COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

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COMMISSION

In the Matter Of:

THE APPLICATION OF KENTUCKY POWER COMPANY FOR (1) A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AUTHORIZING KENTUCKY POWER TO CONVERT THE EXISTING BIG SANDY UNIT 1 TO BE EXCLUSIVELY FUELED BY NATURAL GAS (2) FOR DECLARATORY RULINGS; AND (3) FOR ALL OTHER REQUIRED APPROVALS AND RELIEF))) CASE NO. 2013- 00430))

DIRECT TESTIMONY OF

ROBERT L. WALTON

ON BEHALF OF KENTUCKY POWER COMPANY

AMENDED EXHIBIT 2

December 16, 2013

VERIFICATION

The undersigned, Robert L. Walton, being duly sworn, deposes and says he is the Managing Director of Projects for American Electric Power Service Corporation and that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief.

ROBERT L. WALTON

STATE OF OHIO	)	
	)	Case No. 2013-00430
County of FRANKLIN	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Robert L. Walton, this the 10th day of December, 2013.

Regina L. Walker

Notary Public

My Commission Expires: 03-18-2017

REGINA L. WALKER
Notary Public, State of Ohio
My Commission Expires 03-18-2017

B&W Engineering Study P027478

to

American Electric Power Company

for

Natural Gas Conversion

at

Big Sandy Unit 1

submitted by

B&W
power generation group

November 19, 2013

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APPENDICES

INTRODUCTION

The Babcock & Wilcox Power Generation Group (B&W) has provided decades of unparalleled professional expertise and service to a host of utility and industrial customers and continues to be a leader in the supply of boiler equipment for the power generation industry. Founded in 1867, B&W is the oldest continuously operating boiler company in the United States. With over 145 years of history, B&W is well known for its innovations and product excellence in the areas of steam generation, fossil fuel combustion, and environmental controls.

B&W Service Company (BWSC)

B&W Service Company, a division of The Babcock & Wilcox Power Generation Group, has over 500 permanent employees and can draw on corporate manufacturing and specialized engineering resources as well as contract field service and labor to support its work activities. The BWSC business units, Service Projects, Replacement Parts, Field Engineering Services, Package Boilers, and Private Power Systems are supported by Engineering, Sales, and a host of administrative organizations. The group with responsibility for the work proposed herein, Service Projects, carries out unit maintenance and upgrade projects ranging from total EPC SCR installations to in-kind replacements of boiler components. We draw on support from an engineering and design group having an average of almost two decades of experience per employee and from estimating, scheduling, accounting, quality assurance, manufacturing, and construction organizations.

On large and complex projects typical in the power generation industry today, success is based in large part on the supplier's ability to coordinate all the different disciplines required to complete the project. We are in a unique position in the industry to undertake these projects because personnel with all of the requisite skills are co-located on our Barberton, OH, campus, thus facilitating the exchange of information throughout planning, project execution, and start-up activities.

Research and Development

B&W established a Research and Development Division in Alliance, Ohio, in 1947 to maintain its leadership in custom-engineered systems and equipment for the power generation industry. In 2007 B&W celebrated the inauguration of its new 55,000-square foot research center co-located in Barberton, OH with its other business units supporting the power generation industry.

This research center focuses on the development efforts in the areas of steam production and pollution control technologies, as well as technologies to capture carbon dioxide (CO2) from the emissions of coal-fired power plants. The research center is the residence for B&W's new small boiler simulator (SBSII), an integrated combustion and environmental control test system; the fireside corrosion facility, which is used to evaluate advanced materials for super- and ultra-supercritical boilers; the mercury lab where bench-scale studies for flue gas desulfurization systems and mercury oxidation are conducted, and the entrained flow reactor, used to study the fundamental science of coal combustion.

Today, research specialists focus their attention on development in key technology areas including:

- combustion processes,
- emissions control,
- fuel cells,
- fuels characterization,
- numerical modeling,
- thermal hydraulics, and
- structural mechanics

Current examples of development efforts that utilize these technologies include fuel-cell power generation systems and advanced low-emission burners. Such developments are conducted in accordance with ISO 9001 certified procedures and frequently utilize the Combustion and Environmental Development Facility (CEDF). This integrated state-of-the-art combustion and emissions testing facility offers unique research, development, and demonstration capabilities to improve the environmental performance of current and future power plants.

Manufacturing

B&W maintains a commitments to heavy metal manufacturing at our facilities in Barberton, Ohio; West Point, Mississippi; Cambridge, Ontario, Canada; Melville, Saskatchewan, Canada; and our latest facility in Monterrey, Mexico. We also have access to facilities in Mt. Vernon, Indiana, and Morgan City, Louisiana, and joint venture operations in China and India. Our extensive facilities, skilled manpower, and global presence provide our customers with a complete range of fabricating processes around the world and around the clock. Advanced manufacturing methods and in-plant emphasis on quality ensure that retrofit components are made correctly and shipped on time. As a result, field fit-up problems are minimized and outage sc hedules can be maintained.

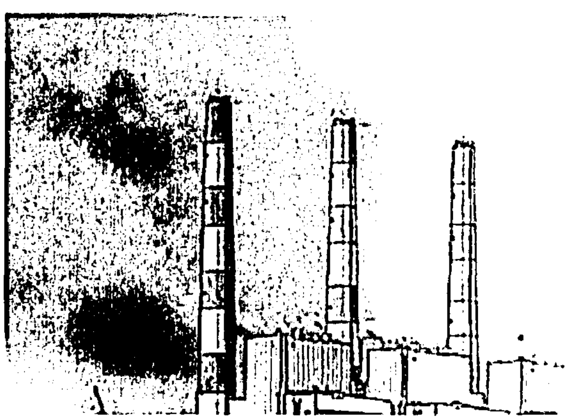
B&W wishes to thank American Electric Power for the opportunity to submit this study. Points of contact for questions and/or additional information are as follows:

Mark A. Zeiger
District Sales Manager
Babcock & Wilcox Power Generation Group, Inc Tel. (513) 326-4362
Email: mazeiger@babcock.com

Bob Dear
Project Manager
Babcock & Wilcox Power Generation Group, Inc Tel. (330) 860-2567
Email: rhdear@babcock.com

COMPANY EXPERIENCE AND QUALIFICATIONS

Babcock & Wilcox Power Generation Group, Inc. (B&W) has provided unparalleled professional expertise and service to a host of utility customers and continues to be a leader in the supply of boiler equipment for the power industry. Founded in 1867, B&W is the oldest continuously operating boiler company in the United States. With over 145 years of history, the company is well known for its innovations and product excellence delivering unparalleled results for the power industry.



- Babcock & Wilcox boilers supply more than 300,000 megawatts of installed capacity in over 90 countries around the world.
- Approximately half of the world's electric power is supplied by water-tube boilers. In addition, boilers using Babcock & Wilcox technology are now providing more than 23 percent of the world's boiler-powered electricity generation capacity, and more than 35 percent of the capacity in the U.S.

B&W's role as an original equipment manufacturer, B&W has an extensive resume as a major supplier of repair, refurbishment, and upgrade equipment.

Throughout our many years of successful performance, we have demonstrated technical competence, flexibility, and attention to "lessons learned."

Worldwide Manufacturing

Through comprehensive supply chain management, worldwide sourcing, and alliances with domestic and international fabricators, you can depend on quality materials, on-time delivery and reduced total cost. B&W PGG's commitment to quality products and services is also demonstrated by our continuous capital investments at our manufacturing facilities around the world.

Burner Equipment Upgrades

Our leadership in the field of NOx reduction technology began in 1962 with the award of the first patent for the use of overfire air for reducing NOx emissions in the world. That leadership continues with unparalleled experience, proven equipment, and innovative technology to this day. Our systems are designed to be cost-effective, dependable, and adaptable to the full range of fuels and boiler arrangements in new or retrofit applications.

Babcock & Wilcox's history of combustion design innovation, experience, and technology is unmatched in the industry, and the following study is supported by our long history of low NOx combustion innovation and success.

Since 1971, B&W has successfully installed over 135,000 MWe of low NOx combustion systems in both new and retrofit applications, including thousands of low NOx bumers.

Operating & Maintenance

Mechanical reliability has been a primary design consideration for B&W burner equipment for over 50 years. Minimal maintenance requirements on B&W equipment have historically reflected the emphasis that we place on a rugged design to maintain operability. Our burner equipment is low maintenance and easy to operate. This traditional philosophy within B&W has not changed, and our new equipment designs continue to operate with high reliability and low maintenance requirements.

Company Financials

Please see visit our company website www.babcock.com for the latest financial information.

TECHNICAL DESCRIPTION

Overview

Engineering Study for the Natural Gas Conversion on Big Sandy Unit 1.

Unit Background

B&W contract RB-364 is a pressurized, radiant boiler that commenced operation in 1962. The original design fired pulverized coal from eighteen (18) burners located on the front and rear walls. The furnace dimensions are 42 feet wide, 28 feet deep and 120 feet from the lower wall header centerline to the drum centerline. The unit has a parallel path horizontal convection pass.

The original design maximum continuous rating (MCR) for Big Sandy 1 is 1,890,000 lb/hr of main steam at 1050°F and 2500 psig. The original reheat conditions at MCR are 1,534,000 lb/hr at 1050°F and 510 psig.

Superheater and reheater steam temperature control was originally by means of biasing dampers for the parallel path horizontal convection pass, gas recirculation, and spray attemperators.

The gas recirculation equipment has been removed and therefore neither gas recirculation nor gas tempering are in use. In addition, the biasing dampers in the horizontal convection pass are currently not functional. Therefore, the primary means of steam temperature control currently are spray attemperation and excess air.

The reheater materials were upgraded to T91 by others in the mid-1990s.

In 2008, B&W upgraded the secondary superheater outlet bank to TP304H material.

The secondary superheater inlet bank was also upgraded in 2008 to T22 (by others).

Both the reheater and secondary superheater outlet headers have been upgraded by others to P91 material.

