APPLICANTS' EXHIBIT 24

SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

CASE NO. EL05-022

IN THE MATTER OF THE APPLICATION BY OTTER TAIL POWER COMPANY

ON BEHALF OF THE BIG STONE II CO-OWNERS

FOR AN ENERGY CONVERSION FACILITY SITING PERMIT FOR THE

CONSTRUCTION OF THE BIG STONE II PROJECT

DIRECT TESTIMONY

OF

STEPHEN J. GOSOROSKI, P.E.

PROJECT MANAGER

BURNS & MCDONNELL ENGINEERING COMPANY

MARCH 15, 2006

BIG STONE II

PARTNERS IN GENERATION

TESTIMONY OF STEPHEN J. GOSOROSKI, P.E.

TABLE OF CONTENTS

BEFORE THE SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

DIRECT TESTIMONY OF STEPHEN J. GOSOROSKI, P.E.

I. INTRODUCTION

Q: Please state your name and business address.

A: Stephen (Steve) J. Gosoroski, P.E., Burns & McDonnell Engineering Company, 9400 Ward Parkway, Kansas City, MO, 64114.

Q: By whom are you employed, and in what capacity?

A: I am employed by Burns & McDonnell Engineering Co. Currently, I am a Project Manager for the company's Energy Division.

Q: What are your responsibilities in your current position?

A: I am responsible for overseeing the design and engineering execution of projects where I am assigned as the Project Manager.

Q: What is your educational background?

A: I have a Bachelors Degree in Mechanical Engineering from the University of Missouri-Columbia, and an MBA Degree from the University of Missouri-Kansas City. I am a Professional Engineer with 29 years of experience as an engineering consultant with Burns & McDonnell.

Q: What is your employment history?

A: I was a design engineer in the Mechanical Department of the Energy Division for ten years and worked on the design of several coal fired plants during that time. I served as Assistant Project Manager for a period of five years before becoming the Project Manager, and have served in the role of Project Manager for a period of fourteen years on several coal and natural gas projects for the Energy Division.

II. PHASE I REPORT

Q: What is the Phase I Report?

A: The Phase I Report is a report prepared by Burns & McDonnell in July 2005 entitiled "Phase I Report Big Stone Unit II." The existing Big Stone station in South Dakota is a nominal 450 megawatt (MW) coal-fired generating plant owned by Otter Tail Power Company, Northwestern Energy (formerly Northwestern Public Service Company), and Montana-Dakota Utilities. These owners and other utility companies undertook a screening analysis of potential generation alternatives that is outlined in the testimony of Mr. Mark Rolfes of Otter Tail Power Company. Following and as part of the screening analysis, Burns & McDonnell was engaged to prepare the Phase I Report on Big Stone Unit II.

The Phase I Report provided a conceptual basis for estimating costs of different generation alternatives that were evaluated in an economic analysis. The Burns & McDonnell Phase I Report on Big Stone Unit II dated July 2005 is included as Applicants' Exhibit 24-A.

Q: What is the objective of the Phase I Report?

A: The objective of the Phase I Report was to evaluate the feasibility of adding an additional generation unit (Unit II) to the existing station site from both quantitative and qualitative perspectives. The Phase I Report developed comparative capital costs, operating costs, performance, and emissions characteristics of different generation alternatives for the existing Big Stone site. The Phase I Report also included a quantitative economic evaluation of the life-cycle capital and operating costs of the different generation alternatives.

Q: What were your responsibilities for the Phase I Report on Big Stone Unit II completed by Burns & McDonnell in July 2005?

A: I was the Project Manager for the Phase I Report. As such, I was responsible for the overall report preparation.

Q: What generation alternatives were considered in the Phase I Report on Big Stone Unit II?

A: Initially, nine generation alternatives were identified: (1) 600 MW supercritical PC unit, (2) 450 MW supercritical PC unit, (3) 300 MW subcritical PC unit, (4) 600 MW subcritical circulating fluidized bed (CFB) unit, (5) 450 MW subcritical CFB unit, (6) 300 MW subcritical CFB unit, (7) 500 MW Combined Cycle Gas Turbine (CCGT) unit, (8) 550 MW Integrated Gasification Combined Cycle (IGCC) unit, and (9) 250 MW wind turbines. The IGCC alternative and wind alternative were considered initially, but were not recommended based on an initial technology assessment of these alternatives. The remaining seven generation alternatives were evaluated in more detail in the Phase I Report.

Q: What was the conclusion of the Phase I Report on Big Stone Unit II?

A: The Phase I Report concluded that a 600 MW supercritical pulverized coal (PC) plant represented the lowest cost generation alternative of the technologies evaluated for the Big Stone station site on a life-cycle basis considering capital and operating costs.

Q: Why was wind not included in this Phase I study?

A: The Phase I Report noted that wind is among the most common and economically viable renewable resource technologies employed in the Upper Midwest region. However, the Phase I Report was limited to generation alternatives that could provide firm baseload capacity and energy, and could be located at the Big Stone station. Wind resources did not meet either criterion for purposes of this study. Wind resources are not dispatchable and do not have expected capacity factors that are reliable to meet baseload energy requirements. In addition, installation of wind turbines at the Big Stone station would not take advantage of existing infrastructure at the site. The existing investment in the site would not be optimized with the installation of wind turbines at this location.

Q: Why was IGCC not included in this Phase I Report?

A: IGCC is a developing technology in the power generation industry. While coal gasification in the chemical or process industry is established, the recent history of coal gasification integrated with combustion turbine and combined cycle technology in the US has experienced technical and operating reliability issues. There were five IGCC demonstration projects developed in the US with Department of Energy (DOE) funding assistance in the 1980's and 1990's. Today, only two of those facilities remain in operation. Availability and reliability of these existing IGCC facilities have improved in recent years after initial poor performance, and the next generation of IGCC plants is expected to incorporate design changes and redundancy to achieve higher availability and reliability performance. There are several proposed IGCC facilities in development and the major technology suppliers are investing resources to bring the next generation of the technology to the marketplace. Burns & McDonnell is currently engaged as the design engineer on one of the proposed IGCC facilities. However, at this time, IGCC technology is not commercially proven.

A second important factor is the fuel feedstock for IGCC. Neither of the current operating IGCC facilities in the US utilizes subbituminous coal from the Powder River Basin

(PRB). PRB coal is the fuel used at the Big Stone station and is the preferred fuel for any new coal-fired resource located at the site. The majority of current IGCC facilities in development are planning on the use of bituminous coals. Research is continuing into the use of PRB fuel in gasification applications. Southern Company, for instance, one of the country's largest utilities, recently secured DOE funding for an IGCC demonstration project using PRB fuel in a new gasification technology.

Finally, Burns & McDonnell estimated in the Phase I Report that IGCC has a cost premium of 10 to 15 percent compared to a similar size pulverized coal unit, and no schedule advantage compared to proven coal generation technologies. The permitting and construction timeframes are similar. Overall, IGCC technology was not recommended in the Phase I Report due to its lack of commercial development at this time, lack of demonstrated ability to utilize PRB fuel, and cost premium compared to proven technologies.

Q: Explain the basic difference between supercritical and subcritical plants?

A: Subcritical power plants utilize pressures below the critical point of water. The critical point of water, the point at which there is no difference in the density of water and steam, occurs at 3,208 psi and 704.5 °F. The majority of the steam generators built in the US utilize subcritical technology with operating pressure of 2400 to 2520 psig. The existing 450 MW Big Stone station is a subcritical unit. Supercritical units typically operate at 3500 to 3700 psig with main and reheat steam temperatures of 1000°F or greater. Recent supercritical units under design in the US use main steam temperatures between 1050°F and 1075°F and reheat steam temperatures between 1050°F and 1100°F. The economic tradeoff between the technologies is efficiency and capital cost. A supercritical unit will be 3 to 4 percent more efficient than a similar subcritical unit. This results in less fuel costs and less emissions. The capital cost of a supercritical unit will be more than a subcritical unit by a similar percentage due to higher alloy material costs. Both subcritical and supercritical technologies were considered in the Phase I study.

Q: Explain the basic difference between PC and CFB technology?

A: Within a pulverized coal plant (PC), the coal is crushed and further pulverized in mills to a fine powder. It is blown into the furnace with hot air and is combusted in a suspended fireball. The heat generated converts water in the boiler tubes that make up the furnace walls into steam. Most of the coal ash is carried out of the furnace in the exiting flue gas and this fly ash is removed downstream by particulate removal systems such as a baghouse. A smaller portion of the heavier ash particles falls to the bottom of the boiler and is removed as bottom ash.

CFB boilers are a newer technology. Within a circulating fluidized bed boiler, the coal is crushed, but not pulverized. The coal is fed into the furnace where it is combusted on a bed of fuel and limestone that is suspended with upward-blowing air. The limestone is incorporated in the fluidized combustion bed to reduce the formation of sulfur dioxides during the combustion process instead of downstream removal from the flue gas. Bed material and ash that is carried out of the furnace is separated from the flue gas with refractory-line cyclones and recirculated back into the furnace. The heat in the flue gas converts water into steam in a heat exchanger section of the boiler. Most of the ash in this technology is bottom ash that is removed from the boiler.

Q: Explain the different advantages of each technology.

A: The primary benefits of the CFB technology relative to the PC technology are the ability to effectively handle a wider range of fuels and lower emissions exiting the boiler itself. The formation of sulfur dioxides in the furnace is lower due to the addition of limestone in the combustion process, and the formation of nitrous oxides is lower due to lower combustion temperatures. For the PC technology, these emissions must be reduced through back-end control technologies. The primary benefits of the PC technology to the CFB technology are better efficiency due to lower auxiliary loads and lower capital costs. Also, the CFB technology is currently limited to a boiler size of 250 to 300 MW. Plant sizes above this range must incorporate two boilers at a cost disadvantage to a single, larger PC boiler. Both PC and CFB technologies were considered in the Phase I Report.

Q: Describe the process Burns & McDonnell used to develop the Phase I Report.

A: The first step was to define the scope and technical basis of each generation alternative. Attachment A in the Phase I Report outlines the equipment and system descriptions that comprise each technology. Additional major factors that drive the technical development of each generation alternative include the site, fuel supply, water supply, and environmental requirements.

III. SITE FACTORS

Q: How did site factors influence the cost and performance estimates of the generation alternatives?

A: One of the important benefits of the Big Stone site is that it is an existing coal-fired generation site. There are significant infrastructure savings that can accrue to an additional unit added at an existing "brownfield" location compared to a new "greenfield" project. Access to existing infrastructure for fuel delivery and unloading, fuel storage and handling, water supply and storage, ash storage and disposal, warehousing, administrative facilities, and close proximity to transmission facilities are all areas that were reviewed during the development of the capital cost estimates. In addition, staffing costs for any new generation resource will be lower at an existing location since only incremental staff needs to be added for operation and maintenance of an additional unit. This factor was also incorporated in the development of the operation and maintenance (O&M) cost estimates.

Q: How did fuel supply influence the cost and performance estimates of the generation alternatives?

A: The fuel choice impacts the capital and operating cost estimates of the solid fuel generation alternatives in three areas. First, the fuel handling equipment, boiler design, and ash handling/disposal are influenced by fuel characteristics which are incorporated into the capital cost estimates, performance estimates, and O&M estimates. Second, the fuel characteristics and boiler design influence the air quality control systems that are needed to meet environmental requirements. Finally, fuel costs are the largest single ongoing operating expense for the plant and delivered fuel cost estimates are incorporated into the economic analysis. For the solid fuel generation alternatives, PRB coal was the selected fuel. PRB coal is the fuel used at the existing Big Stone station, is a low sulfur coal, and has the lowest expected delivered cost of solid fuel alternatives for the Big Stone location. The capital cost, performance and O&M estimates were based on the use of PRB coal for the solid fuel generation alternatives. For the gas fired alternative, natural gas quality does not vary significantly. The primary impact is the ongoing fuel purchase costs which were modeled in the economic analysis.

Q: How did water supply influence the cost and performance estimates of the generation alternatives?

A: As noted, the existing Big Stone site has existing water supply and storage infrastructure. A primary effort of the Phase I Report on Big Stone Unit II was to evaluate how to integrate a new generation resource within the water supply, storage, quality, treatment, and disposal parameters of the existing site. There is also an existing ethanol facility off-site that is supplied with water from the site. The recommendation for Big Stone Unit II was to utilize a wet cooling tower for heat rejection of the new unit. The capital costs, performance, and O&M cost estimates for the generation alternatives were based on this recommendation.

Q: How did environmental factors influence the cost and performance estimates of the generation alternatives?

A: The air quality control systems planned in the Phase I Report for each of the generation alternatives was estimated based on expected Best Available Control Technology (BACT) requirements to secure an environmental permit for a new resource. For the PC unit alternatives, the cost and performance estimates were based on the use of a Selective Catalytic Reduction (SCR) system to achieve a NO_x emissions rate of 0.07 lb/MMBtu, a dry Flue Gas Desulfurization (FGD) system to achieve an SO_2 emissions rate of 0.12 lb/MMBtu, and a baghouse to achieve particulate emissions of 0.018 lb/MMBtu. Carbon monoxide (CO) would be controlled through good combustion practices. For mercury control, an activated carbon injection system would result in estimated emissions of 0.00002 lb/MWh.

For the CFB unit alternatives, the cost and performance estimates were based on the use of a Selective Non-Catalytic Reduction (SNCR) system to achieve a NO_x emissions rate of 0.08 lb/MMBtu, limestone injection and ash re-injection to the boiler to achieve an SO_2 emissions rate of 0.12 lb/MMBtu, and a baghouse to achieve particulate emissions of 0.018 lb/MMBtu. For mercury control, an activated carbon injection system would result in estimated emissions of 0.00002 lb/MWh. CO would be controlled through good combustion practices.

For the natural gas combined cycle unit, dry low-NO_x burners and an SCR system would be utilized to achieve a NO_x emissions rate of three parts per million, and a CO catalyst would achieve the same emissions rate of CO from the unit. The capital costs, performance, and O&M cost estimates for the generation alternatives were based on the installation of these control technologies.

IV. CAPITAL COST ESTIMATES

Q: Describe how the capital cost estimates in Section 6 of the Phase I Report on Big Stone Unit II were developed.

A: Once the conceptual design basis for each generation alternative was developed, the next step was to prepare the capital cost, performance, and O&M estimates. For the capital cost estimates, Burns & McDonnell uses cost data available from similar projects that we maintain in internal, proprietary databases. The cost of other projects is adjusted to reflect changes in the scope of the project such as the issues discussed regarding site, fuel supply, water supply, and environmental requirements. Other adjustments are made to reflect regional location for labor and material costing, schedule, market conditions, and contracting approach.

To ensure consistency and quality of the different cost estimate we prepare, Burns & McDonnell maintains a full-time Development Engineering department within the Energy Division. This group is responsible for all power generation cost estimates, whether planning level estimates used in feasibility studies such as the Phase I Report or detailed cost estimates used to support bids submitted by Burns & McDonnell on the design and construction of a power plant.

Q: Is Burns & McDonnell active in the design and construction of new coal plants upon which to base the capital cost estimates?

A: Yes. For CFB units, Burns & McDonnell was the owner's engineer for two of the most recent CFB projects completed in the US - the 440 MW Red Hills project owned by Tractebel in Mississippi and the 500 MW Seward project owned by Reliant Energy in Pennsylvania. For PC units, Burns & McDonnell was the design engineer for the rebuild of the 550 MW Hawthorn Station owned by Kansas City Power & Light in Missouri, and we are currently the owner's engineer for the 790 MW supercritical PC unit under construction at the Council Bluffs Station in Iowa for MidAmerican Energy. These are just a few examples of coal-fired projects that Burns & McDonnell has actual capital cost data. In the last five years, we have completed over 30 technology assessments and capital cost estimates on various proposed coal units across the country.

Q: Describe how the performance and O&M cost estimates were developed for Phase I Report on Big Stone Unit II.

A: The performance and O&M cost estimates also reflect the conceptual design basis for each generation alternative. Similar to the capital cost estimates, the performance estimates are based on actual performance information from similar units adjusted for site conditions and the scope of the project. In addition, Burns & McDonnell works with the major equipment manufacturers to evaluate the technical performance and specifications of their current designs for boilers, steam turbines, air quality control systems, and other equipment. O&M cost estimates are prepared under a similar approach. The actual operating cost experience is adjusted for known scope and site changes. For a brownfield expansion such as the Big Stone Unit II, costs for the existing station are reviewed and estimates are developed based on incremental staffing and O&M requirements of each generation alternative.

Q: Do the performance estimates include emissions?

A: Yes, the emissions performance of the proposed air quality control systems is estimated based on actual operating experience with similar applications on similar fuel and the performance guarantees that the manufacturers are willing to provide on the systems.

Q: What type of contingency or margin is included in the capital cost estimates?

A: The capital cost estimates developed for the Phase I Report included an eight percent contingency factor for the coal alternatives and approximately 7.75% for the natural gas combined cycle alternative. In addition, sensitivity analyses were prepared in the economic evaluation with an additional plus or minus ten percent estimate.

V. ANALYSIS OF BASELOAD GENERATION ALTERNATIVES

Q: Did Burns & McDonnell prepare any additional studies to evaluate generation alternatives?

A: Yes. Subsequent to the Phase I Report on Big Stone Unit II, Burns & McDonnell prepared a study titled, "Analysis of Baseload Generation Alternatives – Big Stone Unit II" dated September 2005. This study and report is included as Applicants' Exhibit 23-A, attached as part of Mr. Jeff Greig's Direct Testimony.

Q: What was the purpose of the Generation Alternatives Study?

A: The construction and operation of Big Stone Unit II will necessitate the construction of new transmission lines in Minnesota (and South Dakota) to reliably deliver the output to the loads of some of the participating utilities. A Certificate of Need (CON) is required in Minnesota for a new Large High Voltage Transmission Line (LHVTL) pursuant to Minnesota Statutes, Chapter 216B. The Generation Alternatives Study was prepared in connection with the CON application. The objectives were similar to the Phase I Report, but the Generation Alternatives Study was not limited to generation that could be constructed at the Big Stone site and included an expanded set of generation alternatives. The Generation Alternatives Study evaluated comparative capital costs, operating costs, performance, emissions characteristics, and economics of different baseload generation technologies.

Q: What were your responsibilities for the Generation Alternatives Study?

A: I was the Project Manager.

Q: What alternatives were considered in the Generation Alternatives Study?

A: Six alternative baseload power plant technologies were evaluated. From the Phase I Report on Big Stone Unit II, the low cost alternative of a 600 MW supercritical PC unit was carried forward. The five other generation technologies included: (1) 600 MW subcritical PC unit, (2) 600 MW CCGT unit, (3) 535 MW IGCC unit, (4) 50 MW 100% Biomass unit, and (5) 600 MW CCGT unit plus Wind.

Q: What was the conclusion of the Generation Alternatives Study?

A: This second study reconfirmed that a 600 MW PC plant represents the lowest cost generation alternative of the baseload technologies evaluated for the Big Stone station site on a life-cycle basis considering capital and operating costs. The overall economic difference between subcritical and supercritical PC technology was not material. The supercritical technology has been selected for Big Stone Unit II to minimize emissions.

Q: Why weren't the 250 MW and 450 MW baseload coal technologies evaluated again in the Generation Alternatives Study?

A: The Phase I Report demonstrated that the larger 600 MW alternatives resulted in lower overall economic costs due to economy of scale. There was also additional interest in new baseload resources from potential participants in the Big Stone Unit II project that increased the total need beyond the smaller plant size levels. In the second study, the smaller unit sizes were not included.

Q: Why wasn't the CFB coal technology evaluated again in the Generation Alternatives Study?

A: The Phase I Report demonstrated that PC unit technology represented an economic advantage due to lower capital cost and higher efficiency, particularly at the 600 MW size range. In the second study, CFB technology was not included.

Q: The Phase I Report did not recommend IGCC for Big Stone Unit II. Why was IGCC included in the second study, the Generation Alternatives Study?

A: In the Phase I Report, IGCC technology was not recommended due to three factors: (1) its lack of commercial development; (2) lack of demonstrated ability to utilize PRB fuel; and (3) cost premium compared to proven technologies such as PC and CFB plants. As a result, IGCC was not included in the economic evaluation prepared for the Phase I Report. In the second study, an IGCC concept was developed that might address the three factors sited above so that an economic analysis could be prepared comparing a realistic IGCC alternative with the other generation alternatives.

Q: Explain the IGCC concept included in the Generation Alternatives Study.

A: First, the capital cost estimate developed for the IGCC alternative includes the cost to install a spare gasification train. This would be expected to mitigate some of the operational and availability risk. Second, to mitigate the technological risk associated with the use of PRB fuel, the capital and operating cost estimates developed for the IGCC alternative are based on the use of bituminous coal, which is being used at the two IGCC facilities that are currently operating in the US. Since the cost to deliver bituminous coal to the Big Stone site would be prohibitive, the IGCC facility was assumed to be developed and constructed at a generic, off-site location that would have access to fuel, water and transmission facilities.

Q: Explain the 600 MW CCGT alternative included in the Generation Alternatives Study compared to the 500 MW CCGT alternative included in the Phase I Report.

A: In the Phase I Report, different coal generation alternatives including 450 MW and 600 MW sizes were considered. Therefore, a 500 MW CCGT facility was consistent with these alternatives. In the Generation Alternatives Study, a 600 MW CCGT was selected to be the same size as the 600 MW supercritical PC unit. With supplemental firing of the heat recovery steam generator in a combined-cycle plant, 600 MW of output is achievable. All capital and operating costs are evaluated on an overall dollar per megawatt-hour ($/MWh) basis, so differences in installed capacity do not bias the results, but similar sizes were used when applicable.

Q: Explain why the IGCC alternative is 535 MW instead of 600 MW.

A: An IGCC facility will have higher auxiliary power loads consumed by the plant than a PC unit or CCGT unit for equipment such as the air separation unit. The installed capacity values used in the evaluation represent net capacity. The 535 MW of net output for the IGCC facility is a standard size being considered in development. As discussed, all capital and operating costs are evaluated on an overall dollar per megawatt-hour ($/MWh) basis, so differences in installed capacity do not bias the results.

Q: Explain why the 100% Biomass plant alternative is 50 MW.

A: For this alternative, it simply is not viable to develop a 500 MW or larger biomass facility. Existing wood-fired biomass plants are in the range of 50 MW or smaller. Significant quantities of biomass material are required to meet the heat input requirements of even a small biomass facility. Burns & McDonnell estimated that over 600,000 acres of dedicated biomass crops would be required to support a 600 MW biomass facility.

For a 50 MW plant size, the capital costs of the biomass alternative will suffer from poor economies of scale compared to the larger generation alternatives. However, it was important to evaluate this technology as a viable concept, and not bias the results with a set of assumptions that are not possible.

Q: Explain the 600 MW Wind plus CCGT alternative.

A: As noted in the Phase I Report, wind resources are intermittent and are not dispatchable. Therefore, wind was not considered a technically viable alternative to meet baseload capacity and energy requirements in the Phase I Report. The 600 MW of wind plus CCGT alternative was developed in the Generation Alternatives Study to provide a combination of these two resources that would be firm. To the extent wind energy is available, the CCGT plant dispatch is decreased since it represents the higher cost energy resource. If little or no wind energy is available, the CCGT plant can be fully dispatched as a firm resource to meet baseload requirements.

Q: Why wasn't a simple cycle gas turbine (SCGT) used to backup the wind energy?

A: A simple cycle gas turbine project would represent a lower capital cost alternative to provide firm capacity for the intermittent wind energy. However, the wind resource is expected to yield an overall capacity factor of 40 percent if it was developed at a site with excellent wind resources. The dispatch required by the gas resource would then be at a capacity factor of 48 percent to achieve the high capacity factor achieved by the PC unit. With high gas prices, the higher efficiency of the CCGT plant will offset the lower capital cost of the SCGT plant and result in a net improvement in the economics of this alternative.

Q: The capital cost estimate for the 600 MW supercritical PC unit is different in the Generation Alternatives Study than the Phase I Report. Please explain.

A: The capital cost estimate in the Phase I Report for the 600 MW supercritical PC unit was estimated as $999,893,073, or $1,666/kW. The capital cost estimate in the Generation Alternatives Study for the 600 MW supercritical PC unit was $1,800/kW. There are two primary reasons for the estimated increase in costs between the two studies. First, the emission control technology for SO_2 assumed in the Phase I Report was a dry scrubber, and the second study assumes a higher efficiency, higher cost wet scrubber technology. Secondly, the capital costs of the proposed wet scrubber were increased to oversize the system to also control emissions from the existing Big Stone plant in a common scrubber with Big Stone Unit II. As a result of this common scrubber, SO_2 emissions from the site as a total with the addition of Unit II will be lower than existing emissions. This represents a significant environmental benefit.

Q: Was the same approach and diligence used in developing the capital cost, O&M cost and performance estimates in the Generation Alternatives Study as the Phase I Report?

A: Yes.

Q: Is Burns & McDonnell participating in the construction of the proposed Big Stone Unit II?

A: No. Another engineering firm is responsible for design of Big Stone Unit II.

Q: Does this conclude your testimony?

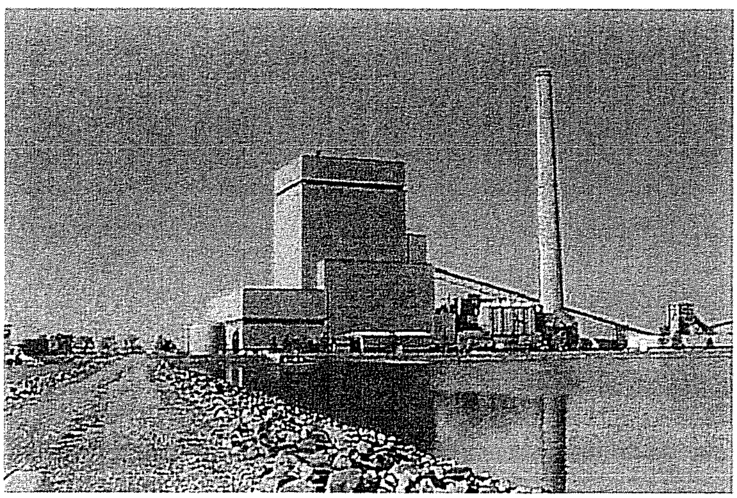
A: Yes.

PHASE I REPORT
BIG STONE UNIT II

FOR

OTTER TAIL
POWER COMPANY

JULY 2005



Burns & McDonnell
SINCE 1898

EXHIBIT
Applicants'
EX 24-A

1576

Phase I Report
Big Stone Unit II

Project 35424
INDEX AND CERTIFICATION PAGE

REPORT INDEX

1577

CERTIFICATION

REGISTERED PROFESSIONAL ENGINEER
REG NO. 8433
STEPHEN J. GOSOROSKI
SOUTH DAKOTA

7/22/05

1573

TABLE OF CONTENTS

1579

SECTION 1
INTRODUCTION

1.1 BACKGROUND

Otter Tail Power Company (OTP) retained Burns & McDonnell (B&McD) to evaluate the feasibility of developing and installing a new solid fuel generation resource (Project) adjacent to its present Big Stone I Station. The evaluated cost of the solid fuel generation alternatives is to be compared to the evaluated cost of a Greenfield combined cycle facility located in the general vicinity of the Big Stone Station. The Phase I study consisted of the following primary components:

- Technology Description (Section 9, Attachment A)
- Performance and Emissions Estimates (Section 7)
- Economic Analysis (Sections 3 & 6)
- Permitting, Engineering and Construction Schedule Timeline (Section 9)

The proposed Project would consist of one unit nominally rated 300, 450 or 600MW net. Fuel for the solid fuel alternatives is assumed to be Black Thunder Powder River Basin (PRB) coal, which is the present primary being burned at the Big Stone I. OTP wishes to keep its options open for burning opportunity fuels in the new boiler if possible.

1.2 OBJECTIVES

The purpose of the study is to provide an overview evaluation of the following questions:

- What are the relative economic costs of gas-fired generation versus solid fuel resources for baseload energy requirements?
- What are the comparative costs, performance, and emissions characteristics of different solid fuel generation alternatives?
- What are the expected BACT environmental requirements and permitting schedule for a solid fuel generation resource?
- How does the plant's present water withdrawal restrictions from Big Stone Lake affect the plant technology selections?

SECTION 2
EXECUTIVE SUMMARY

2.1 SUMMARY OF TECHNOLOGY ASSESSMENT

Burns & McDonnell's focus in the Technology Assessment was to evaluate the conceptual design issues with installing a new base load power generation facility. The assessment investigated the costs, performance, emissions and technologies of potential power plant configurations.

The assessment covered the following basic types of power plant technologies currently used in the industry for the installation of solid fuel, natural gas, and wind generation capacity. Solid fuel base load generation options were evaluated based on constructing a new unit at the existing Big Stone site.

- Supercritical Pulverized Coal (PC) (450MW and 600MW)
- Subcritical PC (300MW)
- Circulating Fluidized Bed (CFB) (300MW, 450MW and 600MW)
- Combined Cycle Gas Turbine (CCGT) (2x1 500MW)
- B&McD also contacted Babcock & Wilcox to determine if a present generation of cyclone boiler, similar to the Big Stone Unit I design is available in the industry today, and if emissions from such a plant can meet present BACT standards. Information provided by Babcock & Wilcox indicates a cost adder of $2,000,000 for the cyclone unit over a conventional PC unit. This cost adder, combined with increased ammonia costs due to a larger SCR for NOx control, leaves the cyclone boiler at a competitive disadvantage. Therefore this option has been dropped from further consideration for this study.
- Integrated Gasification Combined Cycle (IGCC) technology was considered, however such a facility has not been built or proven in the larger unit size ranges being considered. Additionally, of the currently operating IGCC facilities, none are operating on low sulfur Powder River Basin coal. Testing of various coals on the different gasifiers is continuing, and there are a number of power generation projects jointly funded by the Department of Energy (DOE) at several power plant facilities throughout the United States. However, these projects are primarily targeting bituminous (higher sulfur) fuels.

1581

Furthermore, the capital cost of IGCC per kW is currently higher than that of similar size solid fuel units, and availabilities of existing smaller facilities have been 10% to 15% below that of PC units. With a total implementation time of approximately 52 – 64 months, IGCC unit provides no schedule advantage over a pulverized coal unit.

In conclusion, IGCC is considered a developing technology that has not performed reliably in commercial operation to date and therefore cannot be recommended at this time. However, it is recognized there is planned development of the gasification process for coal in the near future and therefore IGCC could potentially become a reliable, low emission source of electrical energy at a later date. It is anticipated that the first of the next generation of 500MW IGCC facilities should become operational within the next four to six years.

- The most common and economically viable renewable resource technology employed in the region, wind turbines, is not appropriate for this project; primarily because it cannot reliably provide base load capacity. According to the American Wind Energy Association (www.awea.org), North Dakota, South Dakota and Minnesota rank 1, 4 and 9, respectively, among the states with the best wind resource. But even in this relatively windy region, wind turbines typically generate electricity only 30 to 40 percent of the time. Additionally, it is not possible to schedule the dispatch of wind turbines, as their operation is as unpredictable as the wind. Base load capacity must be reliable and able to provide virtually continuous output (with only scheduled short-term outages). In conclusion, wind turbines are not recommended.

A cost summary of the four primary technology options is provided in Table 2-1 for PRB coal and detailed in Section 6.

Table 2-1
Summary of Technology

Criteria	PC Subcritical	PC Supercritical	PC Supercritical	CFB Unit	CFB Unit	CFB Unit	CC Unit
Plant Size Number of Units	300 MW (Net) 1 x 300	450 MW (Net) 1 x 450	600 MW (Net) 1 x 600	300 MW (Net) 1 x 300	450 MW (Net) 2 x 225MW Boilers (1 Steam Turbine)	600 MW (Net) 2 x 300 MW Boilers (1 Steam Turbine)	500 MW (Net) 2 x 250 MW
Operating Conditions	Subcritical 2520psig/1050F/1050F	Supercritical 3500psig/1050F/1050F	Supercritical 3500psig/1050F/1050F	Subcritical 2520psig/1050F/1050F	Subcritical 2520psig/1050F/1050F	Subcritical 2520psig/1050F/1050F	Subcritical 1900psig/1050F/1050F
Net Heat Rate (HHV) (Design)	9,665 Btu/kWh	9,418 Btu/kWh	9,392 Btu/kWh	10,033 Btu/kWh	10,132 Btu/kWh	10,105 Btu/kWh	6,900 Btu/kWh
Emissions Control							
NO_x	SCR 0.07 lb/MMBtu	SCR 0.07 lb/MMBtu	SCR 0.07 lb/MMBtu	SNCR 0.08 lb/MMBtu	SNCR 0.08 lb/MMBtu	SNCR 0.08 lb/MMBtu	Dry Low NOx Burners & SCR 3 PPMvd@15% O_2
SO_2	Dry Scrubber 0.12 lb/MMBtu	Dry Scrubber 0.12 lb/MMBtu	Dry Scrubber 0.12 lb/MMBtu	Limestone and Ash Reinjection 0.12 lb/MMBtu	Limestone and Ash Reinjection 0.12 lb/MMBtu	Limestone and Ash Reinjection 0.12 lb/MMBtu	Calculated From Fuel Input
Particulate	Baghouse 0.018 lb/MMBtu	Baghouse 0.018 lb/MMBtu	Baghouse 0.018 lb/MMBtu	Baghouse 0.018 lb/MMBtu	Baghouse 0.018 lb/MMBtu	Baghouse 0.018 lb/MMBtu	Calculated From Fuel Input

1583

Criteria	PC Subcritical	PC Supercritical	PC Supercritical	CFB Unit	CFB Unit	CFB Unit	CC Unit
Mercury	Activated Carbon Injection 0.00002 lb/MWh	Activated Carbon Injection 0.00002 lb/MWh	Activated Carbon Injection 0.00002 lb/MWh	Activated Carbon Injection 0.00002 lb/MWh	Activated Carbon Injection 0.00002 lb/MWh	Activated Carbon Injection 0.00002 lb/MWh	Not required
CO	Controlled By Good Combustion Practice	Controlled By Good Combustion Practice	Controlled By Good Combustion Practice	Controlled By Good Combustion Practice	Controlled By Good Combustion Practice	Controlled By Good Combustion Practice	CO Catalyst - 3 PPMvd@15% O_2
Capital Cost							
Total Cost (Includes Owner's Costs and Escalation to 2008)	$2,092/kW	$1,878/kW	$1,666/kW	$2,022/kW	$2,002/kW	$1,733/kW	$704/kW
O&M Costs (2004$)							
Fixed	$30.71/kW-yr	$23.43/kW-yr	$19.50/kW-yr	$29.94/kW-yr	$22.66/kW-yr	$18.73/kW-yr	$5.34/kW-yr
Non-Fuel Variable	$1.92/MWh	$1.87/MWh	$1.86/MWh	$2.03/MWh	$2.09/MWh	$2.04/MWh	$3.25/MWh
Coal Assumed							
	PRB fuel	PRB fuel	PRB fuel	PRB fuel	PRB fuel	PRB fuel	Nat Gas

1584

2.2 SUMMARY EVALUATION OF ECONOMIC ANALYSIS

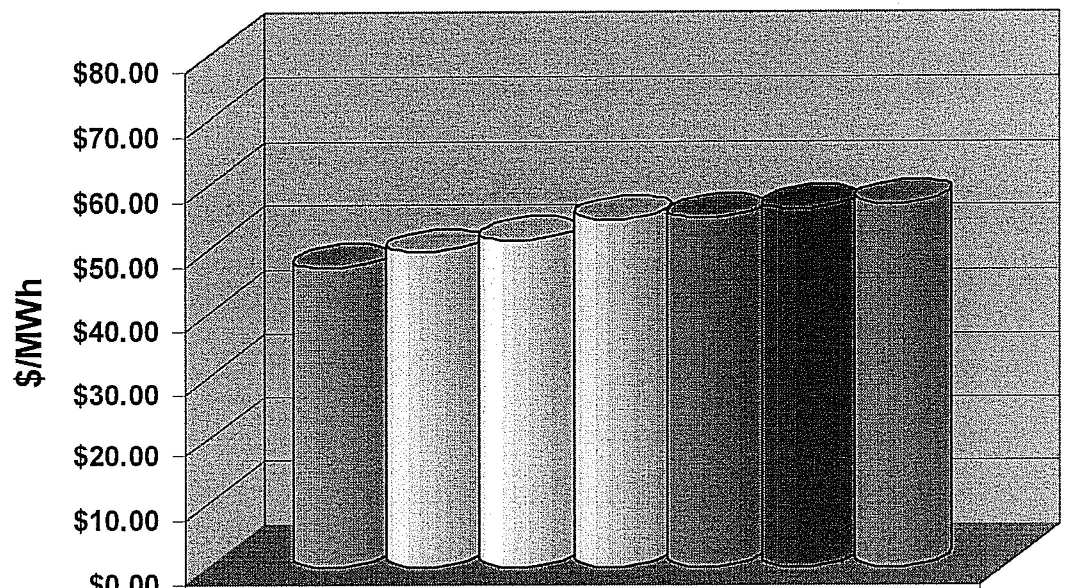
B&McD prepared a number of pro forma economic analyses of various coal-fired Project alternatives. A 20-year economic analysis was prepared based on the estimated capital costs, performance, fuel costs, and operating costs of each Project alternative. The results of the coal-fired Project alternatives were compared against the estimated costs of a combined cycle benchmark alternative using the fuel cost forecast included in Table 3-1.

Economic pro forma analyses were used to determine the busbar cost of power for each alternative. Figure 2-1 presents a graph of the resulting 2010 busbar power costs for the natural gas reference case and the coal-fired options for an investor owned utility. The busbar cost represents the energy cost in 2010$.

Figure 2-2 presents a graph of the resulting 2010 busbar power costs for the natural gas reference case and the coal-fired options for a public power entity. The busbar cost represents the energy cost in 2010$.

The 600MW PC unit was the lowest evaluated generation alternative for both the investor owned and public power entities as shown in Figures 2-2 and 2-3 respectively.

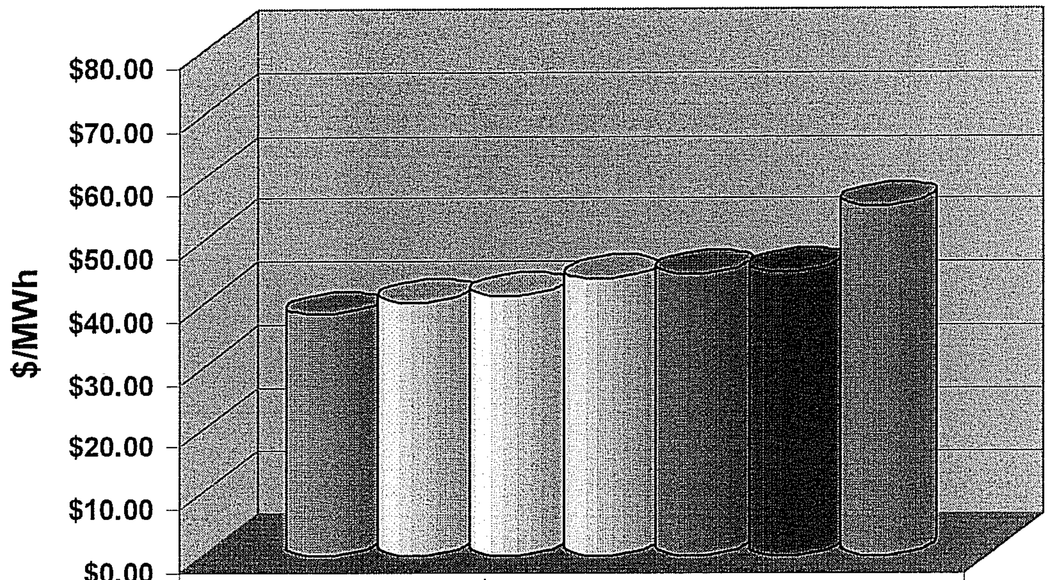
Figure 2-1
2010 Busbar Costs
Investor Owned Utilities



	ALTERNATIVES
600 PC IOU	$47.05
600 CFB IOU	$49.37
450 PC IOU	$51.18
450 CFB IOU	$54.53
300 CFB IOU	$54.63
300 PC IOU	$56.08
500 CCGT IOU	$56.95

1586

Figure 2-2
2010 Busbar Costs
Public Power Utilities



	ALTERNATIVES
600 PC PPU	$38.26
600 CFB PPU	$40.21
450 PC PPU	$41.28
450 CFB PPU	$43.95
300 CFB PPU	$44.81
300 PC PPU	$45.05
500 CCGT PPU	$55.55

1587

2.3 SCHEDULE ISSUES

Preliminary schedules for the design and construction of a 300MW PC/CFB, 600MW PC/CFB and 500 MW CCGT facility is included in Section 9, Attachment B. The schedules include time for

- Permit preparation/engineering support, permit submittal and regulatory review.
- EPC package preparation and bid evaluation/award.
- Facility design.
- Equipment fabrication and delivery.
- Construction/startup

A project permit preparation and regulatory review time of 24 months was included in all of the schedules. Construction time in the field is estimated to require 46 months for the 600MW solid fuel units, 44 months for the 300MW solid fuel units and 21 months for the 500MW combined cycle facility. The schedule for the large CFB units with multiple boilers may take slightly longer to construct than the single PC boiler, however there is enough time in the construction schedules included in Section 9, Attachment B for the PC or CFB boiler erection. The schedules do not include schedule impacts for the construction of a transmission line, which is being evaluated by OTP under a separate study.

The execution method identified in the schedule is a multiple Engineering, Procurement and Construction (EPC) structure for design, construction, and commissioning of the project. EPC bid package preparation and awards were scheduled to be made as much as 10 months before issuance of the air permit, however permanent construction activities were scheduled to begin one month after issuance of the air permit. If EPC contract awards must wait until after the air permit is issued, this will delay the scheduled commercial operation date from June, 2010 until the first quarter of 2011. A single EPC package may present less risk to the Owner in having to release packages before completion of the air permit and will decrease the effort involved in defining bid package scope interfaces. A discussion of contracting methodology is included in Section 9, Attachment J. The method of contracting should be discussed in detail by OTP, its partners and B&McD during the early stages of Phase II of the project.

For planning purposes, the key milestone dates working backward from a June, 2010 commercial operation date for a new solid fuel generation resource would be the following:

- Commercial Operation — June 2010
- Initial Synchronization — November 2009

• Substation Backfeed	February 2009
• Award Materiall Handling EPC Contract and Limited Notice to Proceed (LNTP)	September 2006
• Start Construction	August 2006
• Receive Final Air Permit Approval	July 2006
• Award BOP EPC Contract and LNTP	January 2006
• Award Turbine EPC Contract and LNTP	November 2005
• Award Boiler EPC Contract and LNTP	September 2005
• Submit Air Permit Applications	July 2005
• Start EPC Contract Package Development/Bid	February 2005
• Initiate Phase II Permitting and Permit Engineering Support	July 2004

SECTION 3
PRO FORMA - ECONOMIC ANALYSIS

3.1 OBJECTIVE

B&McD prepared a number of pro forma economic analyses of various coal-fired Project alternatives. An economic analysis was prepared based on the estimated capital costs, performance, fuel costs, and operating costs of each Project alternative. The results of the coal-fired Project alternatives were compared against the estimated costs of a combined cycle benchmark alternative using the natural gas cost forecast included in Table 3-1.

3.2 COAL ASSUMPTIONS & COST ESTIMATES

The following Project estimates and economic assumptions were utilized in the pro forma financial analysis.

• Capital Costs including Owner Costs and Contingency	Table 6-1
• Fuel Cost Assumptions	Table 3-1
• Heat Rate Performance Assumptions	Table 6-1

- Operating Assumptions:

Planned Dispatch	8,016 hours per year (one month planned outage)
Forced Outage Rate	3.0%
Overall Capacity Factor	88.0%

- Financing Assumptions (Investor Owned Utility):

Interest Rate	7.5%
Term	20 years
Debt/Equity Percentage	50%/50%
Return on Equity	12.0%
Construction Financing Fees	0.50%
Permanent Financing Fees	1.00%
Construction Financing	48 months

Table 3-1

Delivered Fuel Price Forecast

($/mmBtu)

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
PRB Coal	Commodity	$ 0.42	$ 0.42	$ 0.43	$ 0.44	$ 0.45	$ 0.46	$ 0.47	$ 0.48	$ 0.49	$ 0.50	$ 0.51	$ 0.52	$ 0.53	$ 0.54	$ 0.55	$ 0.56	$ 0.57	$ 0.58	$ 0.59	$ 0.61
	Transporation	$ 0.87	$ 0.88	$ 0.90	$ 0.92	$ 0.94	$ 0.96	$ 0.98	$ 1.00	$ 1.02	$ 1.04	$ 1.06	$ 1.08	$ 1.10	$ 1.12	$ 1.14	$ 1.17	$ 1.19	$ 1.21	$ 1.24	$ 1.26
	Total	**$ 1.28**	**$ 1.31**	**$ 1.33**	**$ 1.36**	**$ 1.39**	**$ 1.42**	**$ 1.44**	**$ 1.47**	**$ 1.50**	**$ 1.53**	**$ 1.56**	**$ 1.60**	**$ 1.63**	**$ 1.66**	**$ 1.69**	**$ 1.73**	**$ 1.76**	**$ 1.80**	**$ 1.83**	**$ 1.87**
Natural Gas	Commodity	$ 4.65	$ 4.97	$ 5.32	$ 5.69	$ 5.97	$ 6.32	$ 6.49	$ 6.63	$ 6.68	$ 6.74	$ 7.08	$ 7.50	$ 7.60	$ 7.75	$ 7.89	$ 8.02	$ 8.18	$ 8.35	$ 8.52	$ 8.69
	Transporation	$ 0.45	$ 0.46	$ 0.47	$ 0.48	$ 0.49	$ 0.50	$ 0.51	$ 0.52	$ 0.53	$ 0.54	$ 0.55	$ 0.56	$ 0.57	$ 0.58	$ 0.59	$ 0.61	$ 0.62	$ 0.63	$ 0.64	$ 0.66
	Total	**$ 5.10**	**$ 5.43**	**$ 5.79**	**$ 6.17**	**$ 6.46**	**$ 6.81**	**$ 7.00**	**$ 7.15**	**$ 7.21**	**$ 7.27**	**$ 7.63**	**$ 8.06**	**$ 8.17**	**$ 8.33**	**$ 8.48**	**$ 8.63**	**$ 8.80**	**$ 8.98**	**$ 9.16**	**$ 9.34**

1591

- Financing Assumptions (Public Power):

Interest Rate	6.0%
Term	30 years
Debt/Equity Percentage	100%/0%
Return on Equity	N/A
Construction Financing Fees	0.50%
Permanent Financing Fees	1.00%
Construction Financing	48 months

- O&M Cost Assumptions:

Fixed O&M Costs	Table 3-2
Insurance	0.05% of Total Project Cost per year
Property Taxes	0.5% of Total Project Cost per year
Variable O&M Costs	Table 3-2
Transmission Costs	Not Included – Busbar Cost Evaluation
Lime/Limestone Costs	Included in Variable O&M
Emissions Allowances	\$700/ton SO_2 through 2014
	\$1,109/ton SO_2 beginning 2015
	\$1,300/ton NOx through 2014
	\$1,507/ton NOx beginning 2015
	\$35,000/lb Mercury

- Economic Assumptions:

O&M Inflation	2.5% per annum
Construction Cost Inflation	2.5% per annum
Solid Fuel Inflation	Included in forecast
Solid Fuel Transportation Inflation	Included in forecast
Discount Rate (Investor Owned Utility)	9.75%
Discount Rate (Public Power)	6.0%
Effective Tax Rate (IOU only)	40%
Book Depreciation	30 years
Tax Depreciation (IOU only, DDB)	20 years

Table 3-2
O&M Cost Summary
(in Nominal $'s)

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
600 MW PC	Plant Operating Labor Cost	$ 6,367,286	$ 6,526,468	$ 6,689,630	$ 6,856,870	$ 7,028,292	$ 7,204,000	$ 7,384,100	$ 7,568,702	$ 7,757,920	$ 7,951,868
	Plant Maintenance Cost	$ 5,363,907	$ 5,498,004	$ 5,635,455	$ 5,776,341	$ 5,920,749	$ 6,068,768	$ 6,220,487	$ 6,376,000	$ 6,535,400	$ 6,698,785
	Variable O&M, $/MWh	$ 2.16	$ 2.21	$ 2.27	$ 2.33	$ 2.38	$ 2.44	$ 2.51	$ 2.57	$ 2.63	$ 2.70
600 MW CFB	Plant Operating Labor Cost	$ 6,367,286	$ 6,526,468	$ 6,689,630	$ 6,856,870	$ 7,028,292	$ 7,204,000	$ 7,384,100	$ 7,568,702	$ 7,757,920	$ 7,951,868
	Plant Maintenance Cost	$ 4,827,472	$ 4,948,159	$ 5,071,863	$ 5,198,660	$ 5,328,626	$ 5,461,842	$ 5,598,388	$ 5,738,347	$ 5,881,806	$ 6,028,851
	Variable O&M, $/MWh	$ 2.36	$ 2.42	$ 2.48	$ 2.54	$ 2.61	$ 2.67	$ 2.74	$ 2.90	$ 2.97	$ 3.04
450 MW PC	Plant Operating Labor Cost	$ 6,367,286	$ 6,526,468	$ 6,689,630	$ 6,856,870	$ 7,028,292	$ 7,204,000	$ 7,384,100	$ 7,568,702	$ 7,757,920	$ 7,951,868
	Plant Maintenance Cost	$ 4,022,930	$ 4,123,503	$ 4,226,591	$ 4,332,256	$ 4,440,562	$ 4,551,576	$ 4,665,366	$ 4,782,000	$ 4,901,550	$ 5,024,088
	Variable O&M, $/MWh	$ 2.17	$ 2.22	$ 2.28	$ 2.33	$ 2.39	$ 2.45	$ 2.51	$ 2.57	$ 2.64	$ 2.71
450 MW CFB	Plant Operating Labor Cost	$ 6,367,286	$ 6,526,468	$ 6,689,630	$ 6,856,870	$ 7,028,292	$ 7,204,000	$ 7,384,100	$ 7,568,702	$ 7,757,920	$ 7,951,868
	Plant Maintenance Cost	$ 3,620,275	$ 3,710,782	$ 3,803,551	$ 3,898,640	$ 3,996,106	$ 4,096,009	$ 4,198,409	$ 4,303,369	$ 4,410,954	$ 4,521,227
	Variable O&M, $/MWh	$ 2.42	$ 2.48	$ 2.55	$ 2.61	$ 2.67	$ 2.74	$ 2.81	$ 2.88	$ 2.95	$ 3.14
300 MW PC	Plant Operating Labor Cost	$ 6,155,806	$ 6,309,701	$ 6,467,444	$ 6,629,130	$ 6,794,858	$ 6,964,729	$ 7,138,848	$ 7,317,319	$ 7,500,252	$ 7,687,758
	Plant Maintenance Cost	$ 2,681,977	$ 2,749,027	$ 2,817,752	$ 2,888,196	$ 2,960,401	$ 3,034,411	$ 3,110,271	$ 3,188,028	$ 3,267,729	$ 3,349,422
	Variable O&M, $/MWh	$ 2.23	$ 2.28	$ 2.34	$ 2.40	$ 2.46	$ 2.52	$ 2.58	$ 2.65	$ 2.71	$ 2.78
300 MW CFB	Plant Operating Labor Cost	$ 6,155,806	$ 6,309,701	$ 6,467,444	$ 6,629,130	$ 6,794,858	$ 6,964,729	$ 7,138,848	$ 7,317,319	$ 7,500,252	$ 7,687,758
	Plant Maintenance Cost	$ 2,413,768	$ 2,474,112	$ 2,535,965	$ 2,599,364	$ 2,664,348	$ 2,730,957	$ 2,799,231	$ 2,869,211	$ 2,940,942	$ 3,014,465
	Variable O&M, $/MWh	$ 2.35	$ 2.41	$ 2.47	$ 2.53	$ 2.60	$ 2.66	$ 2.73	$ 2.80	$ 2.87	$ 2.94

		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
600 MW PC	Plant Operating Labor Cost	$ 8,150,664	$ 8,354,431	$ 8,563,292	$ 8,777,374	$ 8,996,808	$ 9,221,728	$ 9,452,272	$ 9,688,578	$ 9,930,793	$10,179,063
	Plant Maintenance Cost	$ 6,866,254	$ 7,037,911	$ 7,213,858	$ 7,394,205	$ 7,579,060	$ 7,768,536	$ 7,962,750	$ 8,161,818	$ 8,365,864	$ 8,575,011
	Variable O&M, $/MWh	$ 2.77	$ 2.91	$ 2.99	$ 3.06	$ 3.14	$ 3.22	$ 3.30	$ 3.38	$ 3.46	$ 3.55
600 MW CFB	Plant Operating Labor Cost	$ 8,150,664	$ 8,354,431	$ 8,563,292	$ 8,777,374	$ 8,996,808	$ 9,221,728	$ 9,452,272	$ 9,688,578	$ 9,930,793	$10,179,063
	Plant Maintenance Cost	$ 6,179,573	$ 6,334,062	$ 6,492,413	$ 6,654,724	$ 6,821,092	$ 6,991,619	$ 7,166,410	$ 7,345,570	$ 7,529,209	$ 7,717,439
	Variable O&M, $/MWh	$ 3.12	$ 3.20	$ 3.28	$ 3.36	$ 3.45	$ 3.53	$ 3.62	$ 3.71	$ 3.80	$ 3.90
450 MW PC	Plant Operating Labor Cost	$ 8,150,664	$ 8,354,431	$ 8,563,292	$ 8,777,374	$ 8,996,808	$ 9,221,728	$ 9,452,272	$ 9,688,578	$ 9,930,793	$10,179,063
	Plant Maintenance Cost	$ 5,149,691	$ 5,278,433	$ 5,410,394	$ 5,545,654	$ 5,684,295	$ 5,826,402	$ 5,972,062	$ 6,121,364	$ 6,274,398	$ 6,431,258
	Variable O&M, $/MWh	$ 2.77	$ 2.84	$ 2.91	$ 3.08	$ 3.15	$ 3.23	$ 3.31	$ 3.40	$ 3.48	$ 3.57
450 MW CFB	Plant Operating Labor Cost	$ 8,150,664	$ 8,354,431	$ 8,563,292	$ 8,777,374	$ 8,996,808	$ 9,221,728	$ 9,452,272	$ 9,688,578	$ 9,930,793	$10,179,063
	Plant Maintenance Cost	$ 4,634,258	$ 4,750,115	$ 4,868,867	$ 4,990,589	$ 5,115,354	$ 5,243,238	$ 5,374,319	$ 5,508,677	$ 5,646,393	$ 5,787,553
	Variable O&M, $/MWh	$ 3.22	$ 3.30	$ 3.38	$ 3.46	$ 3.55	$ 3.64	$ 3.73	$ 3.82	$ 3.92	$ 4.02
300 MW PC	Plant Operating Labor Cost	$ 7,879,952	$ 8,076,951	$ 8,278,875	$ 8,485,847	$ 8,697,993	$ 8,915,443	$ 9,138,329	$ 9,366,787	$ 9,600,956	$ 9,840,980
	Plant Maintenance Cost	$ 3,433,158	$ 3,518,987	$ 3,606,961	$ 3,697,135	$ 3,789,564	$ 3,884,303	$ 3,981,410	$ 4,080,946	$ 4,182,969	$ 4,287,543
	Variable O&M, $/MWh	$ 2.85	$ 2.92	$ 3.00	$ 3.07	$ 3.15	$ 3.23	$ 3.43	$ 3.51	$ 3.60	$ 3.69
300 MW CFB	Plant Operating Labor Cost	$ 7,879,952	$ 8,076,951	$ 8,278,875	$ 8,485,847	$ 8,697,993	$ 8,915,443	$ 9,138,329	$ 9,366,787	$ 9,600,956	$ 9,840,980
	Plant Maintenance Cost	$ 3,089,827	$ 3,167,072	$ 3,246,249	$ 3,327,405	$ 3,410,591	$ 3,495,855	$ 3,583,252	$ 3,672,833	$ 3,764,654	$ 3,858,770
	Variable O&M, $/MWh	$ 3.01	$ 3.09	$ 3.30	$ 3.38	$ 3.46	$ 3.55	$ 3.64	$ 3.73	$ 3.82	$ 3.92

1593

Note that the capital cost estimates presented in Section 6 are escalated to 2008$. The O&M estimates in Table 3-2 are presented in nominal costs.

3.3 COMBINED CYCLE BENCHMARK ASSUMPTIONS

The results of the economic analysis of solid fuel generation alternatives were compared to a benchmark combined cycle alternative based on the natural gas cost forecast in Table 3-1. The following summarizes the benchmark cost assumptions included in the combined cycle benchmark case.

- Capital Costs — Table 6-1
- Fuel Assumptions — Table 3-1
- Heat Rate Performance Assumptions — Table 6-1

- Operating Assumptions:
  - Overall Capacity Factor — 88.0% for comparative purposes
- Financing Assumptions (Investor Owned Utility):
  - Interest Rate — 7.5%
  - Term — 20 years
  - Debt/Equity Percentage — 50%/50%
  - Return on Equity — 12.0%
  - Construction Financing Fees — 0.50%
  - Permanent Financing Fees — 1.00%
  - Construction Financing — 24 months

- Financing Assumptions (Public Power):
  - Interest Rate — 6.0%
  - Term — 30 years
  - Debt/Equity Percentage — 100%/0%
  - Return on Equity — N/A
  - Construction Financing Fees — 0.50%
  - Permanent Financing Fees — 1.00%
  - Construction Financing — 24 months

- O&M Cost Assumptions:

Fixed O&M Costs	$5.34/kW-yr (2004$)
Insurance	0.05% of Total Project Cost per year
Property Taxes	0.5% of Total Project Cost per year
Variable O&M Costs	$3.25/MWh (2004$)
Transmission Costs	Not Included – Busbar Cost Evaluation
Emissions Allowances	N/A

- Economic Assumptions:

O&M Inflation	2.5% per annum
Construction Cost Inflation	2.5% per annum
Solid Fuel Inflation	Included in forecast
Solid Fuel Transportation Inflation	Included in forecast
Discount Rate (Investor Owned Utility)	9.75%
Discount Rate (Public Power)	6.0%
Effective Tax Rate (IOU only)	40%
Book Depreciation	30 years
Tax Depreciation (IOU only, DDB)	20 years

The benchmark combined cycle cost assumptions above represent the costs associated with a greenfield site.

3.4 ECONOMIC ANALYSIS RESULTS

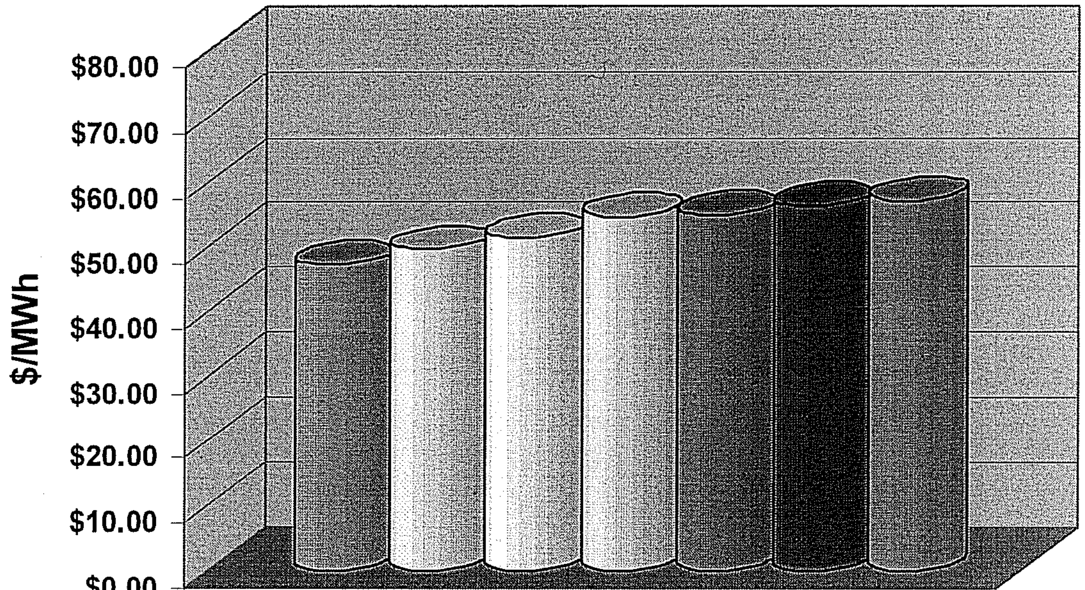
The economic pro forma analyses were used to determine the busbar cost of power for each alternative. A copy of the pro forma model for the 450 MW PC unit for both an investor owned utility and a public power utility is included in Attachment K.

Figure 3-1 presents a graph of the resulting first year busbar power costs for the natural gas reference case and the coal-fired options for the year 2010 for an investor owned utility. Figure 3-1 was developed by preparing a project pro forma for each of the alternatives under consideration. The busbar cost represents the all-in energy cost in 2010$. Figure 3-2 presents the annual busbar cost for the natural gas reference case and the coal-fired options over 20 years for an investor owned utility.

Figure 3-3 presents a graph of the resulting first year busbar power costs for the natural gas reference case and the coal-fired options for the year 2010 for a public power entity. Figure 3-3 was developed by preparing a project pro forma for each of the alternatives under consideration. The busbar cost represents the all-in energy cost in 2010$. Figure 3-4 presents the annual busbar cost for the natural gas reference case and the coal-fired options over 20 years for a public power utility.

Table 3-3 provides the annual busbar cost for the first twenty years of operations for both an investor owned utility and a public power utility for each alternative.

