

2.9 Bed ash is collected wet, passed through grinders and sluiced to the Ash Pond. Two (2) 100 % redundant systems are furnished from the Bed Ash Hoppers to the Ash Ponds.

2.10 The Bed Ash Hoppers are refractory insulated and designed for gravity feed through two (2) 100% capacity discharge cones. The hoppers are equipped with flush nozzles, pressurized lancing doors, air cylinder-operated discharge gates and a seal trough. The discharge gates are equipped with pressure lancing and access doors. The seal trough is designed to isolate the negative furnace pressure conditions throughout the range of boiler thermal growth.

2.11 Three (3) 200% capacity, double roll-type Clinker Grinders are located on the discharges of the bottom ash hopper to reduce slag size to 2.5 inch minus. Work-hardened, manganese teeth are cast onto the crusher rolls so that when they are worn may be built up to original size at the plant with readily available weld rod. The grinders are equipped with slag discharge openings for material that the grinder can't handle. This material is collected in a bin for manual removal.

2.12 From the discharge of the grinder, ash drops into the Ash Jet Pumps and is sluiced to the Ash Pond with high pressure, high flow ash water. A flexible, floatable line is installed on the sluice line discharge to allow consistent depth placement of ash into the pond.

2.13 The ash ponds are adjacent to each other and are U-shaped to accommodate short runs of both sluice and recycle piping. The ponds are mirror-imaged to accommodate a common wet pit for location of the Ash Water Recirc Pumps. The U-shape also provides maximum retention time for settling between sluice discharge and recirculation water pump suction.

2.14 The ash ponds are diked with excavation material to minimize both fill and disposal requirements.

2.15 To conserve water, sluice, cooling and ash seal water is recycled from the Ash Pond to the Ash Water Settling Tank and then to the Ash Water Tank for reuse.

2.16 Two (2) 100% capacity, horizontal, centrifugal Ash Sluice Pumps take suction from the Ash Water Tank and provide the sluice and seal water supply.

2.17 Two (2) 100% capacity, vertical, centrifugal Ash Makeup Water Pumps located in a wet pit at the ponds provide the head to pump makeup water to the Ash Water Tank and to the bottom ash hopper seal trough. Pump operation is set-point range controlled by level in the Ash Water Tank.

2.18 Two (2) 100% capacity vertical, centrifugal Ash Water Recirc Pumps located in a wet pit at the Ash Pond pump the recycled water back to the Ash Settling Tank. Settled water is decanted and gravity flows into the Ash Water Sump and is pumped into the Ash Water Tank. When a pond is nearly full of ash, recirculating water is pulled from the other pond.

2.19 At the pond settled, near-surface water is decanted into the wet pit through a fixed, dual screen. Pump seals are flushed with potable water. The wet pit is designed for sludge removal to prevent plugging the pump suction screens.

2.20 The ash water equipment is located in the Ash Pumphouse.

2.21 Bed ash conveying is monitored and controlled in the DCS. Fly ash handling is control by a PLC supplied with the equipment.

2.22 The bed ash hopper is designed with walls sloped a minimum of 40 degrees to the horizontal and 18 inches of water above the ash design capacity. The water depth insures that water to cool and shatter ash effectively.

2.23 The bed ash hopper is a steel, refractory-lined, rectangular, free-standing hopper fitting the shape of the bottom of the furnace. Boiler thermal growth is accommodated in the seal trough filled with water which isolates the slightly negative pressure in the furnace during operation.

2.24 All parts of the bottom ash hopper except structural supports are fabricated with stainless steel.

2.25 During pulling of bed ash, the seal system is given a high flow rate flush of 8 gpm per lineal hopper ft. Flushing is required to avoid build up of ash in the seal trough/cooling system which would result in uneven cooling and subsequent refractory spalling.

2.26 The three (3) hopper discharge gates are 2 x 2 ft. As each section of the hopper is emptied the sloped walls are flushed with 100 psig ash water through slope nozzles to move material that failed to fall by gravity.