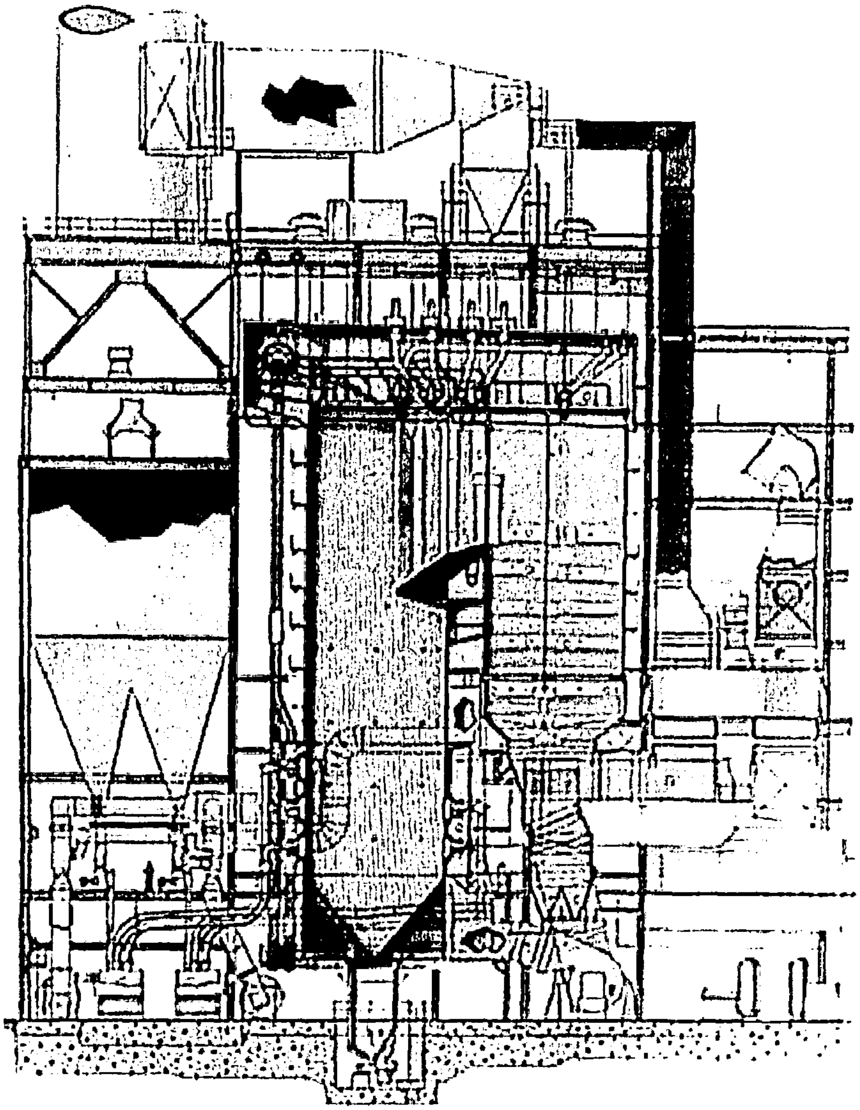


Figure 1 - AEP Big Sandy Unit 1 - (RB-364)

Design Basis

AEP provided several weeks of natural gas analyses for our review and use. The natural gas analysis used in B&W's performance predictions is listed below in Table 1.

Table 1: Fuel Analysis

Fuel Type	Natural Gas
	% by volume
Methane	76.69
Ethane	16.54
Carbon Dioxide	0.08
Nitrogen	1.13
Propane	4.33
Butane	0.94
Pentane	0.20
Hexane	0.09
Total	100.00
HHV(btu/ft)	1205

The boiler was designed for an MCR main steam flow of 1,890,000 lb/hr. For this Engineering Study, AEP advised that the top load should be 2,080,000 lb/hr main steam flow, where the unit has run since a turbine upgrade in 2008. In addition, we have reviewed the original control load and a "mini" load specified by AEP.

Expected Emissions Performance

Thermal NOx is controlled through the reduction in peak flame temperatures. This is accomplished through staging and a slow fuel/secondary air mixing rate. Due to the reducing environment, high levels of CO are produced which must be combusted when the balance of combustion air is reintroduced higher in the furnace (through OFA ports). The balance of combustion air has to be introduced in such a way as to avoid the formation of thermal NOx. To the extent that the OFA system is effective, low stoichiometries (and thus low NOx) are achievable while still oxidizing CO to acceptable levels.

In the effort to oxidize as much CO as possible, experience in system retrofits indicates that is advantageous to locate outermost OFA ports outboard of the outer burner columns between the burners and the sidewalls. Commonly, these ports are located halfway between the outer burner columns and the sidewalls to provide combustion air to oxidize the CO that typical forms along the sidewalls and in the corners of the furnace due to the colder environment in those areas.

The existing OFA ports do not offer the ability to balance straight jetted air versus spun air which would allow for increased mixing of the over-fire air with the substoichiometric combustion gases from lower in the furnace which in turn reduces CO formation.

The following options were considered in this Engineering Study:

Option 1 - New XCL - S burners with Existing OFA Ports

This option requires the least amount of modification and the lower expected NOx emissions of the two options. The NOx emissions for this modification option are not expected to exceed 0.22 $lb/10^6btu$ from maximum load (2,080,000 lb/hr) to control load (1,260,000 lb/hr). Since the existing OFA ports will be reused in this option, the CO emissions are expected to be 115 PPM at 3% O_2. Due to the composition of the gas not being that of pipeline quality natural gas, B&W would like to refer to EPA's AP 42, Fifth Edition, Volume I, Chapter 1: External Combustion Sources, Section 4: Natural Gas Combustion (Table 1.4-2) for expected VOC emissions.

Option 2 - New XCL - S burners with removed OFA Ports

This option requires the removal of the existing OFA Ports. The NOx emissions for this modification option are not expected to exceed 0.30 $lb/10^6btu$ from MCR to control load. The CO emissions are expected to be 115 PPM at 3% O_2. Due to the composition of the gas not being that of pipeline quality natural gas B&W would like to refer to EPA's AP 42, Fifth Edition, Volume I, Chapter 1: External Combustion Sources, Section 4: Natural Gas Combustion (Table 1.4-2) for expected VOC emissions.

Non-Pressure Parts

B&W XCL-S Burners

NOx Formation

NOx is formed during combustion of fossil fuels by several mechanisms. At flame temperatures in excess of 2800°F, significant quantities of thermal NOx are formed by dissociation and oxidation of nitrogen from the combustion air. Thermal NOx is the primary cause of NOx from firing natural gas, and a major contributor with fuel oil. Fuel NOx refers to emissions which result from oxidation of nitrogen which is bonded to the fuel molecules. This nitrogen becomes actively involved in the combustion process as hydrocarbon chains are broken and oxidized, and a portion of the fuel nitrogen is oxidized as a result. Fuel bound nitrogen is found to varying degrees in heavier fuel oils (and coal), but is insignificant in light oil (No. 2) and natural gas. Fuel NOx is the primary cause of NOx from pulverized coal and a major contributor for No. 6 fuel oil. Prompt NOx refers to emissions formed during combustion from hydrocarbon radicals dissociating atmospheric nitrogen, followed by oxidation. Prompt NOx plays a minor role in overall NOx production with fossil fuels.

NOx Control Strategies

Several methods are available to limit NOx formation during combustion effectively. The combustion system design will depend upon the capacity and fuels to be fired, as well as the requirements to limit NOx emissions. Thermal NOx can be controlled by reducing the thermal loading to the combustion zone. Mechanisms include increasing the size of the combustion zone for a given thermal input; reducing the rate of combustion and peak flame temperatures by burner design; and addition of re-circulated flue gas to the combustion air to depress flame temperature. Fuel NOx can be controlled by limiting oxygen availability during early phases of combustion. Mechanisms include reducing excess air; reducing burner stoichiometry by removing a portion of the combustion air from the burner and introducing this air later through NOx ports (air staging); and by burner designs which limit the rate of which air is introduced to the fuel early in the flame. Peak NOx levels tend to occur early in the combustion process as flame temperatures peak and while oxygen availability is highest, whether or not countermeasures are employed. The NOx formed early in the process can be reduced downstream by use of fuel staging principles. Fuel staging involves introduction of fuel downstream of the flame under fuel rich conditions. Hydrocarbon radicals can thereby be generated which attach the NOx molecules, resulting in NOx destruction.

Fuel staging can be accomplished by fuel staging burners located downstream of the main burners and in combination with air staging ports; or by a burner design to accomplish these effects by fuel injection/air flow patterns.

B&W XCL-S Burner

The B&W XCL-S burner makes use of air staging and fuel staging technology by virtue of its design. The gas elements are centrally located in the burner in an arrangement which carefully limits air/fuel interaction in the root of the flame. The fuel elements are all housed in a single, central flame stabilizer which results in excellent flame stability and turndown, while separating the fuel elements from the combustion air. The XCL uses multiple Hemi gas spuds to achieve the desired fuel injection patterns. Secondary air introduction to the fuel is regulated by dual air zones with multi-stage swirl vanes. Peak NOx formation is reduced by controlling the rate of combustion and apparent stoichiometry. Hydrocarbon radicals are produced which react with the NOx formed early in the flame and further reduce NOx emissions. Combustion air gradually mixes with these products of combustion further downstream to complete char reactions while minimizing NOx re-formation.

Burner Air Flow Control - Sliding Air Damper

The XCL-S burner can be used in either compartmented or open windboxes. Each burner is equipped with a sliding disk damper to regulate secondary air flow to the outer air zones for light off, normal operation, and burner out of service (BOOS) cooling.

A second sliding sleeve damper is provided for air biasing between the core air and the outer secondary air. The air biasing damper is set manually at commissioning and does not require adjustment during normal operation.

Burner Air Flow Control -BECK Electric Actuator

Each burner can be equipped with a BECK linear actuator specifically designed for application to XCL-S burners.

Burner Air Flow Control - Air Measuring Pitot Grid

The XCL-S is equipped with an air measuring device located in the air sleeve of each burner. This measuring device is an impact-suction or reverse type Pitot tube arrangement consisting of two separate manifolds joining six radial impact-suction tubes. This multi-point averaging grid provides a relative indication of air flow to each burner by measuring a pressure differential across the impact and suction manifolds. This air monitor is instrumental in detecting burner to burner flow imbalances within the common windbox and may be used as a tool for future tuning efforts.

Flame Control - Adjustable Gas Spud Orientation

Each of the gas spuds in the XCL-S burner is capable of having their rotational orientation adjusted on-line for greater operational and tuning flexibility. Such adjustments can be made from the burner front while the burner is firing.