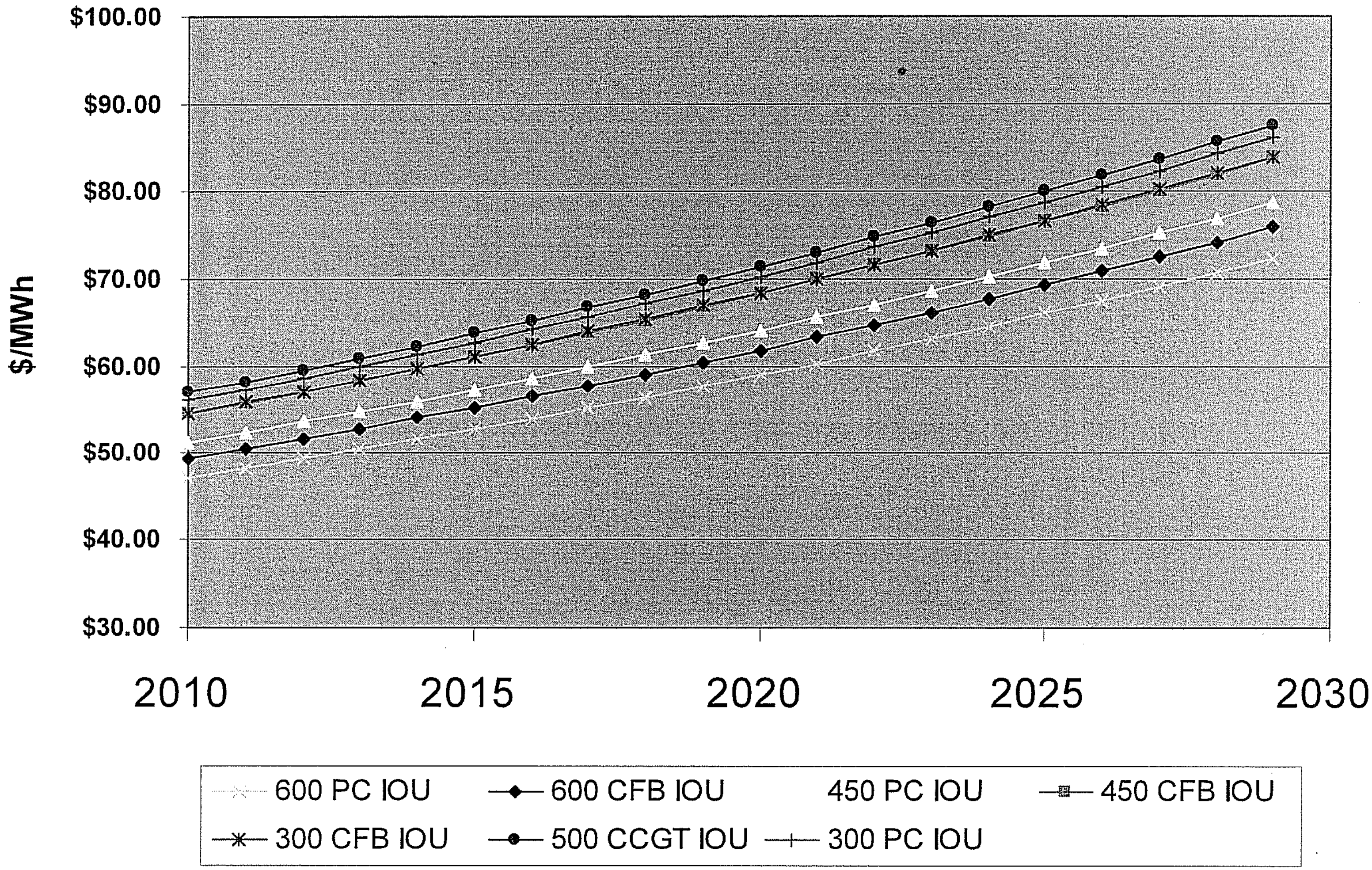
Figure 3-1
2010 Busbar Costs
Investor Owned Utilities



	ALTERNATIVES
600 PC IOU	$47.05
600 CFB IOU	$49.37
450 PC IOU	$51.18
450 CFB IOU	$54.53
300 CFB IOU	$54.63
300 PC IOU	$56.08
500 CCGT IOU	$56.95

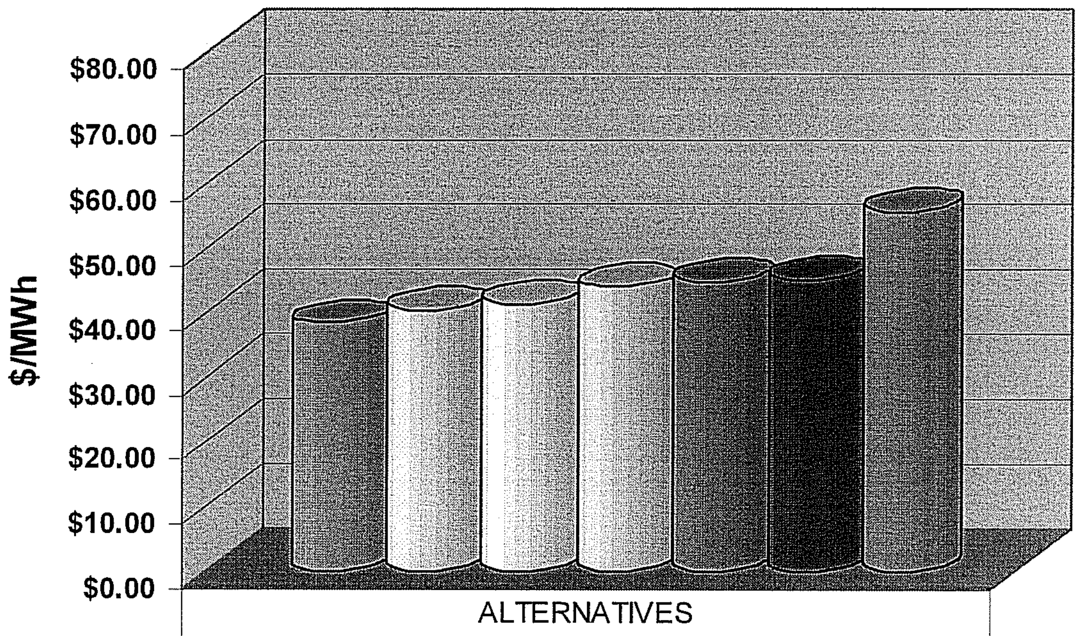
1597

Figure 3-2
Annual Busbar Costs
Investor Owned Utilities



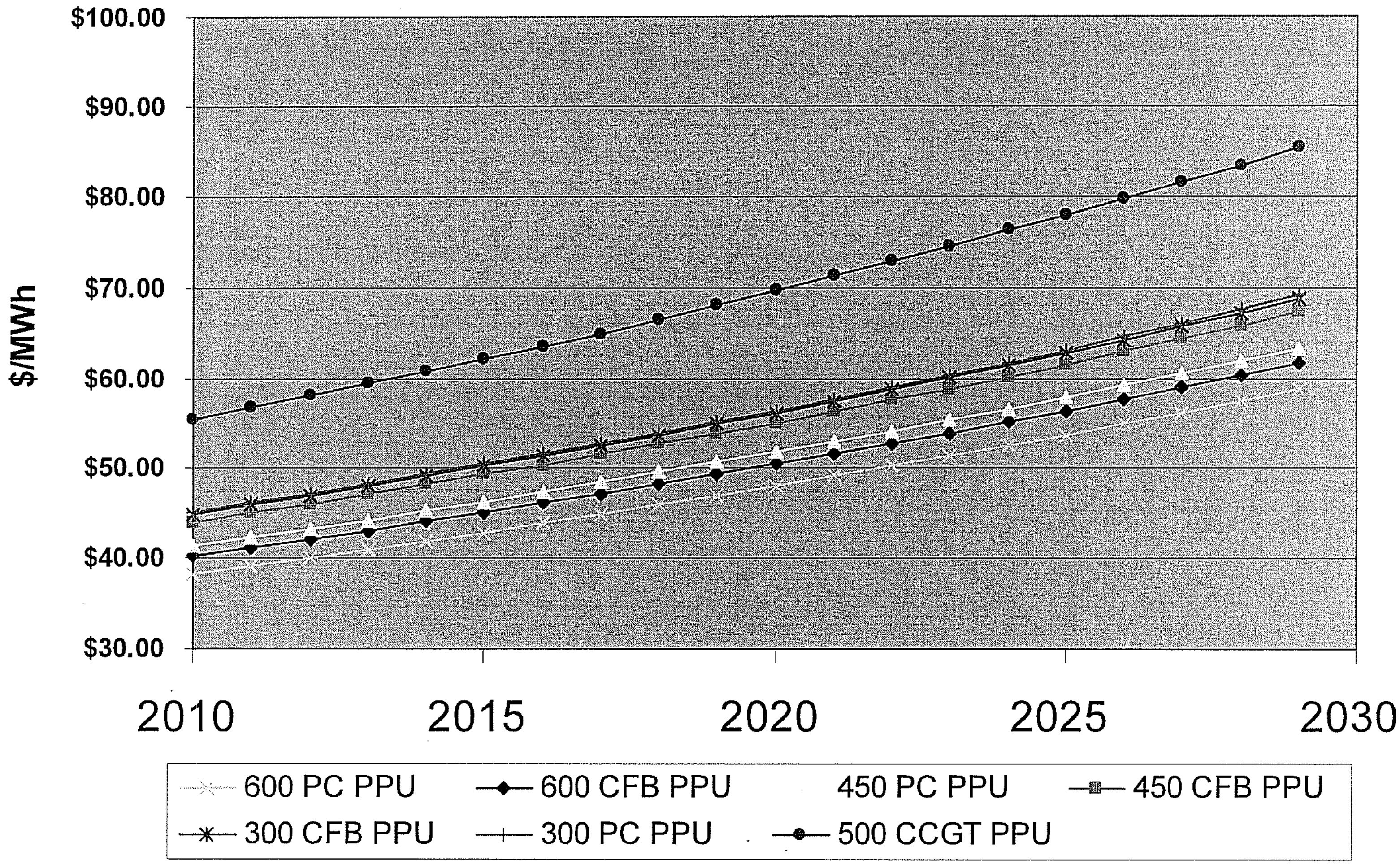
1598

Figure 3-3
2010 Busbar Costs
Public Power Utilities



	ALTERNATIVES
600 PC PPU	$38.26
600 CFB PPU	$40.21
450 PC PPU	$41.28
450 CFB PPU	$43.95
300 CFB PPU	$44.81
300 PC PPU	$45.05
500 CCGT PPU	$55.55

Figure 3-4
Annual Busbar Costs
Public Power Utilities



1600

Table 3-3

Annual Busbar Cost

($/MWh)

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Investor Owned Utility	300 MW CFB	$54.63	$55.88	$57.15	$58.46	$59.80	$61.16	$62.56	$63.99	$65.46	$66.95	$68.48	$70.05	$71.65	$73.29	$74.96	$76.68	$78.43	$80.22	$82.06	$83.93
	300 MW PC	$56.08	$57.36	$58.67	$60.01	$61.38	$62.79	$64.22	$65.69	$67.19	$68.73	$70.30	$71.91	$73.55	$75.23	$76.95	$78.71	$80.51	$82.35	$84.23	$86.16
	450 MW CFB	$54.53	$55.78	$57.05	$58.35	$59.69	$61.05	$62.45	$63.88	$65.34	$66.83	$68.36	$69.92	$71.52	$73.16	$74.83	$76.54	$78.29	$80.08	$81.91	$83.78
	450 MW PC	$51.18	$52.35	$53.54	$54.77	$56.02	$57.30	$58.61	$59.95	$61.32	$62.72	$64.16	$65.62	$67.12	$68.66	$70.23	$71.83	$73.48	$75.16	$76.87	$78.63
	600 MW CFB	$49.37	$50.50	$51.65	$52.83	$54.04	$55.27	$56.54	$57.83	$59.15	$60.50	$61.89	$63.30	$64.75	$66.23	$67.74	$69.29	$70.88	$72.50	$74.15	$75.85
	600 MW PC	$47.05	$48.13	$49.23	$50.35	$51.50	$52.68	$53.89	$55.12	$56.38	$57.67	$58.98	$60.33	$61.71	$63.12	$64.57	$66.04	$67.55	$69.10	$70.68	$72.29
	500 MW CCGT	$56.95	$58.26	$59.59	$60.96	$62.35	$63.78	$65.24	$66.74	$68.26	$69.83	$71.43	$73.06	$74.74	$76.45	$78.20	$79.99	$81.82	$83.69	$85.61	$87.57
Public Power Utility	300 MW CFB	$44.81	$45.84	$46.88	$47.96	$49.05	$50.17	$51.32	$52.49	$53.69	$54.92	$56.18	$57.46	$58.77	$60.12	$61.49	$62.90	$64.34	$65.81	$67.31	$68.85
	300 MW PC	$45.05	$46.08	$47.13	$48.21	$49.31	$50.44	$51.59	$52.77	$53.97	$55.21	$56.47	$57.76	$59.08	$60.43	$61.81	$63.23	$64.67	$66.15	$67.66	$69.21
	450 MW CFB	$43.95	$44.95	$45.98	$47.03	$48.11	$49.21	$50.33	$51.48	$52.66	$53.86	$55.10	$56.36	$57.64	$58.96	$60.31	$61.69	$63.10	$64.54	$66.02	$67.53
	450 MW PC	$41.28	$42.22	$43.19	$44.17	$45.18	$46.22	$47.27	$48.35	$49.46	$50.59	$51.75	$52.93	$54.14	$55.38	$56.64	$57.94	$59.26	$60.62	$62.00	$63.42
	600 MW CFB	$40.21	$41.13	$42.07	$43.03	$44.01	$45.02	$46.05	$47.10	$48.18	$49.28	$50.41	$51.56	$52.74	$53.94	$55.18	$56.44	$57.73	$59.05	$60.40	$61.78
	600 MW PC	$38.26	$39.14	$40.03	$40.95	$41.88	$42.84	$43.82	$44.82	$45.85	$46.89	$47.97	$49.06	$50.19	$51.33	$52.51	$53.71	$54.93	$56.19	$57.47	$58.79
	500 MW CCGT	$55.55	$56.82	$58.12	$59.46	$60.82	$62.21	$63.63	$65.09	$66.58	$68.11	$69.67	$71.26	$72.89	$74.56	$76.27	$78.02	$79.80	$81.63	$83.50	$85.41

1601

3.5 ECONOMIC CONCLUSIONS

The most cost-effective coal fired project is a 600 MW PC unit. Larger plant sizes such as 600 MW will result in improved economics due to reduced capital costs and reduced O&M costs. For the larger plant sizes, PC technology is preferred to CFB technology. CFB technology is more capital cost intensive, therefore more cost effective fuels must be utilized in order for it to be competitive with PC technology. However, for the smaller plant sizes, economies of scale are not as prevalent in the PC units, therefore, CFB technology is preferred to PC technology for the smaller plant sizes.

All coal-fired options are preferred to a combined cycle plant for baseload dispatch.

3.6 SENSITIVITY ANALYSIS RESULTS

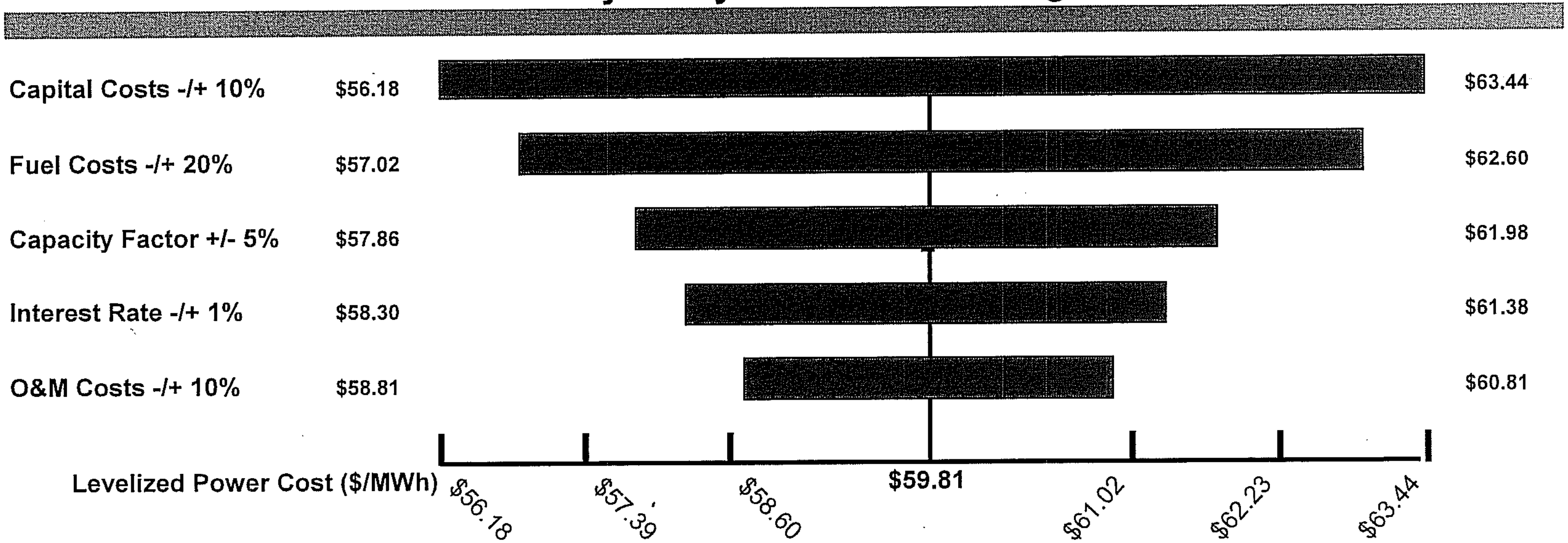
A sensitivity analysis was prepared for the 450 MW PC unit for both the investor owned utility and public power options, as well as the 500 MW CCGT reference case for both the investor owned utility and public power options under the following cases:

- Capital Cost (plus or minus 10%)
- Interest Rate (plus or minus one (1) percentage point)
- Capacity Factor (plus or minus 5%)
- Fuel Cost (plus or minus 20%)
- O&M Costs (plus or minus 10%)

The results of the sensitivity analyses are presented in tornado diagrams in Figures 3-5, 3-6, 3-7 and 3-8. A tornado diagram illustrates the range of results for each sensitivity case and its impact on the levelized power cost, and ranks the results from greatest impact to least impact. The sensitivity analysis indicates that capital cost and fuel cost are the two most significant factors affecting the economics of a coal-fired unit. For a public power utility, the interest rate is the most significant factor affecting the economies of a coal-fired unit. Delivered fuel cost by far has the strongest impact on the overall economics of a combined cycle unit. This is an important result since the market price of natural gas is inherently volatile and nearly impossible for a utility to control over the long term. Hence, many utilities have a renewed interest in coal generation with its more stable fuel costs as means to protect customers from future natural gas market conditions.

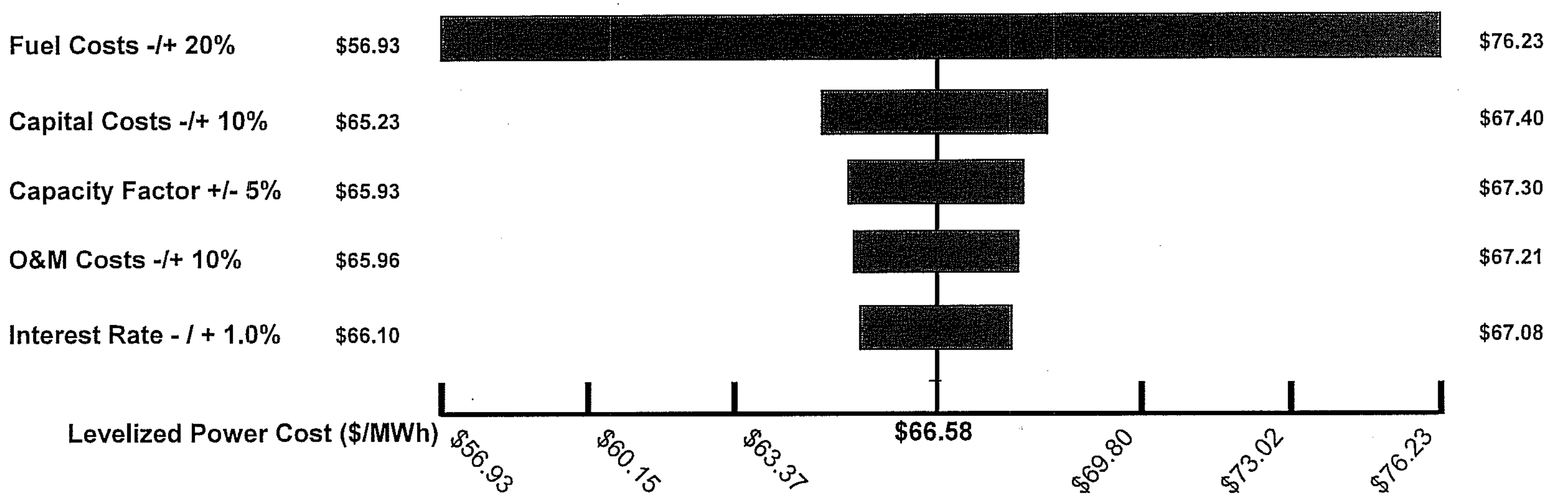
Coal-fired generation resources are significantly more capital intensive than natural gas combined cycle plants, and have a construction period that can be more than twice the length of a combined cycle plant. This results in substantially more capital risk due to interest costs, labor availability and costs, and general inflation. Other risk factors associated with the construction of new solid fuel generation plants include the fact that several US boiler manufacturers are currently under financial duress, and the skilled workforce that constructed a number of coal units in the 1970's and 1980's have aged without a significant influx of younger construction workers with similar specialized skills and experience. If a number of new coal units initiate construction within the next decade, the supply of skilled construction workers could be strained. The primary tradeoff for these higher capital risks with a solid fuel generation resource is the long-term stability of coal and other solid fuel alternatives which have few competing uses relative to natural gas that is used by almost all economic sectors including residential heating.

Figure 3-5
450 MW PC Unit - Investor Owned Utility
Sensitivity Analysis - Tornado Diagram



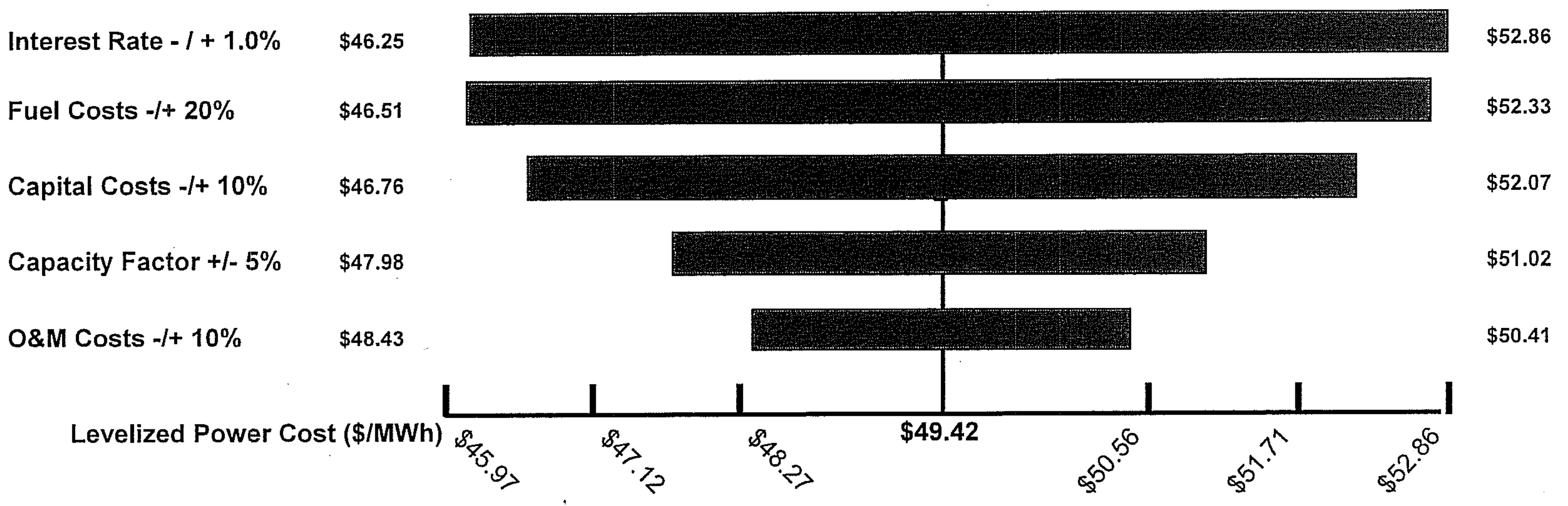
1604

Figure 3-6
2 x 1 - 500 MW CCGT Unit (Reference Gas) - Investor Owned Utility
Sensitivity Analysis - Tornado Diagram



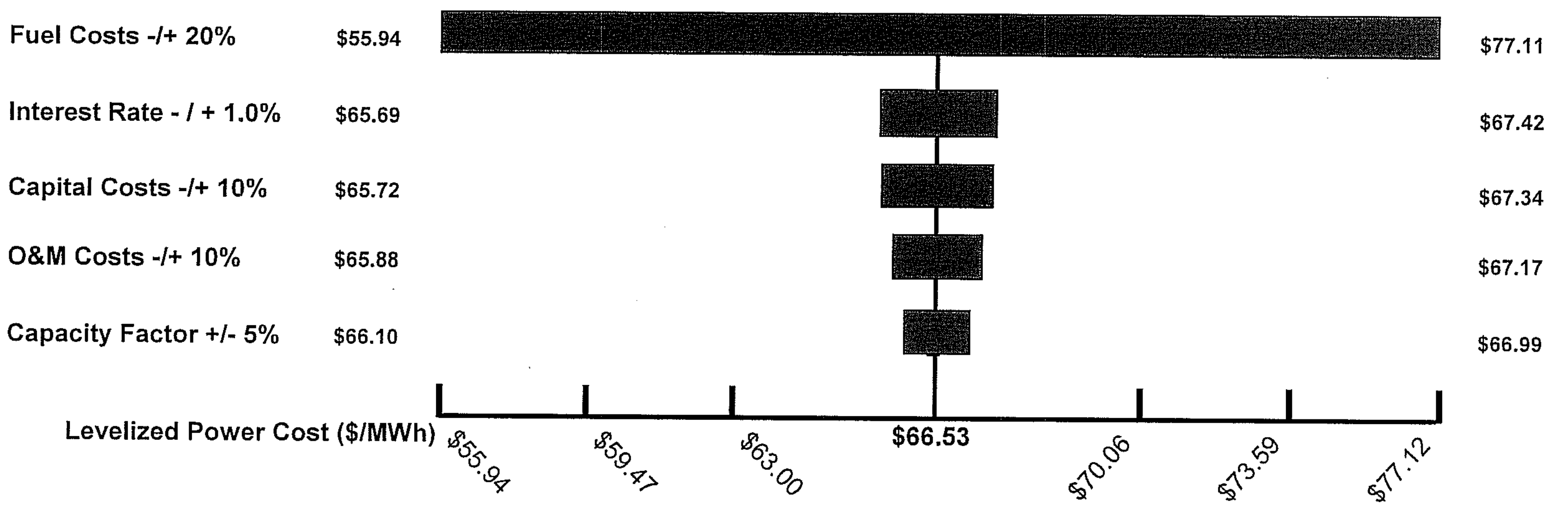
1605

Figure 3-7
450 MW PC Unit - Public Power Utility
Sensitivity Analysis - Tornado Diagram



1606

Figure 3-8
2 x 1 - 500 MW CCGT Unit (Reference Gas) - Public Power Utility
Sensitivity Analysis - Tornado Diagram



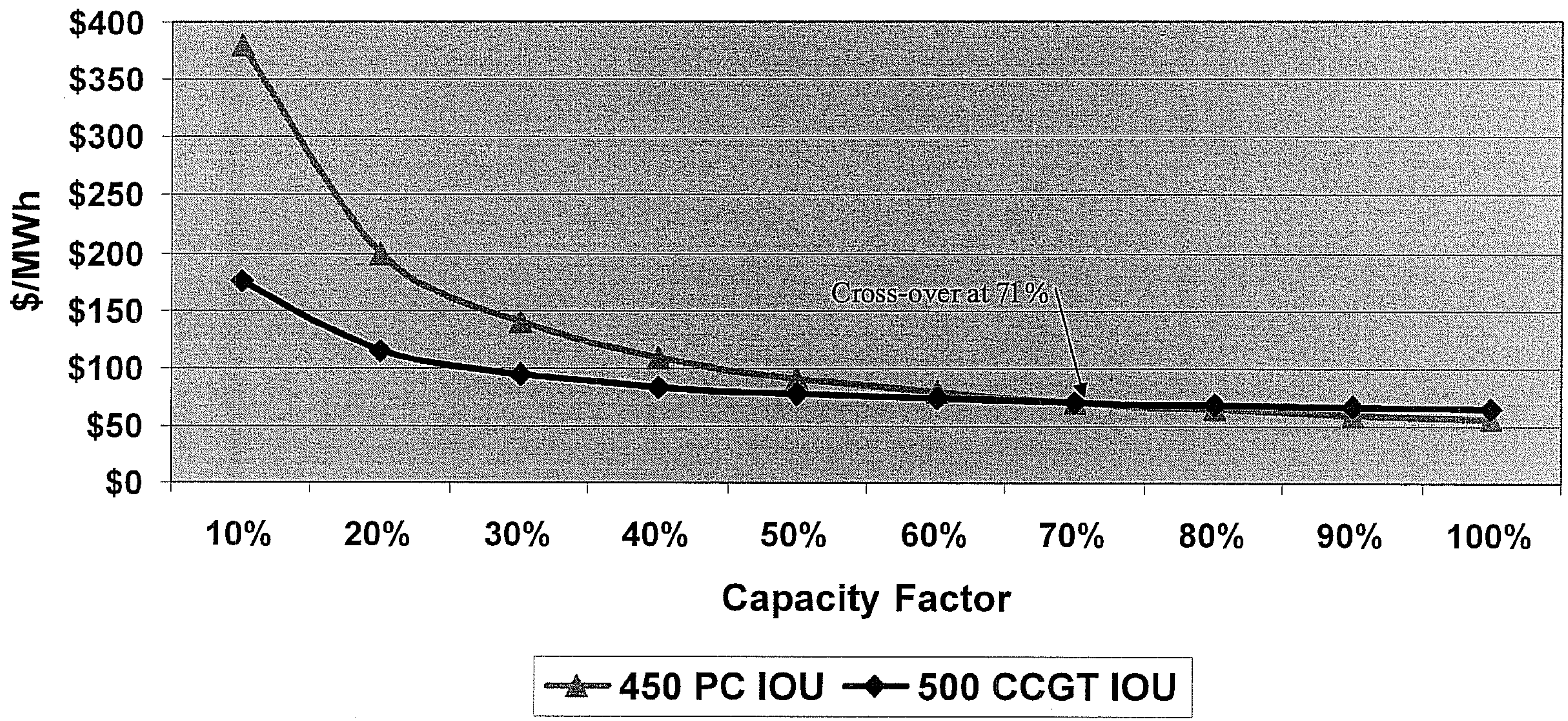
1607

3.7 CAPACITY FACTOR SENSITIVITY

The economic analyses presented in this section assume an 88% capacity factor for both the gas combined cycle benchmark and the coal-fired generation alternatives. This allows a consistent comparison of busbar costs on an energy delivery basis. However, an 88% capacity factor represents a baseload resource, which is typically not the planned or actual dispatch of a gas combined cycle plant. These resources are typically designed and operated as an intermediate resource with capacity factors of 20% to 60%.

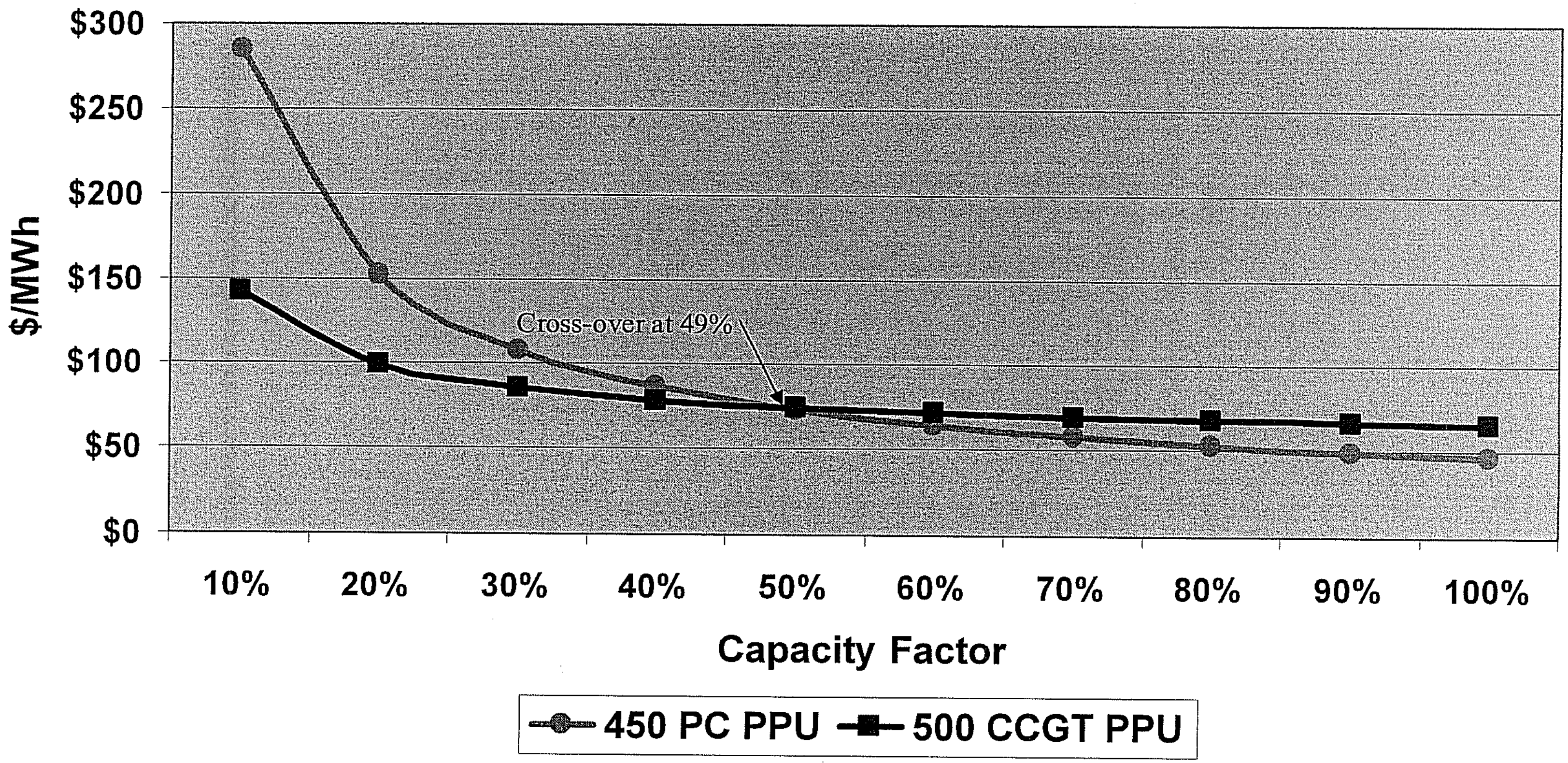
Figures 3-9 and 3-10 present the economic results a 450 MW PC unit compared to the combined cycle benchmark case across various capacity factors for dispatch. As indicated in Figures 3-7 and 3-8, a combined cycle resource has a clear economic advantage at low and intermediate dispatch levels. The coal-fired resource is only economically competitive under higher dispatch cases representing baseload operations.

Figure 3-9
Levelized 20 Year Busbar Costs
For Varying Capacity Factors
Investor Owned Utilities



1609

Figure 3-10
Levelized 20 Year Busbar Costs
For Varying Capacity Factors
Public Power Utilities



1610

3.8 BUSBAR COST BREAKDOWN

Figure 3-11 presents a breakdown of the 2010 busbar costs for the natural gas reference case and the coal-fired options. For each alternative, the following costs are included:

- Fuel Cost
- Fixed O&M
- Variable O&M
- Return

In addition to the above costs the following costs are included:

For an Investor Owned Utility:

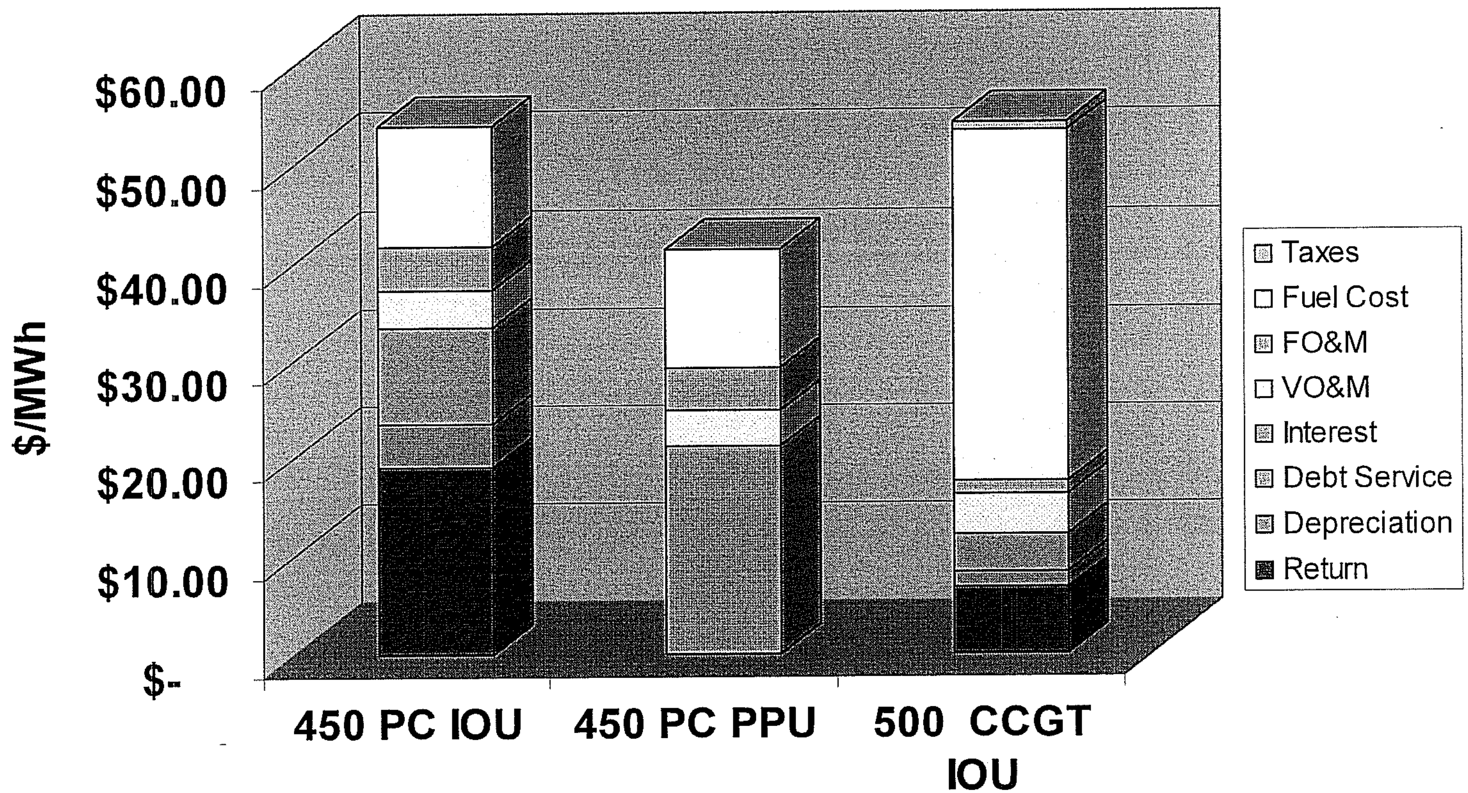
- Interest
- Taxes
- Depreciation

For a Public Power Utility:

- Debt Service

Figure 3-11

2010 Busbar Cost Breakdown



1612

SECTION 4
MAJOR COMMERCIAL TERMS

4.1 TERMS

The following lists the major commercial terms assumed for the Project cost estimates.

1) Cost estimates are given in 2008$. Escalation at the rate of 2.5% to the midpoint of the Project's construction is included in the estimates. Equipment/material escalation, especially where structural steel is involved, has become a major concern regarding the accuracy of capital cost estimates.

2) Project is assumed to be executed using merit shop labor.

3) Project is assumed to be performed under a multiple EPC contract approach.

4) Project will be executed with durations similar to those shown on the Project schedule included in Section 9, Attachment B with a target COD of June 2010.

5) A performance bond is included for each EPC contract at the rate of 0.5% of the estimated contract value.

6) Property taxes incurred during construction are not included. Sales taxes on the Project's construction are included and includes 4% sales tax and 2 % contractor's excise tax, totaling 6%.

7) Owners will provide a Builder's Risk policy for the project that is included in the estimate. Policy will have not more than $100,000 deductible. An insurance cost of 0.6% is included in the capital cost estimate.

8) An insurance cost of 0.05% of the total Project cost (less interest during construction) is included in the pro-forma analysis during operations.

9) A property tax cost of 0.5% of the total Project cost (less interest during construction) is included in the pro-forma analysis during operations.

10) Reasonable liquidated damage/bonus provisions related to schedule and performance will be negotiated between the EPC contractors and Otter Tail. Typical levels for liquidated damages are as stated below:

a) Total Aggregate EPC Contract Liquidated Damages (LD) Cap – Maximum of 20-percent of EPC contract price.
b) Project Schedule - Maximum of 15-percent of the EPC contract price.
c) Output and Heat Rate – Maximum of 15-percent of the EPC contract price.

The availability of liquidated damage insurance for EPC contractors on coal-fired projects is uncertain. The cost and availability of this insurance could have a significant impact on the EPC price, and the commercial terms the EPC contractors will accept. This estimate does not include funds for L/D insurance.

4.2 SCHEDULE

The Level 1 schedules for the Project from start of permitting through commercial operation is included in Section 9, Attachment B. The schedule for construction of the solid fuel plant is based on market conditions that exist today and is 46 months in duration for the larger unit (450MW and 600MW).

1614

SECTION 5
DIVISION OF RESPONSIBILITY

5.1 Scope Definition

To define the scope of supply assumed for the Project Cost Estimates, the following table summarizes the scope to be provided by the various EPC Contractor (EPC) and OTP (Owner). The costs for the following items are apportioned in accordance with the following table in Section 6.0.

ITEM	EPC	OWNER	NOTES
Engineering & Procurement			
Environmental Consulting / Permitting		√	
Engineering & Architectural Design	√		As required by the EPC Contractor
As-Built Record Drawings	√		
Equipment Procurement	√		
Boiler and APC/auxiliaries	√		
Steam Turbine	√		
Balance of Plant Equipment	√		
Vendor Service Representatives	√		For equipment supplied by the EPC Contractor
Site acquisition, Easements and Right-of–Ways		√	Includes additional area for construction laydown and landfill expansion
Site Survey		√	
Geotechnical Investigation		√	Provided from data collected during design of Unit 1
Site Clearing and Grubbing	√		
Landscaping	√		(1) Minimal landscaping is included
Interior Furnishings		√	
Construction Power and Construction Water		√	
Construction Inspections	√		
Checkout, Startup, Testing, And Training			
Checkout Procedures and System Checkout	√		Owner to provide operations staff
Relay Settings	√	√(1)	(1) Interconnect relay settings by Owner
Startup Procedures	√		
Startup of Systems and Plant	√(1)	√(2)	(1) Craft labor (2) Operating personnel
Consumables Required for Startup, Testing prior to Commercial Operation	√		

ITEM	EPC	OWNER	NOTES
Startup Spares (i.e. Fuses, Lamps, Filters, and Gaskets)	√		
Initial Charge of Fluids, Resins, Chemicals, Desiccants and Lubricants		√	
Operating & Maintenance Spare Parts		√	
Performance Testing Procedures	√		
Test Equipment	√		Excludes water chemistry testing equipment and reagents.
Performance Test	√	√(1)	(1) Operating personnel
Emission Compliance Testing	√(1)	√(2)	(1) Testing (2) Witness certification
Calibration of CEMS	√		
Operator Training	√		For equipment supplied by the EPC Contractor
Operating and Maintenance Manuals	√		For equipment supplied by the EPC Contractor
Equipment Instruction Manuals	√		For equipment supplied by the EPC Contractor
Operation and Maintenance Personnel		√	
Commercial			
Warranties	√	√	EPC Contractor will administer claims while on site. After demobilization, EPC Contractor will assign warranties to Owner for administration only.
Project Labor Agreement			Not Applicable
Bonds			
Performance	√		
Insurance			
Worker's Compensation	√		
Employer Liability	√		
Comprehensive General Liability	√		
Auto Liability	√		
Excess Liability	√		
Builder's Risk		√	Assumes policy is acceptable to EPC Contractor
Sales Taxes		√	
Startup Fuel		√	

SECTION 6
PROJECT COST ESTIMATES

The cost estimates summarized in this section represent the Phase I screening-level cost estimates used in evaluating the various options for installing a power generation facility adjacent to the existing Big Stone Unit.

6.1 CAPITAL COST ESTIMATE BASIS

Equipment costs are based on recent vendor quotes for similar equipment or in-house data. Construction commodities and indirect costs are based on our experience. Burns & McDonnell did not solicit bids from equipment manufacturers or contractors for equipment or construction services. A capital cost summary comparing each of the coal fired facilities and the combined cycle facility is included in Table 6-1.

6.1.1 Capital Cost Estimate Assumptions

The cost basis for each of the various options is described in the Attachments to this report, including Attachments A and G. In addition to these technical descriptions, the following are the major assumptions and exclusions upon which the facility cost estimates are based:

- Project will be executed under multiple Engineer-Procure-Construct (EPC) Contracts.
- Cost estimate is based on open shop labor force for the Big Stone City, South Dakota area, 50-hour work week, single shift (see Section 6.1.3 below for estimated cost impact for union labor force).
- Rail access is nearby and suitable for receipt of heavy equipment.
- Cost estimate includes escalation to support commercial operation in 2010. Escalation at the rate of 2.5% to the midpoint of the Project's construction in 2008 is included in the estimate.
- No piles have been included. All foundations are assumed to be spread footings or matt foundations.
- Rock, existing structures, underground utilities, or other obstructions will not be encountered in the area of the plant.
- Hazardous substances will not be encountered in the area of the plant.
- No aesthetic landscaping or structures are included.

6.1.2 Capital Cost Estimate Exclusions

The following are not included in the scope of this cost estimate:

- Transmission interconnection/upgrades.

- Switchyard costs.
- Initial fuel inventory.
- Off-site road, bridge, or other improvements.
- Owner corporate staffing.
- Development costs.
- Maintenance Equipment.

6.1.3 Limitations, Qualifications and Estimate Risk Assessment

The estimates and projections prepared by Burns & McDonnell relating to construction costs and schedules are based on our experience, qualifications and judgment as a professional consultant. Since Burns & McDonnell has no control over weather, cost and availability of labor, material and equipment, labor productivity, construction contractor's procedures and methods, unavoidable delays, construction contractor's method of determining prices, economic conditions, government regulations and laws (including interpretation thereof), competitive bidding and market conditions or other factors affecting such estimates or projections, Burns & McDonnell does not guarantee that actual rates, costs, performance, schedules, etc., will not vary from the estimates and projections prepared by Burns & McDonnell.

Due to the capital intensive nature of solid fuel generation resources are and length of construction period, there is capital cost risk due to interest costs, labor availability and costs, and general inflation. Other risk factors associated with the construction of new solid fuel generation plants include the fact several US boiler manufacturers are currently under financial duress, and the skilled workforce that constructed a number of coal units in the 1970's and 1980's have aged without a significant influx of younger construction workers with similar specialized skills and experience. If a number of new coal units initiate construction within the next decade, the supply of skilled construction workers could be strained. The primary tradeoff for these higher capital risks with a solid fuel generation resource is the long-term stability of coal and other solid fuel alternatives, which have few competing uses relative to natural gas that is used by almost all economic sectors including residential heating.

If the project is performed with a union labor force in lieu of an open shop work force, Burns & McDonnell estimates that the cost impact to the Project will be approximately $57,000,000. This estimate is based on predominately on contractors self performing their work without multi-layers of subcontractor markup.

6.2 OPERATIONS & MAINTENANCE (O&M) COST ESTIMATE BASIS

A summary of the calculated variable and fixed O&M costs for each of the options is included in Table 2-1. An O&M cost summary sheet for the 600MW PC case is included as part of Table 6-1 included in this section. These costs were estimated based on the assumptions discussed below.

6.2.1 Staffing

The additional staffing required for each of the six coal fired options was estimated and added to the existing Big Stone Unit I staff. Half of the total staff of 104 for both units was capitalized and included in the O&M cost estimates for Big Stone Unit II.

6.2.2 Ash Disposal

For each of the six coal fired options, the estimated ash disposal costs was adjusted to account for the expansion of the existing landfill. An ash disposal cost of $1/ton was used up until the time that construction on a landfill expansion would start. Then the ash disposal cost was adjusted based on the cost of expanding the existing landfill. However, the adjusted ash disposal cost was only assigned a portion of the landfill expansion cost, based on the estimated yearly ash productions of both units.

The ash disposal costs are based on the assumption that none of the ash being produced will be sold.

6.2.3 O&M Cost Estimate Assumptions

The following costs were assumed in estimating the non-fuel variable O&M Costs:

- Ash Disposal, $1/ton (not including landfill expansion cost)
- Limestone, $12/ton
- Lime, $65/ton
- Anhydrous Ammonia, $450/ton
- Activated Carbon, $1,040/ton

TABLE 6-1: COST ESTIMATES

Description	600 MW PC Dollars	600 MW CFB Dollars	450 MW PC Dollars	450 MW CFB Dollars	300 MW PC Dollars	300 MW CFB Dollars	500 MW CC Dollars
PROCUREMENT							
Mechanical Procurement							
Steam Turbine - Generator	$ 40,143,000	$ 40,143,000	$ 34,043,000	$ 34,043,000	$ 23,743,000	$ 23,743,000	$ 22,520,000
Boiler Island/APC Equipment	$ 137,726,125	$ 134,400,000	$ 111,097,628	$ 116,350,642	$ 80,301,832	$ 74,450,000	$ 25,500,000
Surface Condenser & Air Removal Equipment	$ 4,000,000	$ 4,046,982	$ 3,302,140	$ 3,350,000	$ 2,537,092	$ 2,580,000	$ 1,745,000
Boiler Feed Pumps	$ 3,579,866	$ 3,250,366	$ 3,274,260	$ 2,919,413	$ 2,155,971	$ 2,155,971	$ 1,100,000
Condensate Pumps/Circulating Water Pumps	$ 1,460,500	$ 1,460,500	$ 1,294,800	$ 1,294,800	$ 860,200	$ 860,200	$ 754,518
Miscellaneous Mechanical Equipment	$ 8,431,828	$ 9,243,024	$ 7,284,232	$ 8,006,613	$ 5,401,223	$ 5,046,634	$ 10,256,019
Gas Turbine - Generator	$ -	$ -	$ -	$ -	$ -	$ -	$ 50,000,000
Electrical & Control Procurement							
GSU, Auxiliary Transformers	$ 3,000,000	$ 3,000,000	$ 2,740,000	$ 2,500,000	$ 2,250,000	$ 2,250,000	$ 3,700,000
Medium Voltage Metal-Clad Switchgear	$ 3,815,000	$ 4,010,000	$ 3,780,000	$ 2,930,000	$ 2,940,000	$ 3,170,000	$ -
480 V Switchgear & Transformers	$ 2,630,000	$ 2,275,000	$ 2,710,000	$ 2,845,000	$ 2,200,000	$ 1,830,000	$ 1,180,000
Miscellaneous Electrical Equipment	$ 4,397,095	$ 5,422,095	$ 3,742,095	$ 5,372,579	$ 4,065,158	$ 3,505,158	$ 2,860,000
Control Procurement	$ 6,386,810	$ 7,919,135	$ 6,386,810	$ 7,919,135	$ 6,386,810	$ 5,316,335	$ 1,796,750
Water Treatment Procurement	$ 6,008,447	$ 6,201,698	$ 5,352,349	$ 5,634,041	$ 4,256,561	$ 4,858,033	$ 1,778,419
Structural Procurement	$ 6,947,600	$ 6,947,600	$ 4,298,660	$ 4,448,660	$ 3,024,272	$ 2,364,872	$ 370,000
CONSTRUCTION							
Major Equipment Erection							
Steam Turbine - Generator Erection	$ 7,299,476	$ 7,299,476	$ 6,533,100	$ 6,533,100	$ 3,064,822	$ 3,032,689	$ 1,957,587
Boiler Island/APC Equipment Erection	$ 116,689,119	$ 111,245,290	$ 95,668,229	$ 96,861,202	$ 69,323,463	$ 61,324,147	$ 7,963,810
Gas Turbine - Generator Erection	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,942,795
Furnish & Erect Packages							
Cooling Tower	$ 5,869,201	$ 6,489,420	$ 4,424,196	$ 4,890,788	$ 2,934,284	$ 3,013,758	$ 2,381,432
Material Handling Systems	$ 32,445,129	$ 40,885,000	$ 31,515,032	$ 37,055,000	$ 21,979,559	$ 24,460,000	$ -
Chimney	$ 7,500,000	$ 10,000,000	$ 4,000,000	$ 5,000,000	$ 4,000,000	$ 4,000,000	$ -
Civil / Structural Construction	$ 75,969,620	$ 77,991,540	$ 59,404,432	$ 63,122,832	$ 45,532,849	$ 44,743,870	$ 34,428,022
Mechanical Construction	$ 79,384,418	$ 84,449,880	$ 68,972,544	$ 78,324,026	$ 45,559,000	$ 44,210,517	$ 33,993,518
Electrical Construction	$ 31,351,008	$ 36,029,014	$ 28,213,811	$ 30,479,349	$ 20,876,458	$ 22,119,741	$ 9,353,751
EPC INDIRECTS							
Construction Management	$ 23,706,897	$ 24,760,536	$ 22,653,257	$ 23,706,897	$ 21,072,797	$ 21,072,797	$ 9,337,274
Preoperational Testing, Startup, & Calibration	$ 13,932,471	$ 15,819,147	$ 12,204,936	$ 14,120,941	$ 9,340,427	$ 9,246,360	$ 2,460,000
Miscellaneous Construction Indirects	$ 4,619,750	$ 4,988,250	$ 4,469,750	$ 4,838,250	$ 4,174,220	$ 4,174,220	$ 2,425,000
Project Management & Engineering	$ 38,000,000	$ 41,800,000	$ 29,925,000	$ 32,917,500	$ 20,900,000	$ 20,900,000	$ 12,350,000
Project Bonds	$ 4,050,000	$ 4,050,000	$ 3,375,000	$ 3,375,000	$ 2,400,000	$ 2,400,000	$ 1,440,000
Escalation	$ 66,331,761	$ 72,059,325	$ 58,204,281	$ 62,167,184	$ 42,696,165	$ 41,195,893	$ 27,309,006
Contractors Contingency/Overhead & Profit	$ 121,239,260	$ 126,267,499	$ 101,989,700	$ 108,933,781	$ 74,815,272	$ 72,186,387	$ 26,782,441
TOTAL EPC PROJECT COST	**856,914,381**	**892,453,776**	**720,859,242**	**769,939,735**	**528,791,434**	**510,210,583**	**299,685,342**
Owner Costs							
Project Development	Not Included	Not Included	Not Included	Not Included	Not Included	Not Included	Not Included
Owner Operations Personnel	$ 2,856,373	$ 2,972,000	$ 2,855,000	$ 2,972,000	$ 2,816,000	$ 2,816,000	$ 1,250,000
Switchyard	Not Included	Not Included	Not Included	Not Included	Not Included	Not Included	Not Included
Transmission Interconnection/Upgrades	Not Included	Not Included	Not Included	Not Included	Not Included	Not Included	Not Included
Land	$ 1,440,000	$ 1,440,000	$ 1,200,000	$ 1,200,000	$ 720,000	$ 960,000	$ 420,000
Permitting & License Fees	$ 2,342,513	$ 2,342,513	$ 2,342,513	$ 2,342,513	$ 2,342,513	$ 2,342,513	$ 287,200
Initial Fuel Inventory	Not Included	Not Included	Not Included	Not Included	Not Included	Not Included	Not Included
Miscellaneous Owner Costs	$ 16,676,090	$ 17,010,912	$ 14,419,680	$ 15,013,639	$ 11,495,690	$ 11,175,884	$ 7,683,908
Owner Indirects							
Owner's Engineer	$ 15,700,000	$ 15,700,000	$ 15,700,000	$ 15,700,000	$ 15,700,000	$ 15,700,000	$ 3,498,000
Startup/Testing	$ 1,174,640	$ 1,688,572	$ 895,021	$ 1,282,493	$ 685,604	$ 816,832	$ 816,832
Escalation Owner's Indirects	$ 4,172,200	$ 4,272,315	$ 3,883,870	$ 3,997,901	$ 3,504,703	$ 3,510,041	$ 3,510,041
Sales Tax & Duties	$ 24,550,722	$ 25,151,794	$ 20,360,899	$ 21,685,186	$ 15,130,706	$ 14,272,661	$ 9,308,282
Owner Contingency	$ 74,066,154	$ 77,042,551	$ 62,601,298	$ 66,730,677	$ 46,494,932	$ 44,944,361	$ 25,372,106
TOTAL OWNER COSTS	**142,978,691**	**147,620,658**	**124,258,280**	**130,924,410**	**98,890,148**	**96,538,294**	**52,146,370**
TOTAL PROJECT COST	**$ 999,893,073**	**$ 1,040,074,434**	**$ 845,117,522**	**$ 900,864,144**	**$ 627,681,583**	**$ 606,748,877**	**$ 351,831,712**

OTTER TAIL
BIG STONE UNIT II
1x600 MW PC SUPERCRITICAL
BMCD PROJECT 35424

Operating Assumptions								
Capacity Factor						88.0%		
Net Unit Ouput, kW						600,000		
Number of Units						1		
Net Output, kW						600,000		
Net Output, MWh						4,625,280		
Fixed O&M (2004$)								
Labor	52 people @	$ 77,529			$	4,031,491		
Office & Admin					$	250,000		
Other Fixed O&M					$	1,209,000		
Employee Expenses/Training								
Contract Labor								
Environmental Expenses								
Safety Expenses								
Buildings, Grounds, and Painting								
Other Supplies & Expenses								
Communication								
Control Room/Lab Expenses								
Annual major maintenance service director fee						*Not Included*		
Start-up power demand charge	$ -	per kW-Mo	0 KW		$	-		
Water supply demand charge	$ -	per acre-ft	0 acre-ft		$	-		
Water discharge demand charge	$ -	per acre-ft	0 acre-ft		$	-		
Standby Power Energy Costs	$ -	per kW-hr	0 KW-hr		$	-		
Standby Power Service Fee	$ -	per Month	0 Mo		$	-		
Property Taxes						*In Proforma*		
Insurance						*In Proforma*		
Total Fixed O&M Annual Cost					$	5,490,491		
Non-Fuel Variable O&M (2004$)								
Water Consumption								
Plant Makeup Water	0 MMGal/yr @		$0.00 /kGal		$	-	$ -	$/MWh
Potable Water	0 MMGal/yr @		$0.00 /kGal		$	-	$ -	$/MWh
Water Discharge	0 MMGal/yr @		$0.00 /kGal		$	-	$ -	$/MWh
Other Variable O&M					$	4,625,280	$ 1.0000	$/MWh
Electronics, Controls, BOP Electrical								
Steam Generators								
Steam turbine Generators								
BOP								
Misc. Maintenance Expenses								
Consummables								
Chemical Feed								
Lime Consumption	15,065 tpy @		$65.00 /ton		$	979,227	3.6407	tons/tonSulfur
SCR Ammonia	1,730 tpy @		$450.00 /ton		$	778,546	0.7481	lbs/MWh
SCR Catalyst Replacements & Disposal	$4,261,407	Catalyst Cost	3 yrs life		$	1,420,469	$ 0.3071	$/MWh
Ash and Scrubber Waste Disposal	153,338 tpy @		$1.00 /ton		$	153,338	0.0716	ton/coalton
Carbon Consumption	5,082 tpy @		$1,040.00 /ton		$	5,285,388		
Emissions								
NOx Allowance			$0.00 /ton			*In Proforma*		
SOx Allowance			$0.00 /ton			*In Proforma*		
CO2 Allowance			$0.00 /ton		$	-		
HG Allowance			$0.00 /lb			*In Proforma*		
Total Non-Fuel Variable O&M Annual Cost					$	13,242,248	$ 2.8630	$/MWh
Total Fixed and Variable O&M Annual Cost					$	18,732,739		
Total Fixed O&M Annual Cost, $/kW-yr						9.15		
Total Non-Fuel Variable O&M Annual Cost, $/MWh					$	2.86		
Total O&M Cost, $/MWHr						4.05		

Notes:

1. O&M costs do not include the following:
   - Taxes
   - Insurance
   - Emissions allowances
   - Firm fuel supply costs
   - Wheeling costs
   - Fuel
   - Backup or standby power
   - Initial spares, pre-op costs(computers, software, office equipment, etc.), or O&M mobilization fees

SECTION 7
PROJECT PERFORMANCE AND EMISSION ESTIMATES

7.0 PROJECT PERFORMANCE AND EMISSIONS ESTIMATES

A total of three solid fuel fired technologies, Pulverized Coal (PC), both subcritical and supercritical, and Circulating Fluidized Bed Combustion (CFB) were evaluated. The fuel for each of the different solid fuel technologies was PRB. In addition, a typical 500 MW Combined Cycle (CCGT) gas fired unit firing pipeline quality natural gas was evaluated. This section addresses each technology with respect to the expected plant performance and emissions.