2.27 The Ash Water Tank is sized to hold 3 days supply in addition to the system fill volume. For pump protection, dual screens with backwash capability are provided in the tank discharge line. Dependent upon ash chemical composition, acid may be required to be added to minimize pipe scaling or caustic added to minimize pipe corrosion. These chemicals are added into the Ash Water Tank from the chemical feed pumps.

2.28 The sluice system is designed for 100 tph with short operation 3 times a day. This is based on emptying the bottom ash hopper at an ash density of 45 lb/cuft (50 % voids in the ash), 8 fps sluice pipe velocity and a 3-compartment hopper with an ash storage capacity of 12 hours. This results in sluice pump design at 1,950 gpm and 350 psig discharge pressure with the sluice lines less than 1,000 ft in length, 10 inch diameter pipe and a jet-pump efficiency of 35 %.

2.29 Jet-pump minimum throat diameter is 3 times the size of the largest ash particle through the clinker grinder. This minimizes the possibility of wedging ash in the pump throat.

2.30 Sluice piping is routed above ground so that it can be rotated to extend pipe life. Ash flows on the bottom of the sluice pipe and this is where most of the erosion takes place. Pipe can be rotated 3 times. Victolic-type couplings are used to join sections of pipe to accommodate rotation. Erosion-resistant, wear-back fittings are used. Routing is designed to minimize turns. Sluice piping is located in a trench to permit vehicular traffic around the Power Building.

2.31 Sluice pipe material is alloy cast iron. During freezing weather a constant low flow of water is run through the pipe to prevent freezing. The sluice lines flow water continuously to prevent oxidation corrosion. The slide gate at the pond is partially open for freeze prevention flow.

2.32 The settling tank in the ash water recirculation system is designed to settle solids out down to less than 1,000 ppm of suspended solids to minimize pump wear. Sludge is removed continuously during recirculation operation from the settling tank and is pumped back to the pond.

2.33 The settling tank discharge weir is sized for a 2 gpm/sqft of active surface area. The hopper cone is 45 degrees from the horizontal to promote gravity flow of sludge for discharge.

2.34 Abrasion resistant materials are used in all ash water pump applications.

MILL PYRITES

2.35 The rock content of this coal does not justify automatic, sluicing of mill pyrites. Mill pyrites are collected into a wheelbarrow for manual transport to a truck for disposal.

3.0 Limestone Handling

The unloading and storage portion of the system includes all equipment for receiving and handling of crushed limestone from railcars to the Limestone Day Tanks. Unloading and receiving extends from the railcar outlet hopper adaptors located beneath the track through the outlet nozzles of the Limestone Receiving Tank. Transfer and storage extends from the Limestone Silo Feeders under the receiving tank to the outlet nozzles of the Limestone Silos. Limestone feed extends from the Limestone Day Tank Feeders under the silos to the inlet nozzles of the Limestone Day Tanks.

Major equipment includes:

1 Limestone Receiving Tank

1 Limestone Tank Vent Filter

2 Limestone Unloading Blowers

2 Limestone Silo Blowers

2 Limestone Silo Feeders

4 Limestone Silos

4 Limestone Silo Bin Activators

4 Limestone Silo Vent Filters

2 Limestone Silo Fluidizing Blowers

2 Limestone Day Tank Blowers

4 Limestone Day Tank Feeders

4 Limestone Blowers

UNLOADING AND RECEIVING

3.1 Two (2) 100 % capacity negative pressure conveying lines are provided for unloading. Each suction nozzle at the railcar hopper is equipped with an air-operated hopper adapter. Flexible hoses are provided for connecting to the vacuum feed headers.

3.2 Limestone flows from the rail car by gravity assisted by vacuum. Each conveying line is full-load controlled to prevent system pluggage. Conveying air is provided by two (2) 100 % capacity, centrifugal, negative-pressure Limestone Unloading Blowers. Limestone is conveyed through the vacuum feed header by air flow at a velocity and negative pressure sufficient for the tonnage required. Limestone is separated from the air stream in the Limestone Receiving Tank which contains a centrifugal separator and a bin vent filter on top. Limestone enters an air-lock which allows the tank to operate at atmosphere. The tank is vented to atmosphere through the bin vent filter. Transport air is dis-entrained in the air-lock, passes through a filter, through the blower and through a silencer to atmosphere. Blower controls are procured with the blowers.