Gas spud inspection/maintenance may occur with the unit in service and the burner out of service.

The cut-away view below is typical of the XCL-S burner arrangement when configured for gas firing.

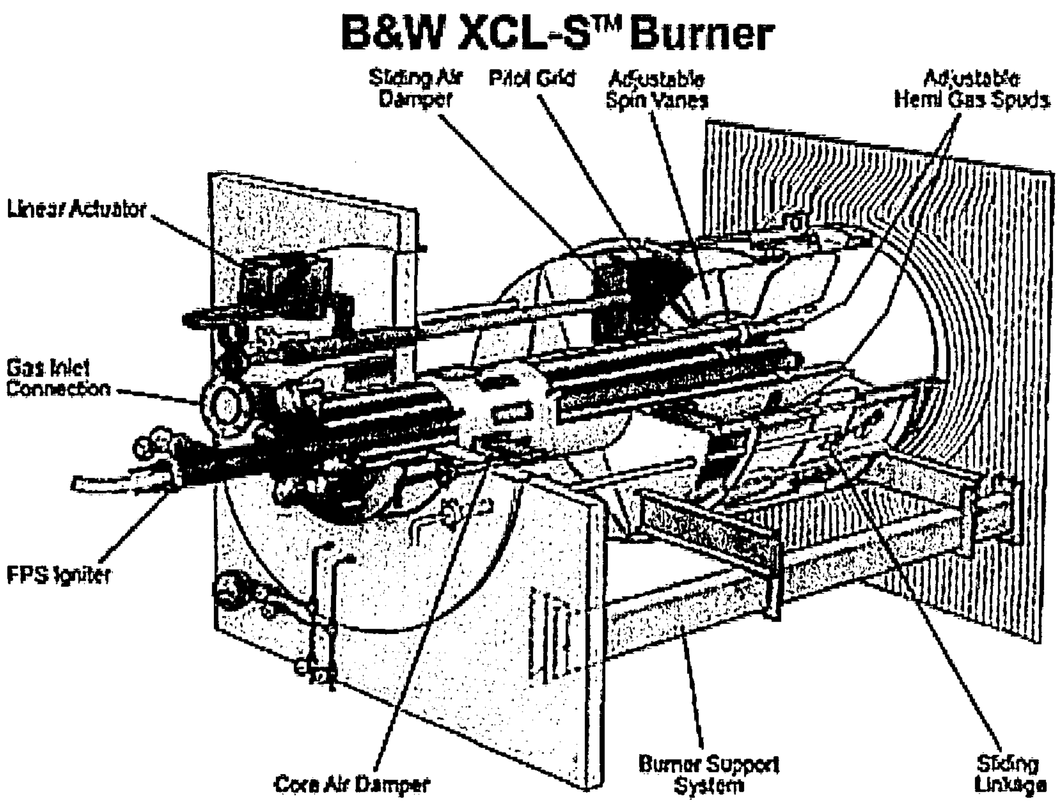


Figure 2 - B&W XCL-S Gas Burner

The scope of supply would include **eighteen (18)** XCL-S low NOx gas burners. All 18 burners will be located at an existing burner pressure part throat opening. No modification of the boiler tube wall would be necessary.

Fossil Power Systems (FPS) 4.0"OD HO Gas Ignitor, 4-20 Million BTU/hr

A Class I Ignitor assembly would be included to fit the a B&W XCL-S burner. Each ignitor is supplied complete with its own SunSpot flame detection system.

The 4.0"OD ignitor includes the integral Sunspot flame detection system. The SunSpot is an instrument designed to verify the presence of flame in FPS ignitors. It does this by measuring the ionization of gases caused by the combustion process. A probe is inserted into the flame envelope, and the ionization is detected by passing a small electrical current through the flame to ground. The SunSpot is reliable, requires no maintenance, and is very economical. It is supplied as an assembly, which includes the plug-in electronics module and a relay socket. Replacing the module takes only a matter of seconds.

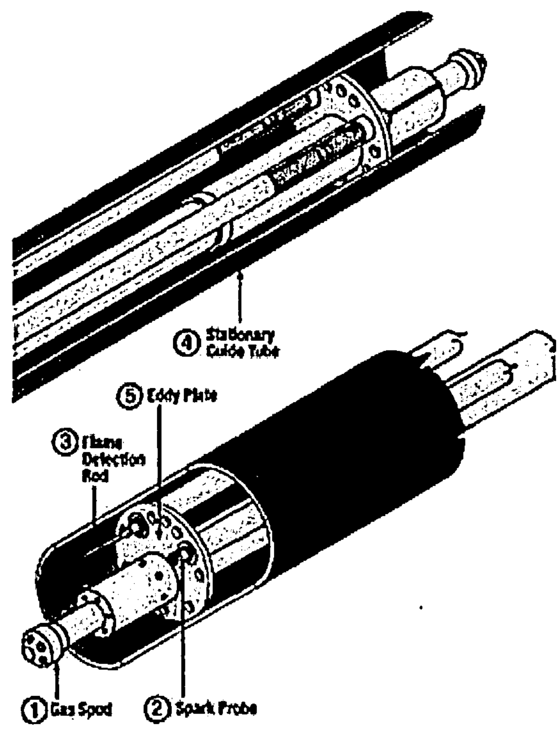


Figure 3 - FPS Gas Ignitor

Combustion Air Blower Skid & Air Piping

Each ignitor and scanner requires combustion air flow.

A duplex blower skid would provide adequate air flow to each ignitor. Pressure switches would be included as part of the blower supply to provide indication and control of header air pressure and can be wired directly to MCC equipment or the unit's DCS to provide backup fan starting. Each fan would include a filter/silencer.

Combustion air piping from the blower skid to the burner fronts would be required.

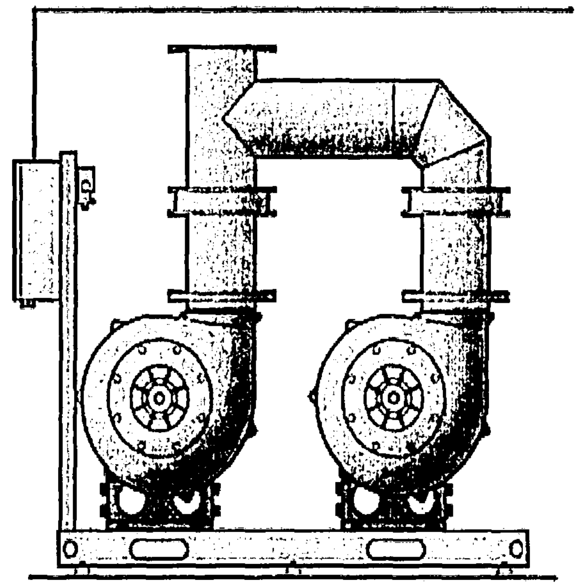


Figure 4 - FPS Duplex Blower

Main Flame Scanners

FPS, tri-color, rigid fiber optic, main flame scanners, and main flame scanner electronics cabinet.

FPS Scanner System Description

The scanner heads have the ability to detect the light emissions from the flame envelope in the infrared, visible and ultra-violet wave spectrum. This would allow the user unsurpassed flexibility in tuning the flame scanners for detection of gas flames.

The fiber-optic viewing head extends into the windbox and ends just before the exit into the furnace. The viewing lens is arranged in a skewed manner allowing an angled view into the furnace that can be easily adjusted on the boiler front. The primary benefit of the skewed viewing angle is that it allows the scanner to be sighted on the optimal area of the flame envelope for flame detection, while directing the scanner view away from the opposing burners and ignitors. A second benefit to this type of scanner arrangement is the ability to rotate the scanner head about its own axis, allowing the scanner to be sighted at the optimal area in the furnace for both flame detection and flame discrimination.

Main Gas & Ignitor Supply Header Station – see appendix B for P&ID's

A main gas header station would be necessary to control the flow feeding the Burner Front Valve Racks. This station contains instrumentation, block valves, vent valve, and flow control valves all preassembled on one assembly.

Valve Racks and Controls - Burner & Igniter On/Off Control – see appendix B for P&ID's

A valve rack per burner containing both the igniter and main gas double-block-and-bleed valve trains for on/off/vent gas flow control would be required.
These racks serve to provide on/off control to each burner and igniter and have no pressure reducing function.

The valve racks would be completely shop assembled. The control/terminal box would have indicating lights and operator controls with remote/local switch to provide for manual local operation and operation by a Burner management System.

Gas & Vent Piping – see appendix B for P&ID's

Natural gas piping from the natural gas header flow station to the local burner and ignitor valve racks would be required. Vent piping from the burner & ignitor supply header station discharging above the roof would also be required.

Pressure Parts

Existing Arrangement

Performance Boiler predicted performance was calculated using the current boiler arrangement with the indicated natural gas fuel for a range of boiler loads. Performance was analyzed in a natural gas "clean" and "dirty" condition.

The top load that AEP requested we review has a main steam flow of 2,080,000 lb/hr due to a turbine upgrade in 2008. It is important for AEP to recognize that the MCR rating for this boiler is 1,890,000 lb/hr and B&W has not reviewed safety valve capacity and/or settings nor unit circulation for the higher load.

B&W also reviewed the original control load of 1,260,000 lb/hr main steam flow and a "mini-load" requested by AEP of 780,000 lb/hr main steam flow (roughly 100 MW).

The unit was originally supplied with flue gas recirculation (FGR) and gas tempering capability. These features were eliminated when the plant removed the flue gas recirculation equipment years ago. Gas tempering was used to reduce the furnace exit gas temperature (FEGT) at higher loads and FGR was available at lower loads to assist in obtaining the desired superheater and reheater steam temperatures. Without the gas tempering and combined with the switch to natural gas, the predicted FEGT on natural gas is roughly 300°F higher than the original FEGT for coal firing while using tempering. The higher FEGT cascades through the boiler resulting in higher gas temperatures through the convection pass and this drives up tube metallurgy requirements.

The gas biasing dampers in the parallel path horizontal convection pass are no longer functional. Restoring their functionality would help to increase the reheat temperature at the lower loads by allowing additional flue gas to be directed to the reheat surface.

At the full load, both the superheater and reheater are predicted to make the desired 1050°F. At the lower loads, the reheater is predicted to not make full temperature. Not having the ability to turn on flue gas recirculation at the lower loads, and no gas biasing, contribute to this issue.