7.1 PERFORMANCE ESTIMATES

The performance estimates summarized in this section were based on in-house data and information from similar projects. A performance summary comparing each of the coal fired facilities being evaluated is included in Table 7-1 below:

Table 7-1: Solid Fuel Units Performance Estimates

Boiler Type Description	PC 600 MW Supercritical	CFB 600 MW 1050/1050	PC 450 MW Supercritical	CFB 450 MW 1050/1050	PC 300 MW Subcritical 1050/1050	CFB 300 MW 1050/1050
STG Heat Rate (Btu/kW-hr)	7,201	7,520	7,221	7,540	7,470	7,470
STG Gross Output (kW)	662,446	674,479	496,850	505,814	328,590	337,080
Boiler Efficiency (%)	85.5%	84.5%	85.5%	84.5%	85.5%	84.5%
Auxiliary Power (kW)	62,446	74,485	46,850	55,859	28,587	37,079
Auxiliary Power (%)	9.4%	11.0%	9.4%	11.0%	8.7%	11.0%
Net Plant Heat Rate (Btu/kW-hr)	9,392	10,105	9,418	10,132	9,665	10,033
Net Plant Output (kW)	600,000	599,995	450,000	449,955	300,003	300,001

Table 7-2 summarizes expected performance for a typical 500 MW gas fired combined cycle facility with gas turbine inlet cooling and without duct burning. Further, the plant performance in Table 7-2 is representative of a 2x1 arrangement consisting of two "F" class gas turbines and a D11 STG.

Table 7-2: CCGT Performance Estimates

ST Output (kW)	190,000
CTG Output (kW)	325,000
Auxiliary Power (kW)	13,000
Auxiliary Power (%)	2.5
Net Plant Heat Rate (Btu/kW-hr)	7,000
Net Plant Output (kW)	502,000

7.1.1 PC Boiler Description

Conventional pulverized coal technology is a reliable energy producer around the world and is characterized by the operating pressure of the cycle, subcritical and supercritical. Subcritical and supercritical technology refers to the state of the water that is used in the steam generation process.

7.1.1.1 Subcritical PC Boiler Performance

Subcritical power plants utilize pressures below the critical point of water (3206.2 psia@705F) in which there is a distinct difference between liquid and vapor states of water. These units utilize a steam drum and internal separators to separate the steam from the water. In this evaluation, the plants using a PC boiler consists of one steam generator and one steam turbine generator.

In the steam generator, high-pressure steam is generated for main steam to the steam turbine. The steam conditions are typically 2400 psig and 1000°F at the steam turbine inlet. However, cycle efficiency was improved by estimating the performance based on running with the steam turbine at valves wide open (VWO) to the maximum steam turbine inlet pressure of 2520 psig as well as superheating the steam to 1050°F. These adjustments result in a net efficiency gains over efficiencies of typical steam conditions listed above.

7.1.1.2 Supercritical PC Boiler Performance

The general description of the supercritical units is very similar to that of the subcritical units described earlier. The major difference is that the steam generator is a once through system and does not include a steam drum. Since there is no steam drum to allow blowdown of impurities in the system, water chemistry is critical to maintain a reliable system. A full-flow condensate polisher has been included into the condensate system to clean the condensate of impurities.

For the supercritical units used in this performance estimates, steam conditions at the steam turbine inlet of 3500 psig (unit operating with VWO) and 1050°F provide an increase in turbine efficiency over standard subcritical units with steam conditions of 2400 psig and 1000°F.

For the supercritical unit, the auxiliary power consumption is expected to be substantially more compared to a subcritical unit. In a typical subcritical unit, the boiler feedwater pumps require less of the turbine output. However, the increase is justified in the improved thermal cycle efficiency.

7.1.2 CFB Boiler Description

Circulating fluidized bed combustion occurs in a suspended or "fluidized" bed of fuel, limestone, char, and ash inside a boiler at atmospheric pressure. This fluidized bed of material is suspended with combustion air that is forced in vertically at the bottom of the boiler. Some of materials in the bed become entrained in the flue gas and carried out of the furnace. This material is collected with cyclone separators or other collection device at the furnace outlet and injected back into the bed at the base of the furnace.

7.1.2.1 CFB Boiler Performance

As with the subcritical PC units, the steam conditions for the CFB boiler are typically 2400 psig and 1000°F at the steam turbine inlet. However, once again, cycle efficiency was improved by estimating the performance based on running with the steam turbine at VWO to the maximum steam turbine inlet pressure of 2520 psig as well as superheating the steam to 1050°F. These adjustments result in a net efficiency gain over efficiencies of typical steam conditions listed above.

7.1.3 CCGT Description

The basic configuration is a 2x1 7FA General Electric Frame technology. The power block consists of two 7FA technology combustion turbine generators at 175MW nominal, and two heat recovery steam generators (HRSGs) and one reheat steam turbine at 200MW nominal. The primary fuel source is natural gas.

7.1.4 Start-up and Load Following

Cold start-up times for a CFB boiler are commonly in the 15-24 hour range compared to a subcritical PC boiler start-up time of 4-5 hours. CFB boiler's capability for load following is also reduced compared to a PC boiler due to limitations in thermal change rates of the thick refractory utilized in the bed section of a fluidized bed boiler. This limitation would present a significant challenge to a large power facility operating one or more units in load following operation.

Supercritical boilers are capable of reaching maximum load 15% to 20% faster than subcritical units due to the lack of a steam drum and other thick water wall components. However, supercritical units should be base loaded units due to the economic advantage of the cycle.

Combined cycle units are capable of achieving full load within 90 minutes on a hot start and within 4 hours on a cold start.

7.2 EMISSIONS ESTIMATES

A Best Available Control Technology (BACT) review of this facility has not been performed. However, based on recent determinations and conversations with OTP, we have assumed that the following combination of technologies forms the basis of the design.

7.2.1 PC Boiler Emissions

Pulverized coal-fired steam generator technology firing low-sulfur, PRB fuel:

- Selective Catalytic Reduction (SCR) for NO_x control.
- Carbon injection system for mercury (Hg) control
- Spray dryer absorber for SO_2 control.
- Fabric filter for particulate (PM_{10}) control.

The 600 MW PC option and the 450 MW PC option will each have two spray dryers while the 300 MW PC option will only have one.

7.2.2 CFB Boiler Emissions

Circulating fluidized bed steam generator technology firing low-sulfur, PRB fuel:

- Limestone injection into the boiler for SO_2 control.
- Selective Non-catalytic Reduction (SNCR) for NO_x control.

- Carbon injection system for mercury (Hg) control
- Fabric filter for particulate (PM_{10}) control.

7.2.3 CCGT Emissions

A combined cycle technology firing pipeline quality natural gas:

- Dry low NO_s combustors and SCR for NO_s control.
- Catalyst for CO control.

7.2.4 Expected Pollutant Limits

Based on the control technology described above, the emissions estimates for the two types of coal fired plants being evaluated are as follows:

Table 7-2: Emissions Estimates

Pollutant	PC Limit	CFB Limit	CCGT Limit
NO_x	0.07 lb/MMBtu	0.08 lb/MMBtu	3PPMvd@15%O_2
SO_2	0.12 lb/MMBtu	0.12 lb/MMBtu	Calc. from Fuel Input
PM_{10}	0.018 lb/MMBtu	0.018 lb/MMBtu	Calc. from Fuel Input
Hg	2 x 10^{-5} lb/MW-hr	2 x 10^{-5} lb/MW-hr	Not Required
CO	Good Combustion Practices	Good Combustion Practices	3PPMvd@15%O_2

Even though a spray dryer absorber was assumed for the pulverized coal options in this study, it is recommended that a detailed comparison between a spray dryer and a wet scrubber be completed in Phase II of this assessment. The detailed comparison should account for both sulfur dioxide and mercury control.

SECTION 8
CONCLUSIONS AND RECOMMENDATIONS

8.1 ECONOMIC CONCLUSIONS

The most cost-effective coal fired project is a 600 MW PC supercritical unit. Larger plant sizes such as 600 MW will result in improved economics due to reduced capital costs and reduced O&M costs. For the larger plant sizes, PC technology is preferred to CFB technology for the following reasons.

1. CFB technology is more capital cost intensive, therefore low cost opportunity fuels must be utilized in order for it to be competitive with PC technology.
2. The efficiencies of a larger supercritical PC unit versus a subcritical unit with two steam generators feeding one steam turbine presents an inherent performance advantage and a capital cost advantage for the PC unit.
3. The cost savings for using small amounts of cheaper opportunity fuels in a CFB unit is too small to offset additional cost if the main source (PRB) represents 90% of the heat input for both technologies.

Coal-fired generation resources are significantly more capital intensive than natural gas combined cycle plants, and have a construction period that can be more than twice the length of a combined cycle plant. This results in substantially more capital risk due to interest costs, labor availability and costs, and general inflation. Other risk factors include the stability of boiler manufacturers and the availability of a skilled workforce. The primary tradeoff for these higher capital risks with a solid fuel generation resource is the long-term stability of coal and other solid fuel alternatives.

8.2 SENSITIVITY ANALYSIS RESULTS

A sensitivity analysis was prepared for the 450 MW PC unit for both the investor owned utility and public power options, as well as the 500 MW CCGT reference case for both the investor owned utility and public power options under the following cases:

- Capital Cost (plus or minus 10%)
- Interest Rate (plus or minus one (1) percentage point)
- Capacity Factor (plus or minus 5%)
- Fuel Cost (plus or minus 20%)
- O&M Costs (plus or minus 10%)

The results of the sensitivity analyses are presented in tornado diagrams in Figures 3-3, 3-4, 3-5 and 3-6. For an investor owner utility, the sensitivity analysis indicates that capital cost and fuel cost are the two most significant factors affecting the economics of a coal-fired unit. For a public power utility, the interest rate is the most significant factor affecting the economies of a coal-fired unit. Delivered fuel cost by far has the strongest impact on the overall economics of a combined cycle unit for any owning entity. This is an important result since the market price of natural gas is inherently volatile and nearly impossible for a utility to control over the long term. Hence, many utilities have a renewed interest in coal generation with its more stable fuel costs as means to protect customers from future natural gas market conditions.

8.3 RECOMMENDATIONS

B&McD recommends that OTP proceed with preliminary engineering to support the permit process for a 600MW PC unit based on the economic analysis presented in Section 3. Based on the extensive study conducted by B&McD regarding water treatment and wastewater management and the unique problems this presents at the Big Stone station (see Section 9, Attachment E), the technology should be based on utilizing a cooling tower for unit heat rejection.

Based on pricing information provided by Babcock & Wilcox regarding a cyclone type boiler, similar to Big Stone I, at this point it does not appear to be a cost effective option. When the boiler is specified for procurement (either by a multiple contract approach or as part of an EPC contract), an alternate bid may be requested for the cyclone design to determine if the economics are more favorable at that time.

8.4 STATEMENT OF LIMITATIONS

In preparation of this Feasibility Study, Burns & McDonnell has made certain assumptions regarding future market conditions for construction and operation of solid fuel generation resources. While we believe the use of these assumptions is reasonable for the purposes of this Feasibility Study, Burns & McDonnell makes no representations or warranties regarding future inflation, labor costs and availability, material supplies, equipment availability, weather, and site conditions. To the extent future actual conditions vary from the assumptions used herein, perhaps significantly, the estimated costs presented in the Feasibility Study may vary.

SECTION 9
ATTACHMENTS

9.1 ATTACHMENT DESCRIPTIONS

These attachments support the body of the document and provide additional technical detail where necessary. Section 9 includes the following attachments:

- Attachment A – Plant Technical Description: A technical description of the six coal options and a combined cycle natural gas unit that were considered for this study. The descriptions include all major systems and equipment.

- Attachment B – Schedule: Includes the study, permitting, design, and construction schedule for a 300 and 600 MW PC unit, as well as a 500 MW combined cycle natural gas unit.

- Attachment C – Water Balance Diagrams: The water balance diagrams for all six coal units considered.

- Attachment D – Coal / Reagent Analysis: Includes a historical coal analysis from the existing unit, and a typical lime and limestone chemical analysis.

- Attachment E – Water Treatment and Wastewater Management: The entire water study, including: a cooling tower vs. cooling pond study; an evaluation of several water treatment options; an evaluation of wastewater management options; and comparative costs.

- Attachment F – Site Plan: Site plans for the six coal options considered. All site plans are for cooling tower arrangements and include expansion of the existing cooling pond for additional Unit 1 cooling capacity.

- Attachment G – Fuel Handling System Descriptions and Schematics: Describes the existing fuel handling system and details the upgrades and equipment necessary to accommodate the additional unit. Attachment G also includes fuel handling schematics of 300, 450, and 600 MW units for PC, CFB, and Cyclone boilers.

- Attachment H – Electric One Lines: Includes the electrical one line diagrams for all six coal options that were evaluated.

- Attachment I – Control System Conceptual Architecture: Includes control system architectures for 600 MW PC and CFB units.

- Attachment J – Contracting Alternatives: Includes description of various contracting methods for design, procurement and construction of the new generating unit.

- Attachment K – Pro Forma Model: Includes all pro forma input and output information for the 450MW pulverized coal unit case for the Investor Owned Utility and the Public Power Utility scenarios.

1.0 INTRODUCTION

The generating facilities that will be considered for the new generation include:

1) 600 MW net Supercritical Pulverized Coal (PC)
2) 450 MW net Supercritical PC
3) 300 MW net Subcritical PC
4) 600 MW net Subcritical Circulating Fluidized Bed (CFB)
5) 450 MW net Subcritical CFB
6) 300 MW net Subcritical CFB
7) 500 MW net Combined Cycle Natural Gas
8) 550 MW net Integrated Gasification Combined Cycle (IGCC)
9) 250 MW net Wind

Options 1 through 8 involve constructing a new unit (Big Stone II) at the existing Big Stone I site near Big Stone City, South Dakota. Existing Big Stone unit I is a coal fired cyclone unit that produces 450 MW of net generation.

The 600 MW PC, 600 MW CFB and 500 MW CCNG are base cases that will be reviewed in-depth. The smaller units are alternates to the base cases, and only systems that differ from their respective base case will be discussed. Integrated Gasification Combined Cycle (IGCC) and Wind technologies were considered as alternative generation technologies and are addressed in Sections 8 and 9 respectively, at the end of this Attachment.

The earliest commercial operation date for Big Stone II is June 2010. Permitting issues may delay the date until Spring 2011. Due to the time period between the development of this study and the project's execution, all of the estimates prepared by Burns & McDonnell are based on current technology and market conditions, with normally anticipated market escalation included to the Project's construction midpoint in 2008.

2.0 BASE CASE 1: 600 MW SUPERCRITICAL PULVERIZED COAL STEAM GENERATOR (BOILER)

2.1 GENERAL DESIGN CRITERIA

2.1.1 Project Description

Base Case 1 includes construction of a 600 MW (net) electric generating station utilizing a single pulverized coal (PC) fired steam generator (boiler) and a single, reheat steam turbine on a brownfield site. The proposed location is adjacent to the existing Big Stone Unit I cyclone unit.

The system will be designed to operate on Powder River Basin (PRB) sub-bituminous coal. An existing rail spur will be used to provide the PRB coal supply via unit train. Existing dumping facilities will be used for coal unloading.

The PC-fired steam generator will be balanced-draft combustion with reheat. Additional features will include selective catalytic reduction (SCR) for NO_x reduction, a spray dryer absorber for sulfur dioxide (SO_2) removal and a pulse-jet fabric filter (baghouse) for particulate collection. Steam generated by the steam generator will be supplied to the steam turbine to complete the power generation cycle. The steam turbine will include eight stages of feedwater heating for the supercritical (3500 psig 1050 / 1050 °F) cycle. Treated cooling water for the water-cooled surface condenser will be provided from a closed loop circulating water system that includes a mechanical draft cooling tower and circulating water pumps. Raw water for the cooling system will be supplied from the existing Big Stone Unit I cooling pond.. The water for the cooling pond will be supplied from Big Stone Lake via an existing water line.

Electrical output from the Project will be stepped up to 230 kV and interconnected with the MAAP transmission system. All interconnection costs from the high side bushings of the main step-up and start-up transformers to the transmission system are included in a separate study conducted by the Owner.

2.1.2 Operating and Control Philosophy

The facility is expected to be operated at base load. The project is configured to normally operate at maximum continuous rating (MCR) output. The proposed units are capable of load following with overnight/weekend/holiday load reductions (steam generator at 50-percent load), however the advantage of a supercritical unit is its superior cycle efficiency operating at base load.

All routine start-up and shutdown operations will be from a central control room via a distributed control system (DCS). The Unit II control room will be located in the existing Unit I control room. In addition to the existing Unit I control staff, the Unit II operating staff will consist of two control room operator, one shift supervisor, and one roving operator per shift. There will also be an additional fuel/ash operator on all shifts with the exception of the 300MW solid fuel units. The shift supervisor and control room operator for each shift will be thoroughly trained in all aspects of plant controls and will be fully qualified to operate all plant systems. The shift supervisor will direct shift operations, make assignments, and perform required administrative duties. The shift supervisor will also serve as a second operator during emergencies and provide periodic relief for the primary control room operator.

Big Stone Unit II will share operational staff with the existing unit. The existing staff of 74 employees will be expanded to 104 employees to accommodate the unit expansion. By sharing staff, both units will benefit from added flexibility and will be able to operate with fewer on-site staff per unit.

Facility automation will be designed to insure secure and safe operation of all equipment. Maintenance support will be supplied by on-site staff as required for routine maintenance activities. Maintenance support for major shutdowns is expected to be contracted.

The level of equipment redundancy included in the cost estimates for the facility are based on discussions with Otter Tail Power and a preliminary list developed between Burns & McDonnell and Otter Tail Power that represents accepted industry standards for similar utility grade units.

The Project is not configured to generate electricity while isolated from the utility grid or to have "black-start" capability.

2.1.3 Design Conditions

The following site ambient conditions were used as the basis for preliminary design.

1) Site Elevation — 1123 feet above MSL
2) Extreme Summer Maximum (degree F_{db}): — 112
   a) Applicable design conditions for the following:
      (1) Equipment cooling (lube oil, generators, etc).

(2) Motor design.
(3) Water supply.

3) Summer Design – 0.4 % of time above (F_{db} / F_{wb}): 99 / 76
   a) Applicable design conditions for the following:
      (1) Cooling tower.
      (2) Steam turbine condenser.
4) Average Ambient (degree F_{db} / %RH): 45 / 70%
   a) Applicable design conditions for the following:
      (1) Steam generator.
      (2) Steam system performance optimization.
5) Winter Design – 99 % of time above (degree F_{db}): -16
   a) Applicable design conditions for the following:
      (1) HVAC heating systems.
      (2) Steam turbine.
      (3) Insulation systems.
6) Extreme Winter Minimum (degree F_{db}): -44
   a) Applicable design conditions for the following:
      (1) Freeze Protection.
      (2) Heating of heated areas.
7) Precipitation:
   a) Minimum Annual: 9.7 inches
   b) Average Annual: 19.1 inches
   c) Maximum Annual: 31.7 inches
   d) Maximum 24 Hour Rain: 5.3 inches
   e) Maximum 24 Hour Snow: 18.3 inches
8) Prevailing Wind Direction:
   a) Summer: Northwest
   b) Winter: Southeast
   c) Annual: South-southeast
9) Seismic Zone: Zone 0 (1997 Uniform Building Code)

2.1.4 Equipment Location

Both the steam turbine-generator and steam generator (boiler) will be located indoors.

2.1.5 Emissions Criteria

A Best Available Control Technology (BACT) review of this facility has not been performed. However, based on recent determinations, we have assumed that the following combination of technologies forms the basis of the design.

- Pulverized coal-fired steam generator technology firing low-sulfur, Powder River Basin fuel.
- Selective catalytic reduction (SCR) for NO_x control.
- Spray dryer absorber for SO_2 control.
- Carbon injection system for mercury control.
- Fabric filter for particulate control.

Based on the above, the conceptual design included in this study will meet the following emissions criteria.

Pollutant	Limit
NO_x	0.07 lb/MMBtu
SO_2	0.12 lb/MMBtu
Hg	2×10^{-5} lb/MW-hr
PM / PM_{10}	0.018 lb/MMBtu

2.1.6 Fuel and Reagents

Primary fuel for the pulverized coal-fired steam generator will be low sulfur coal supplied from mines in the Powder River Basin area of Wyoming and Montana. This fuel is relatively high moisture, low sulfur Western sub-bituminous coal with excellent combustion but low grindability qualities.

OTP will procure this fuel and arrange for coal freight service. The Project does not include any additional spurs from the existing mainline. OTP will utilize the existing unloader to serve the facility using rotary dump-type railcars. Attachment G of this report outlines the fuel handling modifications to support the various technology options for the new unit.

The existing No. 2 fuel oil system will be used to supply start-up fuel for the new steam generator. The new unit will also use the existing auxiliary boiler for start-up when auxiliary steam from Big Stone I is not available.

Lime can be delivered by rail or truck to the site. It will then be slaked to form a calcium hydroxide ($Ca(OH)_2$) slurry that will be injected into the spray dryer to react with the sulfur dioxide in the flue gas. The lime is expected to come from existing sources in the region.

Anhydrous ammonia will be delivered by truck to the site. It will be diluted with air and be injected at the economizer outlet, upstream of the SCR catalyst to reduce NOx emissions.

Activated carbon will be delivered by truck. The activated carbon will then be injected in to the flue gas upstream of the spray dryer for mercury control.

2.1.7 Water Supply

Raw water will be supplied from Big Stone Lake using the existing water supply pumps and piping. Raw water will be pumped to the new makeup water storage pond for makeup to the existing Unit 1 cooling pond. Makeup to the Unit 2 cooling tower will be supplied from the existing cooling pond. A detailed evaluation of the water supply and wastewater management options is included in Attachment E. Water balance diagrams for the facility are included in Section 9, Attachment C.

Potable-quality water for drinking fountains, washrooms, showers, and toilet facilities will be supplied from a tie to the existing unit.

2.1.8 Wastewater

Surface water, collected from floor drains and containment areas around equipment, that may contain small amounts of oil, will be directed through an oil/water separator. The water discharged from the oil/water separator will be combined with other waste streams and discharged to the cooling pond. Collected oil from the oil/water separator will be burned, along with other plant-generated waste oils in one of the two coal-fired boilers for energy recovery.

A concentrated waste stream from the new holding pond (cooling tower blowdown pond) will be discharged to the existing brine concentrator, supplemented by a new brine concentrator. The new brine concentration will provide additional needed wastewater treatment and will provide some degree of redundancy for producing condensate for plant use as well as supply to the ethanol plant.

Storm water runoff from non-process equipment areas, such as parking lots and building roofs, will be directed through an on-site storm water collection system to a detention pond and released into the existing surface drainage system.

Sanitary waste, from showers, wash basins, and toilet facilities, will be collected for treatment in the existing treatment system.

2.1.9 Noise Criteria

A detailed noise study for this project has not been performed. For this Project, we have assumed that the steam generator, steam turbine-generator and other equipment are supplied with standard silencing equipment.

2.1.10 Electrical Interconnection

The turbine generator output will be connected through a generator stepup transformer to the existing 230 kV switchyard. The unit startup source will be provided through the addition of a 13.8 kV breaker to the switchyard 13.8 kV switchgear and via underground cable to the plant 13.8 kV switchgear in a manner similar to Unit 1. The switchyard 13.8 kV switchgear is connected to the tertiary of the 115/230 kV autotransformer. The tertiary has a maximum capability of approximately 50 mva that should be adequate for starting the unit but will not provide for full load operation in the event both unit auxiliary transformers are out of service.

2.1.11 Provisions for Future Facilities

Previous studies conducted by Burns & McDonnell have identified preferred locations for air pollution control equipment retrofits to Big Stone Unit 1, in the event that they were required by future regulatory developments. The potential locations for both spray dryer SO_2 absorbers and selective catalytic reduction (SCR) modules were identified as being along the north and south sides of the Unit 1 boiler building. In each case the gas flow would be divided into two streams, corresponding to the two air preheaters, with one stream treated in APC equipment modules to the north of the steam generator and the other to the south. The space to the south of the existing steam generator building would need to be reserved for these potential future APC equipment modules. This will affect the spacing between the new steam generator and the existing steam generator.

2.2 CIVIL / STRUCTURAL FEATURES

2.2.1 General

The site arrangement drawings can be found in Attachment F – Site Plans.

The elevation of the site varies from approximately 1060 feet MSL to 1140 feet MSL. Grade elevation of the main structures and supporting structures will be approximately 1126 feet MSL. Design of structures will be for 1997 Uniform Building Code (UBC) Seismic Zone 0.

The plant will be oriented with the axis of the steam generator perpendicular to the turbine axis. Future units (if any) will align with the turbine axis and expand to the west. The spray dryer and fabric filter will be located symmetrically about the boiler axis and extend to the north. The stack will be located west of the fabric filter.

Facility will be laid out to facilitate access to equipment and systems for maintenance and operations. Platforms will be provided to allow personnel to access equipment, valves and instrumentation requiring frequent (more than twice a year) attention for maintenance, calibration or operation. Stairs will be utilized to access platforms that are used more than once a week. Ladders will be utilized to access platforms that are used less than once a week.

The plant will consist of a number of buildings and structures. The primary structures include the steam turbine-generator structure, the steam generator structure, a tie bay between the units to connect the turbine halls that will also house an additional administrative office area of approximately 8,000 ft^2, the cooling tower, administration building, structures for handling and storage of fuel, lime, and ash, a 13,000 ft^2 yard maintenance building, and other miscellaneous structures. The main control room will be located in the existing Unit I control room. Roads, drives and parking areas will be located to provide a satisfactory circulation pattern and to provide access to all plant facilities.

Auxiliary buildings will be provided as required for the functions of the power generating facilities. Auxiliary buildings will be constructed, wherever possible, utilizing a pre-engineered building system.

2.2.2 Main Structures

The main structures will be the turbine, steam generator, spray-dryer absorber, fabric filters, chimney, yard maintenance building and the tie bay between turbine buildings. The turbine and steam generator will be located in adjacent enclosures. The fabric filters and spray dryer will be outdoors. The administration building will be located between the Unit I turbine enclosure and the Unit II turbine enclosure. The administration building will include the mechanical maintenance shop. Stairs, one elevator and platforms will provide full access within and to all enclosures and inspection/maintenance access to functional equipment parts.

Walls will be a system of insulated metal panels of galvanized steel on structural steel girts, having a factory-applied fluoropolymer coating with a life expectancy of at least 20 years.

The roofing will be standard lap-seam insulated roof panels fabricated from metallic coated steel sheets pre-painted with coil coating. Walkways will be provided where required for maintenance of roof-mounted equipment and where other foot traffic requirements dictate.

Control rooms, laboratory, offices and other finished areas will have walls combining metal studs, drywall and lightweight concrete block masonry. Toilet/locker room facilities will have glazed concrete block walls. Other partitions inside the plant will primarily be constructed of lightweight concrete block.

Toilets, washroom facilities, laboratories, control rooms and administrative facilities will have suspended acoustical ceilings with recessed lighting. Ceilings for all other areas will be exposed structure.

In general, all main structure ground floors will be constructed of concrete. Elevated floors will be constructed of concrete supported by steel deck or metal bar grating. Flooring materials in the laboratory, control room and other finished areas will be either vinyl composition tile with rubber base, or carpeting. Toilet/locker room facilities will have ceramic tile flooring. Mechanical equipment rooms will have hard-troweled natural gray concrete floors. All other concrete floors will have a troweled finish. Concrete floor coloring will be applied to the operating floor in the turbine room area. Chemical-resistant coatings will be applied to floors in areas exposed to oil, acid and chemicals.

Rolling steel doors will be provided for areas requiring vehicle access. Doors used frequently will be motor-operated. Others will be opened with hand crank operators. Personnel doors will be hollow metal swing-type or sliding-type.

2.2.3 Supporting Structures

Supporting structures include all other buildings as required for the functions of the power generating facilities. Yard buildings will be either pre-engineered buildings or conventional steel frame. Walls and roofs of pre-engineered buildings will be insulated where required. Conventional steel frame buildings will be constructed of a steel framing system enclosed with a combination of concrete and/or masonry and metal panel and roof system. The following is a list of the primary supporting structures on the site:

- Cooling tower.

- Coal conveyors and transfer houses.
- Coal storage silos.
- Coal crusher house.
- Lime storage silo.
- Fly ash silos.
- Yard maintenance building.
- Administration building.

Applicable codes for the main structures will also apply to supporting structures.

2.2.4 Chimney

The chimney height will be determined by air dispersion modeling and good engineering practice (GEP). For the purposes of this study, the height of the Unit I chimney was used for Unit II. The outer shell of the chimney will be reinforced concrete and the inner shell will be carbon steel. Continuous emissions monitoring equipment will be provided to monitor emissions from the plant.

Lighting will meet the FAA's requirements. A ladder and manlift will be provided to extend the full chimney height, with intermediate platforms to meet requirements of lighting maintenance and for access to gas sampling ports.

2.2.5 Ash Handling

The plant considers ash a commodity suitable for use in a number of applications including replacement of Portland cement in concrete, soil stabilization, and a structural fill. It intends to actively market ash for these purposes. Excess ash and ash not meeting marketable specifications will be disposed of in the on-site ash landfill.

The on-site fly ash and bottom ash landfill will have approximately 3,988,000 cubic yards of capacity remaining at the beginning of Unit II operation in 2010. With approximately 315,600 cubic yards of yearly waste production from Units I and II, the existing landfill will have capacity for about 12.6 years of operation. Operating both units until 2040 would require development of approximately 95 acres of new landfill.

Fly ash and bottom ash will be transported from the plant to the disposal area by truck. The fly ash and bottom ash will be compacted in lifts and water will be used to control dusting. When the landfill is closed, a final cover system consisting of 1.5 feet of compacted clay overlaid with one foot of soil capable of sustaining vegetative growth will be used.

2.2.6 Additional Civil / Structural Features

Other Civil / Structural features that were considered include:

- Foundations
- Roads & Parking
- Landscaping, Clearing and Grading
- Fencing
- Containment
- Cranes and Hoists

2.3 MECHANICAL SYSTEMS & EQUIPMENT

2.3.1 Steam Generator

The plant will include one pulverized coal-fired steam-generating unit. The steam generator is a supercritical unit operating at approximately 3,860 psig and 1055 °F / 1055 °F at 100-percent load when burning the design fuel.

Superheat and reheat temperature will be automatically controlled by regulating attemperator spray water flow to spray water control valves with automatic block valves. The superheater and reheater outlet steam temperature will be used to generate the control signal, with attemperator outlet steam temperature and excess airflow to anticipate changes. Means will be provided to prevent overshoot on a load increase due to reset windup during low load periods. The anticipation signal will have no effect until the temperature has reached or exceeded the set point. Spray control valves and block valves will automatically close on no demand and when the turbine trips.

Gravimetric feeders will meter raw coal to the pulverizers. Steam generator auxiliary equipment will also include electric motor-driven primary air (pulverized coal transport) fans and steam generator forced draft (secondary combustion air) fans with an air preheater. The steam generator features low NO_x burners and No. 2 fuel oil igniters.

2.3.2 Air Pollution Control Equipment

Flue gas exiting the steam generator passes through the following equipment and systems to reduce emission levels.

- Selective Catalytic Reduction (SCR) to reduce NO_x emissions.
- Carbon injection system for mercury control.
- Two spray-dryer absorbers (dry scrubbers) to reduce the SO_2 emissions.
- A pulse jet fabric filters to reduce particulate emissions.
- Induced draft fans exhaust the treated flue gas to the stack.

2.3.2.1 Selective Catalytic Reduction System (SCR)

The selective catalytic reduction (SCR) system uses anhydrous ammonia, which is injected into the flue gas at the economizer exit and a catalyst to reduce NO_x to molecular nitrogen and water. Ammonia slip will be below 2 ppm. Sonic horns will be included for removal of fly ash accumulation during operation.

Because extended operation at reduced loads is not anticipated, an economizer bypass is not included to maintain the SCR reactor process temperature.

The anhydrous ammonia is pumped from the storage tanks as a liquid to the ammonia vaporization and injection equipment. The liquid ammonia is vaporized by an electric heater and fed to the dilution equipment. The ammonia is mixed with air and injected into the flue gas ductwork.

A key factor in the operation of a SCR system is the frequency with which the catalyst must be replaced. The loss of performance or activity of the catalyst over time can be due to chemical damage or poisoning. Arsenic and zinc are two elements that are especially detrimental to the life of the catalyst. Prior to determining the viability of a SCR system for an application, a detailed fuel and ash analysis should be performed. This analysis is outside the scope of this study. Should OTP proceed with the development of this project, this analysis should be undertaken.

2.3.2.2 Carbon Injection System

The reagent injection system injects activated carbon into the flue gas upstream of the lime spray dryer for mercury control. The mercury present in the flue gas adsorbs the activated carbon and is collected in a fabric filter downstream of the lime spray dryer.

The carbon injection system consists of a pneumatic loading system, storage silos, hoppers, blowers, transport piping, and control system. The injection equipment would likely be skid mounted. There is a high probability for the need of additional air compressors to convey the carbon to the injection point and provide the flow and pressure to get the carbon into the flue gas stream and properly mixed.

2.3.2.3 Spray Dryer

The spray dryer system utilizes a calcium hydroxide slurry to remove SO_2 from the flue gas. The calcium hydroxide slurry is atomized and injected into the flue gas flowing through each of the spray dryers. Atomization is accomplished with either rotary atomizers or spray nozzles. The SO_2 chemically reacts with the calcium hydroxide to form a byproduct consisting of primarily calcium sulfite ($CaSO_4$) and some calcium sulfate ($CaSO_3$). Additionally, the heat from the incoming flue gas evaporates all of the water entering with the calcium hydroxide slurry to produce a dry solid byproduct. The spray dryer byproducts are collected along with the fly ash in a pulse jet fabric filter (described later). A portion of the spray dryer solids, which contains unreacted lime, are recycled to improve reagent utilization.

2.3.2.3 Lime Storage and Handling

Lime will be received by truck and pneumatically conveyed to a storage silo. Lime will be withdrawn from the silo bottom by mechanical conveyors and fed to the lime slurry preparation (slaker) system. All new transfer points will be provided with dust collection.

2.3.2.4 Pulse Jet Fabric Filter (Baghouse)

One pulse jet fabric filter (PJFF) with two casings will be supplied to control particulate emissions and provide supplemental SO_2 removal to the spray dryer. The fabric filter removes particulate by passing flue gas through felted bag filters.

A PJFF unit consists of isolatable compartments with common inlet and outlet manifolds containing rows of fabric filter bags. The filter bags are made from a synthetic felted material, which has proven to be the fabric of choice for coal fueled PJFF applications. Filter bags are suspended from a tube sheet mounted at the top of each fabric filter compartment. The tube sheet separates the particulate laden flue gas from the clean flue gas. This tube sheet is a flat sheet of carbon steel with holes designed to accommodate filter bags through which the bags are hung. The flue gas passes through the PJFF by flowing from the outside of the bag to the inside up the center of the bag through the hole in the tube sheet and out the PJFF. Fly ash particles are collected on the outside of the bags, and the cleaned gas stream passes through the ID fans and on to the chimney. A long narrow wire cage is located within the bag to prevent collapse of the bag as the flue gas passes through it. Each filter bag alternates between relatively long periods of filtering and short periods of cleaning. During the cleaning period, fly ash that has accumulated on the bags is removed by pulses of air and then is deposited into a hopper for disposal.

Cleaning is either initiated by exceeding a preset differential pressure drop across the tubesheet or based on a maximum time between cleanings. Bags in a PJFF are cleaned by directing a pulse of pressurized air down countercurrent to the flue gas flow to induce a traveling ripple (pulse) in the filter bag. This pulse travels the length of the bag deflecting the bag outward separating the dust cake as it moves. The bag and cage assemblies are attached at the top.

2.3.3 Steam Turbine-Generator

The steam generator will provide steam to a single main steam turbine-generator. The steam turbine-generator converts mechanical energy of the steam turbine to electrical energy. For this project a 3690 psia, 1050 F/ 1050 F, single-reheat, dual casing, four-flow down-exhaust, condensing steam turbine is arranged with eight stages of feedwater heaters and a steam condenser. The steam turbine is designed for 3.5-inch Hg absolute backpressure at summer design conditions. The turbine will drive a 24 kV, 60 Hz, 0.85-power factor, hydrogen-cooled electric generator. Nominal rating of the generator will be 800 MVA. The steam-turbine generator unit will be designed for indoor operation.

2.3.4 Steam Condenser

The water-cooled steam condenser will be a dual, rectangular shell, two pressure, split waterbox, two pass steam condenser with a retention hotwell for the supercritical cycle. The condensers will be designed to maintain a 3.5-inch Hg absolute steam turbine backpressure at normal maximum continuous rating of the steam turbine at summer design conditions. The condenser will accept the steam exhausted from the turbine. Air removal from the condenser's upper portion will be via two full capacity vacuum pumps. The condenser and auxiliaries will be designed in accordance with HEI standards. To dissipate the energy in the condensing steam, a circulating water system will supply cooling water from the wet cooling tower to the water-cooled steam condenser.

Piping at the powerhouse will be arranged to allow the condenser tubes to be removed. Provisions will be made in the system to minimize water hammer and short-circuiting of flow during pump trip conditions. The circulating water pump discharge lines will contain air vent valves to release air trapped in the lines when the pumps are started. Condenser waterbox vents will also be provided to release air from the return and inlet/outlet waterboxes. Expansion joints will be placed at the discharge of the circulating water pumps and at the inlet and outlet of the condenser to accommodate thermal expansion and stress loading.

2.3.5 Circulating Water System

The results of the cooling tower versus cooling pond study outlined in Attachment E show that a cooling tower is the most economical design over the life of the unit. Therefore, the circulating water system will consist of a cooling tower, circulating water pumps, condenser, and associated piping and accessories.

The Circulating Water system is a closed-loop type that will be designed to operate at up to approximately 5 cycles of concentration to limit the quantity of blowdown water. Blowdown from the circulating water system will be discharged to a holding pond (cooling tower blowdown pond), where it will then be sent to a brine concentrator where the dissolved solids in the water will be extracted.

The cooling towers will be multi-cell, mechanical draft, counter-flow type. The cooling towers will be designed to maintain the rated turbine back pressure of 3.5" Hg with the design ambient conditions defined in Section 2.1 of this Attachment A. In addition, there will be a bypass that directs the recirculation to each cooling tower basin to facilitate start-up and operation during cold weather. Cooling water is transported between the water-cooled steam condenser and cooling tower by two 50-percent capacity circulating water pumps.

2.3.6 Closed Cooling Water System

The Closed Cooling Water system is a closed-loop system that provides and cools condensate quality cooling water for various equipment. This system includes the head tank, closed cooling water pumps, and a plate and frame closed cooling water cooler. The system provides cooling to the following equipment:

- Condenser hotwell pump motors.
- Boiler feed pump seal coolers.
- Turbine electrohydraulic coolers.
- Local sample coolers.
- Boiler feed pump lube-oil cooler.
- Hydrogen coolers.
- Exciter coolers.
- Stator water coolers.

- Generator seal oil coolers.
- Air compressor aftercoolers.

Two 100 percent capacity, single-speed, horizontal, motor-driven, closed-cooling water pumps will be provided. Two 100 percent capacity closed cooling water coolers will be provided. This system will be designed so that the flow to any piece of equipment can be controlled either by manual valves or control valves. Provisions will also be made for the independent isolation of any piece of equipment. The closed cooling water head tank will also be used as an expansion tank.

2.3.7 Steam System

The Steam System transports steam from the steam generator to the main steam turbine-generator and various feedwater heaters. Cross-ties with the existing auxiliary boiler and Unit I steam drum will be provided to supply steam for start-up and shutdown operations. A steam turbine bypass system is not included.

The main steam piping transports steam from the superheater outlet of the steam generator to the inlet of the high-pressure turbine. Steam is exhausted from the high-pressure turbine and transported through the cold reheat piping to the reheater section of the steam generator where steam is reheated. The hot reheat piping transports the reheated steam to the intermediate pressure turbine.

This system also transports steam from extractions in the turbine to the high-pressure heaters, low-pressure heaters, and the deaerating feedwater heater. The main steam and hot reheat systems include attemperators, where feedwater is injected as necessary to control the temperature of the steam being supplied to the turbine.

The steam pipelines will be provided with drip drains at all low points. Drain pots will be provided to collect condensate from the low points in the steam piping and return it to the main condenser. The drain pots will drain the various low points of the piping system at the maximum steam flows.

All extraction lines from the turbine, except those leading to the heaters in the condenser neck, will be equipped with power assisted, nonreturn valves to ensure that steam will not flow back to the turbine. These lines will also be supplied with motor-operated shutoff valves to prevent steam turbine water induction.

2.3.8 Condensate System

The Condensate System delivers deaerated condensate via three, 50-percent capacity vertical, condensate pumps. These pumps transport condensate from the steam condenser hotwell, through the gland steam condenser and low-pressure feedwater heaters to the boiler feed pump. A minimum flow bypass system will be provided to assure the pumps operate above their minimum flow rate at all times

2.3.9 Feedwater System

The Feedwater System provides water to the high-pressure feedwater heaters and then to the steam generator's economizer via two 50-percent capacity, barrel type, high-pressure boiler feed pumps. The main boiler feed pump is furnished with an electric motor drive. It also provides spray water for main steam and hot reheat attemperators for steam temperature control. A minimum flow system will be provided to assure the pumps operate above their minimum flow rate at all times.

A warm-up system is also provided to facilitate placing the pumps in operation.

2.3.10 Coal Unloading & Storage System

See Attachment G – Fuel Handling System Descriptions.

2.3.11 Water Systems & Treatment

See Attachment E – Water Treatment & Wastewater Management.

2.3.11.1 Sample Analysis System

The water quality control system shall consist of three major components: a sample rack, a water quality panel, and a sample chiller. Samples from the following points in the plant shall be routed to the centrally located water quality control system for the indicated continuous analyses, monitoring, data logging, and trending analysis and recording.

A sample analysis system will include sample points at:

- The Condensate/Demineralized water tank (Local), (Silica & Specific conductivity)
- Condensate Pump Discharge, (Specific conductivity, Cation conductivity, sodium, pH & Dissolved oxygen)
- Condensate after Condensate Polisher, (Sodium, Cation conductivity)
- Feedwater from deaerator (or economizer inlet) (pH, Dissolved oxygen, Specific Conductivity)
- Main steam (Cation conductivity, Sodium, Silica) Saturated steam (alternate to Main Steam)

Analyzers will be shared by different sample points where continuous analysis of parameters is not critical (i.e. sodium and silica). System will include a conditioning panel utilizing condensate for primary cooling and cooling water or chilled water for secondary cooling to condition the samples to the necessary temperature. A second wet panel will contain the analyzers and sensors. A third dry panel (NEMA 12) will contain the monitors.

2.3.11.2 Condensate Polisher

The condensate system will be provided with full flow deep bed condensate polishing. The Condensate Polishing System will treat the water from the discharge of the condensate pumps. All of the unit's condensate will flow from the Condensate System through the condensate polisher exchangers. The condensate will pass through exchanger beds consisting of a mixture of cation and anion resins. The bed serves as both an ion exchange media and as a filter. The effluent of the Condensate Polishing System will be returned to the Condensate System upstream of the gland steam condenser.

2.3.12 Additional Mechanical Systems & Equipment

Other Mechanical Systems and Equipment that are included in the Unit II estimate are listed below:

- Turbine Lube Oil System
- Turbine Warm-up and Drains System
- Turbine Gland Steam System
- Auxiliary Circulating Water System
- Heater Drains System
- Vents
- Generator Gas System
- Utilities
- Compressed Air System
- Fire Protection System
- Heating Ventilating and Air Conditioning System
- Service Water System
- Potable Water System
- Boiler Blowdown
- Sanitary Waste Collection
- Wastewater Collection and Treatment
- Stormwater Management

- Plant Drains
- Roof Drains
- Pressurized Pneumatic Ash Handling System to the Silos
- Truck Ash Handling System to the Landfill

2.4 ELECTRICAL SYSTEMS & EQUIPMENT

2.4.1 Electrical Generation & Distribution

The electrical systems supply the power produced by the plant to the transmission system and supply the power required for operation of all plant equipment. The systems include all metering and protective relaying required for operation of the plant electrical systems.

The steam turbine generator produces power at a voltage level of approximately 24 kV. The generator step-up transformer converts electrical power received at generator voltage level to the transmission voltage of 230 kV.

The auxiliary power system is based on a unit-connected generator with two two-winding station auxiliary transformers providing auxiliary power to the 13,800 V switchgear plant buses. Startup power is provided through the tertiary of the 115/230 kV autotransformer via 13.8 kV switchgear located in the switchyard. Power will be distributed through the facility at the 13,800, 4160 and 480 volt level as required with major power centers located at the turbine area, boiler area, gas cleaning area, cooling tower area and the fuel handling area.

The generator will be connected to the step-up transformer through isolated phase bus with taps for the auxiliary transformers. The step-up transformer will be sized for 65°C rise at the maximum capability of the generator. The primary power distribution through the plant will be through 13.8 kV and 4.16 kV metal clad switchgear. 480-volt power demands will be served through 13,800 or 4,160-480 volt transformers connected to low voltage switchgear. Small power loads will be supplied from 120/240- or 120/208-volt utility panels fed from 480-volt motor control centers or power panels.

Essential AC and DC power systems will include batteries, battery charger/eliminators, inverters and an emergency diesel generator. The essential power systems provide power for essential control loads and loads that are critical to a shutdown of the plant.

2.4.2 Generator System

The Generator System converts the mechanical rotating energy of the turbine into electrical energy to supply the power system load through the substation and transmission systems, the load of the auxiliary power supply system, and its own excitation demand. The system includes:

- Generator and generator cooling systems.
- Generator neutral grounding equipment.
- Generator terminal Current Transformers (CT's) and Potential Transformers (PT's) and surge protective equipment.
- Isolated phase bus.
- Main transformer.
- Generator excitation equipment.
- Generator controls, protective relaying and metering.

The generator rotor and stator core will be hydrogen cooled. The stator windings will be inner-cooled using either hydrogen or water. The generator will include the necessary ancillary cooling system components, such as heat exchangers for cooling of the hydrogen and water, hydrogen purging system, and deionization systems for the stator cooling water (if applicable).

The generator will be high resistance grounded through the primary of a single-phase distribution type transformer with a secondary loading resistor. Surge arrestors and surge capacitors connected on the generator side of the generator breaker will provide generator surge protection. Included in the same equipment enclosure for the generator surge protective equipment will be a set of potential transformers for use with the generator regulator, synchronizing, ground detection, metering and protective relaying.

Generator controls, including breaker, load and voltage controls, will be located in the plant control room. Generator breaker closing will be by an automatic synchronizing system. Generator metering and protective relaying will be located in the main control room.

Generator protective relaying will include:

- Differential.
- Negative phase sequence.
- Loss of excitation.
- Over excitation.
- Under frequency.

- Reverse power.
- Stator ground.
- Rotor ground.
- Backup impedance.
- Accidental energization of generator on turning gear.
- Out-of-step (if required by system conditions).

Generator metering will include:

- Generator watts, vars, amperes, volts and frequency.
- Generators gross watt-hours and elapsed time.
- Field amperes and volts (if available).
- Regulator transfer volts or ampere.
- Generator winding and gas temperatures and exciter gas temperature.
- Main step-up and unit auxiliary transformer winding temperatures.

The main generator transformer will be designed for a 65 degree C rise force cooled (OFAF) capacity rating equal to the rated output of the generator at 40 ° C ambient. Transformer protection will include tank-mounted surge arrestors connected to the high-voltage for surge protection; differential, fault pressure, overexcitation and ground overcurrent relaying for electrical protection; and alarms for various abnormal physical conditions.

The isolated phase bus will be self-cooled and its capacity will be the nearest standard 65 deg. C rise rating equal to or greater than the rated generator current. A tap from the main bus will supply primary power to the unit auxiliary transformers and excitation transformer if required.

2.4.3 Station Metering

The unit's gross output and station auxiliary power will be monitored as follows:

- Watts and Vars will be recorded in the main control room with provision for telemetering to a remote dispatcher.
- Watt-hour digital data will be recorded in the main control room on a 60-minute demand interval.

2.4.4 Auxiliary Power Supply

This system normally receives power from either the substation via the switchyard 13.8 kV switchgear, or the generator via the unit auxiliary transformer and steps it down to various voltage levels for distribution to all of the systems requiring ac electrical power for their operation. After the generator is on-line, station power will be received from the unit auxiliary transformers.

The auxiliary power supply system includes:

- Unit auxiliary transformer.
- Switchyard 13.8 kV switchgear.
- Unit auxiliary medium-voltage switchgear.
- Coal handling, cooling tower, etc. switchgear.
- 480-volt load centers, motor control centers and power panels.
- 120/240-volt or 120/208-volt utility panels and transformers.

Auxiliary power in the main power plant will be distributed from multiple 13,800 and 4,160-volt buses. 13.8 kV buses will be connected to the auxiliary transformers via non-segregated bus duct and to the 13.8 kV switchgear via underground cable. The auxiliary transformers will be designed with capacity to supply the full-load auxiliary power demand of the unit, without exceeding the 65 degree C rating.

Transformer impedance will be selected so that the voltage at the largest motor served by the transformer, when starting the motor under fully-loaded transformer conditions, will not be less than 85 percent of the rated motor voltage. The transformer impedance will also be coordinated with the short circuit capacity of the medium-voltage switchgear.

The 480-volt power requirements will be supplied from the medium-voltage switchgear through 480-volt (metal-enclosed switchgear type) load center substations. The medium-voltage to 480-volt supply transformers for the load center substations in the main plant building will be indoor dry type. Outdoor liquid-filled or weather-protected cast-coil transformers may be used for some of the load centers outside of the main plant building. The load center substations will distribute the power to motor control centers and power panels and will supply the 460V motors.

Each load center substation will be arranged for standby supply, through a tie breaker, from an interconnecting tie bus normally energized from a single lightly loaded standby load center. Motor control centers will be connected by cable or bus duct to the load center substations.

Small power loads will be supplied from 120/240- or 120/208-volt utility panels fed from 480-volt motor control centers or power panels.

Auxiliary power requirements for major loads outside of the plant, such as cooling towers, coal handling and flue gas cleaning will be supplied from 480-volt load centers or medium-voltage switchgear located in these areas, served from the unit switchgear in the plant. Each medium-voltage bus and critical 480-volt buses outside of the plant will be arranged with two sources of power supply.

2.4.5 Additional Electrical Systems & Equipment

Other Electrical Systems and Equipment that are included in the estimate are listed below:

- Raceways
- Wiring
- Grounding
- Motors
- Lighting
- Freeze Protection
- Cathodic Protection
- Essential AC and DC Power Supply
- DC System
- AC Emergency Power System
- AC Essential Low Power System
- General Electrical Construction
- Communications
- Security
- Fire Detection

2.5 CONTROL SYSTEMS & EQUIPMENT

2.5.1 Overview

The operating staff will consist of two control room operators, one shift supervisor, and one roving operator per shift. There will also be an additional fuel/ash handler on all shifts with the exception of the 300MW solid fuel plants. The shift supervisor and control room operators for each shift will be thoroughly trained in all aspects of plant controls and will be fully qualified to operate all plant systems. The shift supervisor will direct shift operations, make assignments, and perform required administrative duties. The shift supervisor will also serve as an additional operator during emergencies and provide periodic relief for the control room operators.

2.5.2 General

The control system will be a physically and functionally distributed microprocessor based, on-line distributed control system (DCS). The DCS will be used for supervisory control and monitoring of all major plant systems. In addition, programmable logic controllers (PLCs) will be provided for auxiliary systems such as coal handling, ash handling, water treatment, sootblowers, etc.

The boiler, turbine and auxiliary controls will be provided under various equipment contracts. In general, where equipment is furnished as a "package", the auxiliary control system will be included in that package. However, since the turbine, boiler and heat cycle are operated as a unit in response to load demand, the associated coordinated load, combustion and burner management controls will be provided under a Distributed Control System (DCS) package. In addition, the DCS will serve as the primary Human Machine Interface (HMI) for plant wide remote controls and monitoring, except where local control is mandated. The auxiliary systems, usually Programmable Logic Control (PLC) based, are each to be designed by the furnishing contract as a turnkey package using project standard requirements for control philosophy and electrical design.

The conceptual architecture of the DCS is depicted in Attachment I – Control System Conceptual Architecture. The components of the DCS are contained in the following five subsystems:

- DCS HMI & Information
- Network DCS Controllers & Input Output
- (I/O)Gateways & Communication
- Interfaces Turbine
- Control System Auxiliary Controls

DCS control cabinets and PLCs will be located as required to enhance reliability and reduce wiring requirements. In general, DCS control cabinets and PLC gateways for control of systems located in the main boiler and steam turbine buildings will be located in the electrical equipment room. The PLCs for control of remotely located systems such as fly ash handling may be located in conditioned spaces near those systems.

Engineering programming terminals will be provided in the electrical equipment room, shift supervisor's office and engineer's office. The workstations will be used to perform system programming and to view historical data.

2.5.3 DCS and Related Systems

All information from DCS Controllers and I/O is passed to the operator through operator server/client personal computers operating on a dedicated Ethernet Local Area Network (LAN), the DCS Information Network. Servers, located in a Computer Room or Control Equipment Room, will provide the gateway from the LAN to the proprietary DCS Data Highway. Operator servers and clients may be installed in the same machine running a Microsoft or a UNIX based operating system. The servers and clients will be powered in two groups from two separate sources of power. The servers may be operated in a redundant mode if throughput allows operator updates once per second.

The operator clients will be installed in the operator console in a centrally located main plant Control Room. These clients will be desktop or tower personal computers installed for cost-effective replacement by the Owner when they malfunction or become obsolete. Each client will consist of a computer, a keyboard, mouse or trackball and two CRTs or LCD displays. The console will be provided in sections for semicircular arrangement with each client's displays side-by-side or over-under. The console design will employ human factors for sit down operation. Two screens, either CRT, LCD or projection displays will be hung from the ceiling over or directly behind the operator console.

An additional operator console server may be required to provide operator graphics to non-operator console clients. These clients may reside on the DCS information network or on the Owner's LAN/WAN external to the DCS Information Network. A LAN gateway or bridge is included to bridge the LANs. Several console software licenses are required for installation on the Owner's personal computers. These Clients will allow the Owner's supervision and engineering personnel access to real time and historical data.

A plant historian will be provided to allow several months of data to be stored from and retrieved by the DCS. It shall also allow for the archive and retrieval of data through the use of CD R/W drive or streaming tape. The historian will supply data to all operator servers and client workstations. The DCS should allow the seamless retrieval of short-term and long-term data into the same DCS operator trends. The historian will be redundant for data backup or will be provided with short- term history storage to backup data for at least several days in event the historian is down.

A performance calculation engine will be provided on the DCS Information Network. This engine will retrieve performance data on an hourly, shift, daily, and monthly basis to provide reports for operations and management. It will then pull analog and digital (on-off) data from the DCS or the historian to perform the calculations and store the results. The results will be available for retrieval by the operator clients or the historian over the network.

2.5.4 Turbine Control System (TCS)

The TCS will include the basic governor speed load control for warming, startup and continuous operation of the turbine. In addition, it will include all turbine/generator monitoring and control for automatic turbine startup (ATS), supervisory instrumentation (TSI), excitation and voltage control supervision, and turbine auxiliaries. Auxiliaries include lube oil, hydraulic oil, seal oil, turning gear, stator cooling, exhaust hood temperature, steam seal system, gland steam condenser, etc. provided with the turbine.

2.5.5 Auxiliary Controls

The following controls are to be provided using PLCs. It is expected that they will be provided by the process equipment suppliers, using a standard PLC and Human Machine Interface (HMI) acceptable to the Owner for local control. The communication interface to these PLCs from the DCS is via Ethernet links or proprietary PLC data highway interfaces.

- Sootblowing Controls.
- Selective Catalytic Reduction (SCR) Controls.
- Fabric Filter Controls.
- Bottom Ash Controls.
- Flyash Controls.
- Flyash Disposal Controls.
- Fan Vibration Analyzer.
- Wastewater Treatment Control.
- Water Treatment Control.
- Condensate Polisher Control
- Continuous Emissions Monitors.
- Water Sample Analysis Panel.

- Air Compressors.
- Condensate Polisher.

The following equipment will require a separate serial or Modbus interface to provide information into the DCS.

- Fan vibration monitor.
- Boiler feed pump vibration monitor.
- Scrubber Controls.

2.5.6 General Control Functions

The control system will include a library of analog functions required to implement the analog control loops. Typical functions include summing, difference, multiplying, PID control, lead/lag, high and low select, function generators, signal generators, high and low limiting, logical selects, and externally requested or operator-selected transfers.

Programming of all digital control loops will be in ladder diagram format or a simplified high-level logic programming language. All digital control loops will be displayed on the operator console. The operator will be able to issue commands to start/stop and open/close process equipment from loop displays (faceplates) on console displays or from the keyboards. These commands will be communicated to the appropriate controller through the data highway and communication networks. The controller will manipulate the appropriate I/O module to provide the required action.

The DCS will automatically supervise the status of predetermined interlocks and provide control functions as the operator initiates such commands as start or stop for various pumps, fans, motor-operated valves, etc., for the power plant proper. This is to prevent improper or dangerous operation in case of inadvertent operator error or certain process equipment malfunction.

Automation will be sufficient to reduce the manual actions required by operating personnel such that three operators can start-up, operate, and shut down the entire plant. During steady state operation at or near base load, automation will allow safe and reliable operation without frequent operator intervention. Auxiliaries such as sump pumps that need not be in continuous operation for electric power production will be monitored, controlled, and protected locally, with limited control room monitoring and control.

The DCS design is based on one uniform system with control over all plant functions, including the boiler, steam turbine-generator (ST), and the balance of plant to the maximum practical extent. The boiler, ST, CEMS, and fire protection systems have dedicated remote input/output DCS or PLC-based controllers supplied with the equipment for main control, supervision, safety interlocks, etc. These controllers communicate with the DCS to allow remote operation of select functions from the control room. A local interface for each of these controllers is included.

A stand-alone dedicated server integrated with the DCS to allow remote information gathering by authorized third parties without direct connection to the DCS is included. Two operator workstations, each with a keyboard and two color displays for monitoring are included. One engineering workstation with keyboard and monitor is included. A dedicated historian log printer and two log printers are included.

2.5.7 Continuous Emissions Monitoring System (CEMS)

One CEMS downstream of the SCR/spray dryer/pulse-jet fabric filter and a data acquisition system is included. The final flue gas outlet CEMS will consist of sampling devices with sample tubing to the emissions rack mounted near the base of the stack in an enclosure. The system will include cylinder rack for calibration gases. The CEMS monitors stack emissions with hardware and reporting package software that meets the requirements of 40 CFR 60 and 40 CFR 75 as determined by the permit requirements. The CEMS is designed to communicate with the plant DCS system to provide automatic report production compatible with permit requirements.

Additional in-situ-type flue gas emission monitors for boiler oxygen and carbon monoxide at the air preheater gas inlet will be provided and connected to the boiler DCS. This is primarily for real-time combustion process control prior to the air pollution control equipment.

2.5.8 Additional Control Systems & Equipment

Other Control Systems & Equipment that are included:

- DCS Controllers & Input/Output (I/O)
- Gateways and Communication Interfaces
- Input/Output Requirements
- Controllers
- Data Highway
- Historical Data Storage

- Control Stations
- Operator Station Display Functions
- Printers
- Engineering Programming Terminals
- Alarm Functions
- Sequence of Events
- Log Functions

3.0 ALTERNATES TO BASE CASE 1

3.1 - 450 MW SUPERCRITICAL PULVERIZED COAL BOILER

The following paragraphs summarize the major differences between a 450 MW PC unit and Base Case 1. If systems are not discussed, it can be assumed that they will be similar to Base Case 1.

3.1.1 General Design Criteria

The design criteria will be similar to Base Case 1 with the obvious exception of the unit size. The gross output of the plant will be approximately 497 MW, and the resulting net generation will be 450 MW.

3.1.2 Civil / Structural Features

The civil / structural features will be similar to Base Case 1 with the exception of the stack location and landfill size. The stack will be located to the north of the fabric filter if space allows. The smaller unit, in combination with Unit 1, would create approximately 269,300 cubic yards of waste per year. The existing landfill would have enough capacity for approximately 14.8 years of operation. Operating both units until 2040 would require the development of approximately 73 acres of new landfill.

3.1.3 Mechanical Systems & Equipment

The mechanical systems and equipment will be similar to Base Case 1, but sized for the smaller unit output.

3.1.4 Electrical Systems & Equipment

The electrical systems will be similar to the base case except equipment will be reduced in rating to support the lower megawatt output.

3.1.5 Control Systems & Equipment

The control systems will be similar to the base case except instruments and I/O will be reduced to match the mechanical systems for the lower megawatt output.

3.2 - 300 MW SUBCRITICAL PULVERIZED COAL BOILER

The following paragraphs summarize the major differences between a 300 MW PC unit and Base Case 1. If systems are not discussed, it can be assumed that they will be similar to Base Case 1.

3.2.1 General Design Criteria

The design criteria will be similar to Base Case 1 with the exception of the net and gross plant output, which will be approximately 300 MW and 330 MW, respectively. Also, the unit will be a subcritical unit instead of a supercritical unit. Finally, the additional plant staff can be reduced by 4 to 26, instead of 30 as in Base Case 1 due to reduced scope of the coal handling system.

3.2.2 Civil / Structural Features

The civil / structural features will be similar to Base Case 1 with the exception of the landfill size, stack location, and the bridge crane. The smaller unit, in combination with Unit 1, would create approximately 225,700 cubic yards of waste per year. The existing landfill would have enough capacity for approximately 17.7 years of operation. Operating both units until 2040 would require the development of approximately 54 acres of new landfill.