3.3 Only one of the two unloading systems is operated at a time. The conveying line is purged between connections to the rail car hoppers. Unloading is stopped by blower shut down if for any reason the receiving tank is full. The unloading system control is local and located enclosed near the railroad spur.

3.4 The railcar is initially positioned over the intake hopper by the locomotive engineer. Further movement of the car is accomplished by an operator. After spotting, the railcar is vented and a flex hose connected to the railcar hopper. Mechanical assistance for inducing flow from the railcar may be required.

3.5 The connection between the railcar hopper and flex hose is a pneumatically-operated adaptor controlled by the operator. When the adaptor is connected the hopper discharge gate is opened and unloading proceeds after the silo fill sequence is selected and the unloading blower is started.

3.6 The unloading and receiving system is designed on the basis of one 8-hour operating shift per week after initial inventories are established. Each unloading line is sized to convey lime at 50 tph to minimize the required unloading time.

3.7 The Limestone Receiving Tank is sized to provide a minimum of 15 minutes storage with both unloading systems operating a full capacity.

3.8 The receiving tank and unloading blowers are located not further than 200 ft from the railroad spur.

TRANSFER AND STORAGE

3.9 The Limestone Receiving Tank is equipped with two (2) discharge hoppers to support two transfer systems to the four storage silos. Each hopper is furnished with a discharge slide-gate and rotary-valve feeder. Conveying air is provided by two (2) 100 % capacity, centrifugal, positive-pressure Limestone Silo Blowers. Automatic, air-operated slide-gates are furnished to route lime from either of the transfer systems into any one of the four storage silos.

3.10 Each silo is equipped with a bin vent filter to vent the transport air to atmosphere, silo pressure safety relief, manway, access ladder and platform, discharge hopper, discharge slide-gate, bin activator, rotary-valve feeder, level indicator and nozzle on the top for manual sounding of silo level.

3.11 Only one of the two silo feed systems is operated at a time. The conveying line is purged between silo fills. Unloading is stopped by blower shut down if for any reason when all silos are full. The transfer system control is local and incorporated with the unloading control.

3.12 Each transfer-to-storage line is designed to convey line to the silos at 120 tph.

3.13 Each silo is sized to provide a minimum of 7.5 days supply or 30 days total for the four (4) silos based on a maximum lime demand shown below. A five (5) ft freeboard in the silo is not considered as part of the working volume of the silo. This area allows disentrainment of the transport air from the limestone.

3.14 Silos are designed to ensure mass flow. The discharge hopper has a minimum slope of 70 degrees from horizontal and includes stainless steel liners with a polished finish. Bin activators are furnished to aid in mass flow from the hopper.

3.15 Silo fill control is automatic, with silo fill sequence manually selectable. The fill sequence includes purge of the conveying line after a silo is filled.

3.16 The silos are located near the boiler area.

TRANSFER TO PREPARATION AREA

3.17 The limestone feed system controls the unloading of limestone from the storage silos to insure that adequate limestone is automatically transported to the day tanks.

3.18 Two (2) 100 % capacity, centrifugal, positive-pressure Limestone Day Tank Blowers provide transport air for the two transfer systems to the two day tanks located in the lime preparation area. Automatic, air-operated slide-gates are furnished to route lime from either transfer system to either day tank.

3.19 Only one of the two day tank transfer systems is operated at a time. The conveying line is purged between day tank fills. Unloading is stopped by blower shut down when both day tanks are full. Controls are local and incorporated with the unloading and silo fill controls.

3.20 Design limestone feed based on performance coal is 190 tpd. The day tank feed system is designed for 15 tph.

Each unit is furnished with two (2) 60% capacity Limestone Blowers in acoustical and weather-proof enclosures for transporting limestone from the day tanks into the boilers. Flow dividers are furnished to equalize flow to the ports in the furnace.