Natural gas firing (as compared to PC firing) results in a higher furnace exit gas temperature and higher attemperation spray flows. As superheater attemperator spray flow increases to control the secondary superheater (SSH) outlet temperature, to primary superheater (PSH) steam flow decreases accordingly and a PSH overheat conditions results.

Superheater and Reheater Superheater and reheater metallurgy was evaluated for natural gas firing based on the existing surface arrangement. B&W uses the ASME Code to determine tube metallurgies and thicknesses. The design temperatures however are based on B&W procedures. Design temperatures are determined through the consideration of gas and steam side temperature and flow upsets and unbalances. The upsets and unbalances include FEGT empirical uncertainty, top to bottom gas temperature deviations, side to side gas temperature deviations, steam flow unbalances (a function of tube side pressure drop and arrangement) and gas flow unbalances. The method applies these upsets and unbalances simultaneously to each row of the superheater and reheater. Tube row metallurgy and thickness are then determined from the resultant tube OD and mean temperatures, respectively, according to ASME Code material oxidation limits and allowable stresses

Many of the Big Sandy 1 tubes have been calculated to operate in a temperature regime where creep occurs. In this regime there is a relationship between allowable stress and life expectancy. Per the 1995 ASME Code Section II, Part D, Appendix 1, Paragraph1-100 (page 696), the allowable stresses are set based on the most conservative of the following three criteria: 100% of the average stress to produce a creep rate of 0.01% per 1000 hours, 67% of the average stress to cause ruptures at 100,000 hours or 80% of the minimum stress to cause ruptures at 100,000 hours.

Further, the remaining tube life expectancy is dependent on the prior operating history, especially on actual tube operating temperatures as compared to design temperatures. The constituents of the flue gas affect heat transfer to the tube banks and consequently affect the tube operating temperature. A fuel switch from coal to natural gas significantly changes the flue gas analysis. Thus, assessing the existing superheater and reheater materials for the proposed natural gas conversion is not straightforward.

Operating hoop stresses (based on the originally supplied minimum tube wall thickness) were determined. The predicted tube operating temperatures, based on B&W's standard design criteria, and the resulting ASME Code allowable stress levels for the existing materials were also determined. Comparing the hoop stress to the code allowable stresses, a percent overstress determination can be made. A modest overstress indicates a modest shortening of remaining life expectancy and, unless otherwise indicated by past maintenance experience, does not warrant immediate tube replacement.

If the overstress analysis shows significant overstress or shows tubes are operating at temperatures above published ASME Code limits, then tube replacement should be considered. Significant overstresses are those tube rows with 20% or greater overstress. An overstress of 20% or more does not necessarily mean that immediate replacement is required, but it identifies which tube rows should be monitored regularly. Signs of creep, internal exfoliation, or swelling should be included in the condition assessment process.

B&W predicted overstress conditions at full load and also the lower loads. In fact, we did not find any load that didn't have some tubes with some level of overstress.

The primary superheater outlet bank was particularly overstressed as a result of the large amount of sprayflow, which reduced the steam mass flow in the primary bank. Should AEP be confident that they will not be firing coal once the natural gas addition is completed, it is B&W's recommendation to look at the removal of primary superheater surface in an attempt to reduce the superheater sprayflow, thereby increasing the steam mass flow in the primary bank tubes which in turn would reduce tube temperatures.

In addition to significant overstresses in the primary outlet bank, the primary superheater outlet header and the steam piping to the superheater attemperators have been found to be inadequate for the natural gas conditions, based on the current surface arrangement. A review of the original design calculations determined that the header and piping are within limits up to 945°F, but the new design temperature with gas firing is predicted to be over 1010°F. B&W recommends their replacement if no modifications are made to the superheater heating surface.

Attemperators Direct contact attemperators are used to control final steam temperature by utilizing excess superheater absorption to evaporate the attemperator spray water. The spray water is introduced into the superheated steam flow between the primary and secondary superheater stages. Big Sandy Unit 1 has two (2) interstage attemperators in parallel to control main steam temperature. Each attemperator is currently designed to handle 120,000 lb/hr (240,000 lb/hr total) spray flow. At full load natural gas clean conditions, with the current surface configuration, the total predicted attemperator spray flow is 276,000 lb/hr. This is more spray flow than the original attemperator's design capacity. Higher capacity superheater attemperators are therefore recommended if no superheater surface is removed.

This unit has two (2) reheater attemperators. At full load natural gas clean conditions, the predicted reheater attemperation sprayflow is 9,400 lb/hr. This value is below the original design condition for the reheat attemperators, therefore B&W expects the existing reheat attemperators to be adequate.

Surface Removal

B&W reviewed several surface modification scenarios in order to reduce the design steam temperature leaving the primary superheater in an effort to retain the primary superheater outlet header and attemperator inlet piping when firing gas.

By removing primary superheater surface, the steam temperature leaving the primary is reduced (due to the reduced absorption in the bank). In addition, the amount of superheater sprayflow is reduced, thus increasing the steam mass flow in the primary bank which helps to reduce tube and steam temperatures in the tubes and outlet header.

By removing the two (2) lowest horizontal primary superheater rear pass banks, B&W was able to decrease the primary superheater outlet header design temperature to 954°F. This is 9°F higher than what the design calculations advise is acceptable for the existing header (945°F) and B&W recommends the replacement of the header and piping for any scenario where the design temperature is above the 945°F. Taking out additional primary horizontal surface could reduce the predicted design temperature further, however that should be weighed against the resultant increase of the flue gas temperatures through the remaining boiler components.

The surface removal lowers the metal temperatures in the primary and in addition to reducing the predicted header design temperature, slightly lowers the overstresses that were found in the primary superheater pendant bank. Unfortunately there was no surface adjustment scenario where overstresses were eliminated in that bank.

With the primary superheater surface removal, the moderate overstresses originally found in the primary superheater rear bank (tube rows 41 - 44) were eliminated.

As stated previously, B&W considers overstresses of 20% or greater to be significant and recommends the replacement of the tubes.

A summary sheet showing full load performance for both natural gas "clean" and "dirty" conditions with existing surface versus the removed primary superheater surface can be found in Appendix A. The most significant impacts to performance from removing the primary surface are:

- Reduction in superheater sprayflow
- Increases in gas temperatures through the economizer and air heater
- Decrease in boiler efficiency due mostly to the increase in exit gas temperature

With the removal of the two (2) banks of primary superheater surface, the predicted amount of superheater sprayflow is reduced such that the existing superheater attemperators should have adequate capacity under normal operation firing natural gas.

SCOPE OF SUPPLY

The following is the Scope of Supply that defines equipment required for the Natural Gas conversion at AEP Big Sandy Unit 1.

BASE SCOPE

Item 1: B&W XCL-S Burners equipped for Natural Gas firing - Qty (18)

Each burner to include:

- Externally adjustable secondary air zone spin vanes
- Externally adjustable core zone damper
- Hemispherical gas spuds
- Bellow-type expansion joint connecting the burner hemi-spud gas ring to the fuel piping
- Pitot tube relative air flow measuring device with magnehelic gage
- Provisions to accept FPS ignitor with integral SunSpot flame detector
- Two Type K permanent thermocouples to monitor core zone and burner outer sleeve temperature with two thermocouple heads
- Field insulated cover plate
- BECK electric linear actuator for automated positioning of sliding secondary air damper
- One set of burner support steel rails with furnace wall and windbox connection hardware

Item 2: Class I Natural Gas Ignitors, 4 - 20 million BTU - Qty (18)

Each ignitor is supplied complete with:

- 4.0" Stationary Guide pipe with 2.5" butterfly valve combustion air inlet. Each ignitor requires 140 SCFM of primary combustion air at 2-4"w.c. above furnace pressure
- SunSpot flame rod with high temperature extension
- Plasma Arc Ignition (PAI) spark plug with high temperature extension.
- NEMA 4X PAI power pack
- B&W plans on reusing the existing SunSpot ignitor flame detector electronic modules from the FPS oil ignitor system.
- Metal braided flex conduit assemblies for ignitor electrical connections (spark and flame rod)
- Stainless steel lined gas hose with male NPT fittings each end, swivel adaptor one end - 1.5 inch diameter x 6 long foot hose.

Item 3: Main Flame Scanner System - (1) Lot

Qty 1 - One (1) NEMA 12 Single bay Scanner Cabinet:

Qty 1 - Rack to house scanner modules including:
- Redundant 120VAC-24VDC power supplies
- Qty 18 - FPS VIR VI flame scanner modules
- Terminal Blocks for customer interface wiring with 10% spare terminals

Qty 18 - Tri-color rigid fiber optic flame scanner viewing heads

Qty 18 - Scanner head guide tubes c/w isolation valve (to prevent blowback when scanner head is withdrawn) and 1.5" NPT cooling air inlet. Each viewing head requires 35 SCFM of cooling air at minimum 4" w.c. above furnace pressure

Qty 10 - FPS scanner head junction boxes, NEMA 4, each with (9) 23' quick disconnect cables to mate with viewing heads

1 Lot - Flame scanner monitoring / tuning software. Computer and cable hardware by Others.

Item 4: Duplex Blower System

Skid mounted duplex blower assembly is sized to supply combustion/cooling air for (18) ignitors and main flame scanners on a pressure fired unit.

- Blower with direct drive, TEFC standard efficiency motors
- Check valve and butterfly isolation valve on blower outlet
- Common discharge pipe with pipe stub outlet and rubber sleeve with clamps
- Control butterfly valve on discharge
- Single loop controller for control valve
- Pressure transmitter. Supplied loose for installation in air header piping by others.
- Inlet filter-silencers
- Inlet air filter restriction gauges. Pressure switches to measure inlet pressure are available as an option. Price adder applies
- SPDT pressure switches to monitor discharge pressure, wired into starter circuits to allow automatic switchover on loss of discharge pressure. Tubing to air header piping to be installed by others.
- Circuit breaker type full voltage combination starter assemblies in NEMA 4X enclosures, each complete with switches and indicators to allow local control and monitoring of blower operation. Starters are factory mounted on blower skid and wired such that loss of discharge pressure will automatically cause the standby blower to start.
- Pre-wired connections between motors, starters and pressure switches
- 1 Lot - Air piping from blower skid to burner front components. Piping to be supplied loose for field fabrication with loose fittings and come coated with red oxide, weld-able, prime paint only.
- Qty (18) - Flex hoses to connect the air piping to the scanner and ignitor cooling air connections on each burner.