The smaller unit will only require a 70-ft bridge crane span. The existing bridge crane has a span of 90 ft. The cost of expanding the existing crane to Unit II, and therefore expanding the administration and powerhouse buildings to accommodate it, would be more expensive than installing a new, 70-ft crane in the new powerhouse building.

The stack will be located to the north of the fabric filter.

3.2.3 Mechanical Systems & Equipment

The mechanical systems and equipment will differ slightly from Base Case 1. In a subcritical system, the boiler will include a drum for steam production. Also, the steam pressures are reduced from 3500 psig at the turbine throttle to a maximum of 2520 psig at the turbine throttle.

Other discrepancies from the base case include the use of 7 feedwater heaters instead of the 8 stated in the base case, the condensate polisher is sized for 50% flow, and only one SO_2 spray dryer absorber.

3.2.4 Electrical Systems & Equipment

The auxiliary power system for this case includes one 13.8 kV and one main 4.16 kV bus with a cross tie 13.8-4.16 kV transformer connecting the two busses. The auxiliary transformer will be three winding with 13.8 and 4.16 kV secondaries. Additional 4.16 busses will be included to serve the boiler and material handling areas. Other components of the electrical systems will be similar to the base case.

3.2.5 Control Systems & Equipment

The control systems will be similar to the base case except instruments and I/O will be reduced to match the mechanical systems for the lower megawatt output. Since this is a subcritical boiler, the feedwater control will utilize drum level for the process variable instead of superheater outlet temperature and flow. Similarly, there will not be controls for the circulating pump, separators, storage vessel, and overflow valves that do not exist with subcritical boilers.

4.0 BASE CASE 2: 600 MW SUBCRITICAL CIRCULATING FLUIDIZED BED BOILER

4.1 GENERAL DESIGN CRITERIA

4.1.1 Project Description

The Project includes construction of a 600 MW (net) electric generating station utilizing two circulating fluidized bed coal (CFB) fired boilers and a single, reheat steam turbine on a brownfield site. The location is adjacent to the existing Big Stone Unit 1 cyclone unit.

The system will be designed to operate on Powder River Basin (PRB) sub-bituminous coal. An existing rail spur will be used to provide the PRB coal supply via unit train. Existing dumping facilities will be used for coal unloading.

The CFB-fired boiler will be balanced-draft combustion with reheat. Additional features will include selective non-catalytic reduction (SNCR) for NO_x reduction and a pulse-jet fabric filter for particulate collection. Steam generated by the boilers will be supplied to the steam turbine to complete the power generation cycle. The steam turbine will include seven stages of feedwater heating for the sub critical (2520 psig-1050 / 1050 °F) cycle. Treated cooling water for the water-cooled surface condenser will be from an closed loop circulating water system including a mechanical draft cooling tower and circulating water pumps. Raw water for the cooling system will be supplied from the existing Big Stone Unit I cooling pond which will be expanded to accommodate Unit II. The water for the cooling pond will be supplied from Big Stone Lake via an existing water line.

Electrical output from the project will be stepped up to 230 kV and interconnected with the MAPP transmission system. All interconnection costs from the high side bushings of the main stepup and startup transformers to the transmission system are by the Owner.

4.1.2 Operating and Control Philosophy

The facility is expected to be operated at base load. The project is configured to normally operate at maximum continuous rating (MCR) output with the capability of overnight/weekend/holiday reductions down to minimum output (boiler at 50-percent load).

All routine start-up and shutdown operations will be from a central control room via a distributed control system (DCS). The operating staff will consist of two control room operators, one shift supervisor, and one roving operator per shift. There will also be a fuel/ash handler on most shifts. The shift supervisor and control room operator for each shift will be thoroughly trained in all aspects of plant controls and will be fully qualified to operate all plant systems. The shift supervisor will direct shift operations, make assignments, and perform required administrative duties. The shift supervisor will also serve as a second operator during emergencies and provide periodic relief for the primary control room operator.

Big Stone Unit II will share operational staff with the existing unit. The existing staff of 74 employees will be expanded to 104 to accommodate the unit expansion. By sharing staff, both units will benefit from added flexibility and will be able to operate with fewer on-site staff per unit.

Facility automation will be designed to insure secure and safe operation of all equipment. Maintenance support will be supplied by on-site staff as required for routine maintenance activities. Maintenance support for major shutdowns is expected to be contracted.

The Project is not configured to generate electricity while isolated from the utility grid or to have "black-start" capability.

4.1.3 Design Conditions

The design conditions will be identical to Base Case 1.

4.1.4 Equipment Location

Both the steam turbine-generator and steam generator (boiler) will be located indoors.

4.1.5 Emissions Criteria

A Best Available Control Technology (BACT) review of this facility has not been performed. However, based on recent determinations, we have assumed that the following combination of technologies forms the basis of the design.

- Circulating Fluidized Bed steam generator technology firing low-sulfur, Powder River Basin fuel.
- Limestone injection into the boiler for SO_2 control. An add-on spray dryer absorber for additional SO_2 control will not initially be required. There will, however, be room left in the ductwork to add a spray dryer absorber unit if it is deemed necessary in the future.
- Selective non-catalytic reduction (SNCR) for NO_x control.

- Carbon injection system for mercury control.
- Fabric filter for particulate control.

Based on the above, the conceptual design included in this study will meet the following emissions criteria.

Pollutant	Limit
NO_x	0.08 lb/MMBtu
SO_2	0.12 lb/MMBtu
Hg	2 x 10^{-5} lb/MW-hr
PM / PM_{10}	0.018 lb/MMBtu

4.1.6 Fuel and Reagents

Primary fuel for the circulating fluidized bed boiler will be low sulfur coal supplied from mines in the Powder River Basin area of Wyoming and Montana. This fuel is relatively high moisture, low sulfur Western sub-bituminous coal with excellent combustion but low grindability qualities.

OTP will procure this fuel and arrange for coal freight service. The project does not include any additional spurs from the existing mainline. OTP will utilize the existing unloader to serve the facility using rotary dump-type railcars. Unloading facilities at the plant accommodate the rotary dump cars and include extensive automation to allow remote car indexing, unloading, stock out, reclaim, and fuel transfer to the plant by an operator in the main plant control room and an operator in the fuel reclaim/stock out areas.

No. 2 fuel oil will be used for the firing of the new boiler. Unit II will tie into the existing fuel oil system. The new unit will also use the existing auxiliary boiler for startup.

Limestone can be delivered by rail or truck to the site. A new underground unloading hopper and reclaim system is included in the estimate for delivery of limestone. The limestone will be used in the combustion process to reduce SO_x emissions by reacting with the sulfur in the fuel. The limestone is expected to come from existing sources in the region.

Anhydrous ammonia or urea will be delivered by truck. It will then be utilized for in the SNCR process to reduce NO_x emissions. The reagent will be injected upstream of the cyclone in the CFB boiler, where it will react with NO_x to form elemental nitrogen and water. The ammonia slip will be below 10 ppm.

Activated carbon will be delivered by truck. The activated carbon will then be injected into the flu gas upstream of the fabric filter for mercury control.

4.1.7 Water Supply

See Base Case 1, Section 2.1.7.

4.1.8 Wastewater

See Base Case 1, Section 2.1.8.

4.1.9 Noise Criteria

See Base Case 1, Section 2.1.9.

4.1.10 Electrical Interconnection

See Base Case 1, Section 2.1.10.

4.1.11 Provisions for Future Facilities

See Base Case 1, Section 2.1.11.

4.2 CIVIL / STRUCTURAL FEATURES

4.2.1 General

The assumed site arrangement drawing is included in Attachment F – Site Plans

The elevation of the site varies from approximately 1060 feet MSL to 1140 feet MSL. Grade elevation of the main structures and supporting structures will be approximately 1126 feet MSL. Design of structures will be for 1997 Uniform Building Code (UBC) Seismic Zone 0.

The plant will be oriented with the axis of the steam generator perpendicular to the turbine axis. Future units (if any) will align with the turbine axis and expand to the west. The fabric filters will be located symmetrically about the boiler axis and extend to the north. The stack will be located north of the fabric filter.

Facility will be laid out to facilitate access to equipment and systems for maintenance and operations. Platforms will be provided to allow personnel to access equipment, valves and instrumentation requiring frequent (more than twice a year) attention for maintenance, calibration or operation. Stairs will be utilized to access platforms that are used more than once a week. Ladders will be utilized to access platforms that are used less than once a week.

The plant will consist of a number of buildings and structures. The primary structures include the steam turbine generator structure, the boiler structure, chimney, the cooling tower, structures for handling and storage of fuel, limestone, and ash and other miscellaneous structures. The main control room will be located in the existing Unit I control room. Roads, drives and parking areas will be located to provide a satisfactory circulation pattern and to provide access to all plant facilities.

Auxiliary buildings will be provided as required for the functions of the power generating facilities. Auxiliary buildings will be constructed, wherever possible, utilizing a pre-engineered building system.

4.2.2 Main Structures

The main structures will be the turbine, steam generators, fabric filters (bag house), and the administration building. The turbine and steam generators will be located in adjacent enclosures. The fabric filters will be outdoors. The administration building will be a located between the Unit I turbine enclosure and the Unit II turbine enclosure. The administration building will include the mechanical maintenance shop. Stairs, one elevator and platforms will provide full access within and to all enclosures and inspection/maintenance access to functional equipment parts.

Walls will be a system of insulated metal panels of galvanized steel on structural steel girts, having a factory-applied fluoropolymer coating with a life expectancy of at least 20 years.

The roofing will be standard lap-seam insulated roof panels fabricated from metallic-coated steel sheets pre-painted with coil coating. Walkways will be provided where required for maintenance of roof-mounted equipment and where other foot traffic requirements dictate.

Control rooms, laboratory, offices and other finished areas will have walls combining metal studs, drywall and lightweight concrete block masonry. Toilet/locker room facilities will have glazed concrete block walls. Other partitions inside the plant will primarily be constructed of lightweight concrete block.

Toilets, washroom facilities, laboratories, control rooms and administrative facilities will have suspended acoustical ceilings with recessed lighting. Ceilings for all other areas will be exposed structure.

In general, all main structure ground floors will be constructed concrete. Elevated floors will be constructed of concrete supported by steel deck or metal bar grating. Flooring materials in the laboratory, control room and other finished areas will be either vinyl composition tile with rubber base or carpeting. Toilet/locker room facilities will have ceramic tile flooring. Mechanical equipment rooms will have hard-troweled natural gray concrete floors. All other concrete floors will have a troweled finish. Concrete floor coloring will be applied to the operating floor in the turbine room area. Chemical-resistant coatings will be applied to floors in areas exposed to oil, acid and chemicals.

Rolling steel doors will be provided for areas requiring vehicle access. Doors used frequently will be motor-operated. Others will be opened with hand crank operators. Personnel doors will be hollow metal swing-type or sliding-type.

4.2.3 Supporting Structures

Supporting structures include all other buildings as required for the functions of the power generating facilities. Yard buildings will be either pre-engineered buildings or conventional steel frame. Walls and roofs of pre-engineered buildings will be insulated where required. Conventional steel frame buildings will be constructed of a steel framing system enclosed with a combination of concrete and/or masonry and metal panel and roof system. The following is a list of the primary supporting structures on the site:

- Cooling tower.
- Coal conveyors and transfer houses.
- Coal storage silos.
- Coal crusher house.
- Limestone receiving hopper.
- Limestone storage silos.
- Fly ash silos.
- Gas cleaning electrical equipment building.
- Yard maintenance building.
- Administration building.

Applicable codes for the main structures will also apply to supporting structures.

4.2.4 Chimney

The chimney height will be determined by doing a good engineering practice (GEP) analysis. A single chimney with two flues, one for each boiler, will be provided. The outer shell of the chimney will be reinforced concrete and the inner shell will be carbon steel. Continuous emissions monitoring equipment will be provided to monitor emissions from the plant.

Lighting will meet the FAA's requirements. A ladder and manlift will be provided to extend the full chimney height, with intermediate platforms to meet requirements of lighting maintenance and for access to gas sampling ports.

4.2.5 Ash Handling

The plant considers ash a commodity suitable for use in a number of applications including replacement of Portland cement in concrete, soil stabilization, and a structural fill. It intends to actively market ash for these purposes. Excess ash and ash not meeting marketable specifications will be disposed of in the on-site ash landfill.

The on-site fly ash and bottom ash landfill will have approximately 3,988,000 cubic yards of capacity remaining at the beginning of Unit II operation in 2010. With approximately 433,400 cubic yards of yearly waste production of Unit I and II, the existing landfill would have capacity for about 9.2 years of operation. Operating both units until 2040 would require development of approximately 138 acres of new landfill.

Fly ash and bottom ash will be transported from the plant to the disposal area by truck. The fly ash and bottom ash will be compacted in lifts and water will be used to control dusting. When the landfill is closed a final cover system consisting of 1.5 feet of compacted clay and overlaid with one foot of soil capable of sustaining vegetative growth will be used.

4.2.6 Additional Civil / Structural Features

Other Civil / Structural features that were considered include:

- Foundations
- Roads & Parking
- Landscaping, Clearing and Grading
- Security
- Containment

- Cranes and Hoists

4.3 MECHANICAL SYSTEMS & EQUIPMENT

4.3.1 Steam Generator

The plant will include two circulating fluidized bed coal-fired steam-generating units. The steam generators are drum units operating at 2,650 psig and 1055 °F / 1055 °F at 100-percent load when burning the design fuel. The steam generators will consist of refractory-lined, fluidized bed combustors, mechanical separators, convection bypass and air heater. The mechanical separator may be refractory-lined or water-cooled.

Superheat and reheat temperature will be automatically controlled by regulating attemperator spray water flow to spray water control valves with automatic block valves. The superheater and reheater outlet steam temperature will be used to generate the control signal, with attemperator outlet steam temperature and excess airflow use to anticipate changes. Means will be provided to prevent overshoot on a load increase due to reset windup during low load periods. The anticipation signal will have no effect until the temperature has reached or exceeded the set point. Spray control valves and block valves will automatically close on no demand and when the turbine trips. Reheat temperature can also be controlled by regulating the external bed heat exchanger.

Gravimetric feeders will meter raw coal and limestone to a solids inducer with air provided by the forced draft fan. Boiler auxiliary equipment includes electric motor-driven forced draft fans, tubular air heater and solids separation equipment for recycling of ash into the fluidized bed of the furnace. The boiler inherently generates low NO_x emissions due to lower firing temperatures.

4.3.2 Air Pollution Control Equipment

Flue gas passes through the following equipment and systems to reduce emission levels.

- The Circulating Fluidized Bed (CFB) with limestone injection to reduce SO_2 emissions.
- Selective non-catalytic reduction (SNCR) section to reduce NO_x emissions.
- Carbon injection system to reduce mercury emissions.
- A pulse jet fabric filter to reduce particulate emissions.
- Induced draft fans exhaust the treated flue gas to the stack.

4.3.2.1 Circulating Fluidized Bed Limestone Injection System

The CFB limestone injection system utilizes crushed limestone to reduce SO_2 emissions. Limestone ($CaCO_3$) is injected with the coal into the combustion chamber. The limestone reacts to form lime (CaO) in the bed. The lime reacts with the sulfate (SO_3) and the sulfur dioxide (SO_2) that is released in the combustion process. This reaction results in the formation of dry byproduct particulate, which consists of calcium sulfate ($CaSO_4$) and calcium sulfite ($CaSO_3$), that is captured along with the ash.

4.3.2.2 Selective Non-Catalytic Reduction System (SNCR)

The selective non-catalytic reduction (SNCR) system uses anhydrous ammonia that is injected into the flue gas upstream of the cyclone in the CFB to reduce NO_x to molecular nitrogen and water. Ammonia slip will be below 10 ppm.

The anhydrous ammonia is pumped from storage tanks as a liquid to the injection equipment. Due to the reduced temperature of the flue gas, catalyst is not required for an SNCR.

4.3.2.3 Limestone Storage and Handling

Limestone will be received through a new track/truck hopper. Vibrating feeders will transfer limestone from the receiving hopper to the unloading conveyor at the rate of 500 tons per hour. The unloading conveyor will transfer limestone to a stacking tube. The stacking tube will minimize dust generation during stockout operations. The new storage pile will contain approximately 20,000 tons and will be provided with an “umbrella” type cover to provide weather protection.

Reclaim will be accomplished via three (3) vibrating reclaim feeders (one under the tube rated at 500 tph and the remaining two on opposite sides of the stacking tube each rated at 125 to 250 tph) located in the reclaim tunnel discharging to the day bin feed conveyor.

The new day bin feed conveyor will be designed to reclaim and convey limestone to the day bins at 500 tons per hour. Limestone will be fed to the first day bin or diverted to the second day bin via a motorized gate and transfer chute. The day bin feed conveyor will be provided with a belt scale and a magnetic separator.

A limestone crusher and dryer will be provided with the limestone preparation equipment. The limestone crusher will be designed to crush the limestone to an acceptable size, which is set by the boiler manufacturer. Since the moisture content of the received limestone is greater than the allowable limit entering a CFB boiler, a dryer will be required. The dryer will be designed such that the limestone entering the CFB boiler will have a moisture content of around one percent or as required by the boiler manufacturer.

All new transfer points will be provided with dust collection.

4.3.2.4 Carbon Injection System

The reagent injection system injects activated carbon into the flue gas upstream of the fabric filter for mercury control. The mercury present in the flue gas adsorbs the activated carbon and is collected in a fabric filter.

The carbon injection system consists of a pneumatic loading system, storage silos, hoppers, blowers, transport piping, and control system. The injection equipment would likely be skid mounted. There is a high probability for the need of additional air compressors to convey the carbon to the injection point and provide the flow and pressure to get the carbon into the flue gas stream and properly mixed.

4.3.2.5 Pulse Jet Fabric Filter

One pulse jet fabric filter (PJFF) will be supplied to control particulate emissions. The fabric filter removes particulate by passing flue gas through felted bag filters.

A PJFF unit consists of isolatable compartments with common inlet and outlet manifolds containing rows of fabric filter bags. The filter bags are made from a synthetic felted material, which has proven to be the fabric of choice for coal fueled PJFF applications. Filter bags are suspended from a tube sheet mounted at the top of each fabric filter compartment. The tube sheet separates the particulate laden flue gas from the clean flue gas. This tube sheet is a flat sheet of carbon steel with holes designed to accommodate filter bags through which the bags are hung. The flue gas passes through the PJFF by flowing from the outside of the bag to the inside up the center of the bag through the hole in the tube sheet and out the PJFF. Fly ash and calcium sulfate/sulfite particles are collected on the outside of the bags, and the cleaned gas stream passes through the ID fans to the chimney. A long narrow wire cage is located within the bag to prevent collapse of the bag as the flue gas passes through it. Each filter bag alternates between relatively long periods of filtering and short periods of cleaning. During the cleaning period, fly ash that has accumulated on the bags is removed by pulses of air and then is deposited into a hopper for disposal.

Cleaning is either initiated by exceeding a preset differential pressure drop across the tubesheet or based on a maximum time between cleanings. Bags in a PJFF are cleaned by directing a pulse of pressurized air down countercurrent to the flue gas flow to induce a traveling ripple (pulse) in the filter bag. This pulse travels the length of the bag deflecting the bag outward separating the dust cake as it moves. The bag and cage assemblies are attached at the top.

4.3.3 Steam Turbine - Generator

The main steam generators will provide steam to a single main steam turbine generator. The steam turbine generator converts mechanical energy of the steam turbine to electrical energy. For this project a 2535 psia, 1050 F/ 1050 F, single-reheat, dual casing, four-flow down-exhaust, condensing steam turbine is arranged with seven stages of feedwater heaters and steam condenser. The steam turbine is designed for 3.5-inch Hg absolute backpressure at summer design conditions. The turbine will drive a 25 kV, 60 Hz, 0.85-power factor, hydrogen-cooled electric generator. Nominal output rating of the generator will be 800 MVA. The steam-turbine generator unit will be designed for indoor operation.

4.3.4 Steam Condenser

The water-cooled steam condenser will be a dual, rectangular shell, two pressure, split waterbox, two pass steam condenser with a retention hotwell for the subcritical cycle. The condensers will be designed to maintain a 3.5-inch Hg absolute steam turbine backpressure at normal maximum continuous rating of the steam turbine at summer design conditions. The condenser will be designed to accept the steam exhausted from the turbine. Air removal from the condenser's upper portion will be via two full capacity vacuum pumps. The condenser and auxiliaries will be designed in accordance with HEI standards. To dissipate the energy in the condensing steam, a circulating water system will supply cooling water from the wet cooling tower to the water-cooled steam condenser.

Piping at the powerhouse will be arranged to allow the condenser tubes to be removed. Provisions will be made in the system to minimize water hammer and short-circuiting of flow during pump trip conditions. Pump discharge, condenser inlet and condenser isolation valves will be motor operated. The circulating water pump discharge lines will contain air vent valves to release air trapped in the lines when the pumps are started. Condenser waterbox vents will also be provided to release air from the return and inlet/outlet waterboxes. Expansion joints will be placed at the discharge of the circulating water pumps and at the inlet and outlet of the condenser to accommodate thermal expansion and stress loading.

4.3.5 Circulating Water System

See Base Case 1, Section 2.3.5.

4.3.6 Closed Cooling Water System

See Base Case 1, Section 2.3.6.

4.3.7 Steam System

The Steam System transports steam from the steam generators to the main steam turbine-generator and various feedwater heaters. Cross-ties with the existing auxiliary boiler and the Unit 1 boiler steam drum will be provided to supply steam for start-up and shutdown operations. A steam turbine bypass system is not included.

The main steam piping transports steam from the superheater outlet of the steam generator to the inlet of the high-pressure turbine. Steam is exhausted from the high-pressure turbine and transported through the cold reheat piping to the reheater section of the steam generator where the temperature of the steam is increased. The hot reheat piping transports the reheated steam to the intermediate pressure turbine.

This system also transports steam from extractions in the turbine to the high-pressure heaters, low-pressure heaters, and the deaerating feedwater heater. The main steam and hot reheat systems include attemperators, where feedwater is injected as necessary to control the temperature of the steam being supplied to the turbine. Drum steam will be supplied to the main deaerator and air preheater steam coils during start-up, unit trip and unit shutdown.

The steam pipelines will be provided with drip drains at all low points. Drain pots will be provided to collect condensate from the low points in the steam piping and return it to the main condenser. The drain pots will adequately drain the various low points of the piping system at the maximum steam flows.

All extraction lines from the turbine, except those leading to the heaters in the condenser neck, will be equipped with power assisted, nonreturn valves to ensure that steam will not flow back to the turbine. These lines will also be supplied with motor-operated shutoff valves to prevent steam turbine water induction.

4.3.8 Condensate System

The Condensate System delivers deaerated condensate via three, 50-percent capacity vertical, condensate pumps. These pumps transport condensate from the steam condenser hotwell, through the gland steam condenser and low-pressure feedwater heaters to the boiler feed pumps. A minimum flow bypass system will be provided to assure the pumps operate above their minimum flow rate at all times

4.3.9 Feedwater System

The Feedwater System provides feedwater to the high-pressure feedwater heaters and then to each boiler's economizer via two 50-percent capacity, high-pressure boiler feed pump. The two CFB boilers will be connected to the feedwater pumps by a common header. Each boiler feed pump is furnished with an electric motor drive. It also provides spray water for main steam and hot reheat attemperators for steam temperature control. A minimum flow system will be provided to assure the pumps operate above their minimum flow rate at all times.

A warm-up system is also provided to facilitate placing the pumps in operation.

4.3.10 Coal Unloading & Storage System

See Attachment G – Fuel Handling System Descriptions.and Schematics

4.3.11 Water Systems & Treatment

See Attachment E – Water Treatment & Wastewater Management.

4.3.11.1 Sample Analysis System

The water quality control system shall consist of three major components: a sample rack, a water quality panel, and a sample chiller. Samples from the following points in the plant shall be routed to the centrally located water quality control system for the indicated continuous analyses, monitoring, data logging, and trending analysis and recording.

A sample analysis system will include sample points at:

- The Condensate/Demineralized water tank (Local), (Silica & Specific conductivity)
- Condensate Pump Discharge, (Specific conductivity, Cation conductivity, sodium, pH & Dissolved oxygen)
- Condensate after Condensate Polisher, (Sodium, Cation conductivity)

- Feedwater from deaerator (or economizer inlet) (pH, Dissolved oxygen, Specific Conductivity)
- Main steam (Cation conductivity, Sodium, Silica) Saturated steam (alternate to Main Steam)
- Boiler blowdown (Specific conductivity, pH, Phosphate, & Sodium)
- Boiler downcomer (Specific conductivity, Dissolved oxygen)

Analyzers will be shared by different sample points where continuous analysis of parameters is not critical (i.e. sodium and silica). System will include a conditioning panel utilizing condensate for primary cooling and cooling water or chilled water for secondary cooling to condition the samples to the necessary temperature. A second wet panel will contain the analyzers and sensors. A third dry panel (NEMA 12) will contain the monitors.

4.3.11.2 Condensate Polisher

The condensate system will be provided with 50% flow deep bed condensate polishing. The Condensate Polishing System will receive water from the discharge of the condensate pumps. All of the unit's condensate will flow from the Condensate System through the condensate polisher exchangers. The condensate will pass through exchanger beds consisting of a mixture of cation and anion resins. The bed serves as both an ion exchange media and as a filter. The effluent of the Condensate Polishing System will be returned to the Condensate System upstream of the gland steam condenser.

4.3.12 Additional Mechanical Systems & Equipment

See Base Case 1, Section 2.3.12.

4.4 ELECTRICAL SYSTEMS & EQUIPMENT

4.4.1 Electrical Generation & Distribution

See Base Case 1, Section 2.4.1.

4.4.2 Generator System

See Base Case 1, Section 2.4.2.

4.4.3 Station Metering

See Base Case 1, Section 2.4.3.

4.4.4 Auxiliary Power Supply

See Base Case 1, Section 2.4.4.

4.4.5 Additional Electrical Systems & Equipment

See Base Case 1, Section 2.4.5.

4.5 CONTROL SYSTEMS & EQUIPMENT

4.5.1 Overview

The operating staff will consist of two control room operators, one shift supervisor, and one roving operator per shift. There will also be a fuel/ash handler on all shifts. The shift supervisor and control room operators for each shift will be thoroughly trained in all aspects of plant controls and will be fully qualified to operate all plant systems. The shift supervisor will direct shift operations, make assignments, and perform required administrative duties. The shift supervisor will also serve as an additional operator during emergencies and provide periodic relief for the control room operators.

4.5.2 General

The control system will be a physically and functionally distributed microprocessor based, on-line distributed control system (DCS). The DCS will be used for supervisory control and monitoring of all major plant systems. In addition, programmable logic controllers (PLCs) will be provided for auxiliary systems such as coal handling, ash handling, water treatment, sootblowers, etc.

The boilers, turbine and auxiliary controls will be provided under various equipment contracts. In general, where equipment is furnished as a "package", the auxiliary control system will be included in that package. However, since the turbine, boiler and heat cycle are operated as a unit in response to load demand, the associated coordinated load, combustion and burner management controls will be provided under a Distributed Control System (DCS) package. In addition, the DCS will serve as the primary Human Machine Interface (HMI) for plant wide remote controls and monitoring, except where local control is mandated. The auxiliary systems, usually Programmable Logic Control (PLC) based, are each to be designed by the furnishing contract as a turnkey package using project standard requirements for control philosophy and electrical design.

The conceptual architecture of the DCS is depicted in Attachment I – Control System Conceptual Architecture. The components of the DCS are contained in the following five subsystems:

- DCS HMI & Information Network
- DCS Controllers & Input Output (I/O)
- Gateways & Communication Interfaces
- Turbine Control System
- Auxiliary Controls

DCS control cabinets and PLCs will be located as required to enhance reliability and reduce wiring requirements. In general, DCS control cabinets and PLC gateways for control of systems located in the main boiler and steam turbine buildings will be located in the electrical equipment room. The PLCs for control of remotely located systems such as fly ash handling may be located in conditioned spaces near those systems.

Engineering programming terminals will be provided in the electrical equipment room, shift supervisor's office and engineer's office. The workstations will be used to perform system programming and to view historical data.

4.5.3 DCS and Related Systems

All information from DCS Controllers and I/O is passed to the operator through operator server/client personal computers operating on a dedicated Ethernet Local Area Network (LAN), the DCS Information Network. Servers, located in a Computer Room or Control Equipment Room, will provide the gateway from the LAN to the proprietary DCS Data Highway. Operator servers and clients may be installed in the same machine running a Microsoft or a UNIX based operating system. The servers and clients will be powered in two groups from two separate sources of power. The servers may be operated in a redundant mode if throughput allows operator updates once per second.

The operator clients will be installed in the operator console in a centrally located main plant Control Room. These clients will be desktop or tower personal computers installed for cost-effective replacement by the Owner when they malfunction or become obsolete. Each client will consist of a computer, a keyboard, mouse or trackball and two CRTs or LCD displays. The console will be provided in sections for semicircular arrangement with each client's displays side-by-side or over-under. The console design will employ human factors for sit down operation. Two screens, either CRT, LCD or projection displays will be hung from the ceiling over or directly behind the operator console.

An additional operator console server may be required to provide operator graphics to non-operator console clients. These clients may reside on the DCS information network or on the Owner's LAN/WAN external to the DCS Information Network. A LAN gateway or bridge is included to bridge the LANs. Several console software licenses are required for installation on the Owner's personal computers. These Clients will allow the Owner's supervision and engineering personnel access to real time and historical data.

A plant historian will be provided to allow several months of data to be stored from and retrieved by the DCS. It shall also allow for the archive and retrieval of data through the use of CD R/W drive or streaming tape. The historian will either be an OIS PI System or the DCS supplier's equal and should supply data to all operator servers and client workstations. The DCS should allow the seamless retrieval of short-term and long-term data into the same DCS operator trends. The historian will be redundant for data backup or will be provided with short- term history storage to backup data for at least several days in event the historian is down.

A performance calculation engine will be provided on the DCS Information Network. This engine will retrieve performance data on an hourly, shift, daily, and monthly basis to provide reports for operations and management. It will then pull analog and digital (on-off) data from the DCS or the historian to perform the calculations and store the results. The results will be available for retrieval by the operator clients or the historian over the network.

4.5.4 Turbine Control System (TCS)

The TCS will include the basic governor speed load control for warming, startup and continuous operation of the turbine. In addition, it will include all turbine/generator monitoring and control for automatic turbine startup (ATS), supervisory instrumentation (TSI), excitation and voltage control supervision, and turbine auxiliaries. Auxiliaries include lube oil, hydraulic oil, seal oil, turning gear, stator cooling, exhaust hood temperature, steam seal system, gland steam condenser, etc. provided with the turbine.

4.5.5 Auxiliary Controls

The following controls are to be provided using PLCs. It is expected that they will be provided by the process equipment suppliers, using a standard PLC and Human Machine Interface (HMI) acceptable to the Owner for local control. The communication interface to these PLCs from the DCS is via Ethernet links or proprietary PLC data highway interfaces.

- Sootblowing Controls.
- Selective Non-Catalytic Reduction (SNCR) Controls.
- Fabric Filter Controls.
- Bed Ash Controls.
- Flyash Controls.
- Flyash Disposal Controls.
- Fan Vibration Analyzer.
- Wastewater Treatment Control.
- Water Treatment Control.
- Condensate Polisher Control
- Continuous Emissions Monitors.

The following equipment will require a separate serial or Modbus interface to provide information into the DCS.

- Fan vibration monitor.
- Boiler feed pump vibration monitor.

4.5.6 General Control Functions

The control system will include a library of analog functions required to implement the analog control loops. Typical functions include summing, difference, multiplying, PID control, lead/lag, high and low select, function generators, signal generators, high and low limiting, logical selects, and externally requested or operator-selected transfers.

Programming of all digital control loops will be in ladder diagram format or a simplified high-level logic programming language. All digital control loops will be displayed on the operator console. The operator will be able to issue commands to start/stop and open/close process equipment from loop displays (faceplates) on console displays or from the keyboards. These commands will be communicated to the appropriate controller through the data highway and communication networks. The controller will manipulate the appropriate I/O module to provide the required action.

The DCS will automatically supervise the status of predetermined interlocks and provide control functions as the operator initiates such commands as start or stop for various pumps, fans, motor-operated valves, etc., for the power plant proper. This is to prevent improper or dangerous operation in case of inadvertent operator error or certain process equipment malfunction.

The Project will be monitored and controlled by a Distributed Control System (DCS). Automation will be sufficient to reduce the manual actions required by operating personnel such that three operators can start-up, operate, and shut down the entire plant. During steady state operation at or near base load, automation will allow safe and reliable operation without frequent operator intervention. Auxiliaries such as sump pumps that need not be in continuous operation for electric power production will be monitored, controlled, and protected locally, with limited control room monitoring and control.

The DCS design is based on one uniform system with control over all plant functions, including the boilers, steam turbine-generator (ST), and the balance of plant to the maximum practical extent. The boilers, ST, CEMS, and fire protection systems have dedicated remote input/output DCS or PLC-based controllers supplied with the equipment for main control, supervision, safety interlocks, etc. These controllers communicate with the DCS to allow remote operation of select functions from the control room. A local interface for each of these controllers is included.

A stand-alone dedicated server integrated with the DCS to allow remote information gathering by authorized third parties without direct connection to the DCS is included. Two operator workstations, each with a keyboard and two color displays for monitoring are included. One engineering workstation with keyboard and monitor is included. A dedicated historian log printer and two log printers are included.

4.5.7 Continuous Emissions Monitoring Systems (CEMS)

One CEMS downstream of the SNCR/pulse-jet fabric filter and a common data acquisition system is included for each boiler. The final flue gas outlet CEMS will consist of sampling devices with sample tubing to the emissions rack mounted near the base of the stack in a common enclosure. The enclosure will include cylinder rack for calibration gases. The CEMS monitor stack emissions with hardware and reporting package software that meets the requirements of 40 CFR 60 and 40 CFR 75 as determined by the permit requirements. The CEMS are designed to communicate with the plant DCS system to provide automatic report production compatible with permit requirements.

Additional in-situ-type flue gas emission monitors for boiler oxygen and carbon monoxide at the air preheater gas outlet will be provided and connected to the each boiler's DCS. This is primarily for real-time combustion process control prior to the air pollution control equipment.

4.5.8 Additional Control Systems & Equipment

Other Control Systems & Equipment that were considered include:

- DCS Controllers & Input/Output (I/O)
- Gateways and Communication Interfaces
- Input/Output Requirements
- Controllers
- Data Highway
- Historical Data Storage
- Control Stations
- Operator Station Display Functions
- Printers
- Engineering Programming Terminals
- Alarm Functions
- Sequence of Events
- Log Functions

5.0 ALTERNATES TO BASE CASE 2

5.1 - 450 MW SUBCRITICAL CIRCULATING FLUIDIZED BED BOILER

The following paragraphs summarize the major differences between a 450 MW CFB unit and Base Case 2. If systems are not discussed, it can be assumed that they will be similar to Base Case 2.

5.1.1 General Design Criteria

The design criteria will be similar to Base Case 2 with the exception of the unit size. The gross output of the plant will be approximately 506 MW, and the resulting net generation will be 450 MW.

5.1.2 Civil / Structural Features

The civil / structural features will be similar to Base Case 2 with the exception of the landfill size. The smaller unit, in combination with Unit 1, would create approximately 358,300 cubic yards of waste per year. The existing landfill would have enough capacity for approximately 11.1 years of operation. Operating both units until 2040 would require the development of approximately 109 acres of new landfill.

5.1.3 Mechanical Systems & Equipment

The mechanical systems and equipment will be similar to Base Case 2, but sized for the smaller unit output.

5.1.4 Electrical Systems & Equipment

Electrical equipment and systems for this option will be similar to the base case except equipment ratings will be smaller for the lower output.

5.1.5 Control Systems & Equipment

The control systems will be similar to the base case except instruments and I/O will be reduced to match the mechanical systems for the lower megawatt output.

5.2 – 300 MW SUBCRITICAL FLUIDIZED BED BOILER

The following paragraphs summarize the major differences between a 300 MW CFB unit and Base Case 2. If systems are not discussed, it can be assumed that they will be similar to Base Case 2.

5.2.1 General Design Criteria

The general design will be similar to Base Case 2, however, the unit will only consist of 1 boiler. Also, the smaller unit will only require 26 additional staff instead of 30.

5.2.2 Civil / Structural Features

The civil / structural features will be similar to Base Case 2 with the exception of the landfill size and bridge crane. The smaller unit, in combination with Unit 1, would create approximately 278,600 cubic yards of waste per year. The existing landfill would have enough capacity for approximately 14.3 years of operation. Operating both units until 2040 would require the development of approximately 77 acres of new landfill.

The smaller unit will only require a 70-ft bridge crane span. The existing bridge crane has a span of 90 ft. The cost of expanding the existing crane to Unit II, and therefore expanding the administration and powerhouse buildings to accommodate it, would be more expensive than installing a new, 70-ft crane in the new powerhouse building.

5.2.3 Mechanical Systems & Equipment

The mechanical systems and equipment will differ from the base case because the unit utilizes a single boiler. There will only be one set of all associated boiler equipment that was in duplicate for the base case.

5.2.4 Electrical Systems & Equipment

The auxiliary power system for this case includes one 13.8 kV and one main 4.16 kV bus with a cross tie 13.8-4.16 kV transformer connecting the two busses. The auxiliary transformer will be three winding with 13.8 and 4.16 kV secondaries. Additional 4.16 kV busses will be included to serve the boiler and material handling areas. Other components of the electrical systems will be similar to the base case.

5.2.5 Control Systems & Equipment

The control systems will be similar to the base case except instruments and I/O will be reduced to match the mechanical systems for the lower megawatt output.

Since there is only on boiler and, therefore, only one flue in the stack, there will be only one CEMS for this option.

6.0 – BASE CASE 3 – 500 MW COMBINED CYCLE GAS TURBINE (CCGT)

6.1 General Description

The basic principle of the CCGT plant is to utilize natural gas to produce power in a gas turbine (GT) - which can be converted to electric power by a coupled generator - but also use the hot exhaust gases from the GT to produce steam in a Heat Recovery Steam Generator (HRSG). This steam is then used to create electric power with a coupled steam turbine and generator. Combined cycle generation is widely used and is a mature technology.

The use of both gas and steam turbine cycles in a single plant to produce electricity results in high conversion efficiencies and low emissions. The gas turbine (Brayton) cycle is one of the most efficient cycles for the conversion of gas fuels to mechanical power or electricity. Adding a steam turbine to the cycle, to utilize the steam produced by the HRSG, increases the efficiencies to a range of 50% to 58%.

Output for combined cycle plants can be increased with the use of duct firing in the HRSG. This method employs burning gas in the HRSG at an intermediate stage to reheat the exhaust gas stream after some energy has been removed for steam superheating. Though the output is increased, the heat rate also increases and the plant becomes less efficient. Duct firing is limited by the HRSG materials of construction but can be used to push the steam turbine output to equal that of the gas turbine(s). Without duct firing the steam turbine(s) output is typically half the gas turbine output.

Gas turbine and HRSG manufacturers are continuing to develop high temperature materials to raise the firing temperature of the turbines and duct burners, as well as increase the efficiency. They are also developing cooling techniques to allow higher firing temperatures.

Typical combined cycle plants operate with natural gas as the operating fuel. Often, the ability to operate on fuel oil is also required in case the demand for power exists when the natural gas supply does not. The combined cycle plant was evaluated with dual fuel capabilities using 100% methane as the primary fuel and distillate #2 as the back up fuel.

6.2 Performance

CCGT power blocks of 60 MW, 125 MW, 250 MW and 500 MW are possible. For the purposes of this study, a power block of 500 MW is composed of a two “F” class gas turbine, two heat recovery steam generators, and a single steam turbine was assumed. This plant size falls in the middle of the range of coal fired plants considered for this study (300 MW – 600 MW net). The steam cycle consists of a three pressure HRSG with reheat. Steam turbine throttle conditions are 1865 psig and 1050 F and a single reheat at 1050 F. The net heat rate this plant can achieve is approximately 7000 Btu/kWh (HHV).

Cold start-up times for CCGT are commonly in the 1-4 hour range compared SCGT times of 10-40 minutes. Hot start times for CCGT are considerably faster than cold start but are still much slower than SCGT. Bypass stacks or a steam bypass system can be installed in CCGT plant to allow for simple cycle operation with similar performance and ramp rates, but this requires a greater capital investment.

6.3 Emission Controls

For a CCGT plant burning natural gas, selective catalytic reduction (SCR) is utilized to achieve a NO_x emissions level around 2.5 - 3 ppm. The SCR system utilizes ammonia injection to achieve the NO_x levels required. On recently permitted projects, a CO catalyst has also be required to reduce CO emissions. Both emission reduction technologies are included in the cost estimate.

Pipeline quality natural gas is normally low in sulfur, therefore no control technology is required. Fuel oil sulfur content is normally limited to 0.05% by weight.

6.4 Waste Disposal

Waste disposal is negligible. Since the primary fuel to be burned is natural gas, no solid byproducts occur from the combustion. The only waste disposal to be addressed is the disposal of the blowdown water.

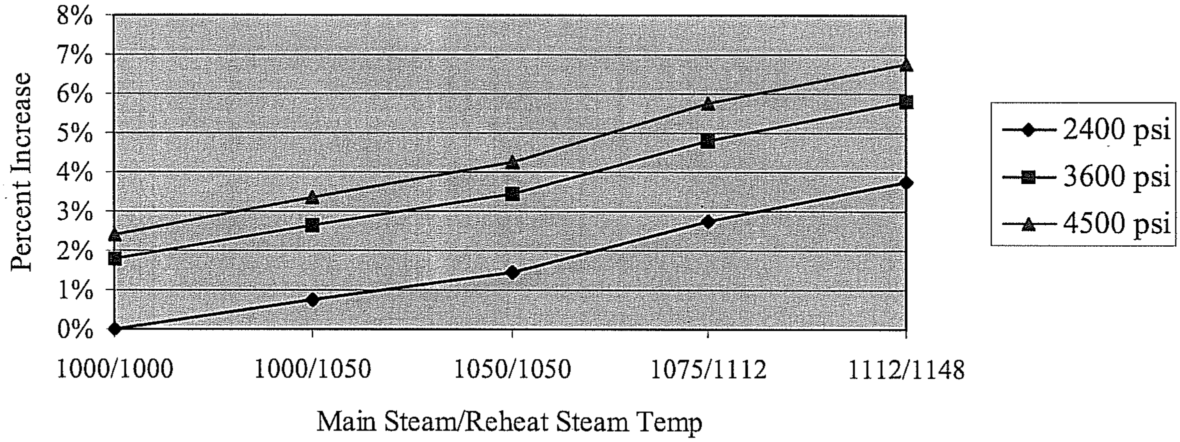
7.0 SUBCRITICAL VERSUS SUPERCRITICAL DESIGN

There are several factors involved in determining what technology should be used for a solid fuel unit. The critical factors are unit efficiency, availability, O&M costs, and capital costs.

7.1 Unit Efficiency

Conventional subcritical cycles are based on turbine throttle conditions of 2400 psig/1000F superheat/ 1000F reheat. Steam cycle efficiency improves as pressure and temperature is increased. For a single reheat cycle, increasing throttle pressure from 2400 psig to 4500psig improves heat rate by 2.5%, while increasing steam temperatures from 1000F/1000F to 1100F/1100F improves heat rate by 3%. The following chart shows the improvements possible with the supercritical steam cycle.

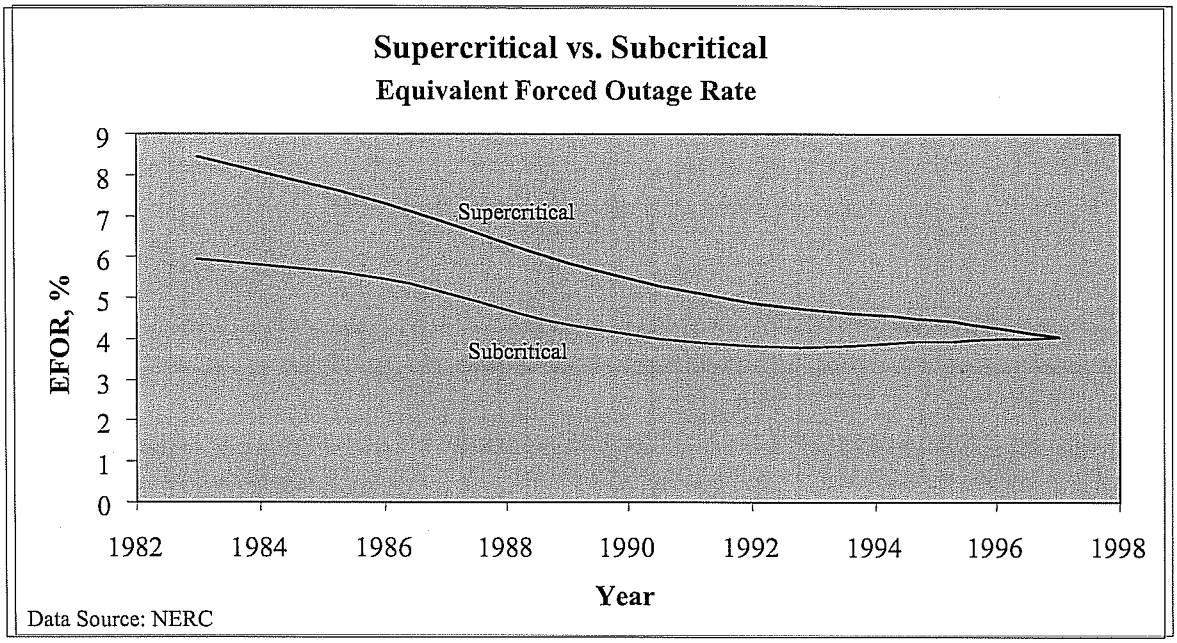
Impact of Steam Conditions on Efficiency



The improved unit efficiency requires reduced fuel consumption for the same net annual power output, therefore a supercritical unit produces lower overall emissions than a subcritical unit with the same output.

7.2 Unit Availability

Unit availability of supercritical power plants in the US has not been as good as that of subcritical units. This is due in large part to the designs of the early units. However with the design and tubing material of construction improvements of the newer generation units, the equivalent forced outage rates (EFOR) for supercritical units has been steadily dropping. Studies conducted by NERC show the availability of supercritical units approaching that of subcritical units as shown in the following graph.



VGB Power Tech in Germany reports an average equivalent availability factor (EAF) of supercritical units in Europe at 85.8% versus 84.76% for subcritical units from 1990 – 1997. New coal fired plants commissioned in Organization for Economic Co-operation and Development (OECD) countries between 1995 and 2000 that use advanced controls and improved materials of construction are reported to be operating with an EAF as high as 90%.

7.3 O&M Costs

Several sources, including Power Magazine in its April 2004 edition, report that O&M costs for supercritical units are nearly identical to that of subcritical units. Reported fixed and variable O&M costs in the article are $6.2/MWh for subcritical units and $6.3/MWh for supercritical units. A Western Power study for new generation in Australia also reported no significant difference in O&M costs between the two designs. There may be slightly higher fixed O&M costs for the supercritical units due to the complexity of the unit and the need for highly trained operators. Offsets in lower variable O&M will come from reduced consumption of lime/limestone, ammonia, carbon and water consumption due to increased efficiency of the supercritical unit.

7.4 Capital Cost

Several studies report a capital cost difference of between 2 and 5 percent higher for the supercritical unit over a subcritical unit. Sources for this difference come from the Western Power study referenced above, Black & Veatch study new generation and the April 2004 Power Magazine data. The cost adders are associated with the boiler design and material costs for high pressure piping. Turbine vendors report little to no cost increase for its equipment.

8.0 INTEGRATED GASIFICATION COMBINED CYCLE (IGCC) TECHNOLOGY

Burns & McDonnell has performed several technical and commercial evaluations of the IGCC technology as an alternative generation technology for a 600MW coal fired power plant. The IGCC technology is currently facing several challenges related to the full scale commercialization of a 600MW (or greater) facility. The major issues are briefly discussed below. These issues pose a considerable risk to any utility considering an IGCC facility, and until such time that the risks can be managed and technical issues be addressed and resolved, it is doubtful that a full scale coal IGCC facility will be built in the U.S.

8.1 General Description

Integrated Gasification Combined Cycle (IGCC) technology produces a low calorific value syngas from coal or solid waste, for firing in a conventional combined cycle plant. The gasification process represents a link between solid fossil fuels such as coal and existing gas turbine technology. The IGCC process is shown in Figure 8.1 below.

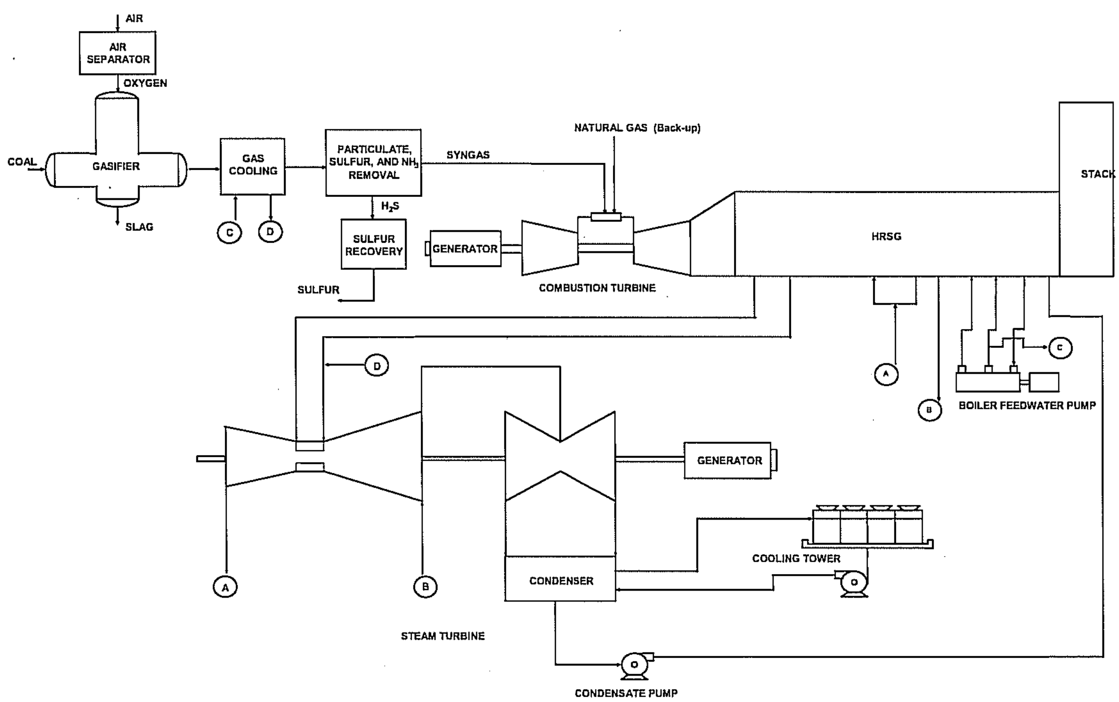


Figure 8.1: IGCC Process Diagram

The gasification process in itself is a proven technology having been previously utilized extensively for production of chemical products such as ammonia for use in fertilizer. However, utilizing coal as a solid feedstock in a gasifier for electrical power generation is currently under development. Three gasifier manufactures have IGCC experience on various U.S. coals. Each of the manufacturers has a slightly different technology that has proven to work differently on different fuels. Testing of various coals on the different gasifiers is continuing. There are a number of power generation projects jointly funded by the Department of Energy (DOE) at several power plant facilities throughout the United States (Refer to Table 8.1). Of the currently operating IGCC facilities, none are operating on low sulfur Powder River Basin coal.

A 550 MW net IGCC plant would typically be comprised of two coal gasifiers, a coal handling system, an air separation unit, a gas conditioning system to remove sulfur and particulate, two gas turbines, two heat recovery steam generators with supplemental duct firing and a single steam turbine.

Integrating proven gasifier technology with proven gas turbine combined cycle technology is a relatively recent development, and continues to be improved at the existing DOE jointly funded power plants. Because gasification-based power generation is a relatively new technology with few operating plants, its unique operating features and its environmental performance capability are not well known.

Gasifiers designed to accept coal as a solid fuel generally fall into three categories: entrained flow, fluidized bed, and moving bed.

<u>Entrained Flow</u>

The entrained flow gasifier reactor technology converts coal into molten slag. This gasifier design utilizes high temperatures with short residence time and will accept either liquid or solid fuel. General Electric (Chevron Texaco), Conoco Phillips (E-Gas), Prenflo, and Shell, all produce gasifiers of this design.

<u>Fluidized Bed</u>

Fluidized-bed reactors are highly back-mixed design in which feed coal particles are mixed with coal particles already undergoing gasification. Fluidized bed gasifiers accept a wide range of solid fuels, but are not suitable for liquid fuels. The KRW and High Temperature Winkler designs use this technology.

Moving Bed

In moving-bed reactors, large particles of coal move slowly down through the bed while reacting with gases moving up through the bed. Moving-bed gasifiers are not suitable for liquid fuels. The Lurgi Dry Ash gasification process is a moving bed design and has been utilized both at the Dakota Gasification plant for production of SNG and the South Africa Sasol plant for production of liquid fuels. BGL is another manufacturer of the moving bed design.

The majority of the DOE test facilities utilize the entrained flow gasification design with coal as feedstock. Coal is fed in conjunction with water and oxygen from an air separation unit (ASU) into the gasifier at around 450 psig where the partial oxidation of the coal occurs. The raw syngas produced by the reaction in the gasifier exits at around 2400 °F and is cooled to less than 400 °F in a gas cooler, which produces additional steam for both the steam turbine and gasification process. Scrubbers then remove particulate, ammonia (NH_3), hydrogen chloride and sulfur from the raw syngas stream. The cooled and treated syngas then feeds into a modified combustion chamber of a gas turbine specifically designed to accept the low calorific value syngas. Exhaust heat from the gas turbine then generates steam in a heat recovery steam generator (HRSG) which in turn powers a steam turbine. However, the syngas cooler greatly improves thermal efficiencies when compared to a quench cooler system typical to those utilized in chemical production gasifiers. Reliability issues associated with fouling and/or tube leaks within the syngas cooler have challenged the existing IGCC installations.

8.2 Current Status

The following table identifies the DOE jointly funded test facilities constructed in the United States, with various gasification system designs.

Table 8.1: IGCC Test Facilities

Facility	Owner	Capacity (MW)	Commercial Operation Date	Gasifier Manufacturer	Status
Polk County	Tampa Electric	252	1996	Chevron Texaco	Operating
Wabash River	PSI Energy	262	1995	Conoco Phillips	Operating
Pinon Pine	Sierra Pacific	99	1997	KRW	Decommissioned
LGTI	Dow Chemical	160	1987	Conoco Phillips	Decommissioned
Cool Water	Texaco	125	1984	Chevron Texaco	Decommissioned

In addition to the constructed units referenced in Table 8-1, the following IGCC projects are currently in the development phase:

- 540 MW power station located in Lima, OH for Global Energy, Inc.
- 530 MW Mesaba Energy Project located in Minnesota for Excelsior Energy.
- 285 MW Stanton Energy Center Project in Florida, jointly owned by Orlando Utilities Commission and The Southern Company.

Commercial operation of these plants, provided the projects proceed, is at least 5 to 6 years in the future.

8.3 Plant Characteristics

8.3.1 Performance

Cold start-up times for IGCC plants have typically ranged from 40-50 hours compared to a conventional PC boiler start-up time of 4-6 hours. Hot restart procedures are in testing at several of these facilities, and Eastman Chemical Company has developed a proprietary process that allows a fairly rapid startup. However, a disadvantage is this startup process requires flaring the syngas produced until it is adequate quality for introduction into the gas turbine.

The gasification plant requires stable operation in order to maintain syngas quality and the technology to support load following continues to be developed.

The performance estimate shown in Table 8.2 was supplied by GE for a typical 550 MW IGCC unit firing 100% Bituminous coal. The GE performance estimate is at 90°F dry-bulb temperature, 60%RH, and 0 ft. elevation.

Table 8.2: 550 MW IGCC Expected Performance

IGCC Performance at 90 F, 60% RH, 0 ft. elevation	
Gross Gas Turbine Output, kW	394,000
Gross Steam Turbine Output, kW	282,800
Gross Plant Output, kW	676,800
Total Auxiliary Loads, kW	123,678
Net Plant Output, kW	**553,122**
Net Plant Heat Rate, Btu/kWh (HHV)	**9,106**

Significant design issues have prevented coal gasification units from achieving industry acceptable availability levels. These design issues include fouling within the syngas cooler, design of the pressurized coal feeding system, molten slag removal from the pressurized gasifier, durability of gas clean-up equipment and solid particulate carryover resulting in erosion within the gas turbine. The complexity of the combined cycle unit in conjunction with the reliability of numerous systems, including the gasifier, O_2 generator, air separation unit and multiple scrubbers have contributed to reduced IGCC plant availabilities.

Unit availability at the DOE jointly funded plants has been improving due to design modifications intended to improve equipment life and reliability. Polk County was able to achieve 83% availability for 2003 and Wabash River achieved 83.7% availability for 2003. All of these DOE funded coal gasification plants have experienced down-time for design modifications and replacement of equipment. Polk County and Wabash River are the only two coal IGCC plants in the United States that have achieved extended periods of commercial operation. Current state-of-the-art IGCC plants are expected to achieve an availability of around 85 percent, compared to 90 percent or higher for conventional steam electric plants.

8.3.2 Emissions Controls

The IGCC facility includes the following emissions controls equipment:

- Nitrous oxide (NO_x) emission control is achieved by injecting either nitrogen or steam into the gas turbine combustors during syngas operation. During natural gas operation, steam injection is utilized for NO_x control. Selective catalytic reduction (SCR) is not required at this time.
- Sulfur dioxide (SO_2) emission control is achieved through sulfur removal in the syngas. Sulfur removal is accomplished by using an amine scrubber that utilizes a methyldiethanolamine (MDEA) solution to absorb Hydrogen Sulfide (H_2S) from the syngas stream prior to combustion. High levels of sulfur removal are accomplished by first passing the syngas through a carbonyl sulfide (COS) hydrolysis reactor prior to the amine scrubber to convert small amounts of COS in the syngas to H_2S.
- Mercury removal is achieved by passing the syngas through a carbon filter bed prior to combustion.
- The syngas is scrubbed prior to combustion to remove particulate. Post-combustion particulate control is not required due to the inherently low particulate emissions of the syngas fuel.

GE proposed gaseous emission rates for an IGCC unit firing 100% bituminous coal are shown in Table 8.3. These emission rates are compared to a 550 MW pulverized coal unit firing a 100% bituminous coal using BACT control technology.

Table 8.3: Pulverized Coal vs. IGCC Emission Rates

Pollutant	550 MW Pulverized Coal Emission Rate	550 MW IGCC Emission Rate
NOx, lb/MMBtu Coal	0.08	0.055
SO2, lb/MMBtu Coal	0.18	0.09
CO, lb/MMBtu Coal	0.12	0.03
Particulate, lb/MMBtu Coal	0.018	0.008

8.3.3 Waste Disposal

The syngas sulfur removal process can result in 99.9 percent pure sulfur, which is potentially a saleable by-product. The gasifier converts coal ash to a low-carbon vitreous slag and flyash. The slag has beneficial use as grit for abrasives, roofing materials, or as an aggregate in construction. Fly ash entrained in the syngas is recovered in the particulate removal system and is either recycled to the gasifier or combined with other solids in the water treatment system and shipped off site for reuse or to be landfilled.

8.3.4 Water Requirements

An IGCC plant uses approximately one third the cooling water for condensing steam compared to a similarly sized conventional steam electric plant. However, a large cooling water supply is required for coal gasification and for the air separation unit used to produce pure oxygen. When combined with the steam condensing requirements, the amount of water is comparable to a similarly sized conventional steam electric plant.

8.3.5 Project Schedule

The permitting process for a greenfield 550 MW net IGCC takes approximately 18 months. The design and construction duration is approximately 48 months. In most cases, the permitting phase and design/construction phase will partially overlap to decrease the overall implementation period; however, this schedule does expose the Owner to some risk if the permit is not approved. Total implementation time for a 550 MW net IGCC including permitting, design, and construction is approximately 52 – 64 months, which is comparable to a pulverized coal unit.

8.3.6 Capital Cost Estimates

GE has estimated the capital cost of a typical IGCC plant based on a 550 MW "greenfield" site firing 100% Bituminous coal to be approximately $1,640/kW excluding Owner's costs. This capital cost is for the three major blocks (gasification block, air separation unit block, and power block) and EPC contractor costs (including indirect costs, engineering costs, construction management, EPC fee, EPC contingency).

B&McD estimated Owner's costs (excluding interest during construction, financing fees, and escalation) for a typical 550 MW IGCC plant to be $230/kW. The total project cost incorporating GE costs and Owner's costs is estimated to be $1,870/kW based on a 550 MW facility.

8.3.7 Operations and Maintenance

There has not been a long operating history for IGCC units. Scheduled maintenance consists of an outage of approximately 3 weeks/year and 4-5 weeks every five years. Tampa Electric's 250 MW IGCC demonstration facility estimates fixed and variable O&M costs are $32.80/kW-yr and $5.91/MWh, respectively. Comparable O&M costs for a 600 MW pulverized coal plant are $9.15/KW-yr and $2.86/MWh. The Tampa Electric plant is staffed by five 10-man O&M teams, and 28 additional support personnel.

8.3.8 Long Term Development

The current largest U.S. coal IGCC facility is approximately 262 MW in size. Much of future IGCC technology development will be supported through government funding of Clean Coal Technology within the power industry. A few large scale (550 MW and greater) IGCC power plants are currently in the preliminary project development and/or permitting stage in the United States, however, commercial operation of these plants, if they proceed, is at least 5 to 6 years in the future.