Item 5: Main Gas & Ignitor Supply Header Station - Qty (1)

Main Gas Header Station for Regulation of Gas Supply to the

Burner Fronts The main gas supply header station to include:

- Main gas SSV
- Gas Inlet shut off valves
- Main gas SVV
- Minimum fire bypass Pressure Reducing Valve (PRV)
- Main gas charging valve
- Fisher flow control valve
- Pressure Transmitters
- Pressure gauge with root valve
- Main gas V-Cone flow meter
- Manual drain valves (supplied loose)
- SW manual vent, test and purge valves

The ignitor supply header station would include:

- Manual shutoff valve
- Ignitor header SSV
- Ignitor header SVV
- Ignitor header PRV for ignitor fuel flow control
- Pressure transmitter
- Pressure gauge with root valve
- Ignitor gas V-Cone flow meter

Item 6: Local Burner & Igniter Gas Racks - Qty 18

The local burner/ignitor gas valve trains would consist of manual isolation and double block & vent valves and ancillary equipment as required for operation of one burner and one ignitor.

Main burner valve train components include:

- Manual isolation valve
- Main gas safety shut-off valves (SSV's)
- Main gas safety vent valve (SVV)
- Manual vent valve c/w limit switch
- Outlet pressure gauge with root valve
- SW test valves

Ignitor valve train components include:

- Manual isolation valve
- Ignitor gas SSV's
- Ignitor gas SVV
- Pressure Gauge with root valve
- Instrument air filter-regulator with manual shutoff valve

Item 7: Local Control Cabinets

Each burner/ignitor valve train would include a local control cabinet. This cabinet will be supplied loose to mount outside of the hazardous area for control and indication of the burner and ignitor.

- Ignitor start permit indicator
- Ignitor on/off (start/stop) switch
- Ignitor flame indicator
- Gas gun inserted indicator
- Burner start permit indicator
- Burner on/off (start/stop) switch
- Burner proven indicator
- Auxiliary fuel trip pushbuttons

Item 8: One (1) lot of 111 Primary Superheater Pendants

The replacement pendant material consists of:

- 2.50"OD x SA213T22
- Tube ends are machined with a 37.5 degree OD bevel and 10 degree ID bevel for field welding.

Item 9: One (1) lot of 111 Primary Superheater Jumper Tubes

The replacement jumper tube material consists of:

- 2.50"OD x SA213T22
- Tube ends are machined with a 37.5 degree OD bevel and 10 degree ID bevel for field welding.

Item 10: One (1) lot of 27 Secondary Superheater Leading Edge Tubes

The replacement SSH material consists of:

- 2.00"OD x SA213T22
- Tube ends are machined with a 37.5 degree OD bevel and 10 degree ID bevel for field welding.

6.00	
32.00	
48.00	
14.00	
100.00	
COAL	Nat Gas
WT	VOL
9.57	
8.44	
65.36	
4.70	
1.16	1.13
3.41	
7.36	
	76.69
	16.54
	4.33
	0.94
	0.20
	0.09
	0.08
0.00	
100.00	100.00
12,034	22,518
	1205

DATE :

cock & Wilcox Company

HEAT AVAILABLE, MKB/HR (FUEL & HEATED AIR)			2523.00	2838.00	2803.00	1795.00	1773.00	1747.00	10
HEAT CREDITS, MKB/HR (PER PTC 4-1998)			0.00	0.00	0.00	0.00	0.00	0.00	11
FUEL INPUT, MKB/HR			2410.00	2818.10	2802.50	1722.00	1775.10	1761.40	12
QUANTITY - MLB/HR		FUEL FLOW (MCF/HR IF GAS)	200.80	2338.60	2325.80	143.10	1473.10	1461.70	13
		FLUE GAS ENTERING AIR HEATER	2330.00	2418.10	2404.80	1682.00	1595.40	1583.10	14
		TOTAL AIR TO BURNING EQUIPMENT	1889.00	2251.30	2238.90	1300.00	1490.30	1478.80	15
		SECONDARY AIR LEAVING AH	-	-	-	-	-	-	16
		PRIMARY AIR LEAVING AH	-	-	-	-	-	-	17
		TEMPERING AIR	-	-	-	-	-	-	18
		AIR HTR LEAKAGE (TOTAL AIR TO GAS)	-	-	-	-	-	-	19
		AIR HTR LEAKAGE (PRI AIR TO GAS)	-	-	-	-	-	-	20
		AIR HTR LEAKAGE (SEC AIR TO GAS)	-	-	-	-	-	-	21
		AIR HTR LEAKAGE (PRI AIR TO SEC AIR)	-	-	-	-	-	-	22
		SUPERHEAT SPRAY FLOW	40.30	219.40	276.00	11.50	99.90	138.70	23
		REHEAT SPRAY FLOW (RH1/RH2)	0/0	12.3/0	9.4/0	0/0	0/0	0/0	24
PRESSURE - PSIG		STEAM AT SH OUTLET	2500	2500	2500	2500	2500	2500	25
		STEAM AT RH1 INLET	535	531	531	357	357	357	26
		STEAM AT RH2 INLET	-	-	-	-	-	-	27
	DROP	REHEATER 1	25	39	39	16	16	16	28
		REHEATER 2	-	-	-	-	-	-	29
		ECONOMIZER (PLUS FURNACE IF UP)	25	30	30	11	11	11	30
		DRUM OR VSS TO SH OUTLET	150	182	182	67	67	67	31
TEMPERATURE - DEG. F	STEAM	LEAVING SUPERHEATER	1050	1050	1050	1050	1050	1050	32
		LEAVING REHEATER 1	1050	1050	1050	1050	990	978	33
		ENTERING REHEATER 1	675	658	661	600	601	601	34
		LEAVING REHEATER 2	-	-	-	-	-	-	35
		ENTERING REHEATER 2	-	-	-	-	-	-	36
	WATER	ENTERING ECONOMIZER	526	523	523	481	481	481	37
	GAS (MHVT)	LEAVING ECONOMIZER	702	711	668	662	658	621	38
		LEAVING AH (EXCL. LKG)	300	314	299	290	289	277	39
		LEAVING AH (INCL. LKG)	-	-	-	-	-	-	40
		ENTERING SSH INLET (24" SPACING)	-	-	-	-	-	-	41
		ENTERING 12" OR LOWER SPACING	-	-	-	-	-	-	42
	AIR	ENTERING PRI. AIR HEATER (1)	-	-	-	-	-	-	43
		ENTERING SEC. AIR HEATER (1)	-	-	-	-	-	-	44
		LEAVING AIR HEATER (SEC)	-	-	-	-	-	-	45
		LEAVING AIR HEATER (PRI)	-	-	-	-	-	-	46
	FUEL	TO BURNING EQUIPMENT	-	-	-	-	-	-	47
RESISTANCE - IN. H2O	GAS	FURNACE & CONVECTION BANKS	-	-	-	-	-	-	48
		FLUES TO AH OUTLET	-	-	-	-	-	-	49
		AIR HEATER	-	-	-	-	-	-	50
		SCR	-	-	-	-	-	-	51
		TOTAL FROM FURNACE TO STACK	-	-	-	-	-	-	52
	PRI AIR	AIR HEATER	-	-	-	-	-	-	53
		DUCTS & FLOW METER	-	-	-	-	-	-	54
		PULVERIZERS	-	-	-	-	-	-	55
		FUEL PIPING TO BURNERS	-	-	-	-	-	-	56
		BURNERS	-	-	-	-	-	-	57
		TOTAL	-	-	-	-	-	-	58
	SEC AIR	FUEL BURNERS & WINDBOX	-	-	-	-	-	-	59
		DUCTS & FLOW METER	-	-	-	-	-	-	60
		AIR HEATER	-	-	-	-	-	-	61
		TOTAL FROM FD FAN TO FURNACE	-	-	-	-	-	-	62
HEAT LOSSES, %		DRY GAS	3.980	3.220	2.950	3.800	3.240	3.010	63
		H2 & H2O IN FUEL	4.370	9.810	9.740	4.340	9.860	9.810	64
		MOISTURE IN AIR	0.100	0.080	0.080	0.100	0.080	0.080	65
		UNBURNED COMBUSTIBLE IN RESIDUE	0.480	0.000	0.000	0.600	0.000	0.000	66
		RADIATION	0.160	0.190	0.190	0.240	0.300	0.300	67
		SENSIBLE HEAT IN REFUSE	0.000	0.000	0.000	0.000	0.000	0.000	68
		MANUFACTURER'S MARGIN	1.500	1.500	1.500	1.500	1.500	1.500	69
		OTHER LOSSES (UNMEASURED)	0.000	0.000	0.000	0.000	0.000	0.000	70
TOTAL LOSSES			10.590	14.800	14.460	10.580	14.980	14.700	71
ITS, %		ENTERING DRY AIR	0.000	0.000	0.000	0.000	0.000	0.000	72
		MOISTURE IN AIR	0.000	0.000	0.000	0.000	0.000	0.000	73

PRESSURE PART HEATING SURFAC	R N	SUPERHEATER (PROJECTED)	
		TOTAL FURNACE HEATING SURFACE	
	C O N V	SATURATED (CIRCUMFERENTIAL)	
		SUPERHEATER (CIRCUMFERENTIAL)	
		ECONOMIZER	
		TOTAL CONVECTION HEATING SURFACE	
		TOTAL FURN & CONV PRESSURE PART HTG S	
		FLAT PROJECTED FURNACE HEATING SURF/	
		TO FACE OF SH (24" CL)	
SQ FT		TO FACE OF CONVECTION SURFACE	
		FURNACE VOLUME, CUBIC FEET	
AIR HEATER		TYPE REGENERATIVE	
		TOTAL HEATING SURFACE, SQUARE FE	
FUEL BURNER		TYPE:	XCL-S PR
		NO.:	18
PULV		TYPE:	
		SIZE:	
		NUMBER:	
STEAM TEMP. CONTROL		SH & RH ATTEMPERATION	
		EXCESS AIR	
UNIT CONSTR. FEATURES		PARALLEL PASS HORIZONTA	

REVISIONS	NO.	DATE	BY	DESCRIPTION

CUSTOMER:

B&W 275R AEP Big Sa
Natural Gas Conve
Existing Surfa

				HEAT AVAILABLE, MKB/HR (FUEL & HEATED AIR)	1141.00	1121.00	10
				HEAT CREDITS, MKB/HR (PER PTC 4-1998)	0.00	0.00	11
				FUEL INPUT, MKB/HR	1146.00	1133.10	12
		QUANTITY - MLB/HR		FUEL FLOW (MCF/HR IF GAS)	951.00	940.40	13
				FLUE GAS ENTERING AIR HEATER	1085.00	2475.13	14
				TOTAL AIR TO BURNING EQUIPMENT	1017.20	1005.80	15
				SECONDARY AIR LEAVING AH	-	-	16
				PRIMARY AIR LEAVING AH	-	-	17
6.00				TEMPERING AIR	-	-	18
32.00				AIR HTR LEAKAGE (TOTAL AIR TO GAS)	-	-	19
48.00				AIR HTR LEAKAGE (PRI AIR TO GAS)	-	-	20
14.00				AIR HTR LEAKAGE (SEC AIR TO GAS)	-	-	21
100.00				AIR HTR LEAKAGE (PRI AIR TO SEC AIR)	-	-	22
COAL	Nat Gas			SUPERHEAT SPRAY FLOW	36.62	56.73	23
WT	VOL			REHEAT SPRAY FLOW (RH1/RH2)	0/0	0/0	24
9.57		PRESSURE - PSIG		STEAM AT SH OUTLET	2500	2500	25
8.44				STEAM AT RH1 INLET	220	220	26
65.36				STEAM AT RH2 INLET	-	-	27
4.70			DROP	REHEATER 1	8	8	28
1.16	1.13			REHEATER 2	-	-	29
3.41				ECONOMIZER (PLUS FURNACE IF UP)	4	4	30
7.36				DRUM OR VSS TO SH OUTLET	26	26	31
	76.69	TEMPERATURE - DEG. F	STEAM	LEAVING SUPERHEATER	1050	1050	32
				LEAVING REHEATER 1	951	928	33
				ENTERING REHEATER 1	553	553	34
	16.54			LEAVING REHEATER 2	-	-	35
	4.33			ENTERING REHEATER 2	-	-	36
	0.94		WATER	ENTERING ECONOMIZER	427	427	37
	0.20		GAS (MHVT)	LEAVING ECONOMIZER	611	576	38
	0.09			LEAVING AH (EXCL. LKG)	268	256	39
				LEAVING AH (INCL. LKG)	-	-	40
	0.08			ENTERING SSH INLET (24" SPACING)	-	-	41
				ENTERING 12" OR LOWER SPACING	-	-	42
0.00			AIR	ENTERING PRI. AIR HEATER (1)	-	-	43
100.00	100.00			ENTERING SEC. AIR HEATER (1)	-	-	44
12,034	22,518			LEAVING AIR HEATER (SEC)	-	-	45
	1205			LEAVING AIR HEATER (PRI)	-	-	46
			FUEL	TO BURNING EQUIPMENT	-	-	47
		RESISTANCE - IN. H2O	GAS	FURNACE & CONVECTION BANKS	-	-	48
				FLUES TO AH OUTLET	-	-	49
				AIR HEATER	-	-	50
				SCR	-	-	51
				TOTAL FROM FURNACE TO STACK	-	-	52
			PRI AIR	AIR HEATER	-	-	53
				DUCTS & FLOW METER	-	-	54
				PULVERIZERS	-	-	55
				FUEL PIPING TO BURNERS	-	-	56
				BURNERS	-	-	57
				TOTAL	-	-	58
			SEC AIR	FUEL BURNERS & WINDBOX	-	-	59
				DUCTS & FLOW METER	-	-	60
				AIR HEATER	-	-	61
				TOTAL FROM FD FAN TO FURNACE	-	-	62
		HEAT LOSSES, %		DRY GAS	3.000	2.760	63
				H2 & H2O IN FUEL	9.770	9.720	64
				MOISTURE IN AIR	0.080	0.070	65
				UNBURNED COMBUSTIBLE IN RESIDUE	0.000	0.000	66
				RADIATION	0.470	0.470	67
				SENSIBLE HEAT IN REFUSE	0.000	0.000	68
				MANUFACTURER'S MARGIN	1.500	1.500	69
	DATE :			OTHER LOSSES (UNMEASURED)	0.000	0.000	70
				TOTAL LOSSES	14.820	14.520	71
		ITS, %		ENTERING DRY AIR	0.000	0.000	72
				MOISTURE IN AIR	0.000	0.000	73

:ock & Wilcox Company

PRESSURE PART HEATING SURFA	R N	SUPERHEATER (PROJECTED)
		TOTAL FURNACE HEATING SURFACE
	CONV	SATURATED (CIRCUMFERENTIAL)
		SUPERHEATER (CIRCUMFERENTIAL)
		ECONOMIZER
		TOTAL CONVECTION HEATING SURFACE
		TOTAL FURN & CONV PRESSURE PART HTG S
		FLAT PROJECTED FURNACE HEATING SURFA
		TO FACE OF SH (24" CL)
	SQ FT	TO FACE OF CONVECTION SURFACE
		FURNACE VOLUME, CUBIC FEET

AIR HEATER	TYPE REGENERATIVE	
	TOTAL HEATING SURFACE, SQUARE FEI	
FUEL BURNER	TYPE:	XCL-S PR
	NO.:	1:
PULV	TYPE:	
	SIZE:	
	NUMBER:	
STEAM TEMP. CONTROL	SH & RH ATTEMPERATION	
	EXCESS AIR	
UNIT CONSTR. FEATURES	PARALLEL PASS HORIZONTAI	

REVISIONS	NO.	DATE	BY	DESCRIPTION

CUSTOMER:

B&W 275R AEP Big Sa
Natural Gas Conve
Existing Surfa

FUSION TEMPS - F				
REDUCING				
REDUCING				
OXIDIZING ID				
OXIDIZING H=1/2W				
OXIDIZING FLUID				
MISC.				
SIZE				
GRINDABILITY				
SURFACE H2O, %				
PROXIMATE ANALYSIS - %				
TOTAL MOISTURE	6.00			
VOLATILE MATTER	32.00			
FIXED CARBON	48.00			
ASH	14.00			
TOTAL	100.00			
ULTIMATE ANALYSIS				
FUEL	COAL	Nat Gas		
% BY	WT	VOL		
ASH	9.57			
H2O	8.44			
C	65.36			
H2	4.70			
N2	1.16	1.13		
S	3.41			
O2	7.36			
CH4		76.69		
C2H4				
C2H6		16.54		
C3H8		4.33		
C4H10		0.94		
C5H12		0.20		
C6H14		0.09		
CO				
CO2		0.08		
SO2				
Cl + F	0.00			
TOTAL	100.00	100.00		
HHV, BTU/LB	12,034	22,518		
HHV, BTU/CUFT AT 60F, 30 IN HG		1205		

NOTES:

BY: DATE:

The Babcock & Wilcox Company

HEAT AVAILABLE, MKB/HR (FUEL & HEATED AIR)	2523.0	2838.00	2803.00	2875.00	2828.00		10
HEAT CREDITS, MKB/HR (PER PTC 4-1998)	0.00	0.00	0.00	0.00	0.00		11
FUEL INPUT, MKB/HR	2410.00	2818.10	2802.50	2833.70	2814.30		12
QUANTITY - MLB/HR							
FUEL FLOW (MCF/HR IF GAS)	200.80	2338.60	2325.80	2351.60	2335.50		13
FLUE GAS ENTERING AIR HEATER	2330.00	2418.10	2404.80	2431.60	2414.90		14
TOTAL AIR TO BURNING EQUIPMENT	1889.00	2251.30	2238.90	2263.80	2248.30		15
SECONDARY AIR LEAVING AH	-	-	-	-	-		16
PRIMARY AIR LEAVING AH	-	-	-	-	-		17
TEMPERING AIR	-	-	-	-	-		18
AIR HTR LEAKAGE (TOTAL AIR TO GAS)	-	-	-	-	-		19
AIR HTR LEAKAGE (PRI AIR TO GAS)	-	-	-	-	-		20
AIR HTR LEAKAGE (SEC AIR TO GAS)	-	-	-	-	-		21
AIR HTR LEAKAGE (PRI AIR TO SEC AIR)	-	-	-	-	-		22
SUPERHEAT SPRAY FLOW	40.30	219.40	276.00	153.60	229.10		23
REHEAT SPRAY FLOW (RH1/RH2)	0/0	12.3/0	9.4/0	15.1/0	12.3/0		24
PRESSURE - PSIG							
STEAM AT SH OUTLET	2500	2500	2500	2500	2500		25
STEAM AT RH1 INLET	535	531	531	531	531		26
STEAM AT RH2 INLET	-	-	-	-	-		27
DROP: REHEATER 1	25	39	39	39	39		28
DROP: REHEATER 2	-	-	-	-	-		29
DROP: ECONOMIZER (PLUS FURNACE IF UP)	25	30	30	30	30		30
DROP: DRUM OR VSS TO SH OUTLET	150	182	182	182	182		31
TEMPERATURE - DEG. F							
STEAM: LEAVING SUPERHEATER	1050	1050	1050	1050	1050		32
STEAM: LEAVING REHEATER 1	1050	1050	1050	1050	1050		33
STEAM: ENTERING REHEATER 1	675	658	661	655	658		34
STEAM: LEAVING REHEATER 2	-	-	-	-	-		35
STEAM: ENTERING REHEATER 2	-	-	-	-	-		36
WATER: ENTERING ECONOMIZER	526	523	523	523	523		37
GAS (MHVT): LEAVING ECONOMIZER	702	711	668	756	698		38
GAS (MHVT): LEAVING AH (EXCL. LKG)	300	314	299	329	309		39
GAS (MHVT): LEAVING AH (INCL. LKG)	-	-	-	-	-		40
GAS (MHVT): ENTERING SSH INLET (24" SPACING)	-	-	-	-	-		41
GAS (MHVT): ENTERING 12" OR LOWER SPACING	-	-	-	-	-		42
AIR: ENTERING PRI. AIR HEATER (1)	-	-	-	-	-		43
AIR: ENTERING SEC. AIR HEATER (1)	-	-	-	-	-		44
AIR: LEAVING AIR HEATER (SEC)	-	-	-	-	-		45
AIR: LEAVING AIR HEATER (PRI)	-	-	-	-	-		46
FUEL: TO BURNING EQUIPMENT	-	-	-	-	-		47
RESISTANCE - IN. H2O							
GAS: FURNACE & CONVECTION BANKS	-	-	-	-	-		48
GAS: FLUES TO AH OUTLET	-	-	-	-	-		49
GAS: AIR HEATER	-	-	-	-	-		50
GAS: SCR	-	-	-	-	-		51
GAS: TOTAL FROM FURNACE TO STACK	-	-	-	-	-		52
PRI AIR: AIR HEATER	-	-	-	-	-		53
PRI AIR: DUCTS & FLOW METER	-	-	-	-	-		54
PRI AIR: PULVERIZERS	-	-	-	-	-		55
PRI AIR: FUEL PIPING TO BURNERS	-	-	-	-	-		56
PRI AIR: BURNERS	-	-	-	-	-		57
PRI AIR: TOTAL	-	-	-	-	-		58
SEC AIR: FUEL BURNERS & WINDBOX	-	-	-	-	-		59
SEC AIR: DUCTS & FLOW METER	-	-	-	-	-		60
SEC AIR: AIR HEATER	-	-	-	-	-		61
SEC AIR: TOTAL FROM FD FAN TO FURNACE	-	-	-	-	-		62
HEAT LOSSES, %							
DRY GAS	3.980	3.220	2.950	3.490	3.130		63
H2 & H2O IN FUEL	4.370	9.810	9.740	9.870	9.790		64
MOISTURE IN AIR	0.100	0.080	0.080	0.090	0.080		65
UNBURNED COMBUSTIBLE IN RESIDUE	0.480	0.000	0.000	0.000	0.000		66
RADIATION	0.160	0.190	0.190	0.190	0.190		67
SENSIBLE HEAT IN REFUSE	0.000	0.000	0.000	0.000	0.000		68
MANUFACTURER'S MARGIN	1.500	1.500	1.500	1.500	1.500		69
OTHER LOSSES (UNMEASURED)	0.000	0.000	0.000	0.000	0.000		70
TOTAL LOSSES	10.590	14.800	14.460	15.140	14.690		71
CREDITS, %							
ENTERING DRY AIR	0.000	0.000	0.000	0.000	0.000		72
MOISTURE IN AIR	0.000	0.000	0.000	0.000	0.000		73