Acceptance of coal within the power industry and the relative price of natural gas will also influence the continuation and future development and commercialization of IGCC in the United States. Current technical issues which must be addressed and resolved for widespread commercialization of IGCC technology are expected to be addressed through future generations of government jointly funded large scale coal IGCC facilities. Once the development effort has been successfully completed, coal fueled IGCC technology may have the potential to be a reliable clean-coal generation within the United States. To date, gasifier manufacturers and IGCC contractors have shown reluctance to provide firm pricing to engineer, procure and construct a 600 MW IGCC facility, or provide complete performance and emissions guarantees.

9.0 WIND TURBINES

9.1 General Description

Wind turbines convert the kinetic energy of the wind into mechanical or electrical energy. Mechanical energy can be used to pump water while electrical energy can be used by homes or sold to utilities. Wind turbine technology is generally grouped into two types:

- Vertical-axis wind turbines, where the axis of rotation is perpendicular to the ground
- Horizontal-axis wind turbines, where the axis of rotation is parallel to the ground.

Over 95% of the turbine market over 100 kW are horizontal-axis configurations. Generally, the subsystems for either configuration include a blade or rotor to convert the energy in the wind to rotational shaft energy; a drive train, usually including a gearbox and a generator; a tower that supports the rotor and drive train; and other equipment, including controls, electrical cables, ground support equipment, and interconnection equipment.

9.2 Plant Characteristics

9.2.1 Performance

Wind turbine capacity is directly related to its size, in particular the rotor or blade diameter. A 10 kW turbine typically has a rotor diameter of over 20 feet, while a 1.5 MW turbine will have a rotor diameter of approximately 230 feet. The power that can be generated by a turbine is proportional to the cube of the prevailing wind. For example, if the wind speed doubles, the available power will increase by a factor of eight. [W^3=P, therefore $(2W)^3=8W^3=8P$] Because of this relationship, proper siting of turbines at locations with the highest possible average wind speeds is very important.

The most common and economically viable renewable resource technology employed in the region, wind turbines, is not appropriate for this project; primarily because it cannot reliably provide base load capacity. According to the American Wind Energy Association (www.awea.org), North Dakota, South Dakota and Minnesota rank 1, 4 and 9, respectively, among the states with the best wind resource. But even in this relatively windy region, wind turbines typically generate electricity only 30 to 40 percent of the time. Additionally, it is not possible to schedule the dispatch of wind turbines, as their operation is as unpredictable as the wind. Base load capacity must be reliable and able to provide virtually continuous output (with only scheduled short-term outages).

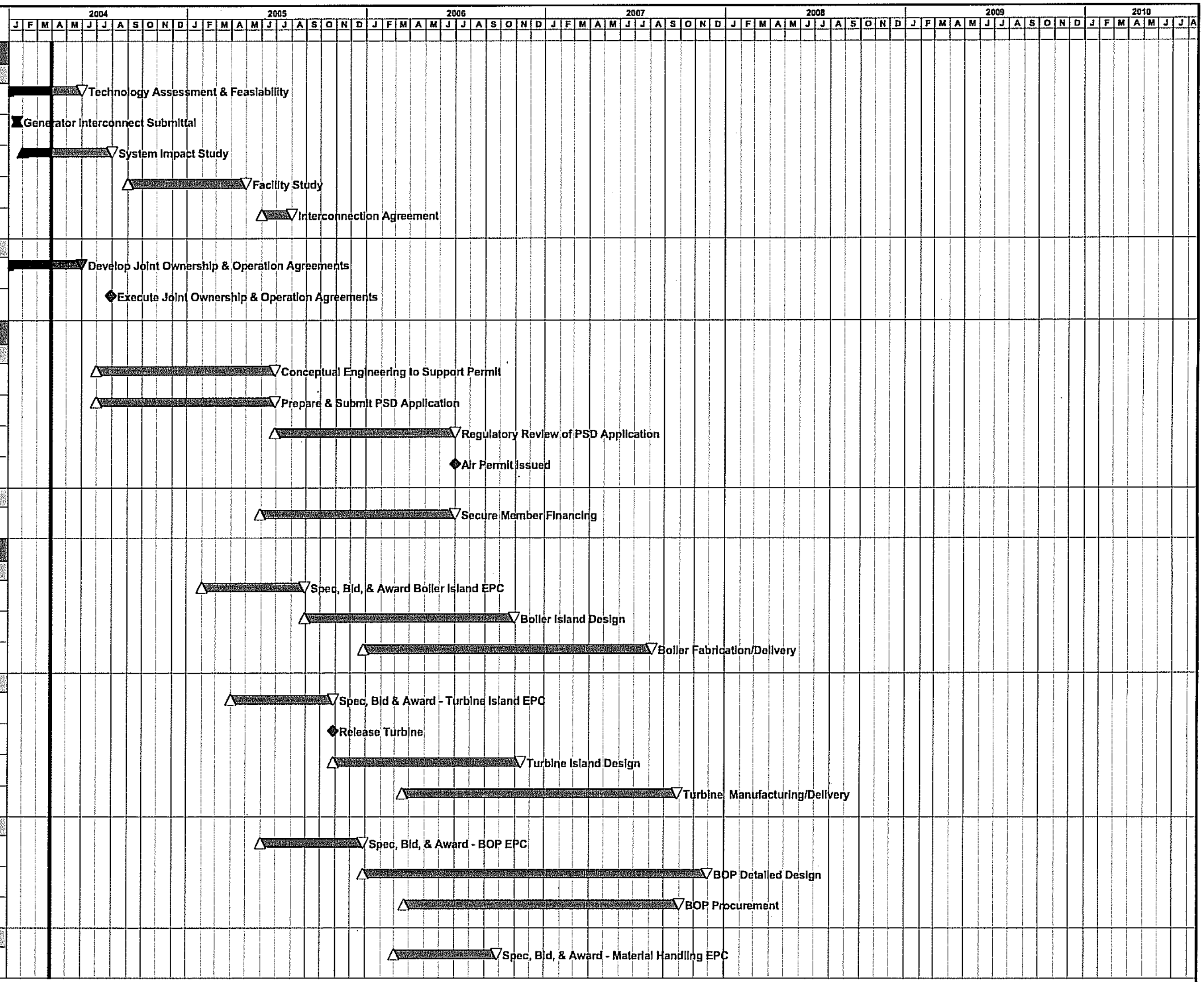
9.3 Capital Cost Estimates

Wind turbines are currently available from many manufacturers, with competition driving improvements in efficiency and costs. Turbines ranging from 750 kW to 1.5 MW are available today with development of 3.2 MW and 3.6 MW units in process. Current cost estimates indicate the capital cost of a 250 MW wind farm to be approximately $1300/kW based on the nominal rating of the turbines.

9.4 Operation and Maintenance

Estimated O&M expenses for a 250 MW wind farm are $13 /kW-yr fixed and $3.7/MWh variable.

Activity ID	Activity Description	Start	Finish
Phase I			
Studies			
C61370	Technology Assessment & Feasiability	01JAN04A	31MAY04
C61400	Generator Interconnect Submittal	20JAN04A	20JAN04A
C61410	System Impact Study	02FEB04A	30JUL04
C61420	Facility Study	01SEP04	29APR05
C61430	Interconnection Agreement	01JUN05	01AUG05
Agreements			
C61380	Develop Joint Ownership & Operation Agreements	01JAN04A	31MAY04
C61390	Execute Joint Ownership & Operation Agreements	30JUL04	
Phase II			
Permitting			
C61310	Conceptual Engineering to Support Permit	01JUL04*	29JUN05
C61340	Prepare & Submit PSD Application	01JUL04	29JUN05
C61360	Regulatory Review of PSD Application	30JUN05	30JUN06
C61350	Air Permit Issued	03JUL06	
Financing			
C61365	Secure Member Financing	30MAY05*	30JUN06
Phase III			
Boiler Island EPC Procurement & Design			
C61190	Spec, Bid, & Award Boiler Island EPC	01FEB05*	29AUG05
C61170	Boiler Island Design	30AUG05	30OCT06
C61050	Boiler Fabrication/Delivery	27DEC05	06AUG07
Turbine Island EPC Procurement & Design			
C61240	Spec, Bid & Award - Turbine Island EPC	01APR05*	27OCT05
C61020	Release Turbine	28OCT05	
C61180	Turbine Island Design	28OCT05	13NOV06
C61040	Turbine Manufacturing/Delivery	17MAR06	27SEP07
BOP EPC Procurement & Design			
C61030	Spec, Bid, & Award - BOP EPC	01JUN05*	27DEC05
C61210	BOP Detailed Design	28DEC05	27NOV07
C61200	BOP Procurement	22MAR06	02OCT07
Material Handling EPC Procurement & Delsgn			
C61270	Spec, Bid, & Award - Material Handling EPC	01MAR06*	26SEP06



Start Date	01JAN04
Finish Date	28MAY10
Data Date	01APR04
Run Date	13APR04 09:09

Burns & McDonnell SINCE 1898

STN1

Sheet 1 of 2

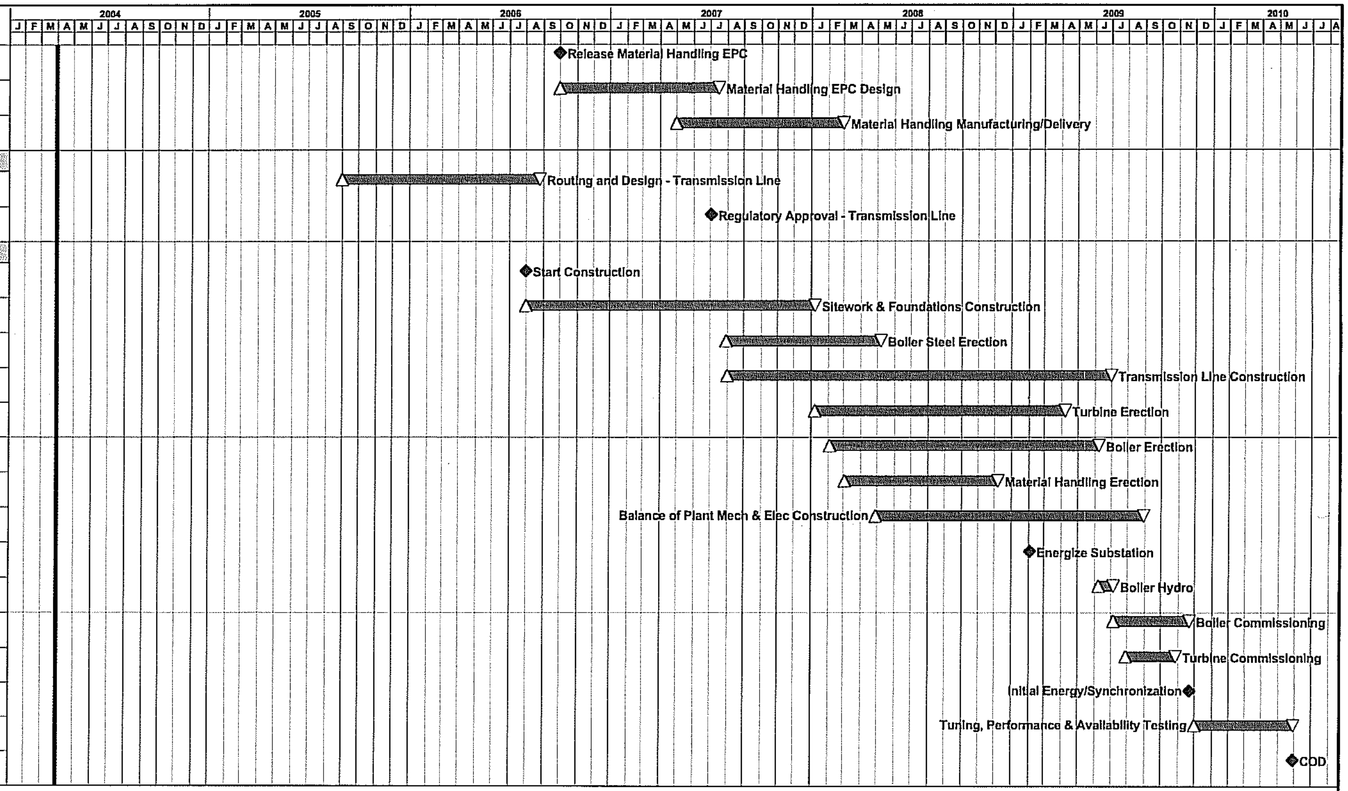
Ottertail Power
Big Stone Coal Plant

600 MW Pulverized Coal / CFB

Date	Revision	Checked	Approved
19MAR04	Initial	LKL	
13APR04	Revised	LKL	

1700

Activity ID	Activity Description	Start	Finish
C61280	Release Material Handling EPC	02OCT06*	
C61290	Material Handling EPC Design	02OCT06	16JUL07
C61300	Material Handling Manufacturing/Delivery	30APR07	29FEB08
Transmission Line Design			
C61320	Routing and Design - Transmission Line	01SEP05*	24AUG06
C61330	Regulatory Approval - Transmission Line	02JUL07*	
Construction & Startup			
C61060	Start Construction	01AUG06	
C61220	Sitework & Foundations Construction	01AUG06	07JAN08
C61070	Boiler Steel Erection	31JUL07	05MAY08
C61260	Transmission Line Construction	01AUG07	01JUL09
C61080	Turbine Erection	08JAN08	07APR09
C61150	Boiler Erection	05FEB08	08JUN09
C61250	Material Handling Erection	03MAR08	05DEC08
C61230	Balance of Plant Mech & Elec Construction	29APR08	28AUG09
C61090	Energize Substation		02FEB09*
C61110	Boiler Hydro	09JUN09	06JUL09
C61120	Boiler Commissioning	07JUL09	20NOV09
C61100	Turbine Commissioning	28JUL09	27OCT09
C61130	Initial Energy/Synchronization		20NOV09
C61160	Tuning, Performance & Availability Testing	30NOV09	28MAY10
C61140	COD		28MAY10



Start Date	01JAN04
Finish Date	28MAY10
Data Date	01APR04
Run Date	13APR04 09:09

Burns & McDonnell
SINCE 1898

STN1

Sheet 2 of 2

Ottertail Power
Big Stone Coal Plant

600 MW Pulverized Coal / CFB

Date	Revision	Checked	Approved
19MAR04	Initial	LKL	
13APR04	Revised	LKL	

1701

Activity ID	Activity Description	Start	Finish
Phase I			
Studies			
C61370	Technology Assessment & Feasiability	01JAN04A	31MAY04
C61400	Generator Interconnect Submittal	20JAN04A	20JAN04A
C61410	System Impact Study	02FEB04A	30JUL04
C61420	Facility Study	01SEP04	29APR05
C61430	Interconnection Agreement	01JUN05	01AUG05
Agreements			
C61380	Develop Joint Ownership & Operation Agreements	01JAN04A	31MAY04
C61390	Execute Joint Ownership & Operation Agreements	30JUL04	
Phase II			
Permitting			
C61310	Conceptual Engineering to Support Permit	01JUL04*	29JUN05
C61340	Prepare & Submit PSD Application	01JUL04	29JUN05
C61360	Regulatory Review of PSD Application	30JUN05	30JUN06
C61350	Air Permit Issued	03JUL06	
Financing			
C61365	Secure Member Financing	30MAY05*	30JUN06
Phase III			
Boiler Island EPC Procurement & Design			
C61190	Spec, Bid, & Award Boiler Island EPC	01FEB05*	29AUG05
C61170	Boiler Island Design	30AUG05	30OCT06
C61050	Boiler Fabrication/Delivery	27DEC05	06AUG07
Turbine Island EPC Procurement & Design			
C61240	Spec, Bid & Award - Turbine Island EPC	01APR05*	27OCT05
C61020	Release Turbine	28OCT05	
C61180	Turbine Island Design	28OCT05	13NOV06
C61040	Turbine Manufacturing/Delivery	17MAR06	27SEP07
BOP EPC Procurement & Design			
C61030	Spec, Bid, & Award - BOP EPC	01JUN05*	27DEC05
C61210	BOP Detailed Design	28DEC05	27NOV07
C61200	BOP Procurement	22MAR06	02OCT07
Material Handling EPC Procurement & Delsgn			
C61270	Spec, Bid, & Award - Material Handling EPC	01MAR06*	26SEP06

Start Date 01JAN04
Finish Date 29MAR10
Data Date 01APR04
Run Date 13APR04 09:10

Burns & McDonnell
SINCE 1898

STN2

Sheet 1 of 2

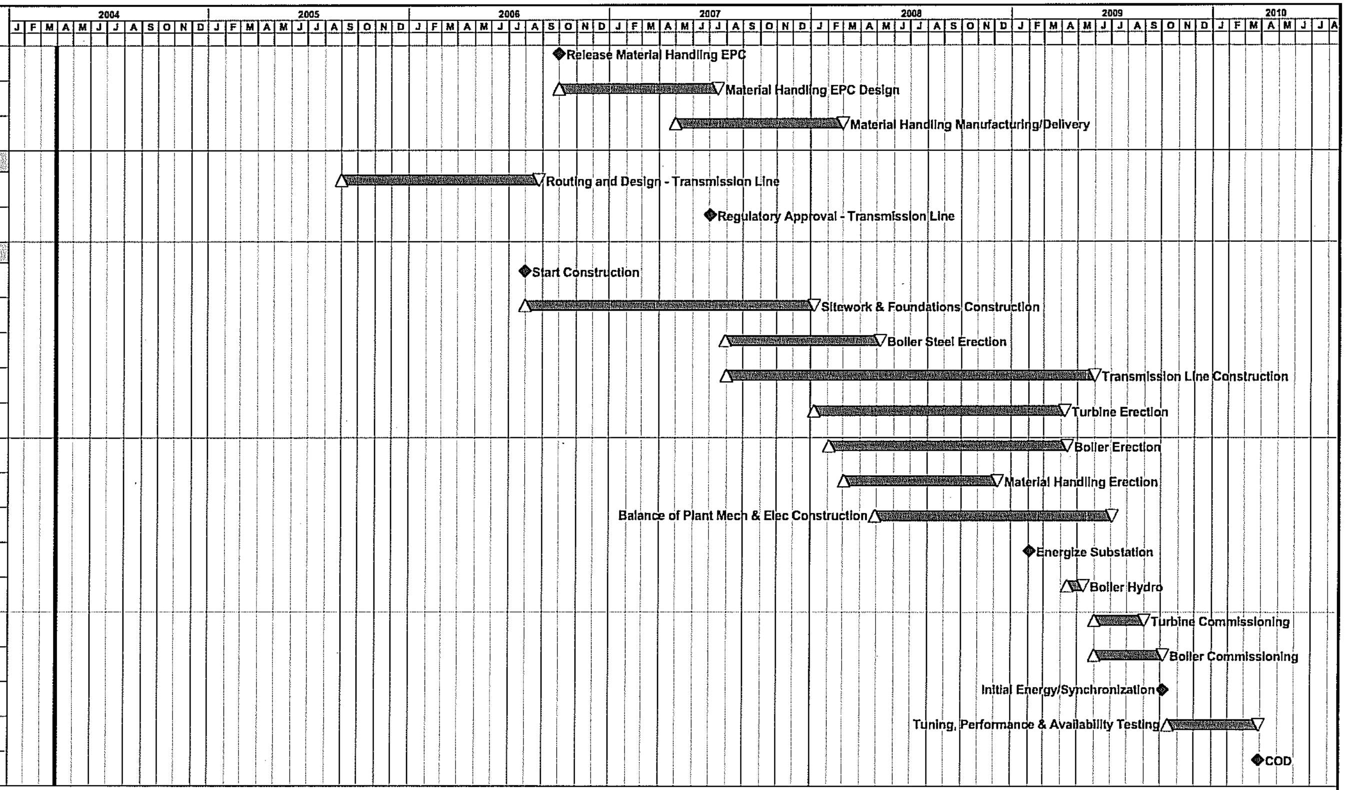
Ottertail Power
Big Stone Coal Plant

300 MW Pulverized Coal / CFB

Date	Revision	Checked	Approved
13APR04	Initial	LKL	

1702

Activity ID	Activity Description	Start	Finish
C61280	Release Material Handling EPC	02OCT06*	
C61290	Material Handling EPC Design	02OCT06	16JUL07
C61300	Material Handling Manufacturing/Delivery	30APR07	29FEB08
Transmission Line Design			
C61320	Routing and Design - Transmission Line	01SEP05*	24AUG06
C61330	Regulatory Approval - Transmission Line	02JUL07*	
Construction & Startup			
C61060	Start Construction	01AUG06	
C61220	Sitework & Foundations Construction	01AUG06	07JAN08
C61070	Boiler Steel Erection	31JUL07	05MAY08
C61260	Transmission Line Construction	01AUG07	02JUN09
C61080	Turbine Erection	08JAN08	07APR09
C61150	Boiler Erection	05FEB08	13APR09
C61250	Material Handling Erection	03MAR08	05DEC08
C61230	Balance of Plant Mech & Elec Construction	29APR08	03JUL09
C61090	Energize Substation		02FEB09*
C61110	Boiler Hydro	14APR09	11MAY09
C61100	Turbine Commissioning	02JUN09	01SEP09
C61120	Boiler Commissioning	03JUN09	05OCT09
C61130	Initial Energy/Synchronization		05OCT09
C61160	Tuning, Performance & Availability Testing	13OCT09	29MAR10
C61140	COD		29MAR10



Start Date	01JAN04
Finish Date	29MAR10
Data Date	01APR04
Run Date	13APR04 09:10

Burns & McDonnell
SINCE 1898

STN2

Sheet 2 of 2

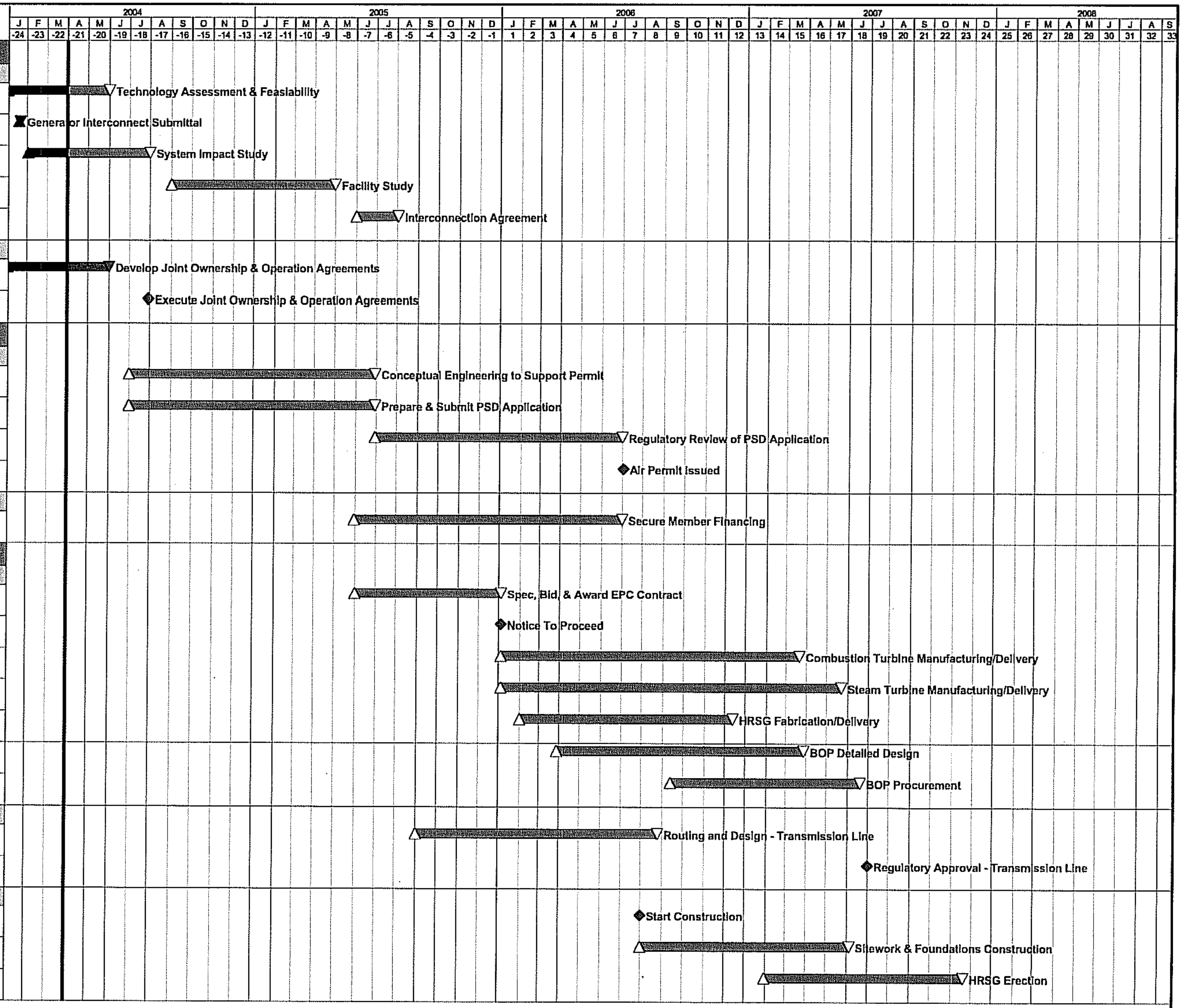
Ottertail Power
Big Stone Coal Plant

300 MW Pulverized Coal / CFB

Date	Revision	Checked	Approved
13APR04	Initial	LKL	

1703

Activity ID	Activity Description	Orig Dur	Start	Finish
Phase I				
Studies				
C61370	Technology Assessment & Feasiability	105	01JAN04A	31MAY04
C61400	Generator Interconnect Submittal	1	20JAN04A	20JAN04A
C61410	System Impact Study	126	02FEB04A	30JUL04
C61420	Facility Study	173	01SEP04	29APR05
C61430	Interconnection Agreement	44	01JUN05	01AUG05
Agreements				
C61380	Develop Joint Ownership & Operation Agreements	105	01JAN04A	31MAY04
C61390	Execute Joint Ownership & Operation Agreements	0	30JUL04	
Phase II				
Permitting				
C61310	Conceptual Engineering to Support Permit	260	01JUL04*	29JUN05
C61340	Prepare & Submit PSD Application	260	01JUL04	29JUN05
C61360	Regulatory Review of PSD Application	262	30JUN05	30JUN06
C61350	Air Permit Issued	0	03JUL06	
Financing				
C61365	Secure Member Financing	285	30MAY05*	30JUN06
Phase III				
EPC Procurement & Design				
C61190	Spec, Bid, & Award EPC Contract	155	01JUN05*	03JAN06
C61290	Notice To Proceed	0	04JAN06	
C61280	Combustion Turbine Manufacturing/Delivery	315	04JAN06	20MAR07
C61040	Steam Turbine Manufacturing/Delivery	360	04JAN06	22MAY07
C61050	HRSG Fabrication/Delivery	225	01FEB06	12DEC06
C61210	BOP Detailed Design	260	29MAR06	27MAR07
C61200	BOP Procurement	200	13SEP06	19JUN07
Transmission Line Design				
C61320	Routing and Design - Transmission Line	256	01SEP05*	24AUG06
C61330	Regulatory Approval - Transmission Line	0	02JUL07*	
Construction & Startup				
C61060	Start Construction	0	01AUG06	
C61220	Sitework & Foundations Construction	220	01AUG06	04JUN07
C61150	HRSG Erection	210	30JAN07	19NOV07



Start Date	01JAN04
Finish Date	28APR08
Data Date	01APR04
Run Date	13APR04 13:51

© Primavera Systems, Inc.

Burns & McDonnell
SINCE 1898

STN3

Sheet 1 of 2

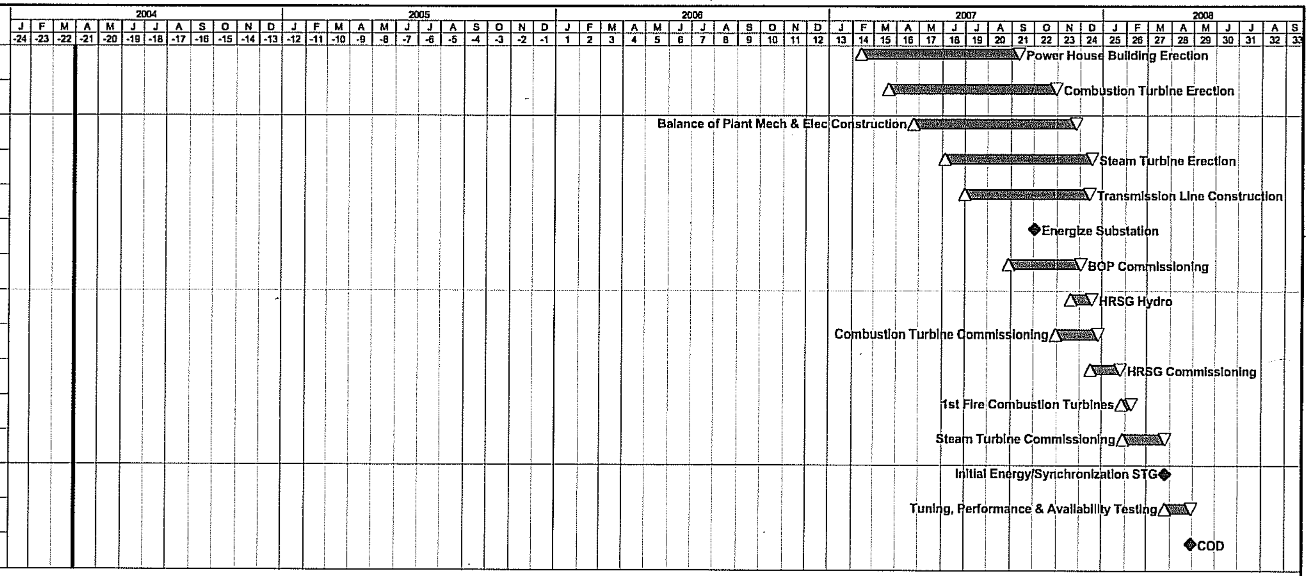
Ottertail Power
Big Stone Coal Plant

500 MW Combined Cycle

Date	Revision	Checked	Approved
13APR04	Initial	LKL	

1704

Activity ID	Activity Description	Orig Dur	Start	Finish
C61070	Power House Building Erection	150	13FEB07	10SEP07
C61250	Combustion Turbine Erection	160	21MAR07	30OCT07
C61230	Balance of Plant Mech & Elec Construction	155	24APR07	26NOV07
C61080	Steam Turbine Erection	140	05JUN07	17DEC07
C61260	Transmission Line Construction	120	02JUL07	14DEC07
C61090	Energize Substation	0		01OCT07*
C61170	BOP Commissioning	70	28AUG07	03DEC07
C61110	HRSG Hydro	20	20NOV07	17DEC07
C61270	Combustion Turbine Commissioning	40	31OCT07	25DEC07
C61120	HRSG Commissioning	30	17DEC07	25JAN08
C61180	1st Fire Combustion Turbines	10	28JAN08	08FEB08
C61100	Steam Turbine Commissioning	40	29JAN08	24MAR08
C61130	Initial Energy/Synchronization STG	0		24MAR08
C61160	Tuning, Performance & Availability Testing	25	25MAR08	28APR08
C61140	COD	0		28APR08



Start Date	01JAN04
Finish Date	28APR08
Data Date	01APR04
Run Date	13APR04 13:51

© Primavera Systems, Inc.

Burns & McDonnell
SINCE 1898

STN3

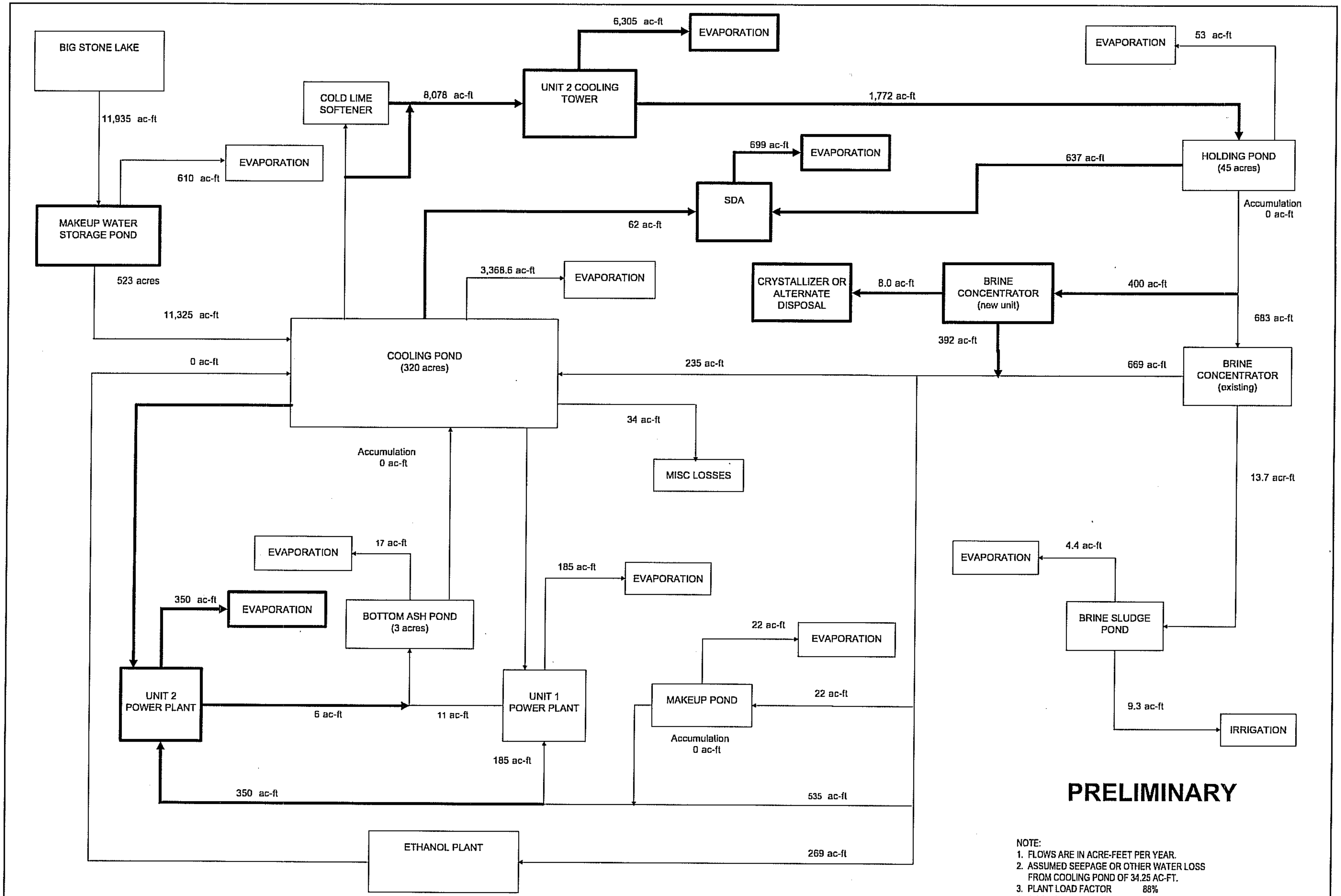
Sheet 2 of 2

Ottertail Power
Big Stone Coal Plant

500 MW Combined Cycle

Date	Revision	Checked	Approved
13APR04	Initial	LKL	

1705



PRELIMINARY

NOTE:
1. FLOWS ARE IN ACRE-FEET PER YEAR.
2. ASSUMED SEEPAGE OR OTHER WATER LOSS FROM COOLING POND OF 34.25 AC-FT.
3. PLANT LOAD FACTOR 88%
4. ANNUAL NET NATURAL EVAP RATE 14 INCHES
5. BOLD LINES INDICATE UNIT 2 MODIFICATIONS

NO	DATE	REVISIONS AND RECORD OF ISSUE	DES	CHK	APP
C	20-Apr-04	Added Bold Indication for Unit 2 Additions			
B	6-Apr-04	Updated Makeup Pond Area			

Burns & McDonnell SINCE 1898

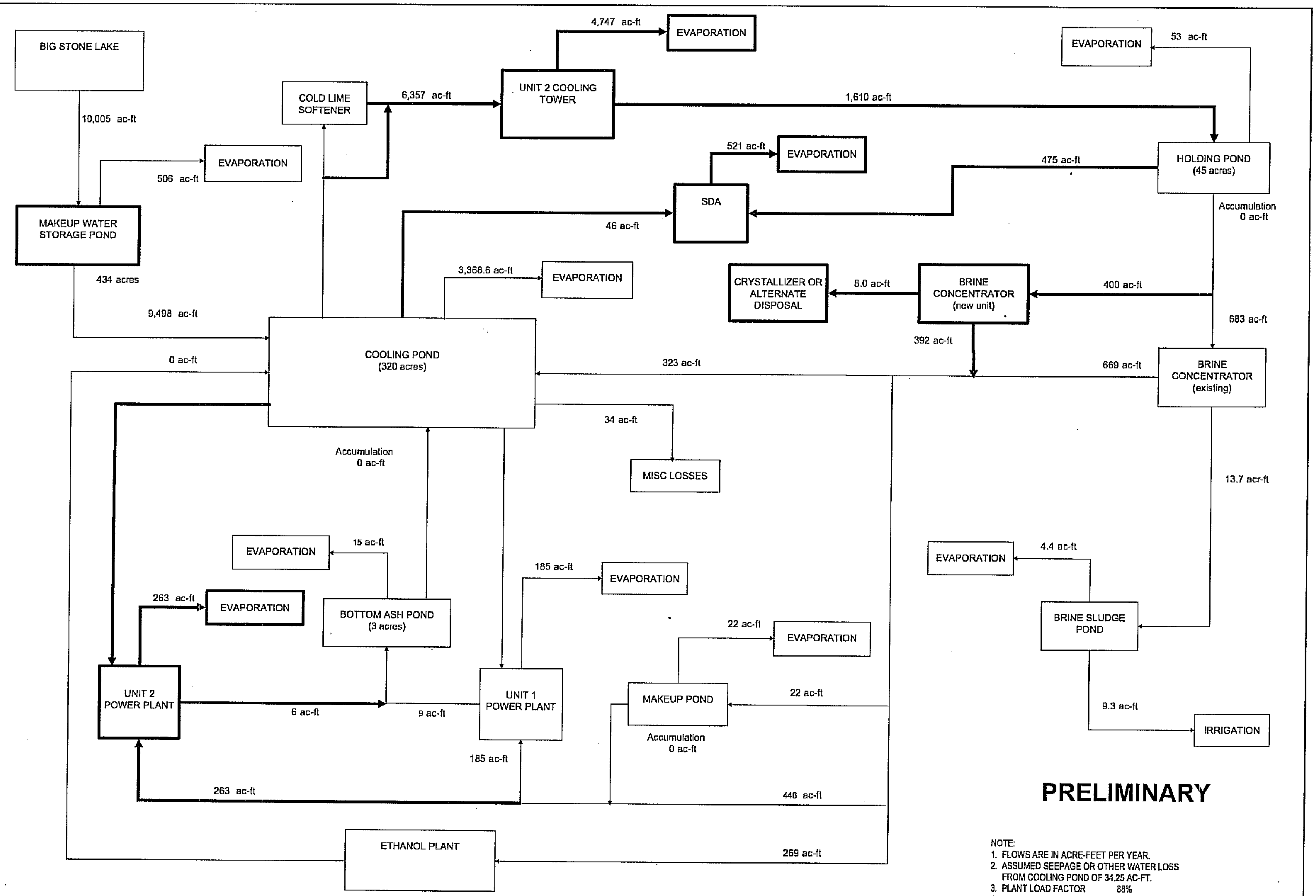
ENGINEER DAS | DRAWN DAS | CHECKED | DATE 9-Mar-04

OTTERTAIL POWER
BIG STONE PLANT
PC Fired 1x600 MW Supercritical
WATER MASS BALANCE

PROJECT | CODE | AREA | REV C | DRAWING NUMBER Figure 1

WMB PC C.T. BC (Rev C).xls

1706



PRELIMINARY

NOTE:
1. FLOWS ARE IN ACRE-FEET PER YEAR.
2. ASSUMED SEEPAGE OR OTHER WATER LOSS FROM COOLING POND OF 34.25 AC-FT.
3. PLANT LOAD FACTOR 88%
4. ANNUAL NET NATURAL EVAP RATE 14 INCHES
5. BOLD LINES INDICATE UNIT 2 MODIFICATIONS

NO	DATE	REVISIONS AND RECORD OF ISSUE	DES	CHK	APP
C	20-Apr-04	Added Bold Indication for Unit 2 Additions			
B	6-Apr-04	Updated Makeup Pond Area			

Burns & McDonnell SINCE 1898

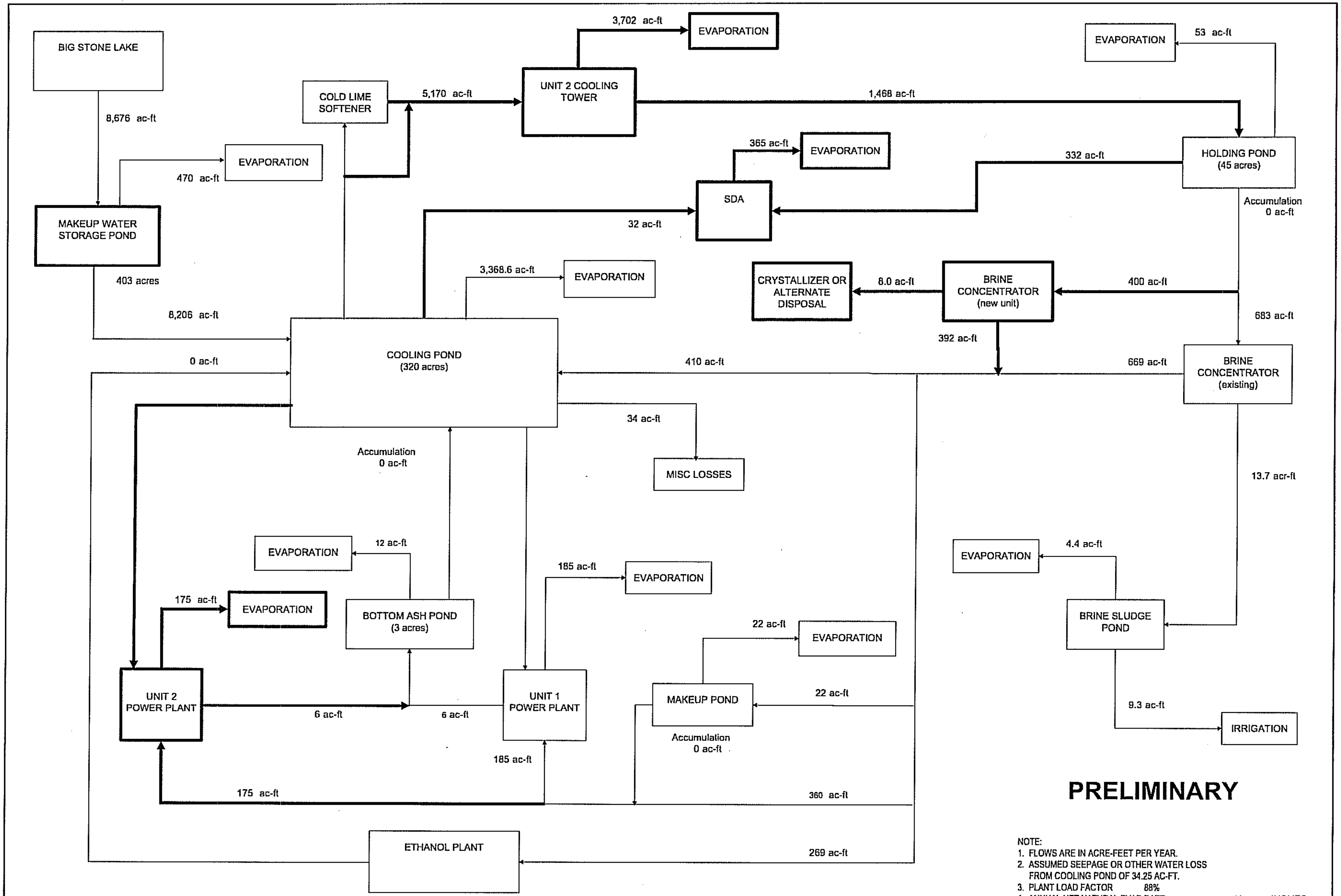
ENGINEER DAS
CHECKED
DRAWN DAS
DATE 9-Mar-04

OTTERTAIL POWER
BIG STONE PLANT
PC Fired 1x450 MW Supercritical
WATER MASS BALANCE

PROJECT
CODE
AREA
REV C
DRAWING NUMBER Figure 2

WMB PC C.T. BC (Rev C).xls

1707



PRELIMINARY

NOTE:
1. FLOWS ARE IN ACRE-FEET PER YEAR.
2. ASSUMED SEEPAGE OR OTHER WATER LOSS FROM COOLING POND OF 34.25 AC-FT.
3. PLANT LOAD FACTOR 88%
4. ANNUAL NET NATURAL EVAP RATE 14 INCHES
5. BOLD LINES INDICATE UNIT 2 MODIFICATIONS

NO	DATE	REVISIONS AND RECORD OF ISSUE	DES	CHK	APP
C	20-Apr-04	Added Bold Indication for Unit 2 Additions			
B	6-Apr-04	Updated Makeup Pond Area			

Burns & McDonnell SINCE 1898

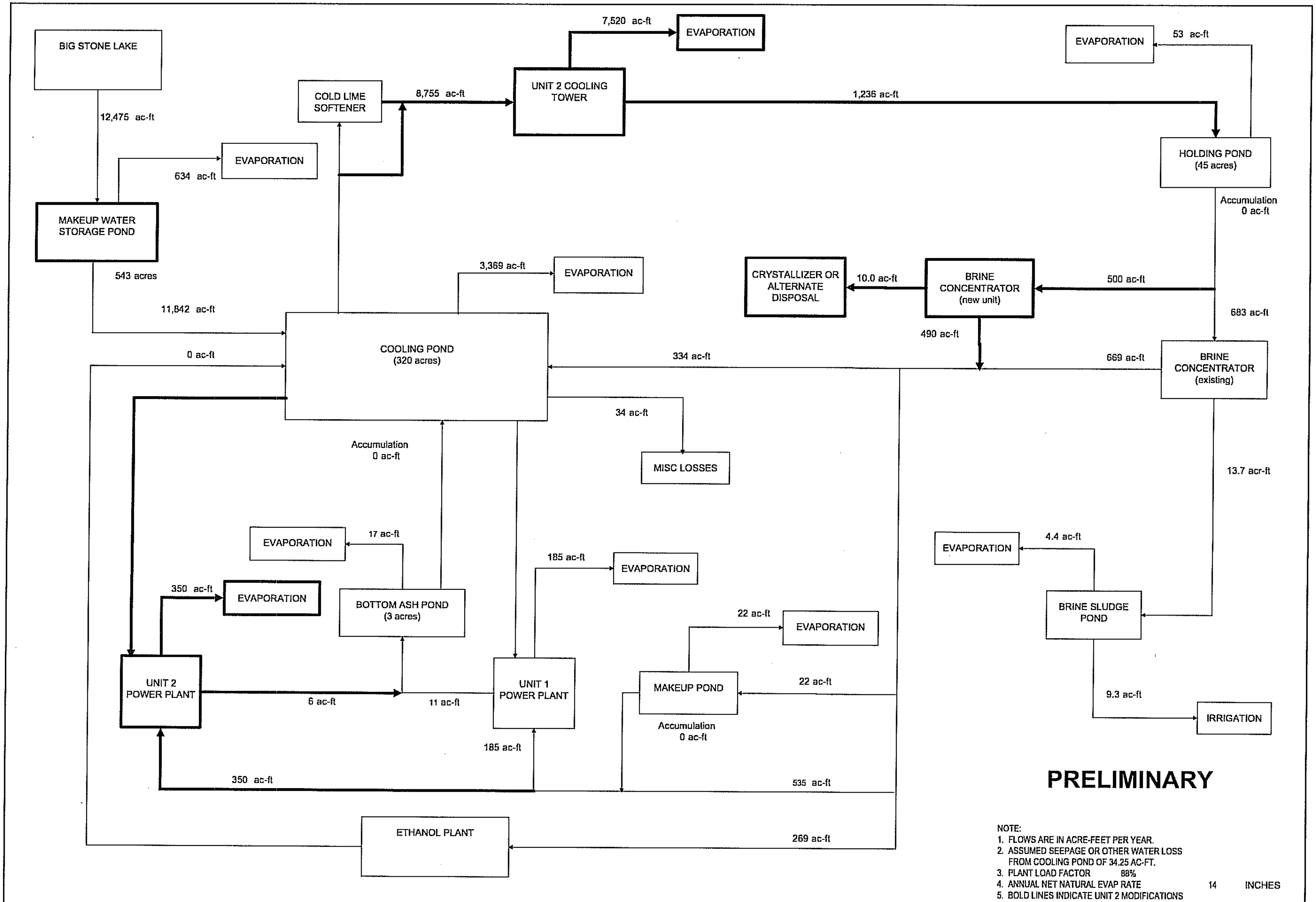
ENGINEER DAS DRAWN DAS
CHECKED DATE 9-Mar-04

OTTERTAIL POWER
BIG STONE PLANT
PC Fired 1x300 MW Subcritical
WATER MASS BALANCE

PROJECT
CODE
AREA
REV C
DRAWING NUMBER Figure 3

1708

WMB PC C.T. BC (Rev C).xls



PRELIMINARY

NOTE:
1. FLOWS ARE IN ACRE-FEET PER YEAR.
2. ASSUMED SEEPAGE OR OTHER WATER LOSS FROM COOLING POND OF 34.25 AC-FT.
3. PLANT LOAD FACTOR 88%
4. ANNUAL NET NATURAL EVAP RATE 14 INCHES
5. BOLD LINES INDICATE UNIT 2 MODIFICATIONS

NO	DATE	REVISIONS AND RECORD OF ISSUE	DES	CHK	APP
C	20-Apr-04	Added Bold Indication for Unit 2 Additions			
B	6-Apr-04	Updated Makeup Water Storage Pond Area			

Burns & McDonnell SINCE 1898

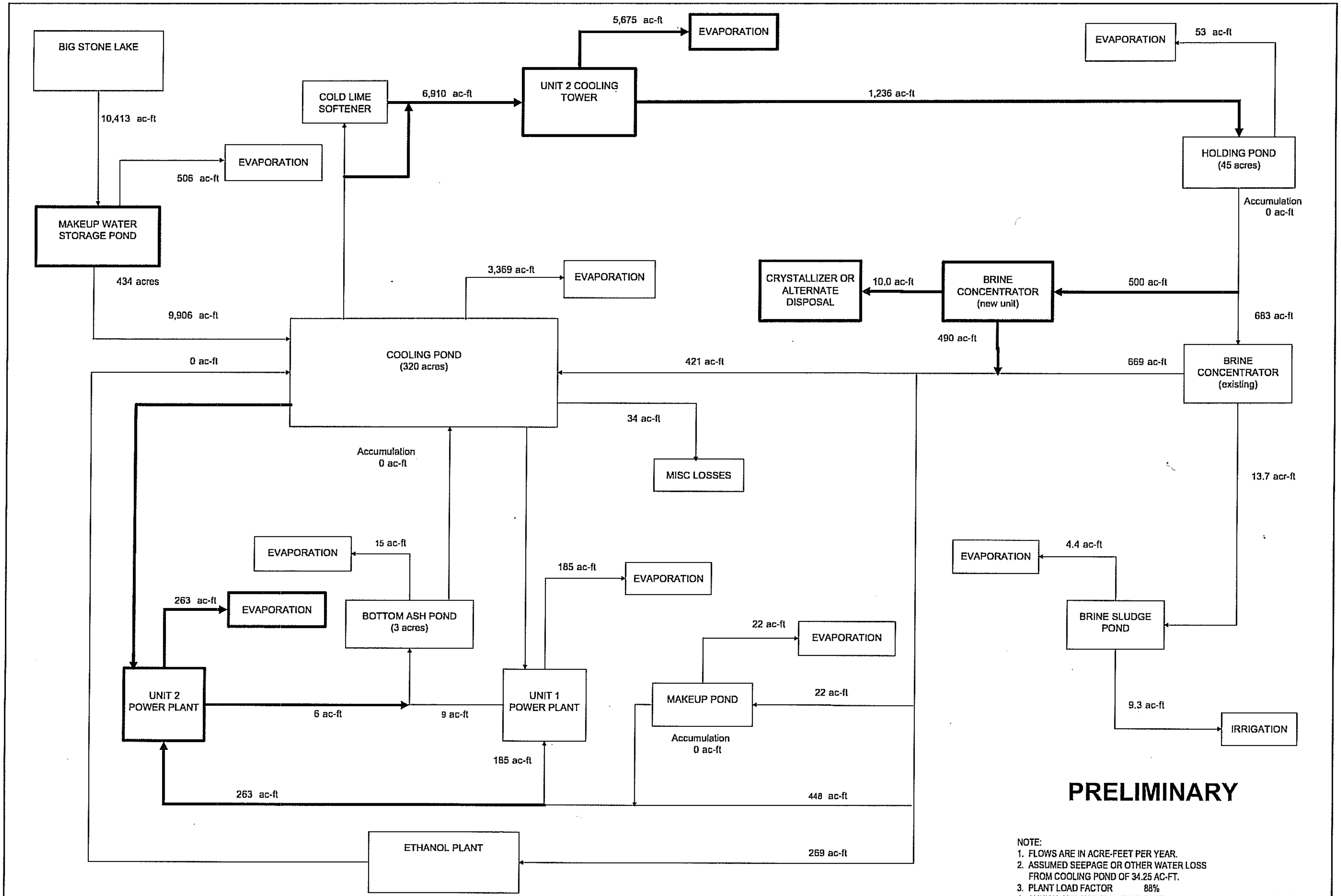
ENGINEER DAS | DRAWN DAS | CHECKED | DATE 9-Mar-04

OTTERTAIL POWER
BIG STONE PLANT
CFB 2x300 MW
WATER MASS BALANCE

PROJECT | CODE | AREA | REV C | DRAWING NUMBER Figure 4

WMB CFB C.T. BC (Rev C).xls

1709



NOTE:
1. FLOWS ARE IN ACRE-FEET PER YEAR.
2. ASSUMED SEEPAGE OR OTHER WATER LOSS FROM COOLING POND OF 34.25 AC-FT.
3. PLANT LOAD FACTOR 88%
4. ANNUAL NET NATURAL EVAP RATE 14 INCHES
5. BOLD LINES INDICATE UNIT 2 MODIFICATIONS

NO	DATE	REVISIONS AND RECORD OF ISSUE	DES	CHK	APP
C	20-Apr-04	Added Bold Indication for Unit 2 Additions			
B	6-Apr-04	Updated Makeup Water Storage Pond Area			

Burns & McDonnell SINCE 1898

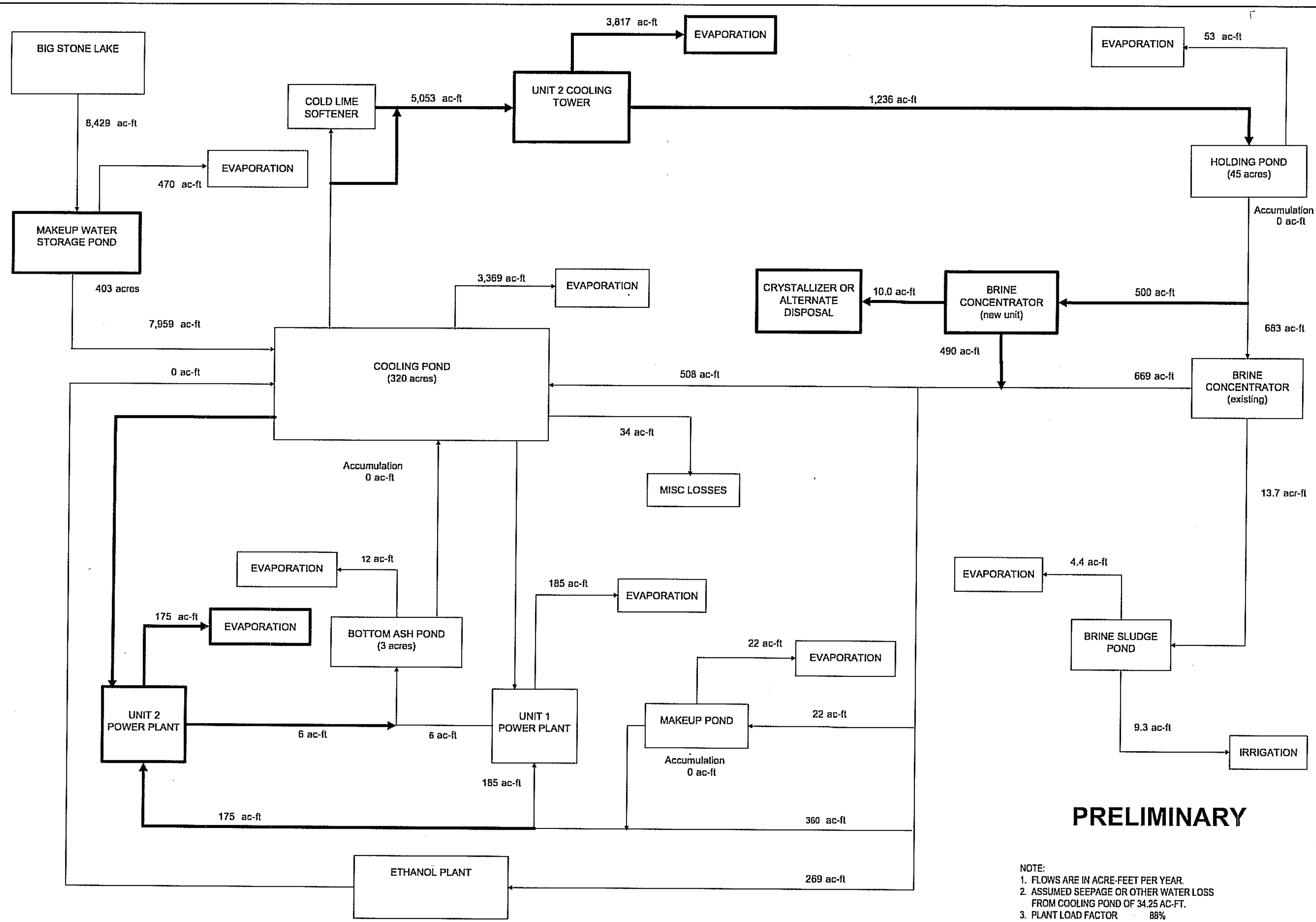
ENGINEER DAS · CHECKED · DRAWN DAS · DATE 9-Mar-04

OTTERTAIL POWER
BIG STONE PLANT
CFB 2x225 MW
WATER MASS BALANCE

PROJECT · CODE · AREA · REV C · DRAWING NUMBER Figure 5

WMB CFB C.T. BC (Rev C).xls

1710



PRELIMINARY

NOTE:
1. FLOWS ARE IN ACRE-FEET PER YEAR.
2. ASSUMED SEEPAGE OR OTHER WATER LOSS FROM COOLING POND OF 34.25 AC-FT.
3. PLANT LOAD FACTOR 88%
4. ANNUAL NET NATURAL EVAP RATE 14 INCHES
5. BOLD LINES INDICATE UNIT 2 MODIFICATIONS

NO	DATE	REVISIONS AND RECORD OF ISSUE	DES	CHK	APP
C	20-Apr-04	Added Bold Indication for Unit 2 Additions			
B	6-Apr-04	Updated Makeup Water Storage Pond Area			

Burns & McDonnell SINCE 1898

ENGINEER DAS | CHECKED | DRAWN DAS | DATE 9-Mar-04

OTTERTAIL POWER
BIG STONE PLANT
CFB 1x300 MW
WATER MASS BALANCE

PROJECT | CODE | AREA | REV C | DRAWING NUMBER Figure 6

WMB CFB C.T. BC (Rev C).xls

1711

Big Stone Plant - 2002 Fuel Analysis - Monthly Weighted Averages

COAL:

Month	Coal Tons	Moisture %	Ash %, AR	HHV, AR	S %, AR	Ash %, Dry	HHV, Dry	S %, Dry	NaO %	N %, AR	N %, Dry	HG ug/g, AR	HG ug/g, Dry
Jan-02	192166	29.72	4.83	8546	0.34	6.88	12161	0.49	1.54	0.7	0.99	0.12	0.169
Feb-02	163211	29.54	4.67	8600	0.36	6.63	12205	0.52	1.88	0.64	0.9	0.068	0.096
Mar-02	200227	29.97	4.71	8514	0.34	6.73	12157	0.48	1.78	0.65	0.92	0.041	0.058
Apr-02	177355	29.52	4.74	8570	0.35	6.73	12160	0.5	1.73	0.74	1.05	0.08	0.113
May-02	145800	29.93	4.49	8555	0.33	6.41	12209	0.46	1.76	0.65	0.92	0.062	0.087
Jun-02	169603	29.76	4.7	8539	0.34	6.69	12157	0.49	1.77	0.63	0.9	0.049	0.07
Jul-02	184347	29.59	4.55	8567	0.32	6.46	12168	0.45	1.62	0.69	0.98	0.073	0.104
Aug-02	176194	29.72	4.58	8552	0.31	6.52	12168	0.44	1.6	0.65	0.92	0.055	0.078
Sep-02	94747	29.85	4.49	8523	0.34	6.4	12148	0.48	1.7	0.69	0.97	0.07	0.099
Oct-02	34258	29.95	4.41	8538	0.31	6.31	12187	0.45	1.64	-	-	-	-
Nov-02	184395	29.69	4.73	8534	0.31	6.55	12139	0.44	1.5	0.66	0.94	0.074	0.106
Dec-02	196554	29.78	4.71	8533	0.31	6.71	12151	0.44	1.49	0.66	0.93	0.176	0.249
Average	**1918858**	**29.75**	**4.63**	**8548**	**0.33**	**6.59**	**12168**	**0.47**	**1.67**	**0.67**	**0.95**	**0.08**	**0.11**

0.771425539 lb/mmBtu

TIRES:

2002 Total	**22744.07**	**1.00**	**7.04**	**15678**	**1.67**	**7.11**	**15836**	**1.69**	**0.09**	**0.27**	**0.27**	-	-

2.128380285 lb/mmBtu

SEEDS:

2002 Total	**11752.1**	**12.7**	**1.1**	**7187**	**0.11**	**1.26**	**8233**	**0.13**	**0.5**	-	-	-	-

0.305821812 lb/mmBtu

90% COAL & 10% TIRES

				8,954.28	**0.41**	

NO	REVISIONS AND RECORD OF ISSUE	DES	CHK	APP	ENGINEER / CHECKED	DRAWN: SMM / DATE: 9-Mar-04

Burns & McDonnell SINCE 1898

OTTERTAIL POWER
BIG STONE PLANT
Historic Fuel Analysis - 2002

PROJECT | REV | CODE | AREA | DRAWING NUMBER: Figure FA-1

Fuel Analysis.xls

1712

Typical Reagent Analysis

LIMESTONE ANALYSIS

CaCO3 =	wt%	90.00
MgCO3 =	wt%	0.50
H2O =	wt%	5
Inerts =	wt%	4.50

LIME ANALYSIS - Quick Lime

CaO =	wt%	95.00
MgO =	wt%	2.00
SiO2 =	wt%	1.00
Al2O3 =	wt%	0.30
Fe2O3 =	wt%	0.20
CO2 =	wt%	1
H2O =	wt%	0.5

NO	REVISIONS AND RECORD OF ISSUE	DES	CHK	APP

Burns & McDonnell SINCE 1898

ENGINEER J Jones | DRAWN S McGreer
CHECKED | DATE 9-Mar-04

OTTERTAIL POWER
BIG STONE PLANT
Typical Reagent Analysis

PROJECT | REV
CODE | AREA | DRAWING NUMBER Figure RA-1

Fuel Analysis.xls

1713

ATTACHMENT E
WATER TREATMENT AND WASTEWATER MANAGEMENT

1.0 INTRODUCTION

Currently, Unit I plant makeup water is pumped directly to the Unit I cooling pond twice a year when the water level in Big Stone Lake allows water to be withdrawn. With the addition of Unit II, makeup water will continue to be intermittently provided from Big Stone Lake but the makeup will either be directed to an onsite makeup water storage pond or to the onsite cooling ponds. This study will evaluate the impact on the makeup supply and storage when using either a cooling pond for Unit II heat rejection or using a cooling tower. When using cooling ponds, the makeup from Big Stone Lake will be directed to the Unit I and Unit II cooling ponds with the pond water management similar to the existing program. When using a cooling tower for Unit II heat rejection, the makeup from Big Stone Lake will be directed to makeup water storage ponds. The combined storage of the existing cooling pond and the makeup water storage pond will support one year of plant operation of both Units without makeup water being required from Big Stone Lake (drought conditions).