PRESSURE PART HEATING SURFACE		
FURN	SUPERHEATER (PROJECTED)	
	TOTAL FURNACE HEATING SURFACE	
CONV	SATURATED (CIRCUMFERENTIAL)	
	SUPERHEATER (CIRCUMFERENTIAL)	
	ECONOMIZER	
	TOTAL CONVECTION HEATING SURFACE	
	TOTAL FURN & CONV PRESSURE PART HTG SURF	
	FLAT PROJECTED FURNACE HEATING SURFACE:	
	TO FACE OF SH (24" CL)	
SQ FT	TO FACE OF CONVECTION SURFACE	
	FURNACE VOLUME, CUBIC FEET	
AIR HEATER	TYPE REGENERATIVE	QUANTITY:
	TOTAL HEATING SURFACE, SQUARE FEET:	
FUEL BURNER	TYPE:	XCL-S PRDPOSED
	NO.:	18
PULV	TYPE:	
	SIZE:	
	NUMBER:	
STEAM TEMP. CONTROL	SH & RH ATTEMPERATION	
	EXCESS AIR	
UNIT CONSTR. FEATURES	PARALLEL PASS HORIZONTAL CONVECTION SURF	

REVISIONS	NO.	DATE	BY	DESCRIPTION

CUSTOMER:

B&W 275R AEP Big Sandy Unit 1
Natural Gas Conversion
SR= With SH Surf Removed

B&W DWG No.	TITLE
B0233970	P&ID DRAWING INDEX
B0233971	P&ID IDENTIFICATION & TAGGING
B0233972	P&ID SYMBOLS & NOMENCLATURE
B0233973	P&ID NATURAL GAS BURNER & IGNITER SUPPLY HEADERS
B0233974	P&ID NATURAL GAS BURNER & IGNITER VALVE RACKS
B0233975	P&ID NATURAL GAS BURNER
B0233976	P&ID SCANNER COOLING AIR BLOWERS

SUCCEEDING LETTERS		
UT OR FUNCTION	OUTPUT FUNCTION	MODIFIER
oice	User's Choice	User's Choice
	Control	
Primary		
evice		
		High, Open
	Control Station	
		Low, Closed
		Middle, Intermediate
oice	User's Choice	User's Choice
estriction		
st) n		
	Switch	
	Transmit	
ion	Multifunction	Multifunction
	Valve, Damper, Louver	
ed	Unclassified	Unclassified
	Relay, Compute, Convert	
	Driver, Actuator, Unclassified Final Control Element	

AFS	ACID FEED (ADDITIVES) SYSTEM
ABP	ABSORPTION PLUS ADDITIVE SYSTEM
ABS	ABSORBER/SCRUBBER
AHS	ASH HANDLING SYSTEM
AIG	AMMONIA INJECTION GRID
AMS	AMMONIA (UNLOADING, STORAGE & HANDLING) SYSTEM
APS	ABSORBER PURGE SYSTEM
ARS	ABSORBER RECYCLE SYSTEM
ASW	ASH WATER
AXS	AUXILIARY STEAM
BAG	BOILER AIR & GAS
BCA	BOILER COMBUSTION AIR
BFW	BOILER FEEDWATER
BMP	BALL MILL PRODUCT
BST	BOILER STEAM
CAS	COOLING AIR SYSTEM
CFS	CHEMICAL FEED SYSTEM
CHS	COAL HANDLING SYSTEM
CKS	CAKE WASH SYSTEM
CLS	CLOTH WASH SYSTEM
CND	CONDENSATE & CONDENSER
COP	CATALYST OUTAGE PROTECTION SYSTEM (COPS)
CWS	COOLING WATER SYSTEM
DAS	DILUTION AIR SYSTEM
EQS	EMERGENCY QUENCH SYSTEM
FAS	FLY ASH SYSTEM
FFS	FILTER FEED SYSTEM
FGS	FLUE GAS SYSTEM
FHS	FUEL HANDLING SYSTEM
FLA	FLUIDIZING AIR
FOS	FUEL OIL SYSTEM
FPS	FIRE PROTECTION SYSTEM
FSS	FEED SLURRY SYSTEM
FWS	FILTRATE WATER SYSTEM
GHS	GYPSUM HANDLING SYSTEM
GSS	GYPSUM SLURRY SYSTEM
HJS	HYDROJET SYSTEM
IAS	INSTRUMENT AIR SUPPLY
IST	INERTING STEAM
LDS	DRY (PEBBLE) LIME SYSTEM
LHS	LIMESTONE HANDLING SYSTEM
LOS	LUBE OIL SYSTEM
LSS	LIMESTONE SLURRY SYSTEM
MAS	MER PLUS ADDITIVE SYSTEM
MEW	MIST ELIMINATOR WASH WATER
MSS	MAIN STEAM SYSTEM
NGS	NATURAL GAS SYSTEM
NOS	NOX REDUCTION SYSTEM
OAS	OXIDATION AIR SYSTEM
ORA	OVERFIRE AIR
PAC	PAC INJECTION SYSTEM
PAF	PRIMARY AIR FLOW
PCS	PULVERIZED COAL SYSTEM
PJF	FABRIC FILTER SYSTEM
PWS	POTABLE WATER SYSTEM
RHS	REHEAT STEAM SYSTEM
RPS	REAGENT PREP SYSTEM
RSS	RECYCLE SLURRY SYSTEM
RWS	RECLAIM WATER SYSTEM
SAF	SECONDARY AIR FLOW
SAS	SERVICE AIR SYSTEM
SBS	SOOT BLOWING SYSTEM
SHS	SONIC HORNS SYSTEM
SIS	SORBENT INJECTION SYSTEM
SLA	SEAL AIR
STM	STEAM
SWS	SERVICE WATER SYSTEM
VDS	VENTS AND DRAINS
VFS	VACUUM FILTER SKID/SYSTEM
WWT	WASTE WATER TREATMENT

AE	ANALYZER ELEMENT
AT	ANALYZER TRANSMITTER
BE	FLAME ELEMENT
BT	FLAME INTENSITY
DE	DENSITY ELEMENT
DT (DIT)	DENSITY TRANSMITTER
FE	FLOW ELEMENT
FI	FLOW INDICATOR
FO	FLOW ORIFICE
FS (HH,H,M,L,LL)	FLOW SWITCH
FT (FIT)	FLOW TRANSMITTER
IT	CURRENT TRANSMITTER
JT	POWER TRANSMITTER
LI	LEVEL INDICATOR
LS (HH,H,M,L,LL)	LEVEL SWITCH
LT (LIT)	LEVEL TRANSMITTER
PDI	DIFFERENTIAL PRESSURE INDICATOR
PDS (HH,H,M,L,LL)	DIFFERENTIAL PRESSURE SWITCH
PDT (PDIT)	DIFFERENTIAL PRESSURE TRANSMITTER
PI	PRESSURE INDICATOR
PS (HH,H,M,L,LL)	PRESSURE SWITCH
PT (PIT)	PRESSURE TRANSMITTER
SS (HH,H,M,L,LL)	SPEED SWITCH
ST (SIT)	SPEED TRANSMITTER
TE	TEMPERATURE ELEMENT
TI	TEMPERATURE INDICATOR
TS (HH,H,M,L,LL)	TEMPERATURE SWITCH
TT (TIT)	TEMPERATURE TRANSMITTER
TW	THERMOWELL
VE	VIBRATION ELEMENT
VT (VIT)	VIBRATION TRANSMITTER
WE	LOAD CELL
WT (WIT)	WEIGHT TRANSMITTER
XS	GENERAL SWITCH
ZS	PROXIMITY SWITCH