The Unit I cooling pond water quality is presently being maintained through blowdown from the cooling pond to the evaporation pond, evaporation out of the plant evaporation pond and holding pond, and concentration of solids in the brine concentrator. A lime softener is also used to further control the hardness concentration of the cooling pond. This study will evaluate wastewater treatment requirements and options for maintaining proper cooling pond water quality and cooling tower circulating water quality for the addition of either a Unit II cooling pond or cooling tower.

The Unit I cooling pond is undersized for the heat rejection duty it experiences in the summer months. The study for Unit II considered what options were available to correct the deficiency for Unit I while adding the additional pond capacity to handle the Unit II cooling duty.

2.0 UNIT II COOLING OPTIONS

The two cooling options being considered for Unit II heat rejection include the use of either a cooling pond or cooling tower. When using a cooling pond, the pond water management will be similar to the existing operation. Water will be continuously evaporated from the pond with the pond blowdown and makeup cycle occurring seasonally as a batch process when water is available from Big Stone Lake. When using a cooling tower, Unit I will continue to use the existing cooling pond but makeup to the Unit

II cooling tower will be provided continuously from the Unit I cooling pond with continuous makeup to the cooling pond being provided continuously from a new onsite makeup storage pond.

2.1 COOLING POND SIZING CRITERIA

To determine the additional cooling pond surface area required for the addition of a 600 MW unit and for the supplementary surface area needed for the current unit at Big Stone, theoretical models of cooling pond performance were applied. Through the use of these models it is possible to determine the pond surface area as a function of the heat rejection to the pond and the assumed inlet temperature to the condenser.

2.1.1 Models Used

The models used in order to predict the cooling pond surface area were those outlined in Appendix H of EPRI Publication No. 74-049-00-3, "Heat Exchange and Transport in the Environment." The actual performance of any cooling pond will fall between the bounds represented by two theoretical models: the "completely mixed" model and the "completely unmixed" model. In order to model the behavior of the cooling pond, actual data was used to determine which model most closely resembles actual cooling pond performance.

2.1.1.1 Completely Mixed Pond Model

The completely mixed model is based on the following equation:

$$\theta = (\rho C Q \Delta T)/(AK)$$

Where:

θ is the excess temperature above the equilibrium temperature (T_E) due to the thermal discharge from the power plant

ρ is the density of water

C is the specific heat of water

Q is the flow through the condenser

ΔT is the temperature rise across the condenser

A is the effective cooling area of the pond

K is the surface heat exchange coefficient

The numerator of the right hand side of this equation represents the heat rejection to the pond by the power plant. This model assumes that the hot water discharge from the plant is instantaneously mixed across the effective cooling area; therefore, the excess temperature is the same throughout the entire cooling area.

The two models have the same average excess temperature, θ, but the excess temperature at the intake, θ_i, is significantly lower in the unmixed model for a given pond surface area. For either model, the power plant cooling water intake and discharge temperature can be predicted from the excess temperature modeling results, the value of the natural equilibrium temperature, T_E, and the condenser temperature rise, ΔT. The intake temperature is the sum of the equilibrium temperature and the excess temperature at the intake, or ($T_E + \theta_i$). The discharge temperature is the sum of the intake temperature and the condenser temperature rise, or ($T_E + \theta_i + \Delta T$).

2.1.1.2 Completely Unmixed Pond Model

The completely unmixed model is based on the following equation:

$$\theta_i = \Delta T/(\exp(\Delta T/\theta) - 1)$$

Where:

θ_i is the excess temperature at the plant cooling water intake

θ is the excess temperature as calculated by the completely mixed pond model

exp represents the exponential function, i.e., $\exp(x) = e^x$

ΔT is the temperature rise across the condenser

The unmixed pond model assumes zero mixing between the hot water discharge and the water in the pond. The excess temperature of the heated water decays exponentially due to heat transfer to the atmosphere as the heated water spreads out and returns to the intake.

2.1.2 Data Used to Determine K and T_E

For this study, the surface heat exchange coefficient, K, and the equilibrium temperature, T_E, for the cooling pond were calculated using the methodology described in the aforementioned report "Heat Exchange and Transport in the Environment". The calculation requires meteorological data, including dew point temperature, wind speed, and solar radiation. The closest meteorological data was available from a 30-year period from a station at Huron, South Dakota. Monthly averages of the meteorological data and solar radiation data were used to calculate T_E and K for each month. It was determined that the month of July was the worst case and required the largest surface area; therefore, the data for the month of July was used to size the cooling pond.

2.1.3 Data Used to Determine Heat Rejection

Heat rejection to the pond is calculated from the circulating water flow rate and the condenser ΔT for each unit of the power plant. The condenser flow rate and the condenser ΔT for Unit I are the average actual values for the existing unit during the month of July. The values for Unit II are the estimated figures for a new 600 MW PC unit. For the purpose of the modeling, it was assumed that each unit will have separate distinct cooling ponds.

Table 1 - Assumed Condenser Temperature Difference

Unit	Condenser Flow gpm	Condenser ΔT °F
1	136,000	32.3
2	216,000	23

Based on the condenser flow and ΔT data, the heat rejection to the pond is calculated to be 2.20×10^9 Btu/hr for Unit I and 2.48×10^9 Btu/hr for Unit II.

2.1.4 Comparison Between Predicted Condenser Inlet Temperature and Actual Data

In order to calibrate the models, the existing facility was modeled and the results were compared to actual data. The results of the cooling pond performance model predictions for the month of July are tabulated below, along with actual data at the circulating water pump inlet.

Table 2 - Existing Cooling Pond Performance

Month	Predicted Temperature Using Completely Mixed Cooling Pond Model °F	Measured Maximum Temperature °F	Measured Average Temperature °F	Predicted Temperature Using Unmixed Cooling Pond Model °F
July	97.8	88.4	87.2	85.7

As expected, the temperature predictions from the two theoretical cooling pond models bracket the observed condenser inlet temperature, with the completely unmixed pond model being closest to the observed behavior of the Unit I cooling pond. The temperature prediction from the completely unmixed cooling pond model case is about 2 to 3°F lower than the historical temperatures measured at the inlet of Unit I circulating water pump.

2.1.5 Determination of Cooling Pond Surface Area

The new cooling ponds need to be sized such that the maximum inlet temperature to each condenser is 88 °F. The completely unmixed model has under-predicted the actual temperature by 2 to 3°F. In order to compensate for this discrepancy, an 85 °F inlet temperature to the condenser was modeled. The completely unmixed model calculated an additional 60 acres is required for Unit I to supplement the existing 320 acres. The model predicted 565 acres of surface area is needed for Unit II. Table 1 below summarizes the pond surface area required to supplement the existing unit and those required for each of the six options. The new cooling ponds will use similar design and construction techniques as the existing cooling pond.

Table 3 - Cooling Pond Area Required for Unit II

Unit Size (MW)	Surface Area (Acre)
Existing Unit	60
300 PC	285
450 PC	425
600 PC	565
300 CFB	295
450 CFB	455
600 CFB	600

2.2 COOLING POND WATER TREATMENT OPTIONS

To minimize the amount of earthwork required for the construction of the Unit II cooling pond, the Unit II cooling pond will be at a higher elevation than the existing Unit I cooling pond. Makeup supply to the cooling ponds will be provided directly from Big Stone Lake to each of the cooling ponds. The pond management of Unit I cooling pond will remain the same as the current operation with the pond makeup and blowdown being an intermittent operation as allowed by the seasons and water level in Big Stone Lake. With this method of pond operation, the water quality in the cooling ponds will vary with the highest quality of water in the pond present immediately after filling. During plant operation, the pond water quality will concentrate until the pond is refilled, at which time, the concentrated pond water will be pumped to fill the evaporation pond. This allows the highest concentrated water to be sent to the evaporation pond and provides the maximum volume available for fresh water fill from Big Stone Lake. Blowdown from the cooling pond will be the intermittent transfer of water from the cooling pond to the evaporation pond. Because the Unit II cooling pond is at a different elevation than the Unit I cooling pond, both ponds will function independently, and a second evaporation pond dedicated to the Unit II cooling pond will be needed to handle the periodic blowdown of the Unit II cooling pond.

Two treatment options have been considered for the Unit II cooling pond. One method evaluated would use an evaporation pond with brine concentrator similar to the existing Unit I cooling pond operation. The second method would be use a lime soda softener to control the hardness concentration in the cooling pond. With lime softener treatment, soluble salts will not be removed from the cooling pond and will continue to concentrate. Blowdown from the pond will be required to regulate the buildup of these salts. Blowdown from the pond would either be used as makeup to the SO_2 spray drier absorber (SDA) or discharged to the Unit II evaporation pond for treatment using a second brine concentrator similar to Unit I.

2.2.1 Cooling Pond Blowdown Treatment Using a Second Brine Concentrator

Using a second brine concentrator provides two benefits. The first is the reduction of dissolved solids in the Unit II cooling pond. Lime/soda softening alone will not remove dissolved salts from the cooling pond. These salts will continue to concentrate unless removed by blowdown. For the PC based unit, a portion of the SDA makeup requirements would be provided from the cooling pond and would serve as cooling pond blowdown. When the makeup to the SDA is the sole blowdown, the cooling pond will concentrate to about 7 cycles of concentration. With the second brine concentrator sized to provide the treatment capacity of one half of the existing Unit I brine concentrator, the pond concentration factor is estimated to be about 5 cycles of concentration. The second benefit is added redundancy to the existing brine concentrator which would be capable of producing the additional condensate for use as Unit II boiler makeup. A circulating fluidized bed (CFB) based unit may not require a SDA. Without the use of cooling pond water for SDA makeup, the amount of cooling pond blowdown would be reduced to the amount used as brine concentrator feed. Using a brine concentrator sized to provide half the capacity of the existing brine concentrator will control the cooling pond concentration factor to about 25 cycles.

The brine concentrator alone will not provide enough blowdown to properly control the cooling pond hardness concentration. Even with the additional brine concentrator, lime/soda softening would be required to provide hardness reduction. Comparative capital and operating costs for the 600 MW PC case with a cooling pond and brine concentrator are provided in Appendix A of this Attachment A. The costs for the CFB case are not shown but will be larger due to the additional treatment rate required since blowdown is not being evaporated in the SDA system.

2.2.2 Cooling Pond with Lime/Soda Softening

To maximize the hardness reduction in the cooling pond softener, lime soda ash softening was evaluated in lieu of lime softening. By using lime soda softening, the treatment rate would be less than the treatment rate required for cold lime softening. Although lime softening will control the hardness concentration of the cooling pond, the dissolved salts will concentrate without some amount of blowdown. For the PC case, this blowdown would be provided as makeup to the SDA. The waste usage by the SDA will be sufficient to limit the pond concentration factor to about 7 cycles of concentration.

The lime/soda softener capacity was sized to limit the calcium hardness of the cooling pond to about 400 mg/l as $CaCO_3$ assuming a hardness reduction from 400 mg/l to 50 mg/l as $CaCO_3$. The estimated treatment rate for the softener system is about 3,500 gpm. Comparative capital and operating costs for the 600 MW PC case with a cooling pond and lime/soda ash softener are provided in Appendix A of this report. Because the CFB case does not have a SDA, a brine concentrator would be required in addition to the lime/soda softener. This treatment process is the same as described above for the brine concentrator treatment option.

2.3 COOLING TOWER WATER TREATMENT OPTION

With the cooling tower option, the makeup supply to the cooling tower will be taken from the Unit I cooling pond. The makeup supplied to the cooling tower will provide continuous blowdown for the existing cooling pond and levelize the cooling pond water quality. Blowdown from the cooling tower will be more concentrated than the current blowdown from the current evaporation pond discharge resulting in a more concentrator makeup to the brine concentration. The cooling tower will tend to serve two purposes. The primary purpose is to provide heat rejection for Unit II. The second is to act as a treatment process concentrating the waste stream to the brine concentrator. With the cooling tower providing waste concentration, the evaporation pond is not needed and can be reused to provide additional on-site storage for the plant makeup water.

Plant wastewater treatment will be required in addition to the existing brine concentrator treatment system to allow the plant to continue to operate as a zero discharge facility. The amount of wastewater generated by the cooling tower will based on the circulating water quality and cooling tower circulating water treatment. Treatment of the circulating water and cooling tower blowdown included the following three options: 1) sidestream softening of the circulating water, 2) membrane treatment of the cooling tower blowdown, and 3) brine concentrator treatment of the cooling tower blowdown.

2.3.1 Cooling Tower Blowdown Treatment Using Sidestream Softening

The sidestream treatment process consists of cold lime/soda ash softening followed by filtration and pH adjustment. This treatment method will remove both permanent and temporary hardness from the circulating water. To estimate the amount of hardness that will need to be removed by the sidestream softening process, the total pounds of hardness contained in the waste stream to the brine concentrator and SDA is subtracted from the pounds of hardness entering the cooling tower in the makeup supply. The difference is the amount of hardness that is to be removed by the softening process. The sidestream treatment will be different for each size of generating unit because each unit size will have a different evaporation rate from the cooling tower resulting in a different makeup rate with a constant blowdown flow to the existing brine concentrator. In addition, the CFB units may not require a SDA, which will increase the amount of hardness that will need to be removed by the sidestream treatment process. Calculations for estimating the amount of hardness that is contained in the cooling tower blowdown and the influent hardness concentration to the sidestream treatment process assume that the circulating water contains 800 mg/l of calcium hardness with 300 mg/l of total alkalinity. The alkalinity concentration in the circulating water will be controlled by acid addition in combination with the sidestream treatment process.

Because the circulating water would contain a significant concentration of non-carbonate hardness, soda ash feed will be necessary to allow softening to the desired level. The amount of soda ash feed is a function of the alkalinity concentration that is maintained in the circulating water. Carrying a higher level of alkalinity will result in less soda ash feed but the higher alkalinity level also will impact the level of calcium hardness that could be maintained and will require a larger sidestream treatment rate. Lower alkalinity would allow a higher calcium hardness concentration to be maintained in the circulating water but would also require significantly more lime and soda ash feed to achieve the desired level of softening.

In addition to the lime and soda ash feed to the sidestream treatment process, the existing softener would continue to be used to soften a portion of the cooling tower makeup. The total estimated lime and soda ash used for the 600 MW pulverized coal case is shown in the comparative cost tables included in Appendix A of this report. The estimated chemical costs were used as comparative costs for evaluating the cooling tower treatment options. This treatment option was not developed for each case because the amount of lime and soda ash required and the amount of waste solids generated were excessive and shown to be much more costly than the other options evaluated.

2.3.2 Cooling Tower Blowdown Treatment Using a Brine Concentrator

Similar to the Unit I, the brine concentrator would treat the plant wastewater stream and produce a high quality condensate for use by the Ethanol Plant and as makeup to the boiler. The waste from the brine concentration would be brine similar to the existing brine concentrator waste stream. Unlike the sidestream softener which removes a portion of the hardness from the treatment stream, the brine concentrator removes all hardness from the treatment stream. Also, because the brine concentrator does not rely on precipitation of alkaline hardness, the hardness can be in either the non-carbonate or the alkaline form. By removing either non-carbonate hardness as effectively as carbonate hardness, the circulating water alkalinity can be controlled at a lower level which would allow the hardness concentration to be maintained much higher than the 800 mg/l limit used with sidestream softening. The recommendation from Nalco allows the calcium hardness to be maintained between 1,600 and 2,000 mg/l as $CaCO_3$ with alkalinity controlled at 100 mg/l as $CaCO_3$. At this higher calcium hardness concentration, the same cooling tower blowdown flow will remove more than twice the amount of hardness that is removed when operating with a sidestream softening system.

For the PC boiler cases, the cooling tower blowdown would be equal to the wastewater treatment capacity of the existing brine concentrator, plus the amount of wastewater that could be reused as makeup to the SDA system, and supplemented as necessary by additional brine concentrator capacity. To establish the needed additional brine concentrator, the minimum capacity was set at half the capacity of the existing brine concentrator. This would provide a minimum of 50 percent redundancy for the existing system. Using the resultant waste treatment capacity, the cooling tower cycles of concentration was determined and the circulating water quality estimated. For the 300 MW, 450 MW, and 600 MW capacity units, the additional brine concentrator of 250 gpm (400 acre-feet per year) was adequate to maintain the circulating water calcium hardness concentration between 1600 mg/l and 1850 mg/l. For this evaluation, the capital and operating costs of the brine concentrator treatment option for the 600 MW PC unit are shown in Appendix A of this report as a comparison to the other treatment options evaluated.

For the CFB boiler cases, the cooling tower blowdown would be equal to the wastewater treatment capacity of the existing brine concentrator supplemented as required by additional brine concentrator capacity. Because the CFB boiler may not require flue gas desulphurization the amount of wastewater that could be disposed in the SDA unit would have to be disposed using the additional brine concentrator capacity. For the 300 MW capacity unit, the additional brine concentrator capacity of about 500 acre-feet per year is necessary to maintain the circulating water calcium alkalinity concentration within a range of 1800 to 1900 mg/l. For the 450 MW unit, a brine concentrator capacity of 900 acre-feet per year would be required and 1200 acre-feet per year for the 600 MW unit.

2.3.3 Cooling Tower Treatment Option Using HERO Membrane Treatment Process

The HERO (high efficiency reverse osmosis) treatment process is a process that is patented by Aquatech International. The treatment process requires complete softening of the wastewater stream followed by degasification for carbon dioxide reduction and caustic feed for pH adjustment prior to treatment using reverse osmosis membranes. The advantage of the HERO process is the ability to treat the wastewater with minimal consideration to silica fouling. Typically, the HERO concentrate can contain silica concentrations up to 2,000 mg/l and TDS values up to 80,000 mg/l allowing very high water recovery rates. The quality of the HERO permeate is not as high as the condensate quality from the brine concentrator condensate and will require additional treatment to achieve the high quality required for boiler makeup. The softening pretreatment for the HERO process would consist of lime/soda softening for maximum hardness reduction followed by complete hardness removal using a weak acid cation (WAC) exchanger. To minimize the wastewater produced, the regeneration waste stream from the WAC exchanger is returned to the lime/soda ash softener for eventual precipitation and removal. Although the capital cost for the HERO process is less than the brine concentrator, the additional cost required for the demineralization equipment which is needed to produce the high purity needed for boiler make will result in a total capital cost for the HERO process and demineralization equipment approximately equal to the estimated cost for the brine concentrator.

The treatment rate for the HERO process is the same as the treatment rate required for the brine concentrator treatment because the treatment streams for both processes serve as cooling tower blowdown with none of the dissolved solids content being returned to the circulating water system. Although the HERO process requires more chemicals than the brine concentrator due to the lime soda ash and WAC softening, the annual cost for these treatment chemicals is offset by the electrical demand of the brine concentrator. Comparative capital and operating costs for the 600 MW PC case with cooling tower heat rejection are provided in Appendix A of this report.

3.0 WATER AND WASTEWATER MANAGEMENT

The cooling tower and cooling pond options require different water and wastewater management plans. The primary difference between the two methods of water management is that the cooling pond option will require a batch type operation similar to the current pond management scheme while the cooling tower will allow more continuous operation with more stable water chemistry. In essence the cooling tower serves as a water treatment process for the existing cooling pond as well as providing heat rejection for Unit II. Water balances for the CPB cases and PC cases both using a cooling tower for Unit II heat rejection and using additional brine concentrator capacity for treating the added plant wastewater are presented in Appendix B, Figure 1 of this report. This option is shown to be the most cost effective as shown in Appendix A.

3.1 COOLING POND OPTION – WASTEWATER MANAGEMENT

The cooling pond option would continue to use the existing cooling pond with a 60 acre extension for improving Unit I heat rejection. During the operation of the plant, water will be evaporated continuously resulting in a continuous concentration of the dissolved solids content of the cooling water. The existing lime softener would treat and recirculate a portion of the water in the cooling pond to provide some control the calcium hardness concentration. Water in the existing evaporation pond will be concentrated by forced evaporation in order to reduce the volume of water and provide a more concentrated waste stream to the brine concentrator. The water from the evaporation pond will be used to supply the holding pond which contains the supply water for the brine concentrator. The brine concentrator will treat the plant wastewater producing condensate quality for use by the ethanol plant and Unit I boiler makeup. The brine concentrator operation will be continuous and will reduce the water volume contained in the evaporation and holding ponds. When these ponds are at low levels and water can be pumped from the Big Stone Lake, the concentrated water from the cooling pond is transferred to the evaporation pond and the cooling pond is filled with fresh water. The plant has experienced an increasing concentration of the water contained in the cooling pond because the water remaining in the pond is more concentrated with each cycle. The result is that the starting concentration after the pond is refilled is greater than the previous year.

The Unit II cooling pond was sized based on providing a minimum surface area that is needed for Unit II heat rejection while providing a minimum storage volume to allow one year plant operation without taking makeup from Big Stone Lake. The surface area is calculated to be 600 acres for the 600 MW PC Unit. The minimum storage volume required is 12,000 acre-feet based on an annual water usage of approximately 11,935 acre-feet and allowing for 3000 acre-feet of usable storage volume in the existing cooling pond with a minimum reserved volume of about 3000 acre-feet in the Unit II cooling pond. This minimum reserved volume in the Unit II cooling pond allows for a cooling water concentration of 4 cycles but with a 600 acre pond results in only a 5 foot pond depth at the end of the drought cycle compared to the current minimum pond depth of nearly 8 feet. To provide the same minimum operating depth for the Unit II pond would require a minimum reserve volume of about 5,000 acre-feet adding 2,000 acre-feet to the total pond volume.

The operation of the Unit II cooling pond will be independent of the existing cooling pond because the water levels of both ponds will need to be different in order to minimize the amount of excavation required to build the Unit II cooling pond. The Unit II pond management will be similar to the Unit I pond management with similar water quality problems. For the PC unit, the SDA makeup will serve as a constant blowdown to the Unit II cooling pond. Additional constant blowdown can be achieved with the addition of the second brine concentrator. This will further improve the Unit II cooling pond water quality and provided a needed source of high purity water for makeup to Unit boiler. Without the second brine concentrator, the lime/soda softener treatment would be larger and another source of high purity water would be required such as a reverse osmosis treatment process with polishing demineralizer or an ion exchange demineralization process. The cost of the supplemental demineralized water system is included in the capital cost for the options that do not include the second brine concentrator.

For the CFB case, pond management would be identical to the existing pond management system with the use of an evaporation pond to reduce the waste volume that would result from pond blowdown in lieu of withdrawing water for SDA makeup. As an alternate to the Unit II evaporation pond, a larger brine concentrator can be used with a capacity equal to the existing brine concentrator plus the evaporation realized from the evaporation pond.

3.2 COOLING TOWER OPTION – WASTEWATER MANAGEMENT

The use of a cooling tower for heat rejection from Unit II operation would provide better integration of Unit II water management with the existing facilities. A water balance for the cooling tower options are provided in Appendix B of this report. Makeup water supplied from Big Stone Lake would be stored in an onsite makeup water storage pond. This storage pond would be sized to contain the two unit plant water needs for one year operation minus the usable storage currently available in the existing cooling pond. The usable storage in the existing cooling pond would only be used as the last source of water during an extended drought condition. All plant water makeup would be pumped directly to the cooling pond to maintain level. Makeup to the Unit II cooling tower would be taken from the cooling pond. This makeup rate would be continuous and would serve as blowdown to the cooling pond. With both generating units online, the makeup to Unit II cooling tower would control the dissolved solids concentration in the cooling pond to about 1.6 times the makeup water concentration. This concentration factor would be significantly less than the current pond water concentration which is about 3 to 4 times the makeup water quality. As a water treatment process, the cooling tower evaporates water which will result in a more concentrated waste stream than the existing evaporation pond which is send to the brine concentrator(s). Because the cooling tower essentially takes the place of the evaporation pond, the existing evaporation would be not needed and would be reused to provide plant makeup water storage capacity.

The management of the cooling pond would be more stable than the current operation. The pond level and pond water quality would be constant except for extreme drought conditions. All waste treatment facilities, either existing or new, will be used to maintain the water quality of the cooling tower. The existing batch operation for the cooling pond and evaporation pond would be eliminated.

4.0 COMPARATIVE COST DESCRIPTIONS

The following are cost descriptions for both the cooling tower and cooling pond options for Big Stone Unit II, presented in Appendix A of this report. The tables summarize major costs for the cooling pond and cooling tower options considered for a 600 MW pulverized coal unit. The tables are for comparative pricing only; they do not include all costs associated with each option, only major costs that are different between the two options. All costs include installation.

4.1 COOLING TOWER OPTION

4.1.1 CAPITAL COSTS:

- Cooling Tower: Includes the total cost for a 15 cell, counter-flow, induced draft cooling tower. The cooling tower is located west of the plant, inside the rail loop. Each cell is 54' x 54' x 47', and includes a 200 hp fan.

- Cooling Tower Basin: The total cost for the construction of a basin that supports the cooling tower, stores circulating water, and accommodates 2-50% circulating water pumps.

- Blowdown Pond: All costs associated with constructing an additional pond for Unit II cooling tower blowdown. The additional pond is approximately 26.5 surface acres and 689 acre-feet, and is located south of the cooling tower (See Appendix B, Figure 2).

- Additional Makeup Storage Pond: Includes the total construction cost for the addition of a new makeup water storage pond. The storage pond provided additional water storage capacity that, combined with the existing site water storage, reserves up to one year of the plant's water supply. The pond is located on the section located west of the plant site and is approximately 219 surface acres and 5,662 acre-feet.

- Additional Storage Pond Cross-Tie Piping: The additional makeup water storage pond needs to be cross-tied to the existing cooling pond. The single cross-tie pipe serves to fill the new storage pond when extra water is available, and to release water back into the existing cooling pond when water is needed. The cost includes a 24" buried, carbon steel pipeline and all necessary accessories. The pipeline is located between the north-east corner of the storage pond and the north-west corner of the cooling pond. It is assumed there is no modification of the existing cooling pond.

- Additional Storage Pond Cross-Tie Pump: Includes the pump cost associated with the above paragraph. Only one side of the pipe requires a pump, as gravity will carry the water from the storage pond back to the cooling pond. The pump is a 100% capacity, 375 hp pump that delivers 10,000 gpm.

- Circulating Water Piping and Valves: All costs associated with the circulating water pipeline that delivers water between the cooling tower and plant condenser. The pipeline is a 114" buried, carbon steel line.

- Circulating Water Pipe Rail Tunnels: Because of the location of the cooling tower in relation to the plant, the circulating water pipeline will have to go under the railroad lines. This cost has not yet been determined, but is probably not a substantial addition and should be similar for both cases.

- Cooling Tower Blowdown Piping: Includes the piping cost for the blowdown pipe from the cooling tower to the holding pond, and from the holding pond to the system's respective water treatment area (to the brine concentrator, e.g.). The two lines are both 10" buried, carbon steel pipe.

- Cooling Tower Makeup Piping: The piping cost for the makeup water line that delivers water from the cooling pond to the cooling tower. The pipe is an 18" buried, carbon steel line.

- Makeup Water Pump: Includes the equipment and installation cost for a 200 hp makeup water pump.

- Water Treatment: The water treatment costs include all capital costs associated with three different water treatment options. Each system includes the following equipment:

    - Brine Concentrator: One 250 gpm (400 acre-feet per year) brine concentrator similar to the existing system. Brine waste will be disposed in the existing brine sludge pond assuming that capacity exists. The cost to treat this brine with a crystallizer is not included in the cost but would add about $1.1 million to the system equipment cost.

    - Sidestream Treatment: The sidestream softener cost is based on providing a lime/soda ash softener, lime feed system with storage silo, soda ash feed system with silo, coagulant feed, acid feed, and gravity filtration of the softened effluent.

    - HERO: The HERO treatment process includes the lime/soda ash softener, lime feed system with storage silo, soda ash feed system with silo, coagulant feed, degasification, caustic feed, followed by membrane reverse osmosis treatment.

- Circulating Water Pumps: The circulating water system utilizes 2-50% pumps. Each pump is 5,500 hp and is capable of pumping 120,000 gpm. The pumps will be installed in the cooling tower basin and will energize the entire cooling water system.

- Main Power and Control Feed: Includes all costs for routing control and power feeds from the plant to the cooling tower.

- Cooling Tower Electrical Equipment: Includes all costs for electrical equipment at the cooling tower.

- Cell Cable and Raceway: Accounts for all raceway and cable that will need to be installed on the cooling tower fans and other areas.

- Water Treatment Power Feed: The cost associated with providing power to the respective water treatment equipment.

- Additional Land Costs: The land on which the additional storage pond will be built will have to be purchased. The total area required is approximately 314 acres, and a land cost of $3,000 / acre is assumed.

- Contingency: A contingency of 10% of the total capital costs is assumed.

4.1.2 YEARLY O&M COSTS:

- Cooling Tower Electrical Use: The cooling tower electrical use includes a 200 hp fan for each cell. The total yearly electrical cost assumes the cells will operate, on average, 75% of the year.

- Water Treatment Electrical Use: The electrical use for each water treatment option is listed. It is assumed that the water treatment equipment runs 88% of the year.

- Circulating Water Pump Electrical Use: It is assumed that each 5,500 hp circulating water pumps operate for 88% of the year.

- Pond Cross-Tie Pump: The pond cross-tie pump will only operate when water is being pumped from the existing cooling pond to the new storage pond. Therefore, it is assumed that the 375 hp pump operates approximately 50% of the year.

- Makeup Pump Electrical Use: It is assumed that the 200 hp pump operates for 88% of the year.

- Water Treatment Chemical Costs: Each water treatment option has its own chemical supply. The respective chemical cost is listed for each option.

- The Average Power Cost, Annual Escalation, Discount Rate, and Life Cycle are based on the pro forma assumptions previously reviewed with Otter Tail.

4.2 COOLING POND OPTION

4.2.1 CAPITAL COSTS

- Additional Cooling Pond: The additional cooling pond serves two purposes: to add surface area for heat rejection and to add volume for water storage. To meet these ends, the additional cooling pond is approximately 565 surface acres and 12,170 acre-feet. The pond will be located directly west of the plant site. (See Appendix B, Figure 3)

- Additional Evaporation Pond: Includes the construction cost of adding an additional evaporation pond for the Unit II cooling pond. The existing evaporation pond will not have enough capacity to handle the additional Unit II blowdown, so the additional pond is necessary. The pond will be located southwest of the existing city sewage treatment lagoon and is 106.5 surface acres and 2,238 acre feet. (See Appendix B, Figure 3)

- Additional Pond Supply Line: The aforementioned cooling pond makeup will be supplied by an extension of the existing water supply pipeline from Big Stone Lake. The new line is 48" in diameter; the same size as the existing line it is branching from. The line is a carbon steel, buried pipe. The existing Big Stone Lake water pumps will be utilized to pump water to the new pond.

- Circulating Water Intake Structure: The circulating pipe will require a new intake structure to supply water to the plant from the additional cooling pond. The intake will facilitate 2-50% circulating water pumps.

- Circulating Water Piping and Valves: The circulating water pipe is a 114" buried, carbon steel line. The pipe runs from the circulating water pumps in the additional cooling pond to the Unit II condenser and back to the cooling pond.

- Circulating Water Pipe Rail Tunnels: Because of the location of the cooling pond in relation to the plant, the circulating water pipeline will have to go under the railroad lines. This cost has not yet been determined, but is probably not a substantial addition and should be similar for both cases.

- Blowdown Piping: Blowdown pipe runs from the circulating water header to the additional blowdown pond. The pipe is 36" buried, carbon steel.

- Water Treatment: The water treatment costs include all capital costs associated with two different water treatment options. The systems include the following equipment:

    - Brine Concentrator: One 250 gpm (400 acre-feet per year) brine concentrator similar to the existing system. Brine waste will be disposed in the existing brine sludge pond assuming that capacity exists. The cost to treat this brine with a crystallizer is not included in the cost but would add about $1.1 million to the system equipment cost.

    - Additional Softener: The sidestream softener cost is based on providing a lime/soda ash softener, lime feed system with storage silo, soda ash feed system with silo, coagulant feed, acid feed, and gravity filtration of the softened effluent.

- Circulating Water Pumps: The two circulating water pumps are each 50% capacity, 4500 hp pumps. They will be installed at the new cooling pond west of the plant and pressurize the Unit II circulating water system.

- Main Power and Controls Feed: The main power and controls feed includes the cost associated with providing power and controls to the circulating water pumps.

- Water Treatment Power Feed: The installed cost of providing power to the water treatment equipment.

- Additional Land Costs: The land on which the additional cooling pond and blowdown pond will be built will have to be purchased. 837 acres are required at a land cost of $3,000 / acre. $200,000 is added for each large structure that has to be demolished and removed, and $25,000 is added for small structures.

- Contingency: A contingency of 10% of the total capital costs is assumed.

4.2.2 YEARLY O&M COSTS:

- Water Treatment Electrical Use: The electrical use for each water treatment option is listed. It is assumed that the water treatment equipment runs 88% of the year.

- Circulating Water Pump Electrical Use: It is assumed that each 4,500 hp circulating water pump operates for 88% of the year.

- Water Treatment Chemical Costs: The respective chemical cost is listed for both options.

- The Average Power Cost, Annual Escalation, Discount Rate, and Life Cycle are based on the pro forma assumptions previously reviewed with Otter Tail.

5.0 TABLES AND FIGURES

Tables 1 through 4 in Appendix A represent comparative capital, operation and maintenance costs for the 600 MW pulverized coal unit cooling tower and cooling pond options for the various methods described in Sections 1 through 4 of this report. These options are also presented at two different discount rates to reflect the interests of the different utility entities involved in the project.

The figures included in Appendix B represent the water balance for the most cost effective option – cooling tower with brine concentrator (Figure 1), the layout of ponds and equipment for the cooling tower option (Figure 2), and the layout of ponds for the cooling pond option (Figure 3). All of the equipment and pond sizing for this study is based on a 600 MW pulverized coal unit.

6.0 CONCLUSIONS AND RECOMMENDATIONS

Based on the comparative costs for the cooling pond option and cooling tower option shown in Appendix A, the most cost effective method of providing heat rejection for Unit II is with the use of a cooling tower. Aside from the cost considerations, the cooling tower option would provide a more simple method of water management for the combined two unit facility with a total plant water consumption less than with the cooling pond option. The cooling tower option would allow the existing cooling pond to operate at a constant water level and with improved water quality. Although the cooling tower option will have a visible plume of saturated vapor leaving the tower, the need for another large storage reservoir of water which may seem aesthetically unpleasant in the public eye is eliminated.

Because of the very high usage of lime and soda ash, sidestream softening of the Unit II circulating water had a much higher comparative net present value than either the HERO or brine concentrator treatment methods. The comparative net present values for the HERO and brine concentrator treatment methods were nearly the same with the chemical costs of the HERO offsetting the power costs of the brine concentrator. The capital and operating costs for the brine concentrator was based on the minimum treatment capacity that would be required for Unit II operation. This capacity of 250 gpm (400 acre-feet per year) is half the capacity of Unit I brine concentrator and would provide 50 percent redundancy of the existing system. A larger system which would provide 100 percent redundancy could be furnished for an additional $2 million (installed).

The product from the brine concentrator would be condensate quality water which would require polishing prior to use as makeup to the boiler. The product from the HERO system would contain several hundred mg/l of dissolved solids and would require demineralization prior to use as makeup to the boiler. The comparative capital cost for the HERO process includes the cost for this demineralization system.

The brine concentrator process offers an advantage of being the same process that has been used at the plant for many years. The operators are familiar with this process and have had good success with the operation of the existing system. The HERO process is more labor intensive than the brine concentrator because it is based on the use of three treatment methods: 1) lime/soda ash softening, 2) ion exchange softening, and 3) reverse osmosis treatment. Each of these processes is new and different from the current treatment experience.

The SDA that is required for the PC case provides a waste disposal capability that is comparable to the Unit I brine concentrator. Without the SDA, added treatment capacity will be required to be provided by the brine concentrator or HERO systems.

Following are Burns & McDonnell recommendations:

- A cooling tower should be used for heat rejection from Unit II. All cost alternatives for new plant technologies being explored in the Phase I new unit study should include a cooling tower as the base technology for heat rejection.
- Convert the existing evaporation pond and holding pond for use as the Makeup Water Storage Pond and supplement this storage with a second Makeup Water Storage Pond.
- Provide makeup to the Unit I cooling pond from the Makeup Water Storage Ponds.
- Collect the cooling tower blowdown in a new holding basin for treatment in both the existing and new brine concentrator.

ATTACHMENT E
APPENDIX A
NET PRESENT VALUE TABLES

TABLE 1 - COOLING TOWER COSTS, PUBLIC UTILITY

CAPITAL COSTS		Brine Concentrator	Side Stream Trt.	HERO
Equipment, Pipe, and Installation	Cooling Tower	$ 5,869,000	$ 5,869,000	$ 5,869,000
	Cooling Tower Basin	$ 1,840,000	$ 1,840,000	$ 1,840,000
	Blowdown Pond	$ 3,716,000	$ 3,716,000	$ 3,716,000
	Additional Storage Pond	$ 15,780,000	$ 15,780,000	$ 15,780,000
	Additional Storage Pond Cross-Tie Piping	$ 1,029,000	$ 1,029,000	$ 1,029,000
	Additional Storage Pond Cross-Tie Pump	$ 75,000	$ 75,000	$ 75,000
	Circ Water Piping and Valves	$ 7,420,000	$ 7,420,000	$ 7,420,000
	Circ Water Pipe Rail Tunnels	TBD	TBD	TBD
	Cooling Tower Blowdown Piping	$ 738,500	$ 650,000	$ 738,500
	Cooling Tower Makeup Piping	$ 696,000	$ 696,000	$ 696,000
	Makeup Water Pump	$ 75,000	$ 75,000	$ 75,000
	Water Treatment	$ 3,120,000	$ 2,470,000	$ 3,120,000
	Circ Water Pumps	$ 745,000	$ 745,000	$ 745,000
Electrical	Main Power and Control Feed	$ 410,000	$ 410,000	$ 410,000
	CT Electrical Equipment	$ 450,000	$ 450,000	$ 450,000
	Cell Cable and Raceway	$ 75,000	$ 75,000	$ 75,000
	Water Treatment Power Feed	$ 200,000	N/A	$ 50,000
	Additional Land Costs	$ 1,342,000	$ 1,342,000	$ 1,342,000
	Contingency %	10%	10%	10%
	Contingency	$ 4,358,050	$ 4,264,200	$ 4,343,050
	Total Capital Costs	**$ 47,939,000**	**$ 46,906,000**	**$ 47,774,000**

YEARLY O&M COSTS		Brine Concentrator	Side Stream Trt.	HERO
Power Costs	Cooling Tower, kW	1,678	1,678	1,678
	Water Treatment, kW	1,028	66	171
	Circ Water Pump, kW	7,218	7,218	7,218
	Pond Cross-Tie Pump, kW	140	140	140
	Makeup Pump, kW	132	132	132
	Annual Power Usage, MWh	89,311	80,882	81,803
	Average Power Cost, $/MWh	$ 30.00	$ 30.00	$ 30.00
	Yearly Power Cost, $	$ 2,679,338	$ 2,426,451	$ 2,454,087
	Water Treatment Chemical Costs	$ 122,777	$ 3,418,886	$315,898
	Annual Escalation	2.5%	2.5%	2.5%
	Discount Rate	6%	6%	6%
	Life Cycle, Years	30	30	30
	Total O&M NPV Costs	**$ 50,822,000**	**$ 106,016,000**	**$ 50,239,000**
	Total NPV Costs	**$ 98,761,000**	**$ 152,922,000**	**$ 98,013,000**

TABLE 2 - COOLING TOWER COSTS, IOU

CAPITAL COSTS

		Brine Concentrator	Side Stream Trt.	HERO
Equipment, Pipe, and Installation	Cooling Tower	$ 5,869,000	$ 5,869,000	$ 5,869,000
	Cooling Tower Basin	$ 1,840,000	$ 1,840,000	$ 1,840,000
	Blowdown Pond	$ 3,716,000	$ 3,716,000	$ 3,716,000
	Additional Storage Pond	$ 15,780,000	$ 15,780,000	$ 15,780,000
	Additional Storage Pond Cross-Tie Piping	$ 1,029,000	$ 1,029,000	$ 1,029,000
	Additional Storage Pond Cross-Tie Pump	$ 75,000	$ 75,000	$ 75,000
	Circ Water Piping and Valves	$ 7,420,000	$ 7,420,000	$ 7,420,000
	Circ Water Pipe Rail Tunnels	TBD	TBD	TBD
	Cooling Tower Blowdown Piping	$ 738,500	$ 650,000	$ 738,500
	Cooling Tower Makeup Piping	$ 696,000	$ 696,000	$ 696,000
	Makeup Water Pump	$ 75,000	$ 75,000	$ 75,000
	Water Treatment	$ 3,120,000	$ 2,470,000	$ 3,120,000
	Circ Water Pumps	$ 745,000	$ 745,000	$ 745,000
Electrical	Main Power and Control Feed	$ 410,000	$ 410,000	$ 410,000
	CT Electrical Equipment	$ 450,000	$ 450,000	$ 450,000
	Cell Cable and Raceway	$ 75,000	$ 75,000	$ 75,000
	Water Treatment Power Feed	$ 200,000	N/A	$ 50,000
	Additional Land Costs	$ 1,342,000	$ 1,342,000	$ 1,342,000
	Contingency %	10%	10%	10%
	Contingency	$ 4,358,050	$ 4,264,200	$ 4,343,050
	Total Capital Costs	**$ 47,939,000**	**$ 46,906,000**	**$ 47,774,000**

YEARLY O&M COSTS

		Brine Concentrator	Side Stream Trt.	HERO
Power Costs	Cooling Tower, kW	1,678	1,678	1,678
	Water Treatment, kW	1,028	66	171
	Circ Water Pump, kW	7,218	7,218	7,218
	Pond Cross-Tie Pump, kW	140	140	140
	Makeup Pump, kW	132	132	132
	Annual Power Usage, MWh	89,311	80,882	81,803
	Average Power Cost, $/MWh	$ 30.00	$ 30.00	$ 30.00
	Yearly Power Cost, $	$ 2,679,338	$ 2,426,451	$ 2,454,087
	Water Treatment Chemical Costs	$ 122,777	$ 3,418,886	$315,898
	Annual Escalation	2.5%	2.5%	2.5%
	Discount Rate	9.75%	9.75%	9.75%
	Life Cycle, Years	30	30	30
	Total O&M NPV Costs	**$ 33,676,000**	**$ 70,249,000**	**$ 33,289,000**
	Total NPV Costs	**$ 81,615,000**	**$ 117,155,000**	**$ 81,063,000**

TABLE 3 - COOLING POND COSTS, PUBLIC UTILITY

CAPITAL COSTS

		Brine Concentrator	Additional Softener
Equipment, Pipe, and Installation	Additional Cooling Pond	$ 44,455,000	$ 44,455,000
	Additional Evap. and Blowdown Pond	$ 13,920,000	$ 13,920,000
	Additional Pond Supply Line	$ 3,827,296	$ 3,827,296
	Circulating Water Intake Structure	$ 300,000	$ 300,000
	Circ Water Piping and Valves	$ 8,039,000	$ 8,039,000
	Circ Water Pipe Rail Tunnels	TBD	TBD
	Blowdown Piping	$ 2,468,000	$ 2,468,000
	Water Treatment	$ 4,420,000	$ 2,080,000
	Circ Water Pumps	$ 665,000	$ 665,000
Elect	Main Power and Controls Feed	$ 260,000	$ 260,000
	Water Treatment Power Feed	$ 200,000	N/A
	Additional Land Costs**	$ 3,411,000	$ 3,411,000
	Contingency %	10%	10%
	Contingency	$ 8,196,530	$ 7,942,530
	Total Capital Costs	**$ 90,162,000**	**$ 87,368,000**

YEARLY O&M COSTS

		Brine Concentrator	Additional Softener
Power Costs	Water Treatment, kW	1,031	13
	Circ Water Pump, kW	5,906	5,906
	Annual Power Usage, MWh	60,768	51,849
	Average Power Cost, $/MWh	$ 30	$ 30
	Yearly Power Cost, $	$ 1,823,054	$ 1,555,459
	Water Treatment Chemical Costs	$ 506,756	$ 585,815
	Electricity Annual Escalation	2.5%	2.5%
	Discount Rate	6%	6%
	Life Cycle, Years	30	30
	Total O&M NPV Costs	**$ 42,256,000**	**$ 38,836,000**
	Total NPV Costs	**$ 132,418,000**	**$ 126,204,000**

TABLE 4 - COOLING POND COSTS, IOU

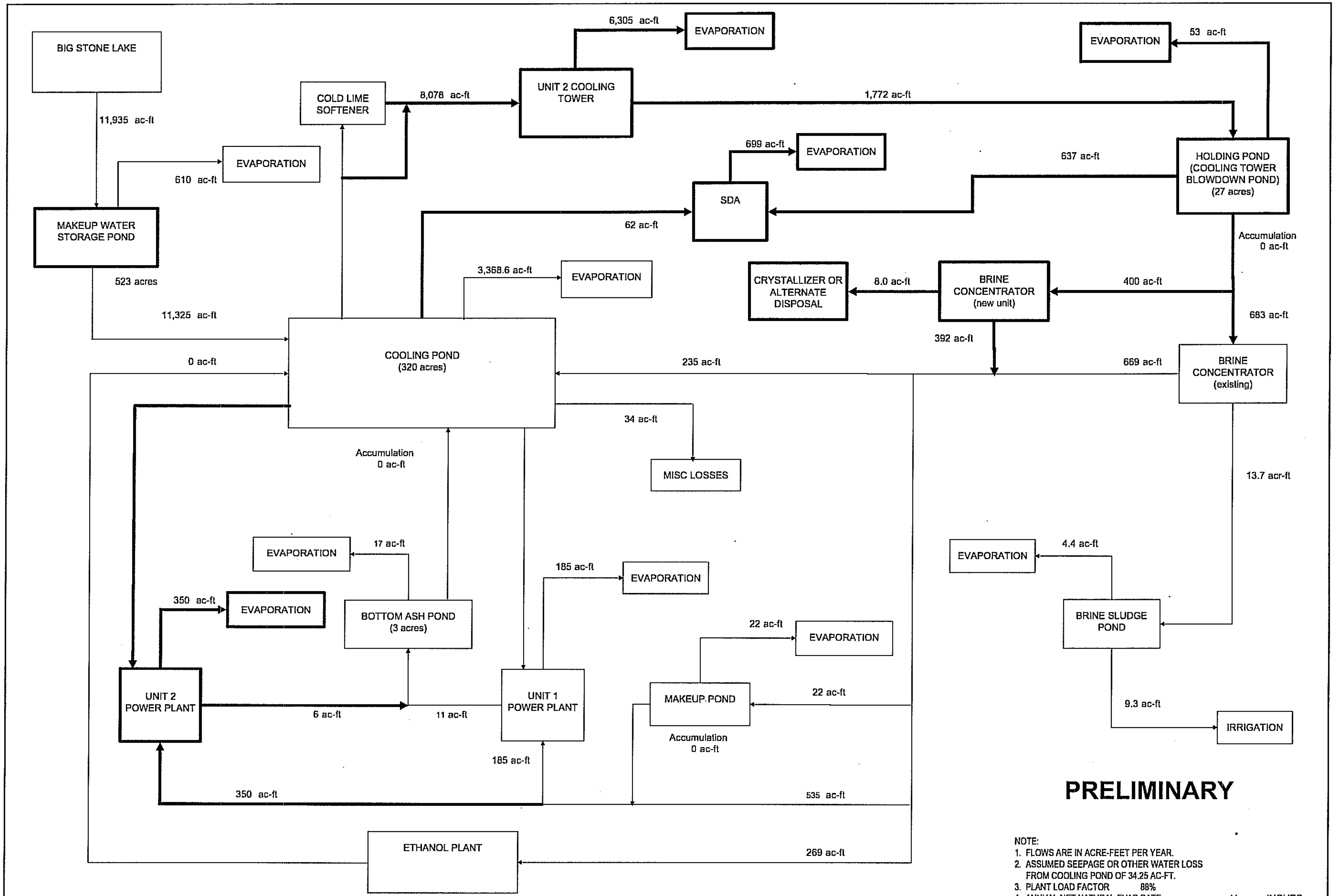
CAPITAL COSTS

		Brine Concentrator	Additional Softener
Equipment, Pipe, and Installation	Additional Cooling Pond	$ 44,455,000	$ 44,455,000
	Additional Evap. and Blowdown Pond	$ 13,920,000	$ 13,920,000
	Additional Pond Supply Line	$ 3,827,296	$ 3,827,296
	Circulating Water Intake Structure	$ 300,000	$ 300,000
	Circ Water Piping and Valves	$ 8,039,000	$ 8,039,000
	Circ Water Pipe Rail Tunnels	TBD	TBD
	Blowdown Piping	$ 2,468,000	$ 2,468,000
	Water Treatment	$ 4,420,000	$ 2,080,000
	Circ Water Pumps	$ 665,000	$ 665,000
Elect.	Main Power and Controls Feed	$ 260,000	$ 260,000
	Water Treatment Power Feed	$ 200,000	N/A
	Additional Land Costs**	$ 3,411,000	$ 3,411,000
	Contingency %	10%	10%
	Contingency	$ 8,196,530	$ 7,942,530
	Total Capital Costs	**$ 90,162,000**	**$ 87,368,000**

YEARLY O&M COSTS

		Brine Concentrator	Additional Softener
Power Costs	Water Treatment, kW	1,031	13
	Circ Water Pump, kW	5,906	5,906
	Annual Power Usage, MWh	60,768	51,849
	Average Power Cost, $/MWh	$ 30	$ 30
	Yearly Power Cost, $	$ 1,823,054	$ 1,555,459
	Water Treatment Chemical Costs	$ 506,756	$ 585,815
	Electricity Annual Escalation	2.5%	2.5%
	Discount Rate	9.75%	9.75%
	Life Cycle, Years	30	30
	Total O&M NPV Costs	**$ 27,999,000**	**$ 25,734,000**
	Total NPV Costs	**$ 118,161,000**	**$ 113,102,000**

ATTACHMENT E
APPENDIX B
FIGURES



PRELIMINARY

NOTE:
1. FLOWS ARE IN ACRE-FEET PER YEAR.
2. ASSUMED SEEPAGE OR OTHER WATER LOSS FROM COOLING POND OF 34.25 AC-FT.
3. PLANT LOAD FACTOR 88%
4. ANNUAL NET NATURAL EVAP RATE 14 INCHES
5. BOLD LINES INDICATE UNIT 2 MODIFICATIONS

NO	DATE	REVISIONS AND RECORD OF ISSUE	DES	CHK	APP
D	17-May-04	Identified Cooling Tower Blowdown Pond			
C	20-Apr-04	Added Bold Indication for Unit 2 Additions			
B	6-Apr-04	Updated Makeup Pond Area			

Burns & McDonnell SINCE 1898

ENGINEER DAS | DRAWN DAS
CHECKED | DATE 9-Mar-04

OTTERTAIL POWER
BIG STONE PLANT
PC Fired 1x600 MW Supercritical
WATER MASS BALANCE

PROJECT | REV D
CODE | AREA | DRAWING NUMBER Figure 1

WMB PC C.T. BC (Rev D).xls

1740

Burns & McDonnell SINCE 1898

date APRIL 9, 2004

designed SEDLACEK

OTTERTAIL POWER COMPANY

600 MW PC WITH COOLING TOWER

project 35424

contract

FIGURE 2

1741

Burns & McDonnell SINCE 1898	OTTERTAIL POWER COMPANY	project 35424
date APRIL 9, 2004		contract
designed SEDLACEK	600 MW PC WITH COOLING POND	FIGURE 3

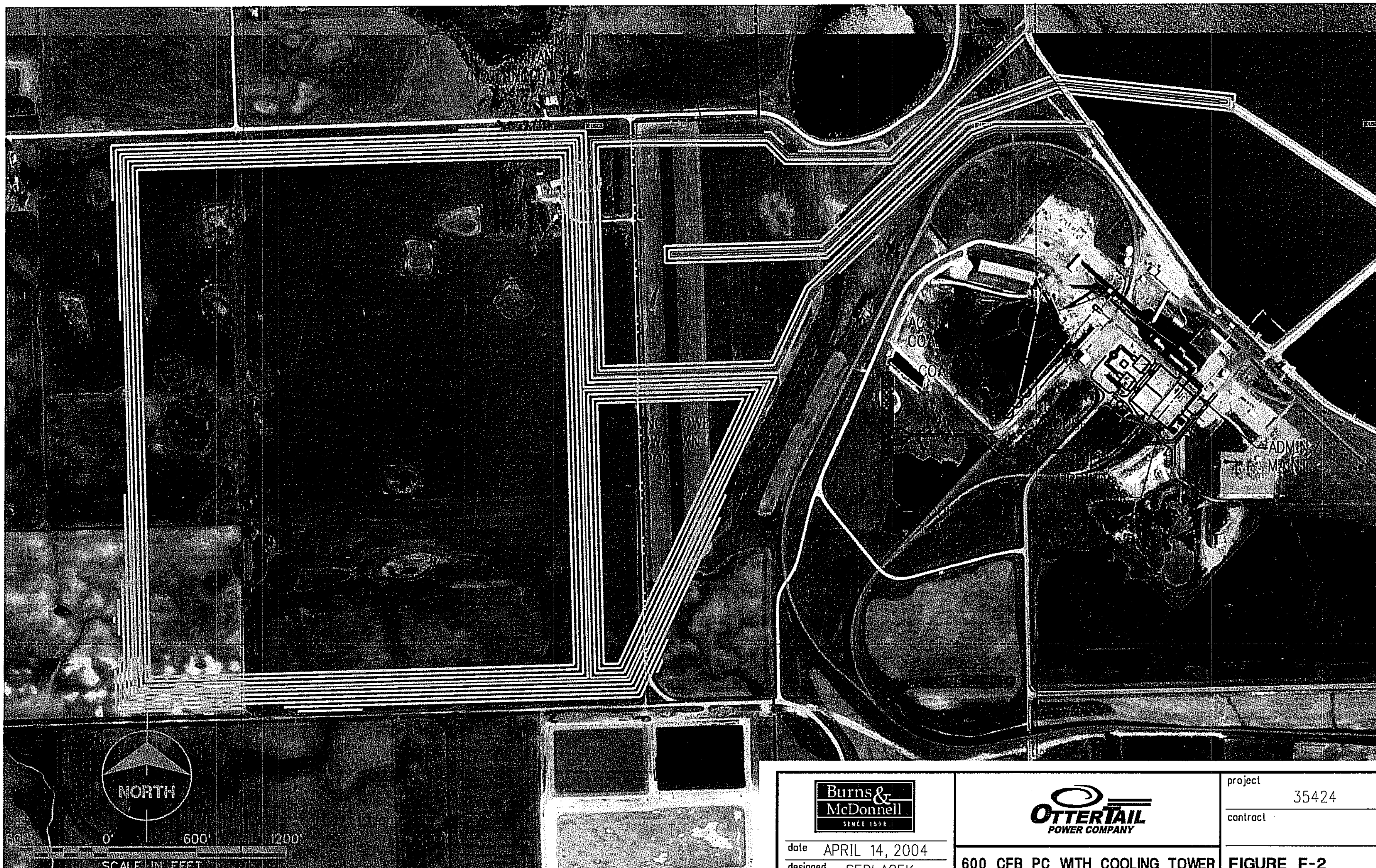
1742

Burns & McDonnell SINCE 1898	OTTERTAIL POWER COMPANY	project	35424
date APRIL 14, 2004		contract	
designed SEDLACEK	600 MW PC WITH COOLING TOWER	FIGURE F-1	

$FILES

DTI

1743



Burns & McDonnell SINCE 1898

OTTER TAIL POWER COMPANY

date APRIL 14, 2004		project 35424
designed SEDLACEK	600 CFB PC WITH COOLING TOWER	contract
		FIGURE F-2

$FILES DT

1744

Burns & McDonnell
SINCE 1898

date APRIL 14, 2004
designed SEDLACEK

OTTERTAIL POWER COMPANY

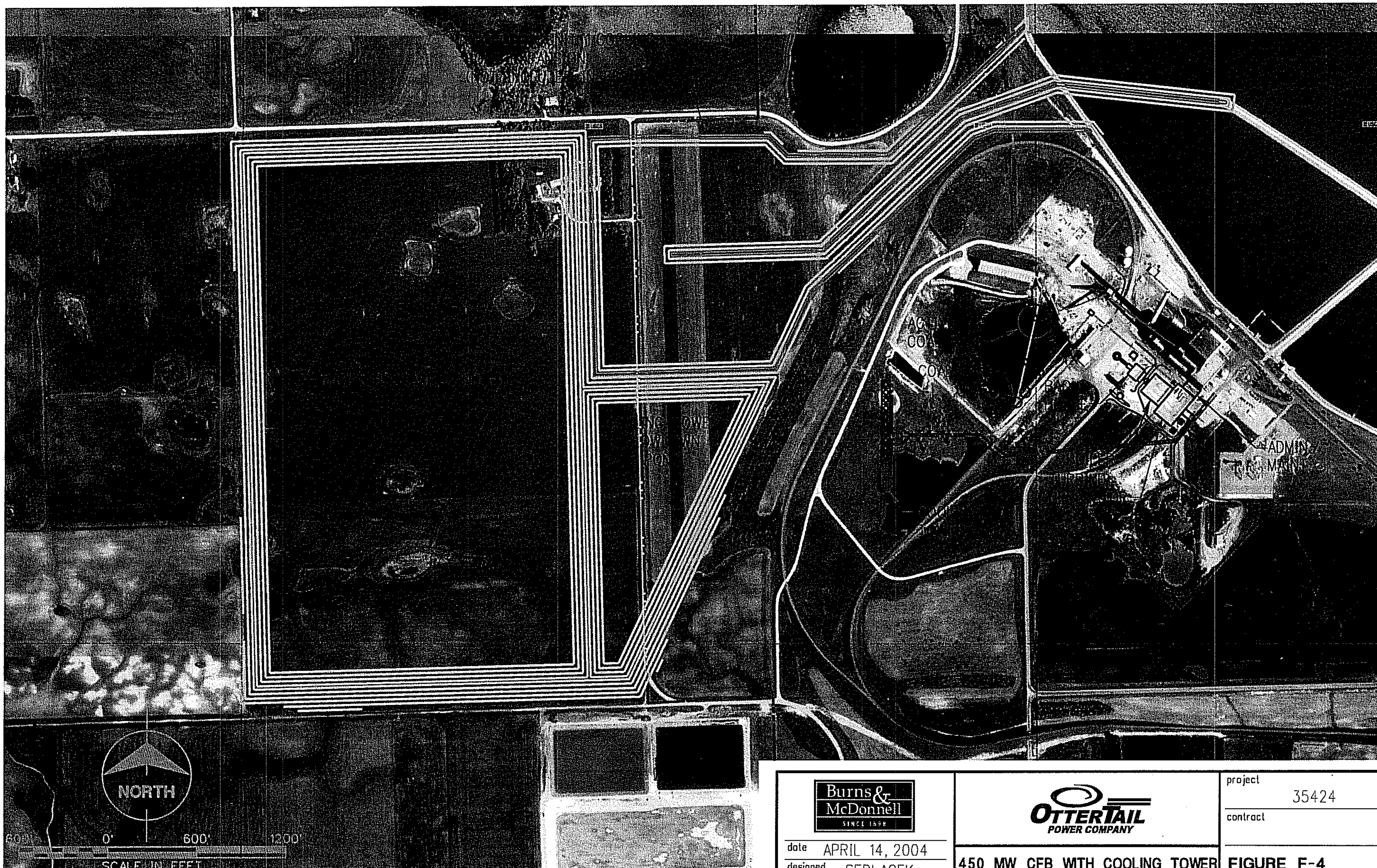
450 MW PC WITH COOLING TOWER

project 35424
contract

FIGURE F-3

$FILES DT

1745



Burns & McDonnell SINCE 1898	OTTERTAIL POWER COMPANY	project 35424
date APRIL 14, 2004		contract
designed SEDLACEK	450 MW CFB WITH COOLING TOWER	FIGURE F-4

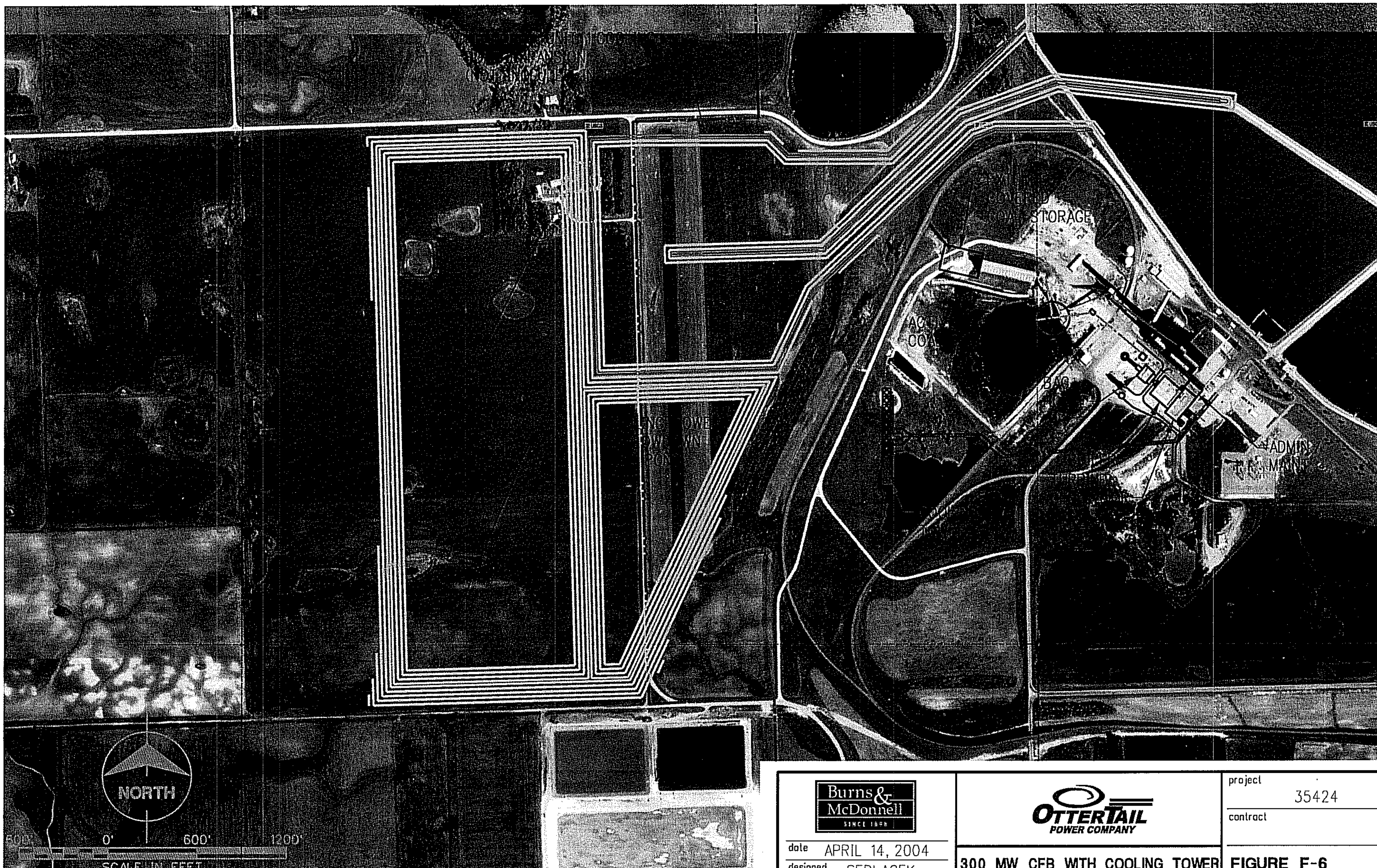
$FILES DT

1746

Burns & McDonnell SINCE 1898	OTTER TAIL POWER COMPANY	project 35424
date APRIL 14, 2004		contract
designed SEDLACEK	300 MW PC WITH COOLING TOWER	FIGURE F-5

$FILES DTI

1747



Burns & McDonnell SINCE 1898 date APRIL 14, 2004 designed SEDLACEK	OTTERTAIL POWER COMPANY 300 MW CFB WITH COOLING TOWER	project 35424 contract FIGURE F-6

$FILES DT

1748

ATTACHMENT G
FUEL HANDLING SYSTEM DESCRIPTIONS AND SCHEMATICS

The coal handling system for the Big Stone Unit 2 Project will be based on handling Powder River Basin (PRB) coal with an assumed density of 45 pounds per cubic foot.
The existing unit train positioner is limited to handling a maximum of approximately 120 railcars due to track configuration and installed horsepower. For purposes of this report we have assumed a 120 car unit train with 120 tons each car for a total unit train tonnage of 14,400 tons.

1.0 EXISTING COAL HANDLING SYSTEM

The existing coal unloading system is comprised of a unit train positioner, rotary dumper, four (4) vibrating feeders, 72" Conveyor 1, 72" Conveyor 2 and 72" Tripper Conveyor 3 and handles 3,150 tons per hour (tph). Tripper Conveyor 3 fills an enclosed a-frame storage barn (approximately 25,000 tons capacity). Emergency stockout is accomplished via a diverter gate and telescopic chute located at the headend of Conveyor 2 and mobile equipment transferring coal to the storage pile. The existing storage pile contains approximately 30 days of inactive storage (approximately 195,000 tons).
Reclaim from the enclosed barn is via a 10 foot diameter, variable speed rotary plow and 36" Conveyor 4. Reclaim from the inactive storage pile is via a single in-ground reclaim hopper with vibrating feeder and 36" Conveyor 5. Conveyor 4 and 5 each handle 550 tph and transfer coal to the existing Transfer (Crusher) House.

The Transfer House is provided with two (2) vibrating feeders and two (2) ring granulator crushers handling 550 tph. The crushers discharge to dual 36" Conveyors 6A and 6B which transport coal to Unit 1.

Unit 1 silo fill is accomplished via a 50 ton distribution bin, 36" transfer conveyors and a series of 36" cascade conveyors at the rate of 550 tph. Total Unit 1 silo storage is approximately 3,000 tons.

2.0 BIG STONE UNIT 2 UPGRADES

2.1 300 MW PC or CFB UNIT 2 UPGRADES (Flow Diagram CHFD001 & CHFD002)

For this review the burn rate for the new 300 MW (PC or CFB) unit will be based on 185 tons per hour (tph). The existing Unit 1 burn rate is approximately 270 tph therefore the total for both units will be 455 tph. Based on a 90% plant capacity factor, existing Unit 1 and new Unit 2 will require approximately

3,600,000 tons per year of PRB coal. Based on 100% capacity requirements and a unit train size of 14,400 tons the unloading system will have to handle approximately 5 ½ unit trains each week. For simplicity we have assumed the unloading system will have to handle one unit train per day.

In order to improve unloading times and minimize demurrage charges the unloading system will be upgraded to handle 3,600 tph. This will allow a unit train to be unloaded in approximately 4 hours. The four (4) vibrating feeders, 72" Conveyor 1, 72" Conveyor 2 and 72" Tripper Conveyor 3 will be upgraded by increasing the speed to achieve the new rate of 3,600 tph.

The existing transfer point structure, located adjacent to the barn storage, will be upgraded to provide the necessary support for the new conveyor upgrades and additions. The existing emergency stockout system (telescopic chute at the headend of Conveyor 2) will be replaced with a new chute which will feed a new 72" fixed boom stockout conveyor. The new stockout conveyor will discharge over the center of the existing reclaim hopper and will be provided with a new telescopic chute. The new pile formed at this location will contain approximately 24,000 tons. Coal will be transferred to inactive storage from this location by existing mobile equipment. The inactive storage pile area will be increased to provide approximately 45 days of storage for both units (approximately 492,000 tons).

In order to provide 4 days live storage for the new Unit 2 the existing a-frame storage barn will be extended approximately 265' which will provide an additional 18,000 tons of storage. Tripper Conveyor 3 and the tripper travel will also be extended to handle the new requirements. All existing 36" conveyors and existing coal handling components (vibrating feeders, crushers, magnetic separators, etc.) will be upgraded to handle 725 tph. Coal to new Unit 2 will be provided by relocating the head end of existing conveyors 6A and 6B. New chutework and motorized diverter gates will allow coal to flow to existing Unit 1 or to dual 36" conveyors which transfer coal to Unit 2.

Silo fill for Unit 2 will be accomplished thru a new transfer tower located adjacent to Unit 2. The new transfer tower will be provided with a new surge bin and belt feeders (2) which will feed silo transfer cascade conveyors. Each silo transfer cascade conveyor will feed dual en-masse silo fill conveyors at the rate of 725 tons per hour.

2.2 300 MW CYCLONE UNIT 2 UPGRADES (Flow Diagram CHFD003)

For this review the burn rate for the new 300 MW (CYCLONE) unit will be based on 185 tons per hour (tph). The existing Unit 1 burn rate is approximately 270 tph therefore the total for both units will be 455 tph. Based on a 90% plant capacity factor, existing Unit 1 and new Unit 2 will require approximately 3,600,000 tons per year of PRB coal. Based on 100% capacity requirements and a unit train size of 14,400 tons the unloading system will have to handle approximately 5 ½ unit trains each week. For simplicity we have assumed the unloading system will have to handle one unit train per day.

In order to improve unloading times and minimize demurrage charges the unloading system will be upgraded to handle 3,600 tph. This will allow a unit train to be unloaded in approximately 4 hours. The four (4) vibrating feeders, 72" Conveyor 1, 72" Conveyor 2 and 72" Tripper Conveyor 3 will be upgraded by increasing the speed to achieve the new rate of 3,600 tph. The existing transfer point structure, located adjacent to the barn storage, will be upgraded to provide the necessary support for the new conveyor upgrades and additions.

The existing emergency stockout system (telescopic chute at the headend of Conveyor 2) will be replaced with a new chute which will feed a new 72" Silo Feed Conveyor. The new Silo Feed Conveyor will be provided with a motorozed, retractable v-plow located adjacent to the existing reclaim hopper to form a new emergency stockout pile. The new pile formed at this location will contain approximately 28,000 tons and will provide coal to the existing reclaim hopper and the new reclaim hopper. A new dual reclaim hopper with two (2) vibrating feeders will be provided (adjacent to the existing reclaim hopper) which will provide coal from the inactive storage to the new Crusher House. Coal will be transferred to inactive storage from this location by existing mobile equipment. The inactive storage pile area will be increased to provide approximately 45 days of storage for both units (approximately 492,000 tons).
In order to provide 4 days live storage for the new Unit 2, two (2) new concrete storage silos will provide an additional 18,000 tons of storage. Each silo will be 70 feet diameter by approximately 153 feet tall with a single mass flow conical hopper. Coal will be withdrawn from each silo by variable speed belt feeders and transferred to the new Crusher House via a 36" conveyor at 550 tph. The new Crusher House will be provided with a surge bin, two (2) belt feeders and two (2) reversible hammermill crushers handling 550 tph. Coal from the new Crusher House to Unit 2 will be provided by dual 36" conveyors.

Silo fill for Unit 2 will be accomplished thru a new transfer tower located adjacent to Unit 2. The new transfer tower will be provided with a new surge bin and two (2) belt feeders which will feed two (2) silo transfer cascade conveyors. Each silo transfer cascade conveyor will feed dual en-masse silo fill conveyors at the rate of 725 tons per hour.

2.3 450 MW PC or CYCLONE or CFB UNIT 2 UPGRADES (Flow Diagram CHFD004, CHFD005 & CHFD006)

For this review the burn rate for the new 450 MW (PC, CYCLONE or CFB) unit will be based on 475 tons per hour (tph). The existing Unit 1 burn rate is approximately 270 tph therefore the total for both units will be 545 tph. Based on a 90% plant capacity factor, existing Unit 1 and new Unit 2 will require approximately 4,300,000 tons per year of PRB coal.

Based on 100% capacity requirements and a unit train size of 14,400 tons the unloading system will have to handle approximately 6 ½ unit trains each week. For simplicity we have assumed the unloading system will have to handle one unit train per day.

In order to improve unloading times and minimize demurrage charges the unloading system will be upgraded to handle 3,600 tph. This will allow a unit train to be unloaded in approximately 4 hours. The four (4) vibrating feeders, 72" Conveyor 1, 72" Conveyor 2 and 72" Tripper Conveyor 3 will be upgraded by increasing the speed to achieve the new rate of 3,600 tph.

The existing transfer point structure, located adjacent to the barn storage, will be upgraded to provide the necessary support for the new conveyor upgrades and additions.

The existing emergency stockout system (telescopic chute at the headend of Conveyor 2) will be replaced with a new chute which will feed a new 72" Silo Feed Conveyor. The new Silo Feed Conveyor will be provided with a motorozed, retractable v-plow located adjacent to the existing reclaim hopper to form a new emergency stockout pile. The new pile formed at this location will contain approximately 28,000 tons and will provide coal to the existing reclaim hopper and the new recalim hopper. A new dual reclaim hopper with two (2) vibrating feeders will be provided (adjacent to the existing reclaim hopper) which will provide coal from the inactive storage to the new Crusher House. Coal will be transferred to inactive storage from this location by existing mobile equipment. The inactive storage pile area will be increased to provide approximately 45 days of storage for both units (approximately 589,000 tons). In order to provide 4 days live storage for the new Unit 2, two (2) new concrete storage silos will provide an additional 27,000 tons of storage. Each silo will be 70 feet diameter by approximately 206 feet tall with a single conical mass flow hopper. Coal will be withdrawn from each silo by variable speed belt feeders and transferred to the new Crusher House via a 36" conveyor at 550 tph.

The new Crusher House for the PC and CFB unit will be provided with a surge bin, two (2) belt feeders and two (2) ring granulator crushers handling 550 tph each. The new Crusher House for the CYCLONE unit will be provided with a surge bin, two (2) belt feeders and two (2) reversible hammermill crushers handling 550 tph each. Coal from the new Crusher House to Unit 2 will be provided by dual 36" conveyors.

Silo fill for a **PC or Cyclone** Unit 2 will be accomplished thru a new transfer tower located adjacent to Unit 2. The new transfer tower will be provided with a new surge bin and two (2) belt feeders which will feed two (2) silo transfer cascade conveyors. Each silo transfer cascade conveyor will feed dual en-masse silo fill conveyors at the rate of 550 tons per hour. Silo fill for **CFB** Unit 2 will be accomplished thru a new transfer tower located adjacent to Unit 2. The new transfer tower will be provided with a new surge bin and two (2) belt feeders which will feed two (2) silo tripper feed conveyors. Each silo tripper feed conveyor will be provided with dual pantleg trippers and will fill the silos at the rate of 550 tons per hour.

2.4 600 MW PC or CYCLONE or CFB UNIT 2 UPGRADES (Flow Diagram CHFD007, CHFD008 & CHFD009)

For this review the burn rate for the new 600 MW (PC, CYCLONE or CFB) unit will be based on 360 tons per hour (tph). The existing Unit 1 burn rate is approximately 270 tph therefore the total for both units will be 630 tph. Based on a 90% plant capacity factor, existing Unit 1 and new Unit 2 will require approximately 5,000,000 tons per year of PRB coal. Based on 100% capacity requirements and a unit train size of 14,400 tons the unloading system will have to handle approximately 7 ½ unit trains each week. For simplicity we have assumed the unloading system will have to handle one unit train per day.

In order to improve unloading times and minimize demurrage charges the unloading system will be upgraded to handle 3,600 tph. This will allow a unit train to be unloaded in approximately 4 hours. The four (4) vibrating feeders, 72" Conveyor 1, 72" Conveyor 2 and 72" Tripper Conveyor 3 will be upgraded by increasing the speed to achieve the new rate of 3,600 tph. The existing transfer point structure, located adjacent to the barn storage, will be upgraded to provide the necessary support for the new conveyor upgrades and additions.

The existing emergency stockout system (telescopic chute at the headend of Conveyor 2) will be replaced with a new chute which will feed a new 72" Silo Feed Conveyor. The new Silo Feed Conveyor will be provided with a motorized, retractable v-plow located adjacent to the existing reclaim hopper to form a new emergency stockout pile. The new pile formed at this location will contain approximately 28,000 tons and will provide coal to the existing reclaim hopper and the new reclaim hopper. A new dual reclaim hopper with two (2) vibrating feeders will be provided (adjacent to the existing reclaim hopper) which will provide coal from the inactive storage to the new Crusher House. Coal will be transferred to inactive storage from this location by existing mobile equipment. The inactive storage pile area will be increased to provide approximately 45 days of storage for both units (approximately 681,000 tons). In order to provide 4 days live storage for the new Unit 2, three (3) new concrete storage silos will provide an additional 35,000 tons of storage.Each silo will be 70 feet diameter by approximately 196 feet tall with a single conical mass flow hopper. Coal will be withdrawn from each silo by a variable speed belt feeder and transferred to the new Crusher House via a 36" conveyor at 725 tph.

The new Crusher House for a **PC or CFB** units will be provided with a surge bin, two (2) belt feeders and two (2) ring granulator crushers each handling 725 tph. The new Crusher House for the **CYCLONE** unit will be provided with a surge bin, four (4) belt feeders and four (4) reversible hammermill crushers each handling 365 tph. Coal from the new Crusher House to Unit 2 will be provided by dual 36" conveyors.

Silo fill for a **PC or Cyclone** Unit 2 will be accomplished thru a new transfer tower located adjacent to Unit 2. The new transfer tower will be provided with a new surge bin and two (2) belt feeders which will feed two (2) silo transfer cascade conveyors. Each silo transfer cascade conveyor will feed dual en-masse silo fill conveyors at the rate of 725 tons per hour. Silo fill for a **CFB** Unit 2 will be accomplished thru a new transfer tower located adjacent to Unit 2. The new transfer tower will be provided with a new surge bin and two (2) belt feeders which will feed two (2) silo tripper feed conveyors. Each silo tripper feed conveyor will be provided with dual pantleg trippers and will fill the silos at the rate of 725 tons per hour.

2.5 ALTERNATE FUEL HANDLING SYSTEM--For CFB or Cyclone Units ONLY (Flow Diagram CHFD010)

The head end of the existing alternate fuel handling conveyor will be relocated in order to provide the alternate fuel to either Unit 1 or new Unit 2. From the relocated conveyor head end the alternate fuel will be conveyed, via an en-masse conveyor, to each of the dual conveyors which feed the respective unit. A series of motorized r & p discharge gates will allow the alternate fuel to be discharged to the selected conveyor.

2.6 MISCELLANEOUS EQUIPMENT AND SYSTEMS

2.6.1 Coal Crushing

The Crusher House will receive coal from the Live Storage Silos (or from the reclaim system) and will be a totally enclosed structure. The Crusher House will contain a surge bin, variable speed belt feeders, crushers and motors and all necessary chutework and gates. Each crushing system will be capable of reducing the received coal to the required size [depending on the unit selection (PC, Cyclone or CFB)] at a rate of 550 or 725 tons per hour. The crushers and motors will be supported on an independent concrete pedestal.

2.6.2 Silo Fill System

Each Plant Feed Conveyor will transport coal to the surge bin located in the plant transfer tower. The surge bin will be provided with cut-off gates and two (2) variable speed belt feeders. Each belt feeder will be capable of feeding coal to one of two Tripper Conveyors at a rate of 550 or 725 tons per hour.

Each Tripper Conveyor will be provided with a traveling tripper to continuously fill Unit 1 and Unit 2 silos. Each tripper will be provided with a motorized gate, pantleg chute and floor seal system.

2.6.3 Dust Control System

Dust control for the new coal handling system will be a dry baghouse type collection system. The dust control systems will be provided to limit particulate emissions complying with all local, state and federal rules and regulations.

A baghouse type dust collector with walk-in clean air plenum, centrifugal fan, ductwork and dust return system will be provided at the following locations.

- Live Storage Silos & Reclaim System
- Crusher House
- Plant Transfer Tower and Silo Fill System

2.6.4 Service Air System

A service air system will be provided throughout the new coal handling system. Air piping complete with air hose connections will be provided at designated locations along all conveyors and throughout all enclosed structures. Air dryers will be provided at each dust collector if required. The service air system will come from the plant air system.

2.6.5 Vacuum Cleaning System

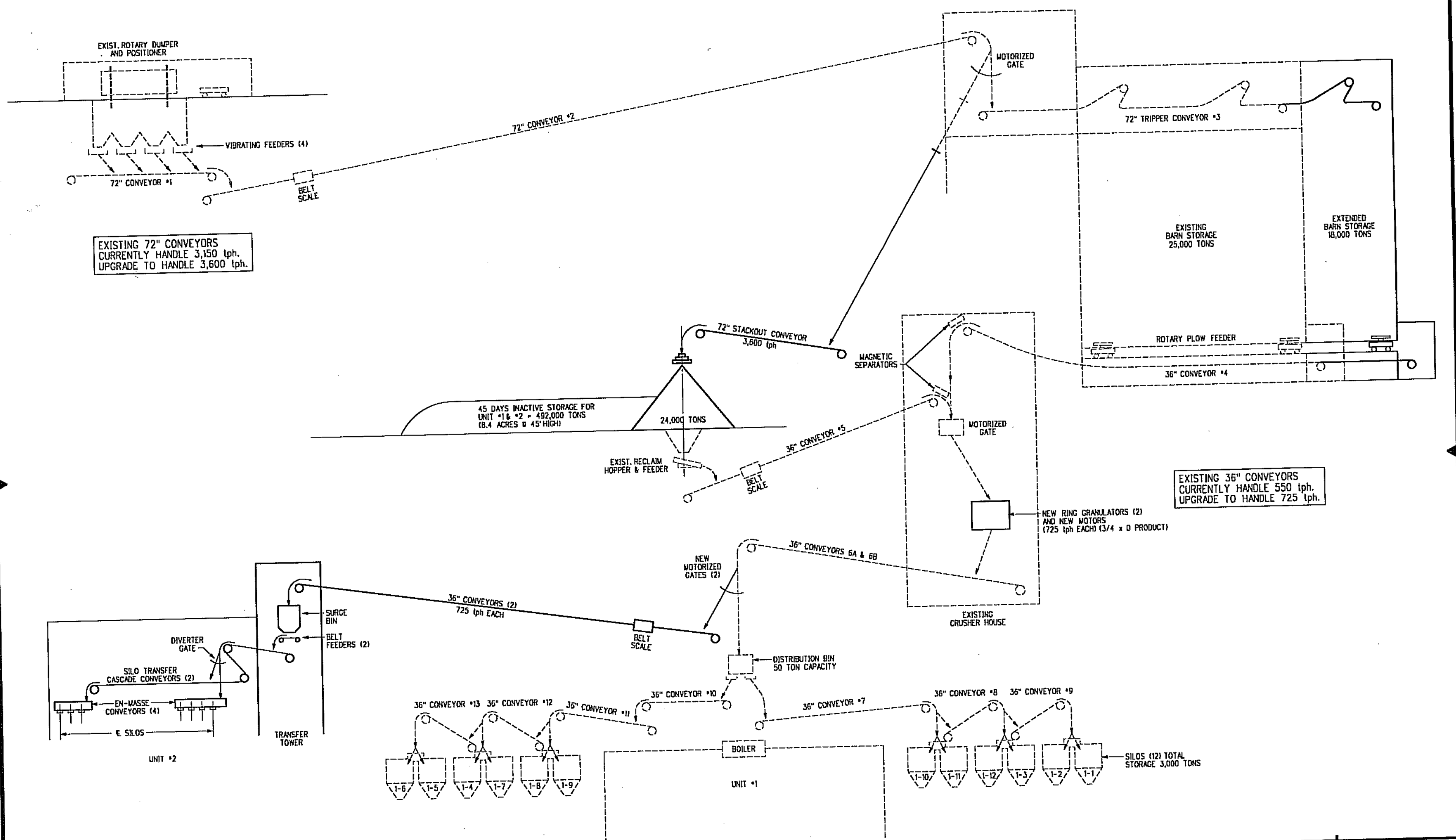
A vacuum cleaning system will be provided for all enclosed structures of the new coal handling system. Each system will consist of a centrally located header pipe with appropriate branch lines which will enable vacuum cleaning coverage with a 50 foot flexible hose at all areas. The header pipe will terminate outside each structure with an appropriate connection for a mobile vacuum truck.

2.6.6 Fire Protection System

An automatic dry pipe sprinkler type fire protection system will be provided for the new coal handling system. All systems will include piping and fittings, alarms, valves, sprinklers, fire hoses and cabinets and all necessary appertunances. All equipment, devices and accessories will be UL listed and FM approved and in accordance with NFPA guidelines.

2.6.7 Ventilation System

All new coal handling enclosed structures and substructures will be provided with ventilation systems.



no.	date	by	revision

Burns & McDonnell

date FEB. 11, 2004	detailed T.BOZARTH
designed G.SKIDMORE	checked

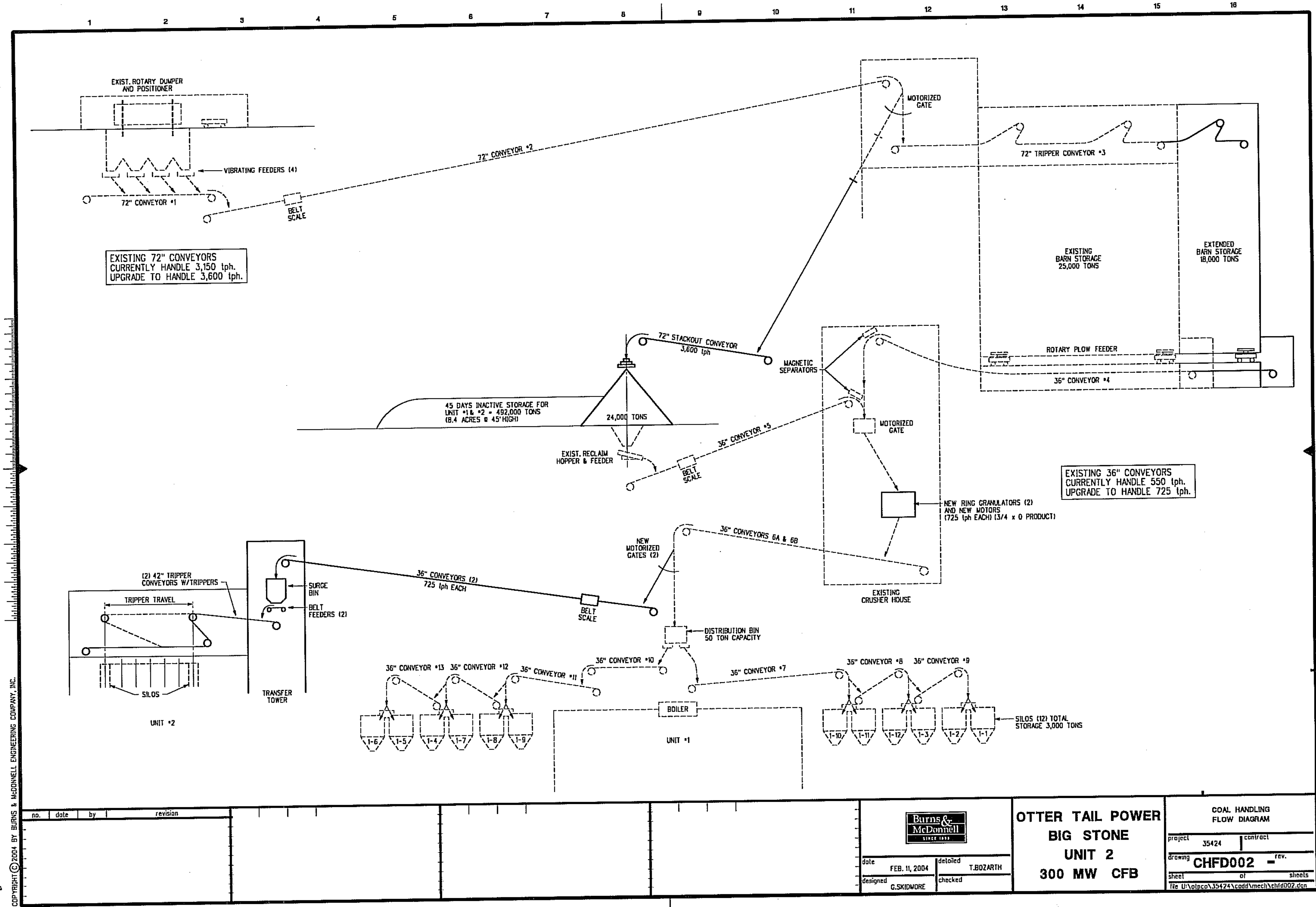
OTTER TAIL POWER
BIG STONE
UNIT 2
300 MW-PC

COAL HANDLING FLOW DIAGRAM

project 35424	contract
drawing CHFD001	rev. -
sheet	of sheets

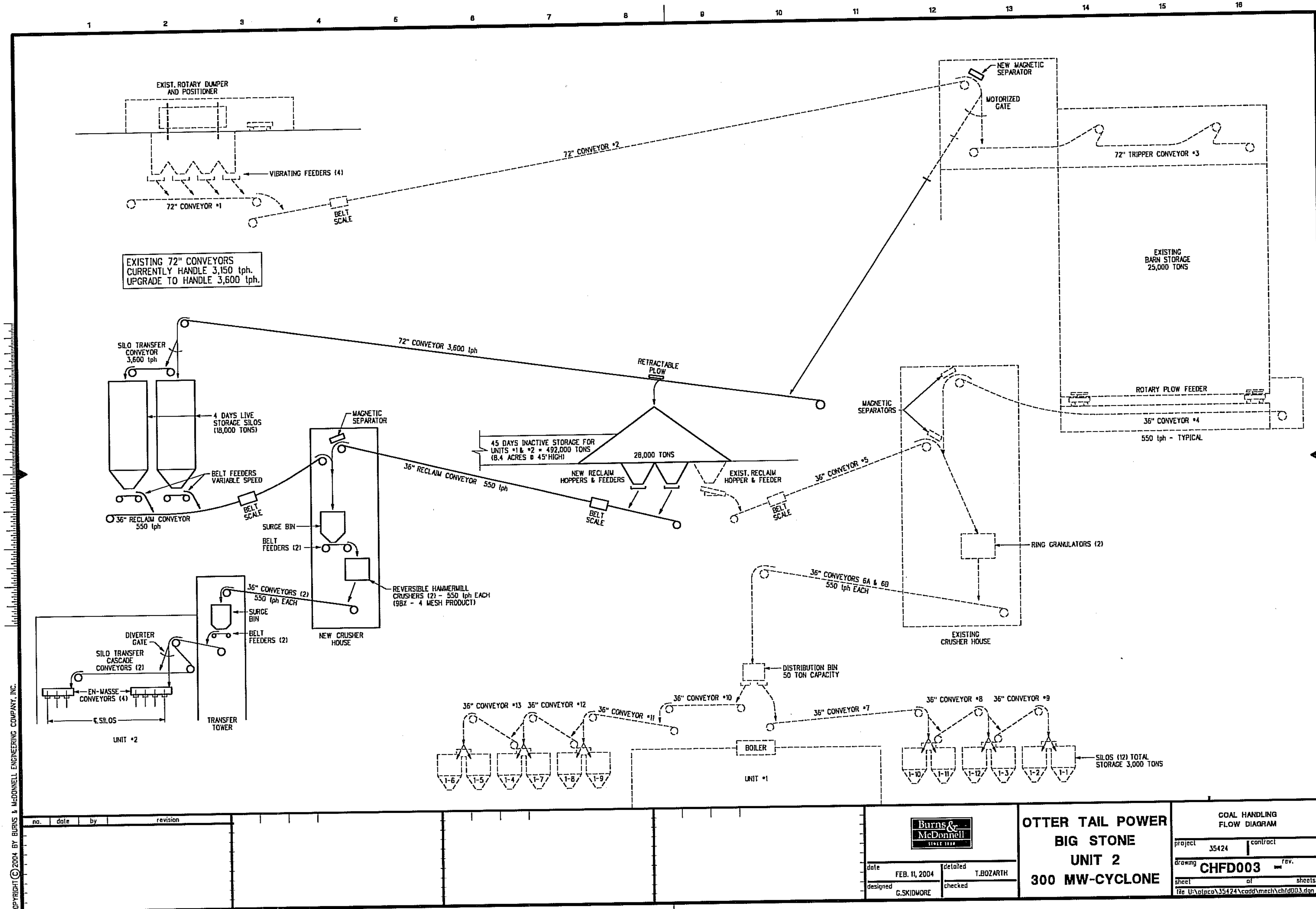
file U:\otpco\35424\cadd\mech\chfd001.dgn

1757

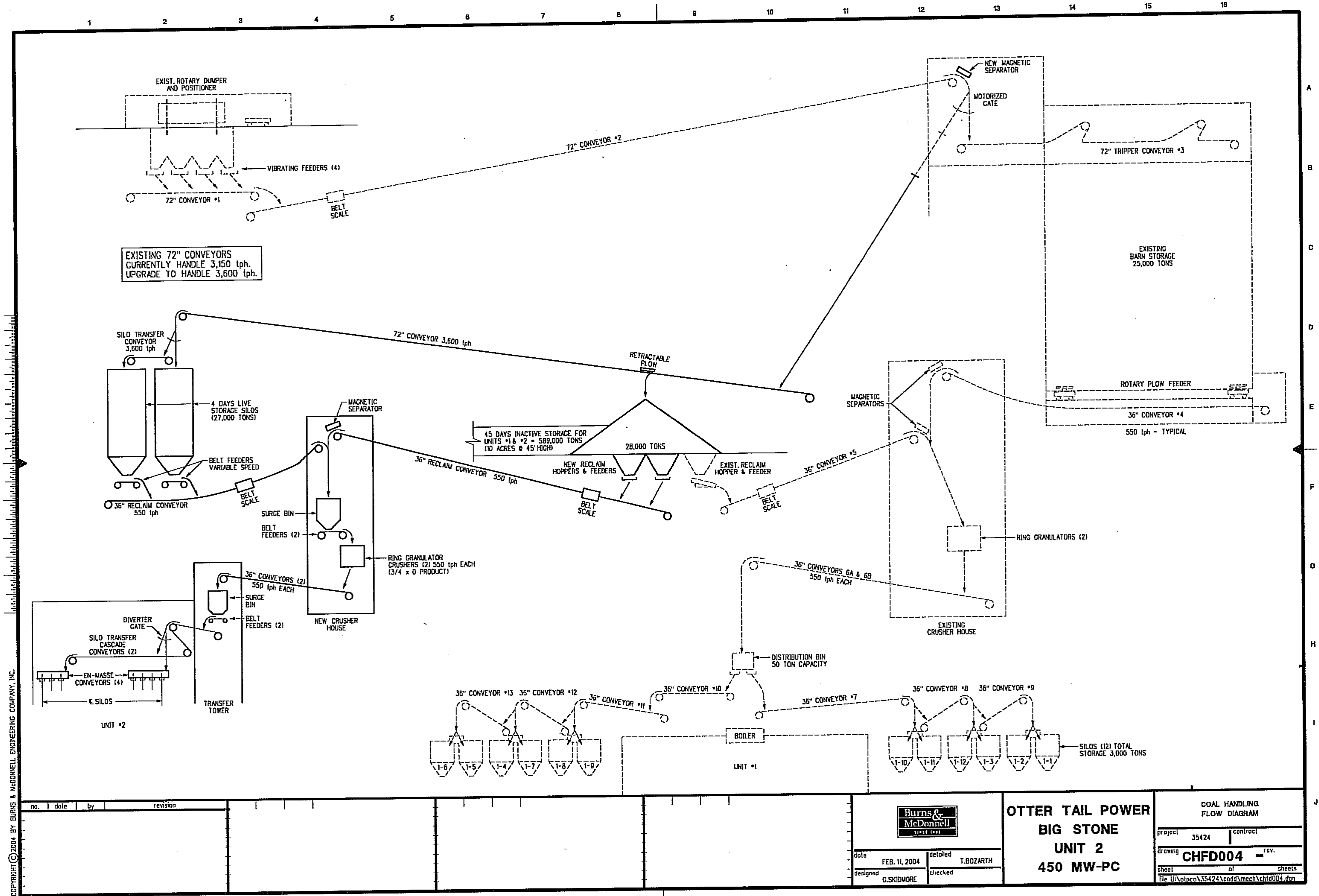


EXIST. ROTARY DUMPER AND POSITIONER
VIBRATING FEEDERS (4)
72" CONVEYOR #1
BELT SCALE
72" CONVEYOR #2
EXISTING 72" CONVEYORS CURRENTLY HANDLE 3,150 tph. UPGRADE TO HANDLE 3,600 tph.
MOTORIZED GATE
72" TRIPPER CONVEYOR #3
EXISTING BARN STORAGE 25,000 TONS
EXTENDED BARN STORAGE 18,000 TONS
ROTARY PLOW FEEDER
36" CONVEYOR #4
72" STACKOUT CONVEYOR 3,600 tph
MAGNETIC SEPARATORS
45 DAYS INACTIVE STORAGE FOR UNIT #1 & #2 = 492,000 TONS (8.4 ACRES @ 45' HIGH)
24,000 TONS
EXIST. RECLAIM HOPPER & FEEDER
36" CONVEYOR #5
BELT SCALE
MOTORIZED GATE
NEW RING GRANULATORS (2) AND NEW MOTORS (725 tph EACH) (3/4 x 0 PRODUCT)
EXISTING 36" CONVEYORS CURRENTLY HANDLE 550 tph. UPGRADE TO HANDLE 725 tph.
36" CONVEYORS 6A & 6B
EXISTING CRUSHER HOUSE
NEW MOTORIZED GATES (2)
(2) 42" TRIPPER CONVEYORS W/TRIPPERS
TRIPPER TRAVEL
SURGE BIN
BELT FEEDERS (2)
36" CONVEYORS (2) 725 tph EACH
BELT SCALE
DISTRIBUTION BIN 50 TON CAPACITY
SILOS
TRANSFER TOWER
UNIT #2
36" CONVEYOR #13
36" CONVEYOR #12
36" CONVEYOR #11
36" CONVEYOR #10
36" CONVEYOR #7
36" CONVEYOR #8
36" CONVEYOR #9
BOILER
UNIT #1
1-6
1-5
1-4
1-7
1-8
1-9
1-10
1-11
1-12
1-3
1-2
1-1
SILOS (12) TOTAL STORAGE 3,000 TONS
no.
date
by
revision
Burns & McDonnell SINCE 1898
date FEB. 11, 2004
detailed T.BOZARTH
designed G.SKIDMORE
checked
OTTER TAIL POWER
BIG STONE
UNIT 2
300 MW CFB
COAL HANDLING FLOW DIAGRAM
project 35424
contract
drawing CHFD002
rev. -
sheet
of
sheets
file U:\otpco\35424\cadd\mech\chfd002.dgn

1758

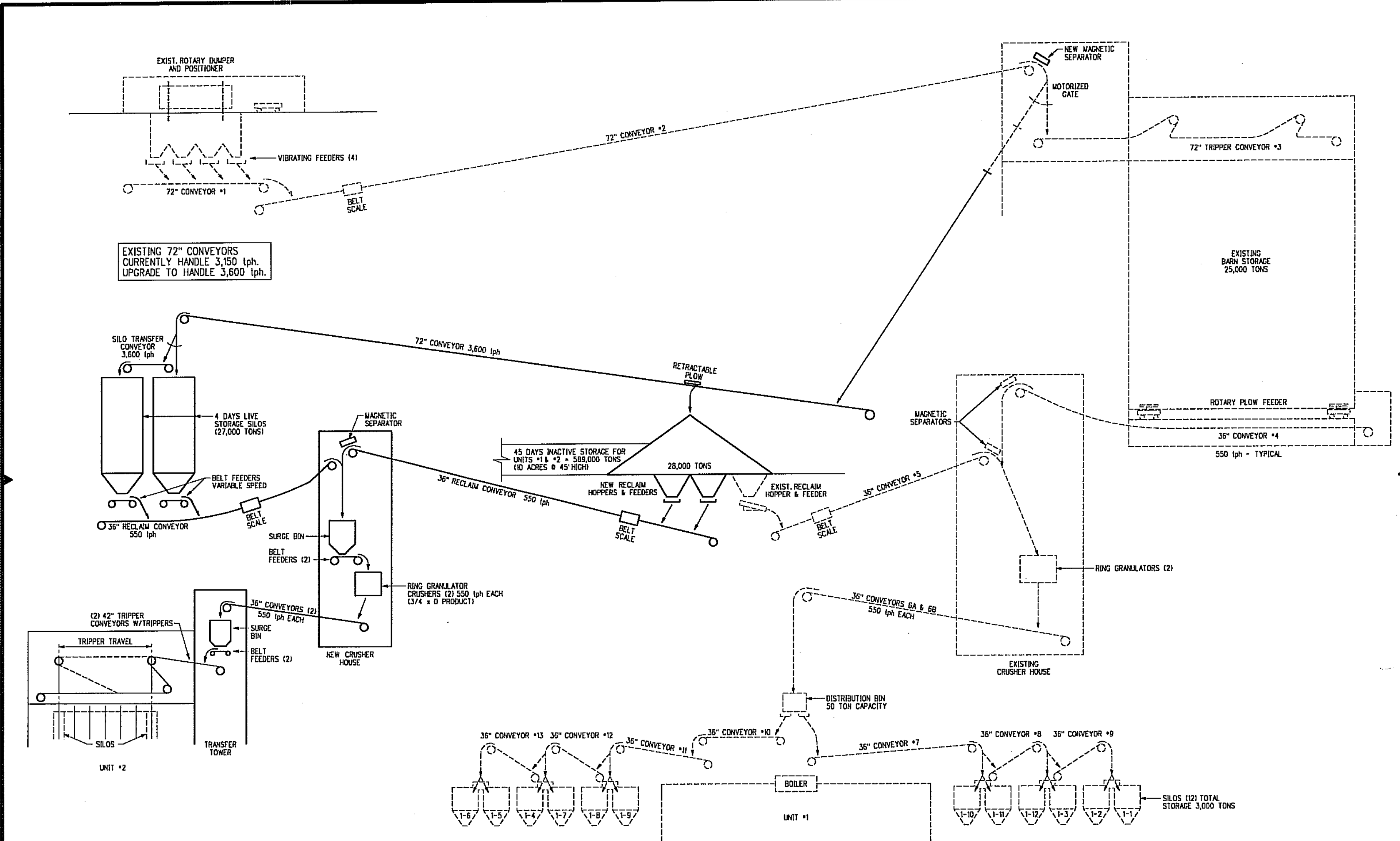

EXIST. ROTARY DUMPER AND POSITIONER
VIBRATING FEEDERS (4)
72" CONVEYOR #1
BELT SCALE
72" CONVEYOR #2
NEW MAGNETIC SEPARATOR
MOTORIZED GATE
72" TRIPPER CONVEYOR #3
EXISTING BARN STORAGE 25,000 TONS
ROTARY PLOW FEEDER
36" CONVEYOR #4
550 tph - TYPICAL
EXISTING 72" CONVEYORS CURRENTLY HANDLE 3,150 tph. UPGRADE TO HANDLE 3,600 tph.
SILO TRANSFER CONVEYOR 3,600 tph
72" CONVEYOR 3,600 tph
RETRACTABLE PLOW
4 DAYS LIVE STORAGE SILOS (18,000 TONS)
MAGNETIC SEPARATOR
45 DAYS INACTIVE STORAGE FOR UNITS #1 & #2 = 492,000 TONS (8.4 ACRES @ 45' HIGH)
28,000 TONS
NEW RECLAIM HOPPERS & FEEDERS
EXIST. RECLAIM HOPPER & FEEDER
MAGNETIC SEPARATORS
36" RECLAIM CONVEYOR 550 tph
BELT FEEDERS VARIABLE SPEED
36" RECLAIM CONVEYOR 550 tph
BELT SCALE
SURGE BIN
BELT FEEDERS (2)
36" CONVEYOR #5
RING GRANULATORS (2)
REVERSIBLE HAMMERMILL CRUSHERS (2) - 550 tph EACH (98% - 4 MESH PRODUCT)
36" CONVEYORS (2) 550 tph EACH
NEW CRUSHER HOUSE
36" CONVEYORS 6A & 6B 550 tph EACH
EXISTING CRUSHER HOUSE
SURGE BIN
BELT FEEDERS (2)
DIVERTER GATE
SILO TRANSFER CASCADE CONVEYORS (2)
EN-MASSE CONVEYORS (4)
℄ SILOS
UNIT #2
TRANSFER TOWER
DISTRIBUTION BIN 50 TON CAPACITY
36" CONVEYOR #13
36" CONVEYOR #12
36" CONVEYOR #11
36" CONVEYOR #10
36" CONVEYOR #7
36" CONVEYOR #8
36" CONVEYOR #9
BOILER
UNIT #1
1-6 1-5 1-4 1-7 1-8 1-9
1-10 1-11 1-12 1-3 1-2 1-1
SILOS (12) TOTAL STORAGE 3,000 TONS
no. date by revision
Burns & McDonnell SINCE 1898
date FEB. 11, 2004
detailed T.BOZARTH
designed G.SKIDMORE
checked
OTTER TAIL POWER
BIG STONE
UNIT 2
300 MW-CYCLONE
COAL HANDLING FLOW DIAGRAM
project 35424
contract
drawing CHFD003
rev.
sheet of sheets
file U:\otpco\35424\cadd\mech\chfd003.dgn

1759



EXIST. ROTARY DUMPER AND POSITIONER
VIBRATING FEEDERS (4)
72" CONVEYOR #1
BELT SCALE
72" CONVEYOR #2
NEW MAGNETIC SEPARATOR
MOTORIZED GATE
72" TRIPPER CONVEYOR #3
EXISTING BARN STORAGE 25,000 TONS
EXISTING 72" CONVEYORS
CURRENTLY HANDLE 3,150 tph.
UPGRADE TO HANDLE 3,600 tph.
SILO TRANSFER CONVEYOR 3,600 tph
72" CONVEYOR 3,600 tph
RETRACTABLE PLOW
4 DAYS LIVE STORAGE SILOS (27,000 TONS)
MAGNETIC SEPARATOR
45 DAYS INACTIVE STORAGE FOR UNITS #1 & #2 = 589,000 TONS (10 ACRES @ 45' HIGH)
28,000 TONS
NEW RECLAIM HOPPERS & FEEDERS
EXIST. RECLAIM HOPPER & FEEDER
BELT FEEDERS VARIABLE SPEED
36" RECLAIM CONVEYOR 550 tph
36" RECLAIM CONVEYOR 550 tph
SURGE BIN
BELT FEEDERS (2)
RING GRANULATOR CRUSHERS (2) 550 tph EACH (3/4 x 0 PRODUCT)
NEW CRUSHER HOUSE
36" CONVEYORS (2) 550 tph EACH
SURGE BIN
BELT FEEDERS (2)
TRANSFER TOWER
DIVERTER GATE
SILO TRANSFER CASCADE CONVEYORS (2)
EN-MASSE CONVEYORS (4)
℄ SILOS
UNIT #2
ROTARY PLOW FEEDER
36" CONVEYOR #4
550 tph - TYPICAL
MAGNETIC SEPARATORS
36" CONVEYOR #5
RING GRANULATORS (2)
36" CONVEYORS 6A & 6B 550 tph EACH
EXISTING CRUSHER HOUSE
DISTRIBUTION BIN 50 TON CAPACITY
36" CONVEYOR #13
36" CONVEYOR #12
36" CONVEYOR #11
36" CONVEYOR #10
36" CONVEYOR #7
36" CONVEYOR #8
36" CONVEYOR #9
BOILER
UNIT #1
1-6 1-5 1-4 1-7 1-8 1-9
1-10 1-11 1-12 1-3 1-2 1-1
SILOS (12) TOTAL STORAGE 3,000 TONS
no. date by revision
Burns & McDonnell SINCE 1898
date FEB. 11, 2004
detailed T.BOZARTH
designed G.SKIDMORE
checked
OTTER TAIL POWER
BIG STONE
UNIT 2
450 MW-PC
COAL HANDLING FLOW DIAGRAM
project 35424
contract
drawing CHFD004
rev. -
sheet of sheets
file U:\otpco\35424\codd\mech\chfd004.dgn
COPYRIGHT © 2004 BY BURNS & McDONNELL ENGINEERING COMPANY, INC.

1760



no.	date	by	revision

Burns & McDonnell

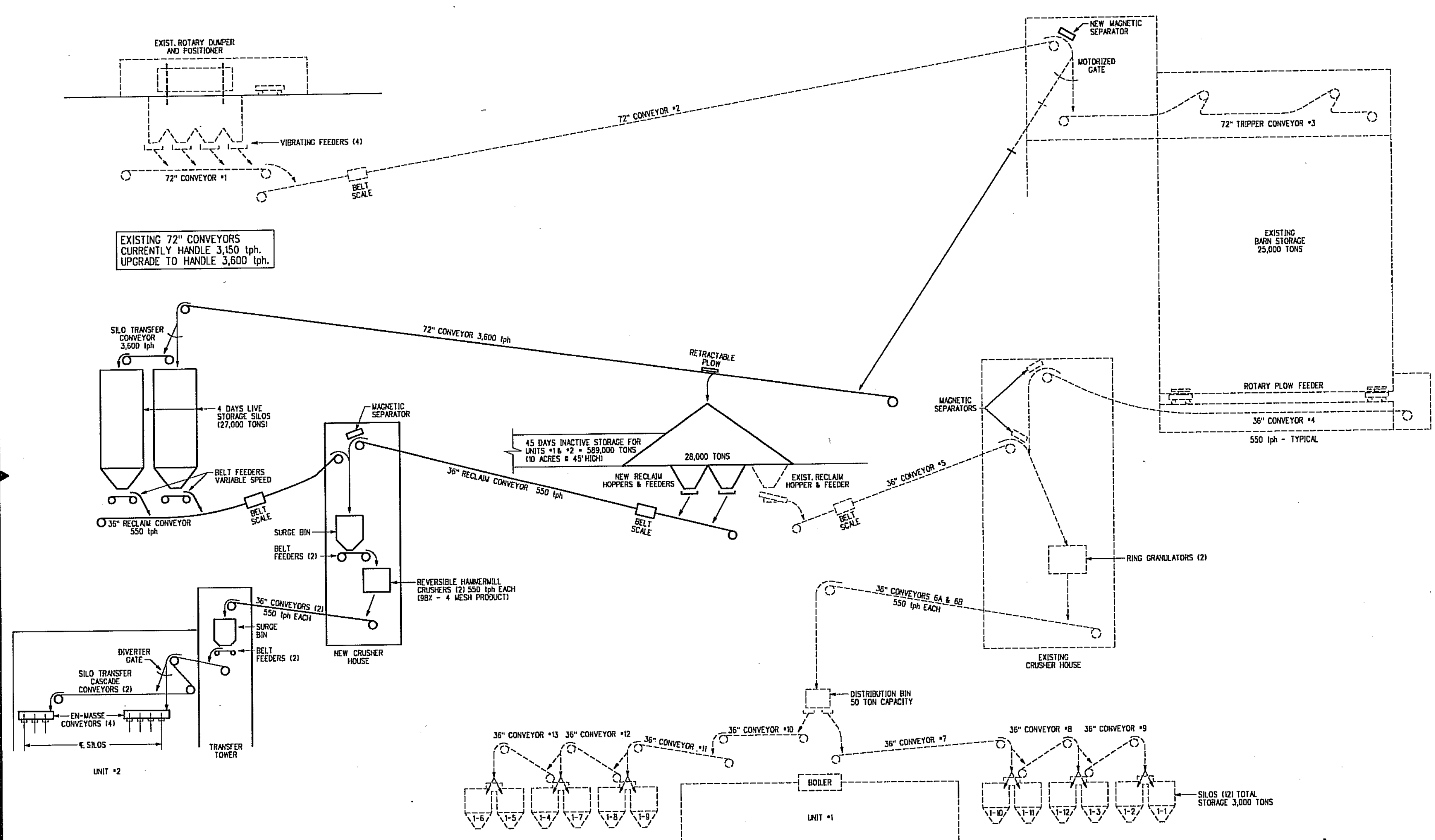
OTTER TAIL POWER
BIG STONE
UNIT 2
450 MW CFB

COAL HANDLING FLOW DIAGRAM

date	FEB. 11, 2004
detailed	T.BOZARTH
designed	G.SKIDMORE
checked	
project	35424
contract	
drawing	CHFD005
rev.	-
sheet	of sheets

file U:\otpco\35424\cadd\mech\chfd005.dgn

1761



no.	date	by	revision

Burns & McDonnell

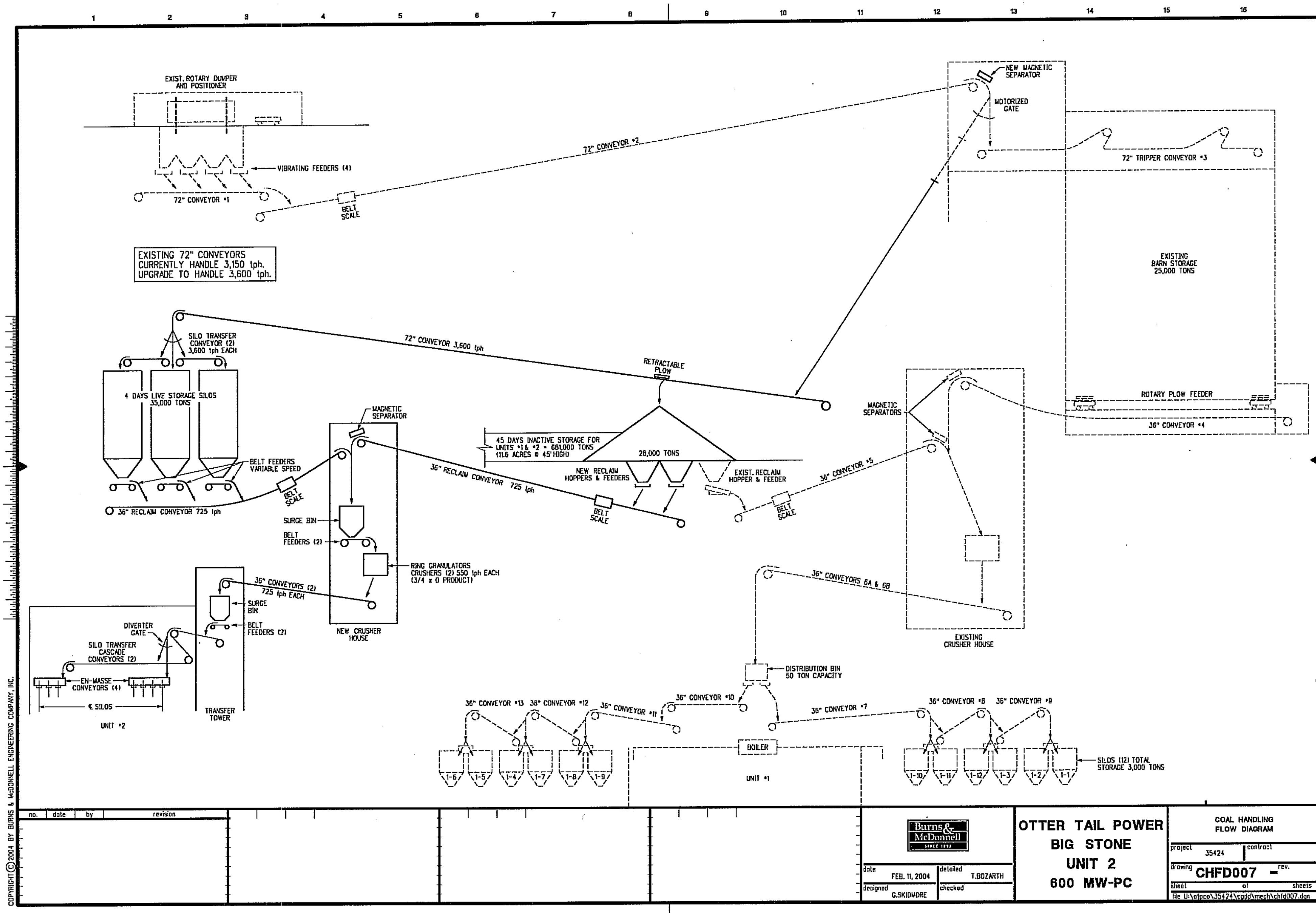
date FEB. 11, 2004	detailed T.BOZARTH
designed G.SKIDMORE	checked

OTTER TAIL POWER
BIG STONE
UNIT 2
450 MW CYCLONE

COAL HANDLING FLOW DIAGRAM

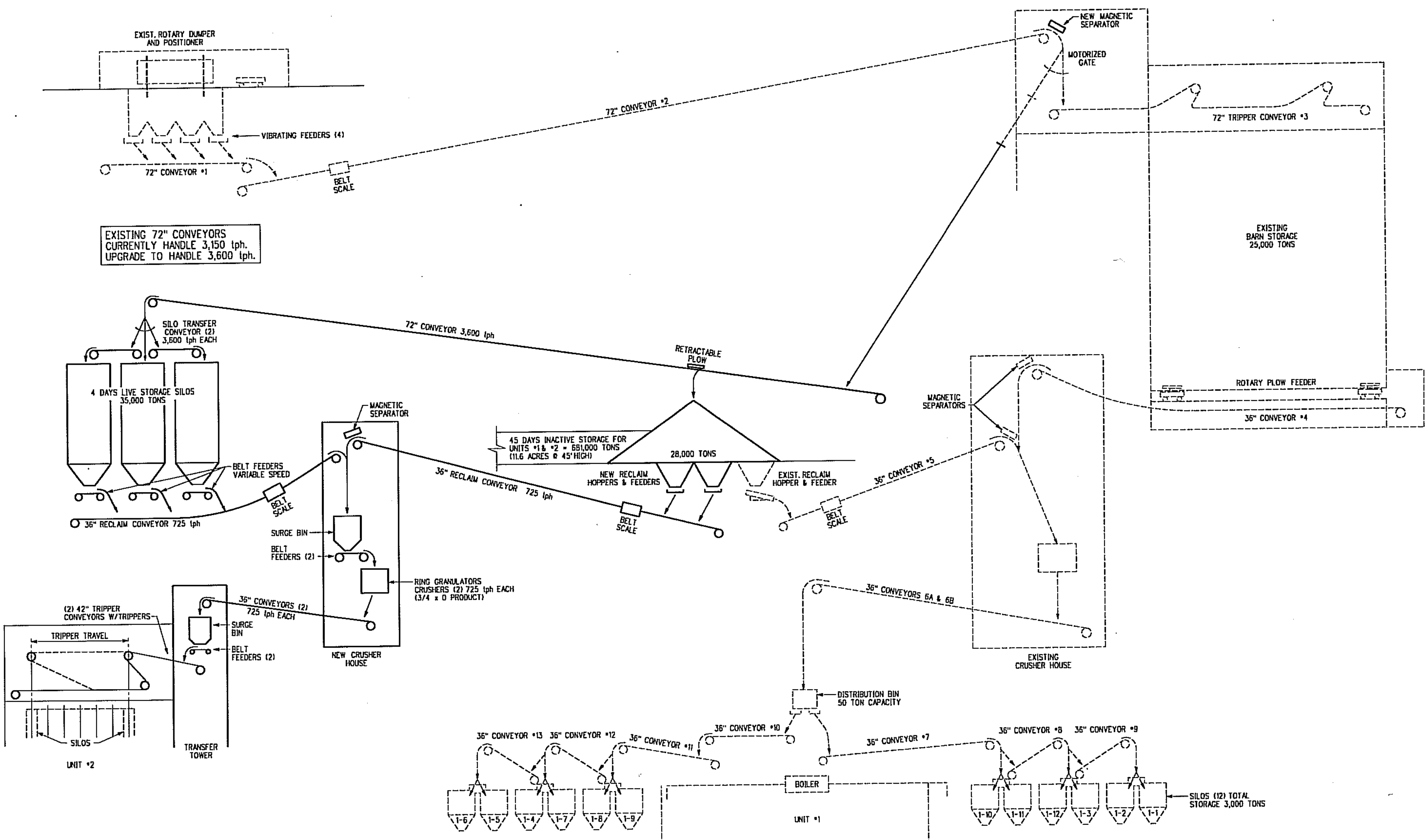
project 35424 | contract
drawing CHFD006 | rev. -
sheet | of | sheets
file U:\otpco\35424\cadd\mech\chfd006.dgn

1762



EXIST. ROTARY DUMPER AND POSITIONER
VIBRATING FEEDERS (4)
72" CONVEYOR #1
BELT SCALE
72" CONVEYOR #2
NEW MAGNETIC SEPARATOR
MOTORIZED GATE
72" TRIPPER CONVEYOR #3
EXISTING BARN STORAGE 25,000 TONS
ROTARY PLOW FEEDER
36" CONVEYOR #4
EXISTING 72" CONVEYORS CURRENTLY HANDLE 3,150 tph. UPGRADE TO HANDLE 3,600 tph.
SILO TRANSFER CONVEYOR (2) 3,600 tph EACH
72" CONVEYOR 3,600 tph
RETRACTABLE PLOW
4 DAYS LIVE STORAGE SILOS 35,000 TONS
BELT FEEDERS VARIABLE SPEED
36" RECLAIM CONVEYOR 725 tph
MAGNETIC SEPARATOR
45 DAYS INACTIVE STORAGE FOR UNITS #1 & #2 = 681,000 TONS (11.6 ACRES @ 45' HIGH)
28,000 TONS
NEW RECLAIM HOPPERS & FEEDERS
EXIST. RECLAIM HOPPER & FEEDER
36" RECLAIM CONVEYOR 725 tph
36" CONVEYOR #5
MAGNETIC SEPARATORS
SURGE BIN
BELT FEEDERS (2)
RING GRANULATORS CRUSHERS (2) 550 tph EACH (3/4 x 0 PRODUCT)
36" CONVEYORS (2) 725 tph EACH
NEW CRUSHER HOUSE
36" CONVEYORS 6A & 6B
EXISTING CRUSHER HOUSE
DIVERTER GATE
SILO TRANSFER CASCADE CONVEYORS (2)
EN-MASSE CONVEYORS (4)
℄ SILOS
UNIT #2
TRANSFER TOWER
DISTRIBUTION BIN 50 TON CAPACITY
36" CONVEYOR #13
36" CONVEYOR #12
36" CONVEYOR #11
36" CONVEYOR #10
36" CONVEYOR #7
36" CONVEYOR #8
36" CONVEYOR #9
BOILER
UNIT #1
SILOS (12) TOTAL STORAGE 3,000 TONS
1-6 1-5 1-4 1-7 1-8 1-9 1-10 1-11 1-12 1-3 1-2 1-1
no. date by revision
Burns & McDonnell
date FEB. 11, 2004
detailed T.BOZARTH
designed G.SKIDMORE
checked
OTTER TAIL POWER
BIG STONE
UNIT 2
600 MW-PC
COAL HANDLING FLOW DIAGRAM
project 35424
contract
drawing CHFD007
rev. -
sheet of sheets
file U:\otpco\35424\cgdd\mech\chfd007.dgn

1763



no.	date	by	revision

Burns & McDonnell

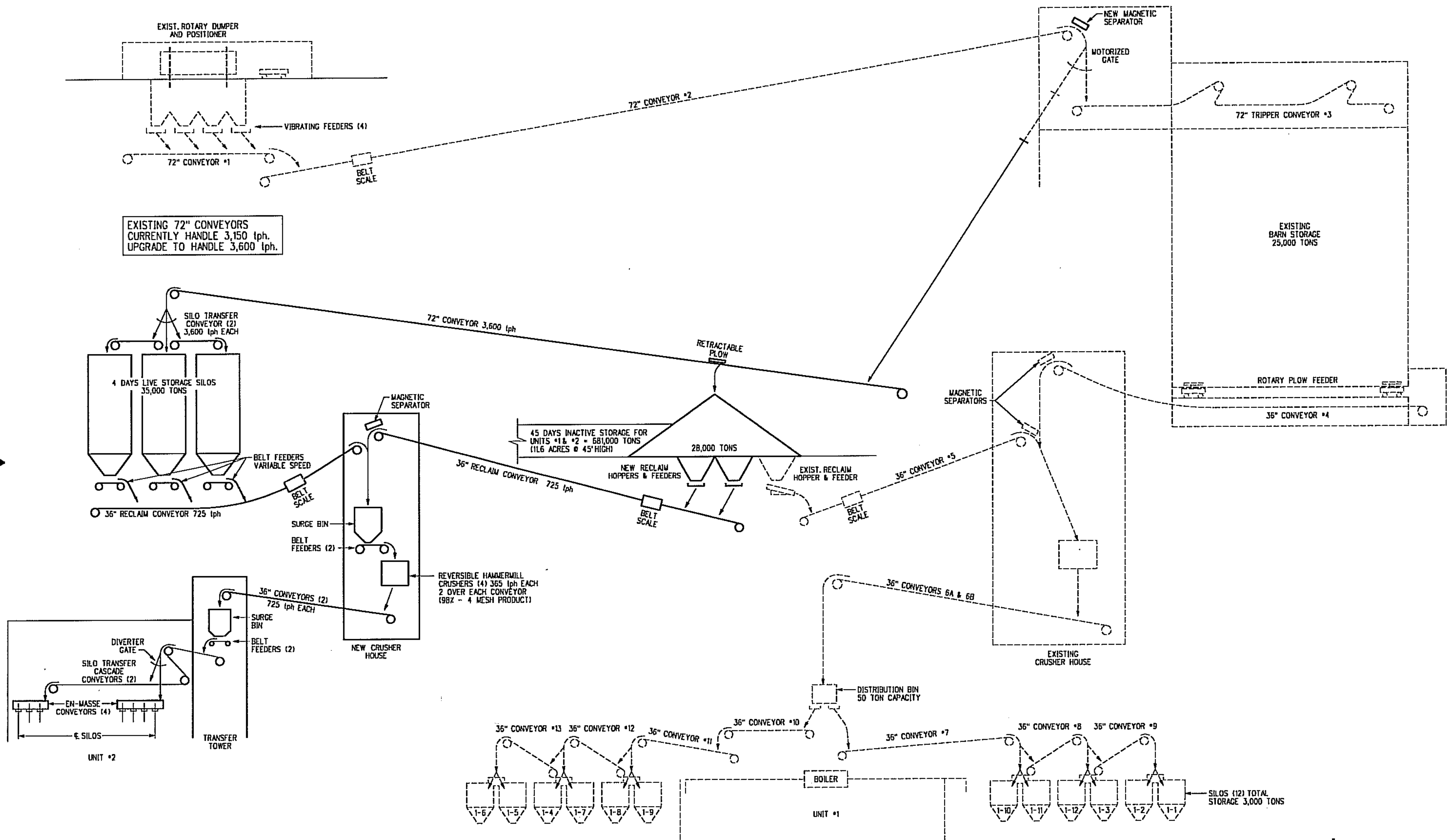
date FEB. 11, 2004 | detailed T.BOZARTH
designed G.SKIDMORE | checked

OTTER TAIL POWER
BIG STONE
UNIT 2
600 MW CFB

COAL HANDLING FLOW DIAGRAM

project 35424 | contract
drawing CHFD008 | rev. -
sheet of sheets
file U:\otpco\35424\cadd\mech\chfd008.dgn

1764



no.	date	by	revision

Burns & McDonnell SINCE 1898

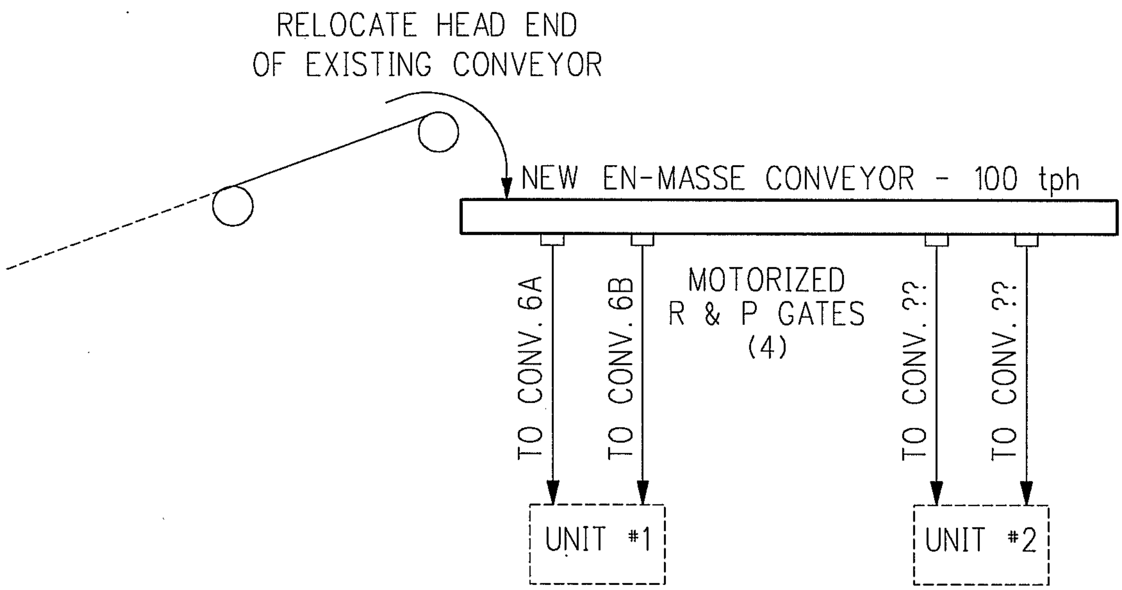
date FEB. 11, 2004 | detailed T.BOZARTH
designed G.SKIDMORE | checked

OTTER TAIL POWER
BIG STONE
UNIT 2
600 MW CYCLONE

COAL HANDLING FLOW DIAGRAM

project 35424 | contract
drawing CHFD009 | rev. –
sheet of sheets
file U:\otpco\35424\cadd\mech\chfd009.dgn

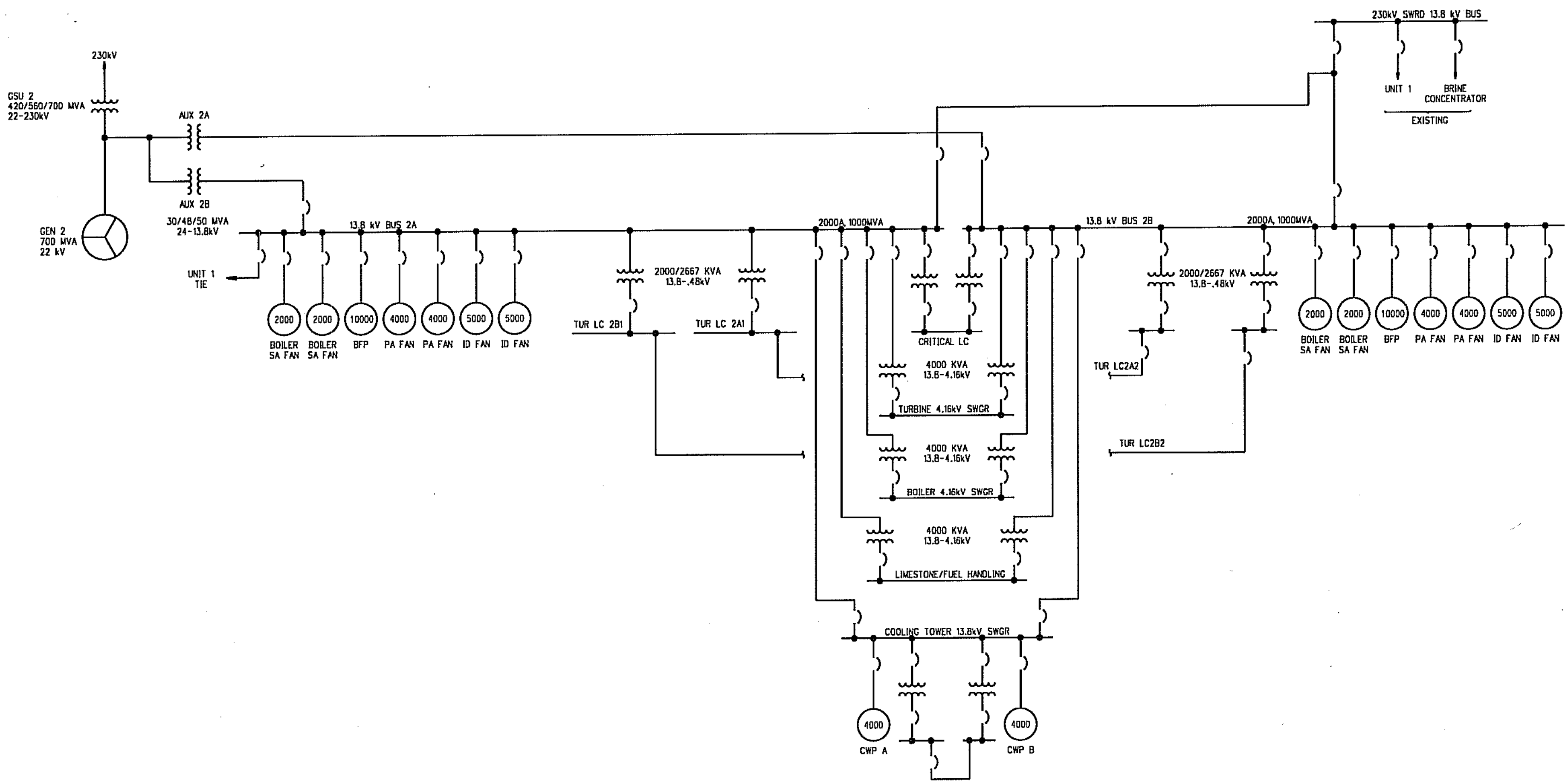
Scale For Microfilming Inches Millimeters



ALTERNATE FUEL HANDLING FOR: 300 MW CYCLONE
450 MW CYCLONE OR CFB
600 MW CYCLONE OR CFB

Burns & McDonnell SINCE 1898	OTTER TAIL POWER BIG STONE UNIT 2 ALTERNATE FUEL HANDLING FLOW DIAGRAM	project 35424
date FEB. 17, 2004		contract
designed G.SKIDMORE		dwg. no. CHFD010 rev. –

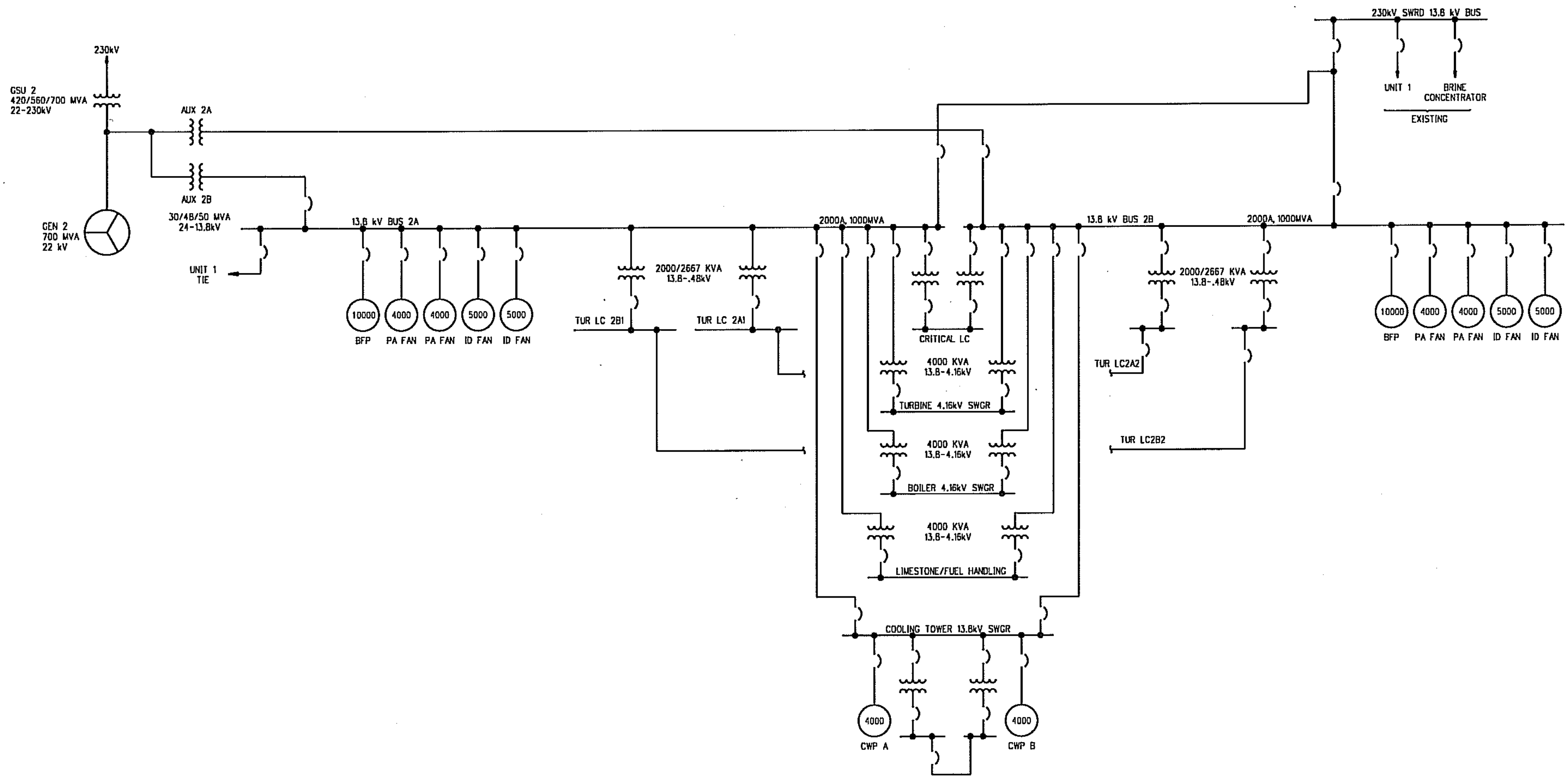
1766



Burns & McDonnell SINCE 1898	OTTERTAIL POWER COMPANY	project 35424	
date MAR. 26, 2004	ELECTRICAL ONE-LINE	contract	
designed D. STEPHENS	600MW CFB	SK-E01	

SK-E01.DGN / 4-12-2004 16:39 / VLV

1767



1768

Burns & McDonnell
SINCE 1898

date MAR. 26, 2004
designed D. STEPHENS

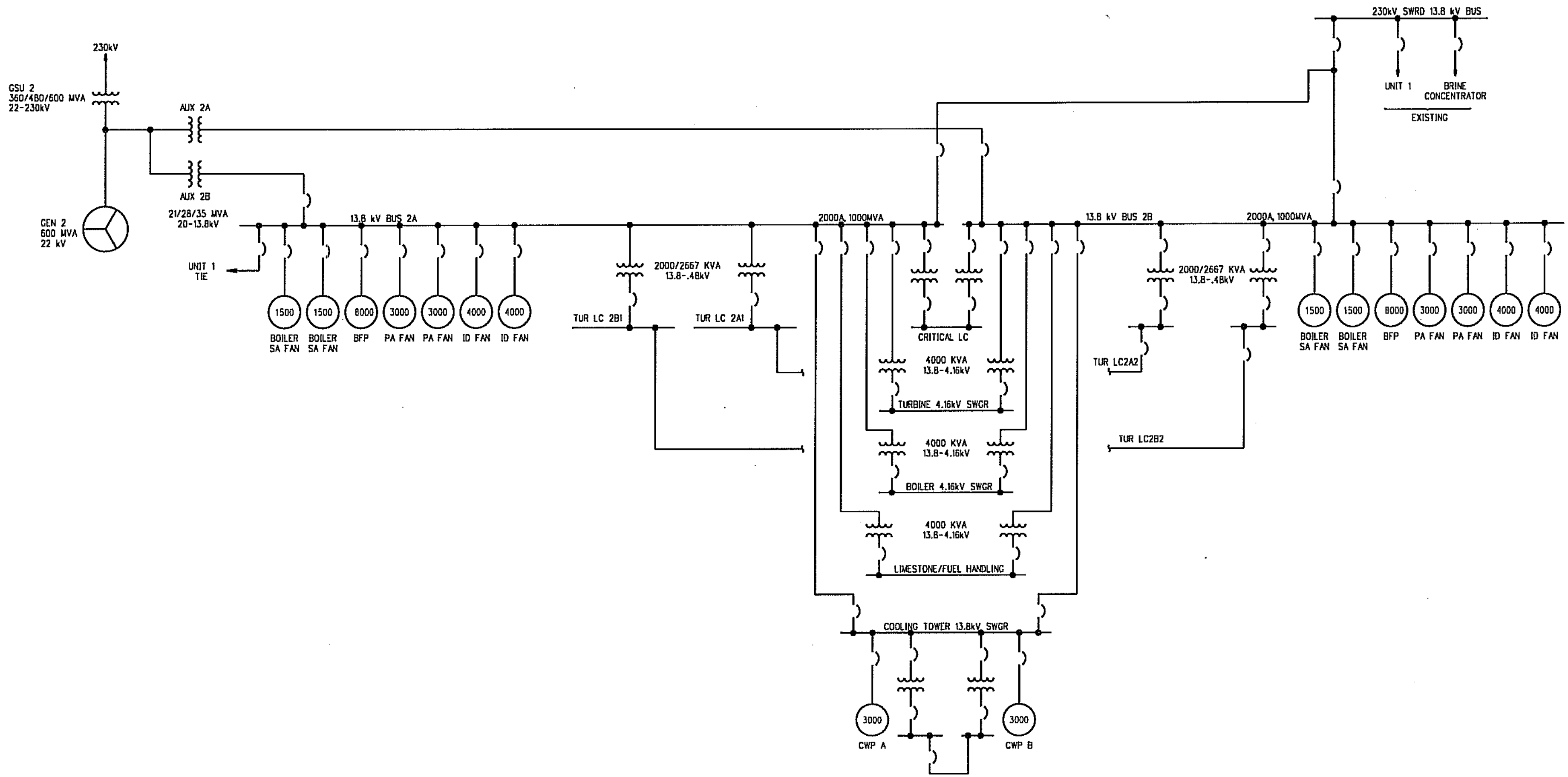
OTTERTAIL
POWER COMPANY

ELECTRICAL ONE-LINE
600MW PC

project 35424
contract

SK-E02

SK-E02.DGN / 4-12-2004 16:42 / VLV



1769

Burns & McDonnell
SINCE 1898

date MAR. 26, 2004
designed D. STEPHENS

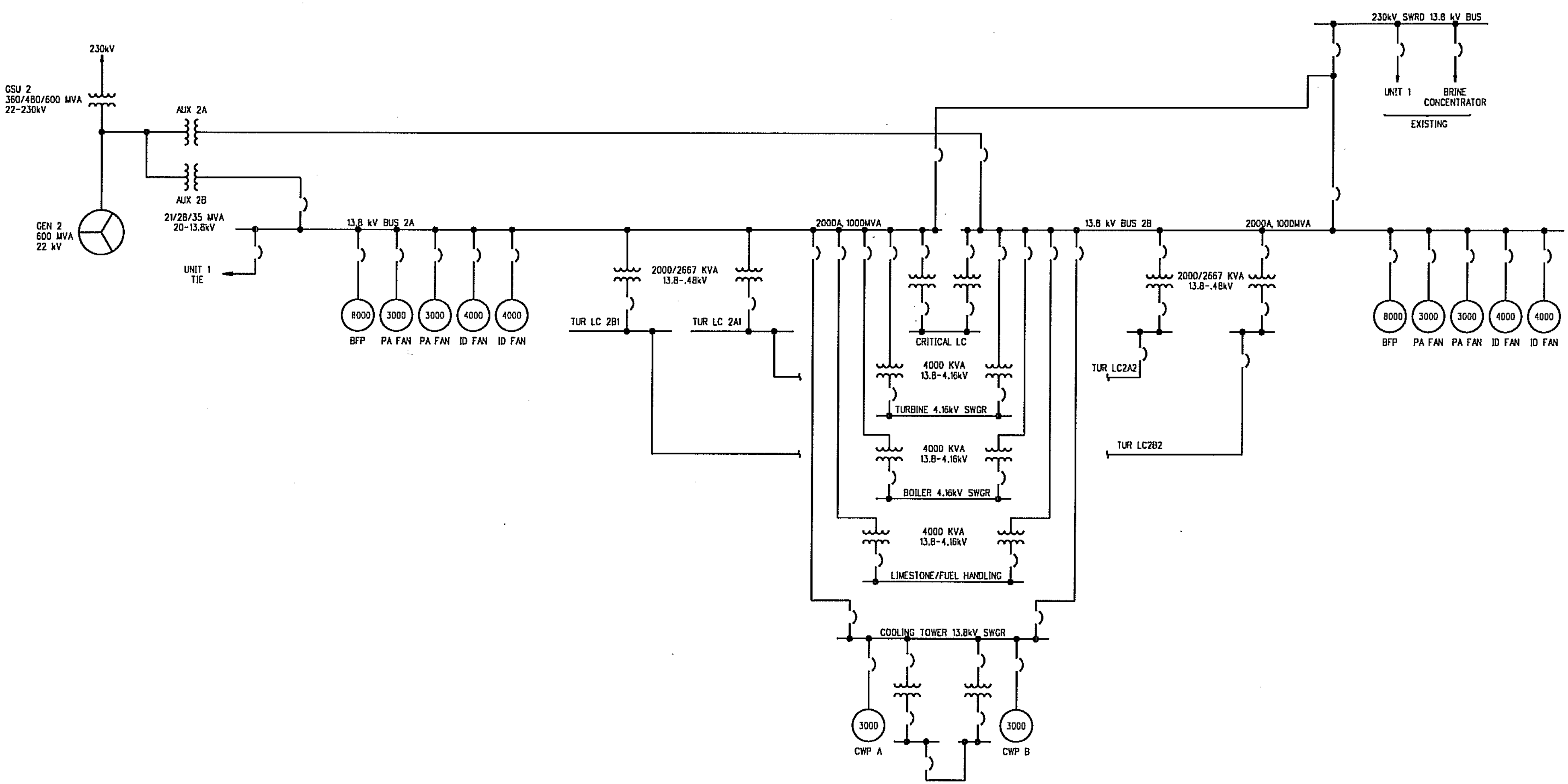
OTTER TAIL
POWER COMPANY

ELECTRICAL ONE-LINE
450MW CFB

project 35424
contract

SK-E03

SK-E03.DGN / 4-12-2004 16:41 / VLV



1770

Burns & McDonnell SINCE 1898

date MAR. 26, 2004

designed D. STEPHENS

OTTERTAIL POWER COMPANY

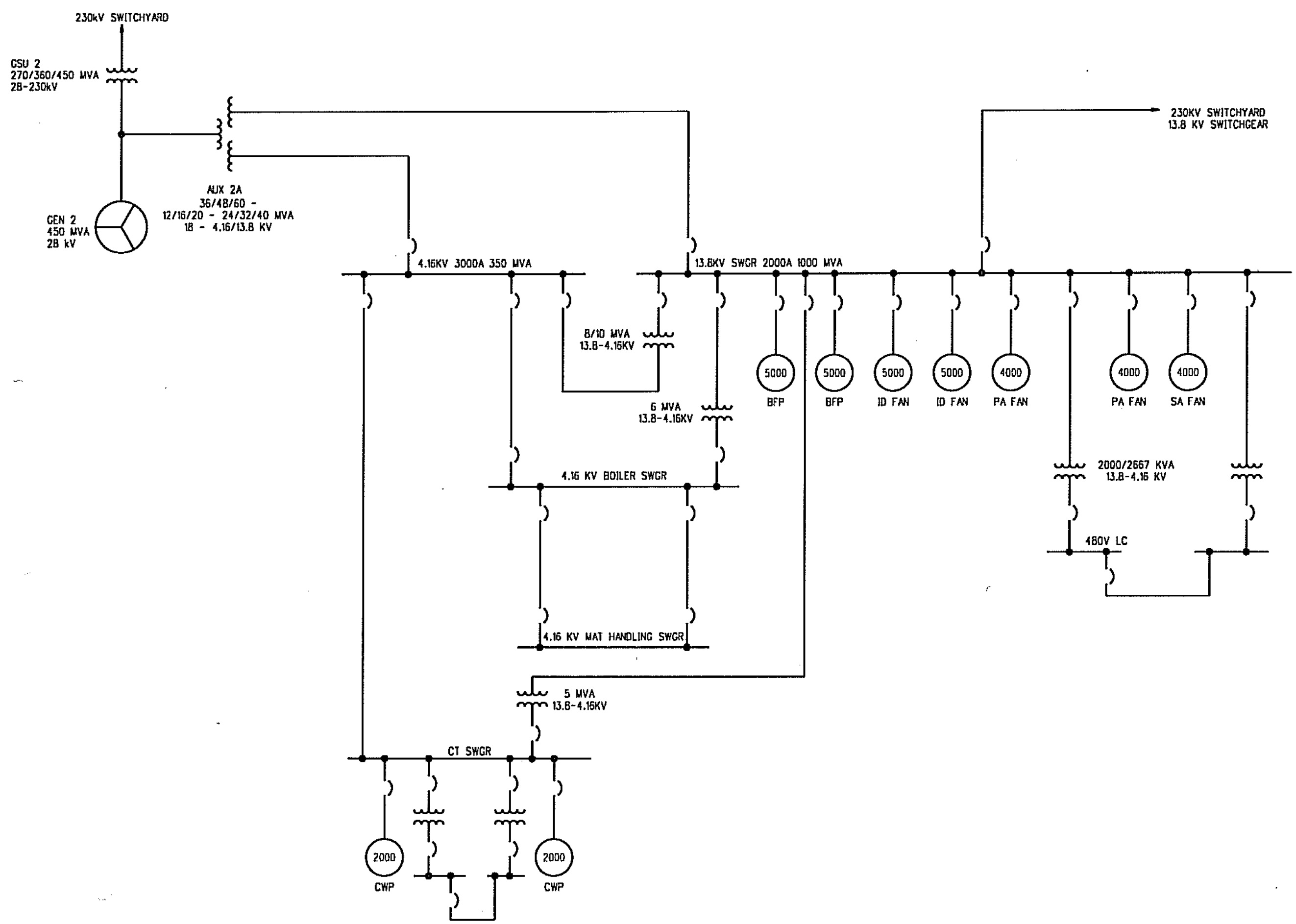
ELECTRICAL ONE-LINE
450MW CFB

project 35424

contract

SK-E04

SK-E04.DGN / 4-12-2004 16:43 / VLV



1771

Burns & McDonnell
SINCE 1898

date MAR. 26, 2004
designed D. STEPHENS

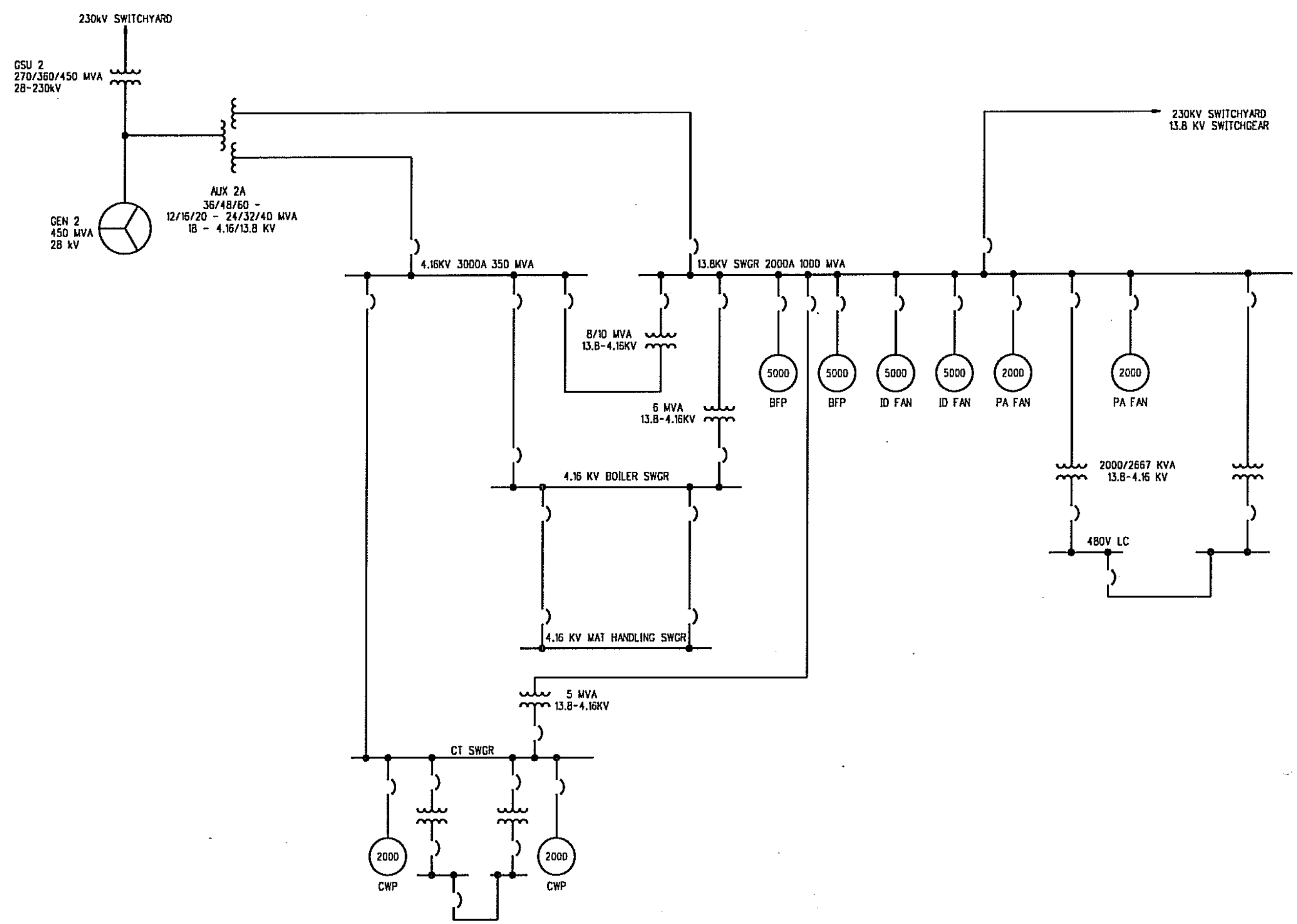
OTTERTAIL POWER COMPANY

ELECTRICAL ONE-LINE
300MW CFB

project 35424
contract

SK-E05

SK-E05.DGN / 4-12-2004 16:44 / VLV



1773

Burns & McDonnell SINCE 1898

date MAR. 26, 2004
designed D. STEPHENS

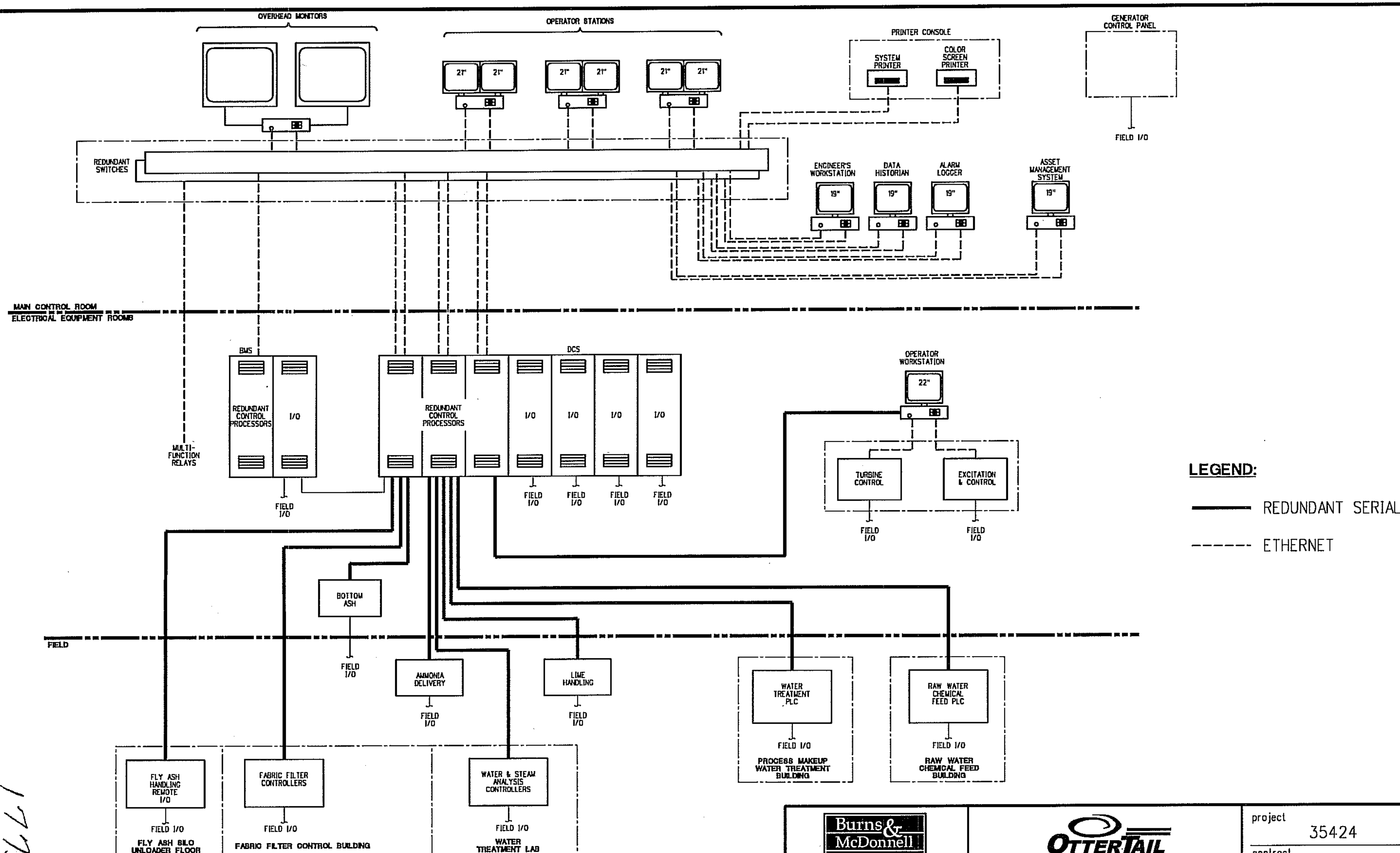
OTTERTAIL POWER COMPANY

ELECTRICAL ONE-LINE
300MW PC

project 35424
contract

SK-E06

SK-E06.DGN / 4-12-2004 16:59 / VLV



Burns & McDonnell SINCE 1898

OTTER TAIL POWER COMPANY

date APR. 12, 2004
designed P. TOIGO

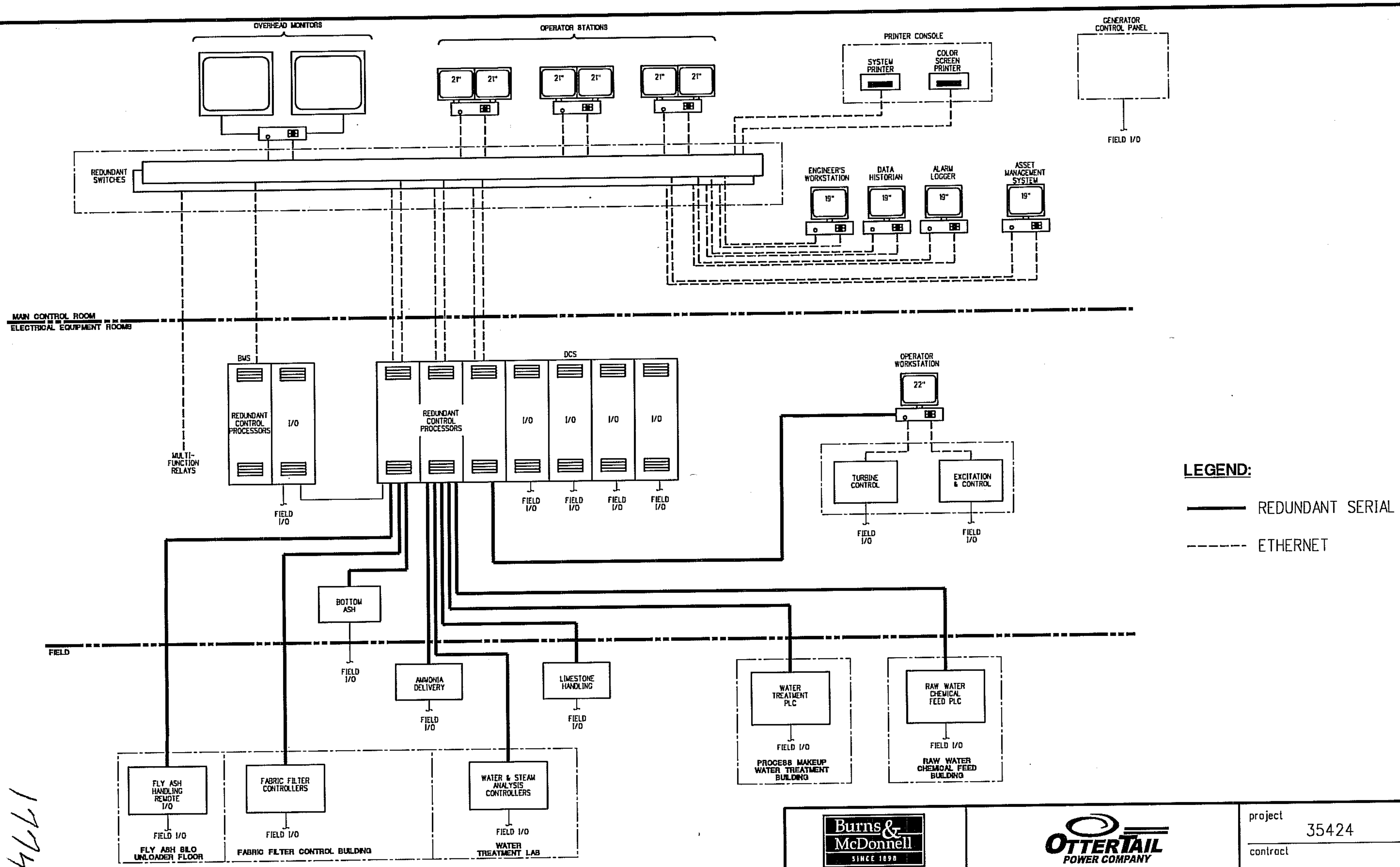
CONTROL SYSTEM
ARCHITECTURE - 600MW PC

project 35424
contract

SK-CA01

SK-CA01.DGN / 4-14-2004 8:40 / VLV

1773



Burns & McDonnell SINCE 1898

OTTERTAIL POWER COMPANY

date APR. 12, 2004	CONTROL SYSTEM ARCHITECTURE - 600MW CFB	project 35424
designed P. TOIGO		contract
		SK-CA02

SK-CA02.DGN / 4-14-2004 8:45 / VLV

1.0 INTRODUCTION

The purpose of this narrative is to identify contracting alternatives that could be used for a utility's proposed new generation project and to describe the advantages and disadvantages of each alternative.

SUMMARY

Contracting alternatives can be divided into three basic types:

- The multiple contract approach, where the Owner hires the engineer, purchases equipment directly, and hires one or more contractors to perform the construction as a separate contract.
- The Engineer, Procure, Construct (EPC) approach (sometimes called design-build or turnkey) where the Owner hires a single firm or group to provide engineering, procurement, and construction for the entire project.
- A variation of the aforementioned approaches, a "hybrid" approach, where the major equipment (boiler and air pollution control, turbine) is contracted in a furnish and erect package, with associated cost, performance and schedule guarantees. The remaining balance of plant would be performed on a multiple contract basis.

This narrative will discuss the three broad categories of contracting alternatives (Multiple Contract, EPC, and Hybrid), discuss the variations available within these broad categories and the advantages and disadvantages of each. The advantages and disadvantages of these approaches in general relate to the Owner's desire for control of the project (including such things as design and equipment selection) versus the Owner's desire to minimize risk associated with the project.

The multiple contract approach typically provides the Owner with more control over the design of the project, increased control over the quality of selected equipment and materials, more ability to make changes as the project evolves, and more ability to dictate the type of documentation provided by the designer and equipment suppliers. Equipment is purchased directly from the suppliers, eliminating contractor markups. The multiple contract approach also potentially reduces project cost by minimizing the amount of subcontracting by construction prime contractors, thereby reducing markups. All packages are competitively bid, thereby increasing competition and minimizing overall cost. Contracts are broken up into sizes that provide for more competition than a full plant EPC Contract.

In return for these benefits, the Owner accepts more risk associated with the procurement and construction stage of a power project, including escalation, equipment delivery, volatility of material costs, unit performance coordination, construction coordination, schedule creep, and other risks that an EPC contractor would encounter.

The primary benefits of EPC contracting are the ability of the Owner to obtain a lump sum price for the project based on the scope of work outlined in the original EPC contract, guarantees on overall plant performance, cost, and completion schedule. These guarantees shift the Owner's risks associated with the construction stage of a power project to the EPC contractor. The EPC contractor charges a fee to accept and manage those risks, which will cause EPC contracting to be more costly than multiple contract approaches.

The hybrid approach brings together the best features of the EPC and Multiple contracting arrangements, minimizing Owner risk, while providing Owner input on key areas of the plant. The largest risk on a coal-fired project is in the boiler island and air pollution control equipment from a cost, schedule, and performance standpoint. This scenario allows the Owner to single source responsibility for the most risky portion of the project and allow about 65-70% of the project cost to be firm price contracted at the same time a project would be awarding an EPC Contract. The remaining scope would be performed on a multiple contract basis. This scope is limited in terms of risk, and is the type of work on which historically the Owner wants to provide the most input. The Balance of Plant (BOP) multiple contract approach allows the Owner the most flexibility and input from management, permitting, operations, maintenance, and engineering.

The best choice for a given project is the approach that best fits the project Owner's experience, existing staffing, risk management style, project schedule and financing restrictions for the specific project.

2.0 NARRATIVE DESCRIPTION

The narrative consists of two primary sections. The first section describes various approaches and the advantages and disadvantages of each. The second section identifies key issues to be used in evaluating the contracting alternatives for the Big Stone Unit II project, and discusses how each alternative meets that issue.

2.1 MULTIPLE CONTRACT APPROACH

In the multiple contract approach, the Owner hires the engineer, purchases equipment directly, and hires one or more contractors to perform the construction under a separate contract or contracts. In most cases, there are multiple construction contracts that are bid and awarded on a lump sum basis. The contracts are structured to allow specialty contractors to perform the work, with subcontracting minimized to reduce contractor markups.

Advantages of the Multiple Contract Approach:

1. The Owner can select an engineer that has his trust and confidence separate from the construction process. The Owner works directly with the engineer, so the utility's standard philosophies and practices can be incorporated into the design. Since the engineer's responsibility is to protect the interests of the Owner throughout the design and construction process the design may take into account the life cycle costs of design decisions instead of just the initial cost.
2. The Owner can have input as design progresses without incurring change orders at potentially inflated costs. It is not necessary for the Owner to identify all of its requirements at the beginning of the project. The Owner can review the design as it is being completed and have its comments incorporated before the documents are issued for bid.
3. The engineer can provide the engineering and design documents in the Owner's typical format, and can provide whatever documentation the Owner desires.
4. Upon deciding to proceed with the project, the Owner can immediately begin to purchase major equipment, without having to define all of its requirements, prepare an EPC bidding document, and obtain EPC bids. Since construction can proceed while design is still in process this can reduce the overall project schedule.

5. Subcontracts are competitively bid at the time of submittal, therefore, subject to schedule timing, Owner can bid the contracts at opportune times, thus reacting and taking advantage of market conditions.
6. The contracts can be structured to minimize the amount of subcontracting by prime contractors, minimizing contractor markup. Equipment is purchased directly from the supplier, eliminating contractor markups. Since the construction contracts are smaller and more specialized a larger number of contractors are capable of bidding, which should result in lower project costs.

Disadvantages of the Multiple Contract Approach:

1. Structuring of the individual contracts is key to this approach. The goal is to divide the work such that the Owner receives lower costs from a competitive range of bidders. Proper coordination is key to minimize schedule delays or increased costs.
2. Total project costs cannot be confirmed until the final construction is completed. A total project estimate would be prepared by Burns & McDonnell prior to the start of the project.
3. Delays in completion of one contract may impact other contracts, resulting in potential additional project delays and/or costs to the Owner. The key is quality construction management.
4. No guarantees are available for the overall plant cost, schedule, and performance.
5. Owner or Owner's Representation (Engineer) manpower and costs to coordinate and manage the interfaces between the construction contracts is increased over approaches that have a single contractor. This is offset somewhat because EPC contractors will have money included to manage their subcontracts in a similar manner.

2.2 EPC CONTRACTING APPROACH

This approach combines of the design function and the construction function under one entity or group.

The term "EPC" is used widely in the power industry but this term has different meanings for different people. Within this narrative it will be used generically to refer to any approach in which Engineering, Procurement, and Construction (thus EPC) is supplied under a single contract.

Traditionally, the term turnkey was used to describe a project approach, in which the Owner explained what was desired and then left the contractor totally responsible for making the project happen in all its aspects including scope, design, schedule, budgeting, and financing constructing, budgeting, and financing. When the project was complete, the Owner returned, accepted the "keys" to the plant and paid the contractor. Such "hands-off" approaches are unusual in the power industry and the terms EPC, design-build and turnkey are generally used interchangeably today to describe an approach where all design and construction is performed by a single contract.

The Cost of EPC Contracting

As discussed above, it is recognized that a multiple contract approach has the potential for a reduced project cost. In order to determine how these costs may be reduced, it is useful to consider where the EPC contractor incurs costs.

The EPC contractor provides the detailed engineering, procurement, construction, and coordination of all the project work. During the bidding period the EPC contractor performs conceptual design and preliminary engineering to estimate the material quantities required for the project and their cost of installation. This may be from the contractor's own experience or from quotations from potential subcontractors. The contractor also obtains prices for equipment from suppliers.

The contractor selects the equipment and construction subcontractors who provide the lowest cost. The EPC Contractor then marks up the cost of the equipment and subcontracts to cover its cost of handling and managing these subcontracts, plus a profit. The EPC Contractor performs the detailed design, or subcontracts that work to an engineering firm. Generally, the EPC contractor's strategy is to purchase equipment and material direct from the supplier (which eliminates subcontractor markups) and to contract directly with specialty contractors for the construction work not performed by its own personnel. The scope of each subcontract is defined as clearly as possible, to reduce the likelihood of change orders.

For providing the overall project management and accepting and managing these risks (and to recover the substantial cost of preparing EPC proposals) the EPC contractor charges a fee. Due to the markups and the fee, the EPC contract should be more expensive than the multiple contract approach.

Advantages of the EPC Approach:

1. The Owner can obtain guarantees on overall plant performance and schedule.
2. Lump Sum price for the outlined scope of work in the EPC Contract.
3. The plant cost is confirmed very early in the project. If the scope is well defined, and the Owner identifies its requirements in the EPC Contract, there should be few change orders.
4. Minimal Owner interface. Monitoring of the contractor from an Owner perspective is still necessary to confirm that the project meets the requirements of the contract.
5. Once the EPC contract has been awarded, speed of the project implementation may be increased due to the coordination between the design function and the construction function. The overall project duration may still be longer than a multiple contract approach because of the time required to prepare bid documents, bid and award the EPC contract.
6. EPC contractors may have standard approaches that are less costly in certain areas than the utility's typical practices. This may provide adequate quality at a reduced cost for specific parts of the project.

Disadvantages of the EPC Approach:

1. This approach can result in a higher cost project, typically 5-10% in today's marketplace. The contractor receives a fee for managing and accepting the added risks of this type of contract. With the increased interest in new coal-fired generation, the amount of power plant construction is likely to increase, particularly for the 2009-2013 timeframe. This may result in less competition for individual projects and thus higher fees, particularly for units contracted for commercial dates toward the middle of this timeframe.
2. With financial corporate conditions, your competitive playing field will be limited to those with the financial wherewithal to tackle a $1 Billion project (very limited), or result in a consortium.
3. Consortiums, although claiming a single source of responsibility, may have internal issues with distribution of risk and truly result in multiple sources of responsibility.

4. The Owner generally does not select the equipment. The contractor will generally select the option with the lowest initial cost, regardless of life cycle cost. This is true of equipment selections and plant layouts.
5. Generally the Owner is not involved in the design decisions that may impact the life cycle costs of the unit. This may create a situation where the design may be adequate but provide for less redundancy or margin than desirable or not provide for future expansion or future growth.
6. Owner offered suggestions or alternatives will likely be cause for the contractor to revise the price of the project upward.

2.3 HYBRID APPROACH - HAWTHORN APPROACH, MULTIPLE TURNKEY "ISLANDS"

A variation on the single EPC approach is the approach the Kansas City Power & Light and Burns & McDonnell utilized for Hawthorn Unit 5. This was a "multiple EPC" or "island" approach. The larger island contracts include the boiler island, turbine island, and air pollution control island. Other islands that can be designated include the ash handling island, controls island, stack, cooling tower, and material handling island. The contractor for each island is typically the equipment manufacturer. There would also typically be a civil contract that would do all the site work and construct all the foundations. Each island may include all the equipment, piping, and electrical work (including electrical equipment) within that area. Buildings required for the equipment would be part of that island as well.

In this approach the Owner has the ability to competitively bid and select the main equipment desired for the project. The equipment manufacturer has responsibility for the selecting the auxiliary equipment for its island, so performance guarantees are available for each "island." Interfaces between the contracts can be minimized, thus making the coordination between contracts less complex. Frequently each contractor is doing their work in a separate area, so there are fewer opportunities for one contractor to interfere with or delay the work of another.

<u>Advantages of the Hybrid Approach:</u>

1. Fewer Contracts than Multiple Contracting Method. You receive the benefits of multiple contracting methods, with certainty developed in the major islands, however with significantly less overall contracts. The most risk for a new coal plant is asscociated with converting the coal to fuel in the boiler and cleaning up the air emissions. The Boiler island would take this risk and minimize the Owner's risks.
2. Fixed Price on 65-70% of the overall project cost at the same time you would award an EPC contract. Owner maintains the flexibility to insert preferences into the balance of plant design further into the project.
3. Less Owner interface for the islands. Monitoring of the contractor from an Owner perspective is still necessary to confirm that the project meets the requirements of the contract.
4. EPC island contractors will be selected based on their area of particular expertise (i.e. boilers, turbines, etc.). They will not have extraneous work in their scope for which they are unfamiliar.
5. Subcontracts are competitively bid at the time of submittal, therefore, subject to schedule timing, Owner can bid the contracts at opportune times, thus reacting and taking advantage of market conditions. With the hybrid approach, the Owner will receive the best price for the balance of plant systems, as well as a competitive EPC pricing for the island package(s).

Disadvantages of the Hybrid Approach:

1. The Owner will still pay a premium, but a much smaller premium. The main equipment manufacturers will supply auxiliary equipment not typically within their scope and will charge a markup for handling the purchase of this equipment.
2. Each island contractor will have their own subcontracts. This may lead to a large number of subcontractors on site at one given time. This can be somewhat mitigated by developing a short list of allowed subcontractors in the EPC specifications.
3. The Owner may still need to deal with multiple EPC island packages where the contractors goal is to minimize the initial cost, since that provides the most profit. For the particular island, the life cycle and redundancy decisions may not align with the rest of the "balance of plant" design in the Owner's control.
4. Owner offered suggestions or alternatives for the islands will likely be cause for the contractor to revise the price of the project upward.
5. Cost, Schedule, and Performance guarantees will be provided for each of the islands, however, this approach does not provide guarantees for the overall plant. This can be somewhat mitigated

from a performance standpoint by close examination of island contractor responsibilities, and ensuring, to the extent possible, back-to-back guarantees for the equipment performance. Cost risk will be mitigated for the 65-70% of the overall plant cost with this approach. Schedule risk will be somewhat mitigated by the use of liquidated damages, however, delays of one contractor may impact another contractor, thereby starting a domino effect.

3.0 THE BEST CONTRACTING ALTERNATIVE FOR SPECIFIC PROJECT

Big Stone Unit II could be constructed using any of the contracting approaches presented above. To evaluate the options for this specific project it is necessary to consider how each option meets Owner's requirements for this project. The best choice will be that which best suits Owner's experience, existing staffing, risk management style, project schedule, and financing restrictions. The following describes typical key evaluation items and how each alternative meets the requirements.

3.1 Owner's Control and Involvement in the Design:

The Owner's control and involvement in the design generally has three different aspects; the amount and type of drawings and documentation received; the Owner's ability to have the project reflect its typical practices; and the Owner's ability to make comments and changes during the design process.

An EPC contractor typically produces only the documents necessary to construct the project. An EPC contract can be structured to require the contractor to produce the types of drawings and other documentation the Owner is accustomed to receiving, in the format and software desired by the Owner. This requirement may limit the number of potential bidders and may increase the contractor's costs to do the project in a "non-standard" way.

In the multiple contract approaches, the engineer works directly for the Owner, so it is easier to require the Owner's typical drawings and documentation in the desired formats.

Any of the contracting approaches can be successful at incorporating the Owner's typical practices. Requirements such as equipment redundancy, specific manufacturers for certain equipment, valve arrangements, control philosophy, etc. can be made a requirement of an EPC contract or can be conveyed to a design engineer working directly for the Owner. The multiple contract and hybrid approaches allow for these philosophies to be identified and incorporated as the design progresses. EPC contract approaches require that these philosophies be identified at the beginning of the project and defined in the EPC contract. Also, EPC Contractors many times will offer designs that are different than specified. Therefore, Owners may not receive their preferences even if they are defined at the time of bidding. In addition, Owner requirements not included in the EPC contract may result in change orders, usually at inflated prices,

EPC contracts can be structured to give the Owner approval rights for all or part of the design. However, unless the comments are consistent with the EPC contract, it may be difficult to incorporate Owner comments without them being considered a change by the contractor. With multiple contract approaches, Owner's comments can generally be incorporated into the design prior to award of the construction contract with minimal impact on overall project cost.

3.2 Project Cost:

Primary issues related to project cost consist of the total cost and the risk of actual cost exceeding budget.

Since the EPC contractor receives a fee for accepting parts of the project risk, the multiple contract approach is likely to have a lower overall cost. The Hybrid Approach falls in between the EPC and multiple contract approach. The EPC contractor's ability to do some things differently from the utility's typical practices may offset some of this added cost.

Project cost risk stems from the following types of issues:

- The accuracy of the scope used to prepare the project budget
- Variations in material quantities required to construct the project (such as piping and concrete quantities)

- The accuracy of equipment cost estimates
- Expected labor cost and productivity
- Escalation

EPC contracting can shift most of this risk away from the Owner. The EPC contractor is responsible for the scope of the project (within the limits defined in the EPC contract), the material quantities, the equipment cost, labor cost and productivity, and escalation. The cost risks that remain with the Owner are primarily due to changes in scope and unexpected events (force majeure). Although, many EPC Contractors have requested additional compensation when they have lost money on a project with no (or little) justification. Due to the size of the project, large cost overruns by the EPC Contractor typically result in large claims to the Owner.

In multiple contract approaches the Owner retains much of this risk. Parts of the risk, such as labor cost, productivity, and escalation are shifted to the contractor when a construction contract is awarded. For a coal-fired project, major equipment purchases (boiler island, turbine island, air pollution control island) will represent 60-65% of the cost of the project. With the hybrid approach, these major components are set early in the project, and thus the major project cost risks are mitigated. The amount of risk in the project cost is reduced substantially after that equipment is awarded.

3.3 Project Schedule:

The key issues that determine the project schedule risk are equipment deliveries, material and manpower availability and labor productivity.

In EPC contracting, the risk for project schedule is shifted almost entirely to the contractor. It is common for the EPC contract to contain liquidated damages for late completion of the project. The liquidated damages are typically calculated to recover the Owner's expected costs due to the late completion of the project. For the hybrid approach , the major equipment is contracted as an EPC package, and thus schedule risk is somewhat mitigated. The Owner still has the overall project schedule risk, tying all the components together.

In the multiple contract approaches, schedule risk is greater for the Owner. With multiple equipment suppliers and contractors on the project, it is more difficult to structure contracts that would allow the Owner to recover from contractors its full cost for late completion of the project. However, Burns & McDonnell has found that with multiple contracts, it can be easier to manage the schedule process. With only one contractor (EPC approach), if that contractor's performance is poor, there is not a "fallback" contractor. With the multiple contract approach, as one contractor falls behind, there are opportunities for other contractors to step up and steer the project back on track.

3.4 Plant Performance:

In EPC contracting the risk for plant performance is shifted almost entirely to the contractor. It is common for the EPC contract to contain liquidated damages for failure of the plant to meet net capacity and heat rate. The liquidated damages are typically calculated to recover the Owner's expected costs due to the lost capacity and increased heat rate.

In multiple contract approaches, the performance risk rests primarily in the main pieces of equipment (boiler, turbine, APC Equipment). The Owner has some risk in coordinating between the pieces of equipment. This risk can be mitigated by the island approach, which would include performance guarantees for each of the islands. The tradeoff is the premium charged by the vendor to purchase the island equipment, and to provide the island performance guarantee. The Owner would still be responsible for overall plant performance.

Although some auxiliary equipment can potentially have an impact on plant performance, the impact is typically small, since overall auxiliary power consumption is a few percent of the gross generation.

3.5 Owner Resources Required for Project:

The amount of staff an Owner assigns to a given project varies widely with the role of the engineer, the Owner's experience with the specific engineer, the Owner's knowledge of the technology used in the project, and the Owner's own philosophies for managing and monitoring projects.

The Owner's required manpower will depend on the engineer's role. In the multiple contract approach, the Owner/Engineer are responsible for the interests of the Owner. The role of the engineer can be limited to the engineering, or can include procurement, project management, and construction monitoring depending on the desires of the Owner

Some utilities underestimate the monitoring requirements necessary for a successful EPC project. Although the EPC contract defines many of the requirements for the project, it is still appropriate for the Owner (or its engineer) to review and monitor the activities of the EPC contractor to confirm that the project is being designed and constructed in accordance with the contract. Substantial review of drawings, schedules and other documents is appropriate in an EPC contract to protect the long term interests of the Owner.

450 MW PC UNIT
INVESTOR OWNED UTILITY