R LEGEND

-XXXX

UNIQUE SEQUENCE NUMBER

EQUIPMENT TYPE
MANUAL VALVE TYPE

INSTRUMENT TYPE
CONTROL/AUTOMATED VALVE TYPE

NT LEGEND

UNIQUE SEQUENCE NUMBER

EQUIPMENT CODES

ABS	ABSORBER
ACT	ACTIVATOR
ACU	ACCUMULATOR
AGT	AGITATOR
AHT	AIR HEATER
AIG	AMMONIA INJECTION GRID
ATM	ATOMIZER
BGH	BAGHOUSE
BIN	BIN
BLO	BLOWER
BMC	BALL MILL CLUTCH
BML	BALL MILL
BOX	BOX
BRL	BARREL
BRN	BURNER
CLF	COOLING FAN
CLR	COOLER
CLT	CLUTCH
CPL	CONTROL PANEL
CPR	COMPRESSOR
CRU	CRUSHER
CSF	CLASSIFIER
CVR	CONVEYOR
DCL	DUST COLLECTOR
DMP	DAMPER
DRM	DRUM
DRV	DRIVE
DRY	DRYER
EDC	EDUCTOR
EES	EMERGENCY EYEWASH SYSTEM
EXJ	EXPANSION JOINT
FAN	FAN
FDR	FEEDER
FLT	FILTER
GBX	GEAR BOX
GRD	GEAR REDUCER
HTR	HEATER
HXR	HEAT EXCHANGER
HYC	HYDROCLONE
HYD	HYDROJET
IGN	IGNITER
JBX	JUNCTION BOX
MFD	MANIFOLD
MIX	AMMONIA AIR MIXER
MXR	MIXER
MTR	MOTOR
PDG	PINION DRIVE GEAR
PLV	PULVERIZER
PMP	PUMP
RCV	RECEIVER
RFO	RESTRICTIVE ORIFACE
RVR	RESERVOIR
SBL	SOOTBLOWER
SCB	SCRUBBER
SCN	SCREEN
SCR	SELECTIVE CATALYTIC REDUCTION
SDA	SPRAY DRYER ABSORBER
SEP	SEPARATOR
SGN	STEAM GENERATOR
SIL	SILO
SIS	SORBENT INJECTION SYSYEM
SKD	SKID
SLC	SILENCER
SLK	SLAKER
SMP	SUMP
SNK	SINK
STP	STANDPIPE
STR	STRAINER
TNK	TANK
TRP	STEAM
VAP	VAPORIZE
VBF	VACUUM BELT FILTER

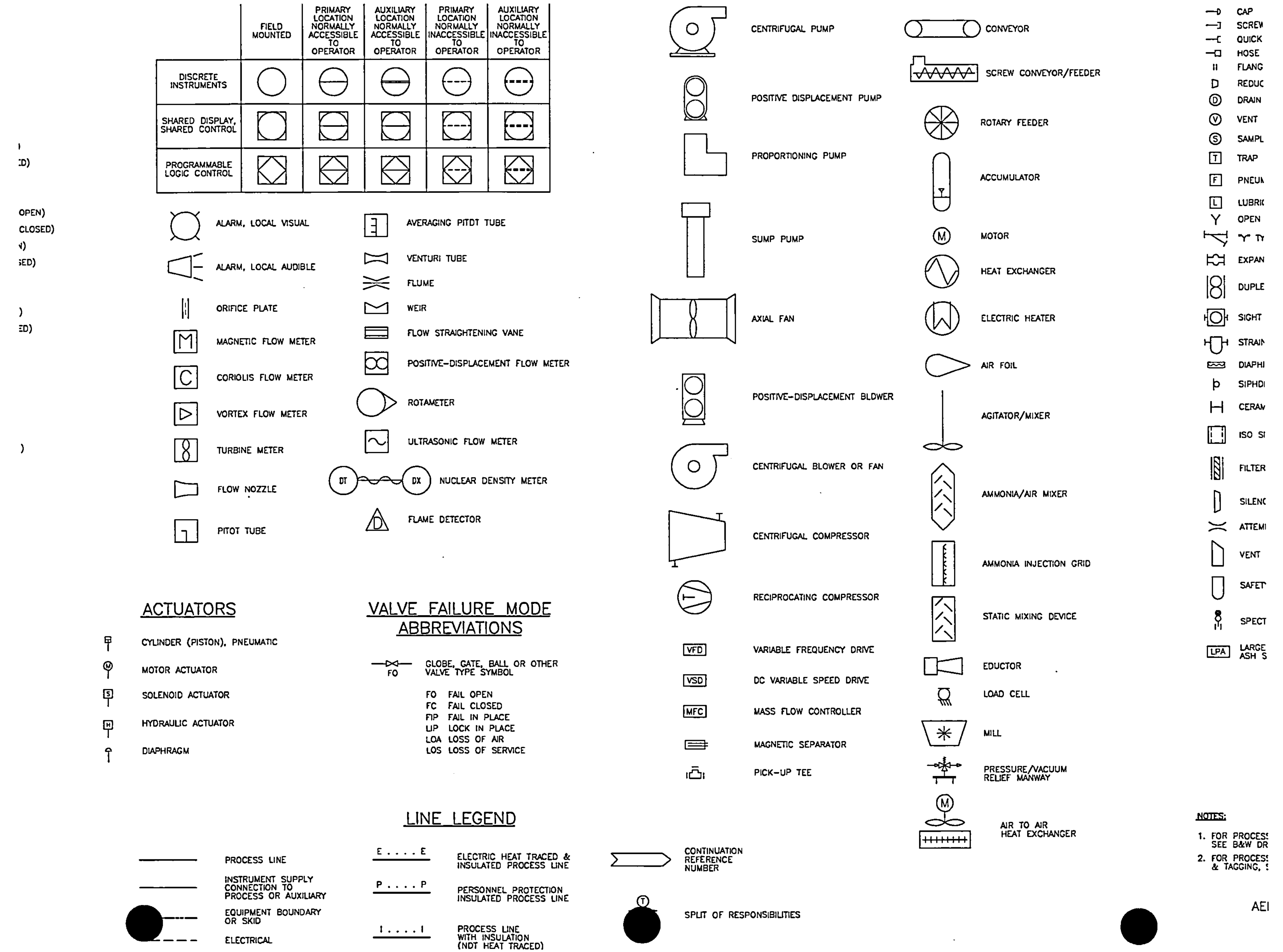
VALVE CODES

CHK	CHECK VALVE
FCV	FLOW CONTROL VALVE
HV	MANUAL VALVE
LCV	LEVEL CONTROL VALVE
MOV	MOTOR OPERATED VALVE
PCV	PRESSURE CONTROL/REGULATING VALVE
PSV	PRESSURE (SAFETY) RELIEF VALVE
SOV	SOLENOID OPERATED VALVE
TCV	TEMPERATURE CONTROL VALVE
XV	AUTOMATED VALVE/DAMPER

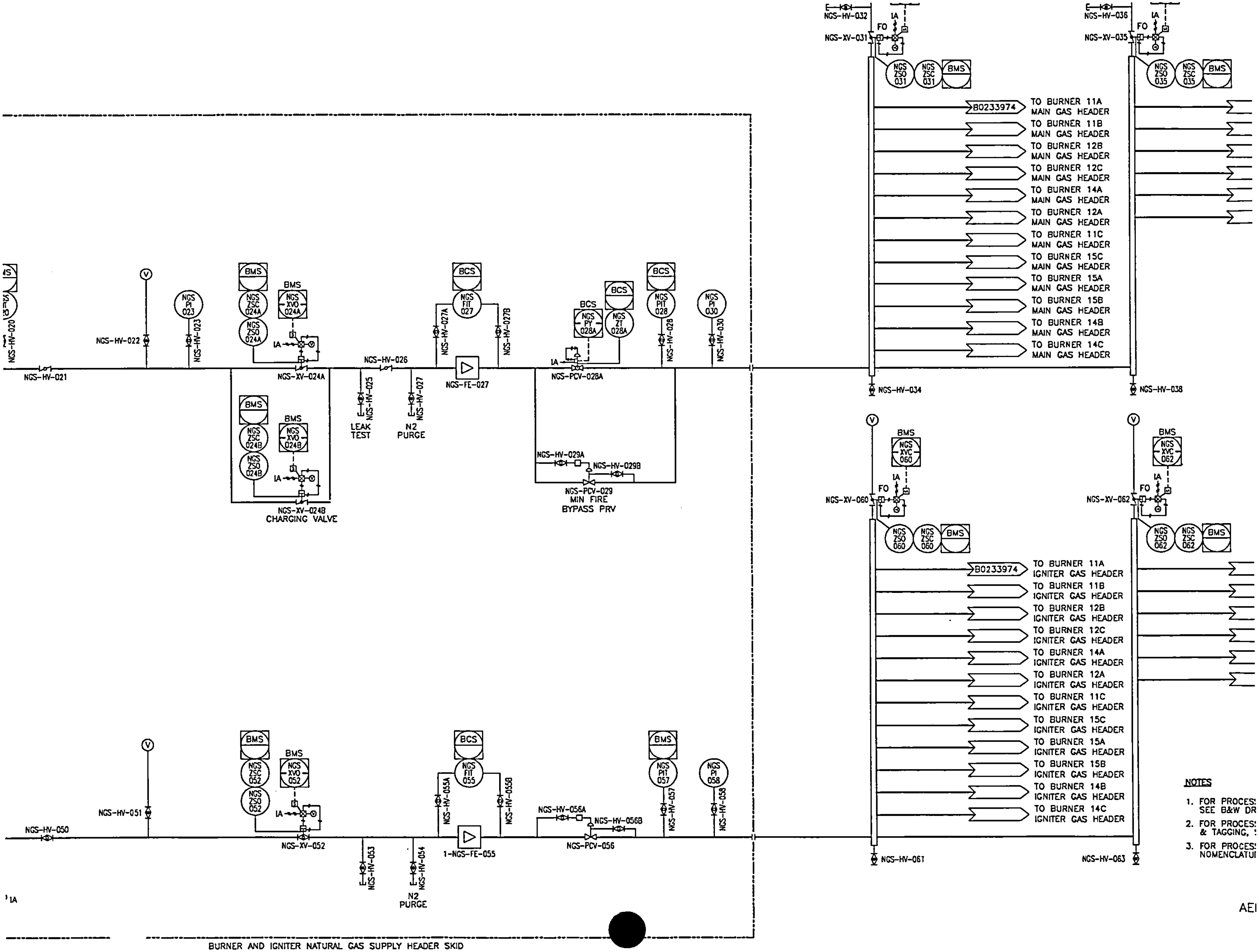
NOTES:

1. FOR PROCES SEE B&W DR
2. FOR PROCES NOMENCLATUR

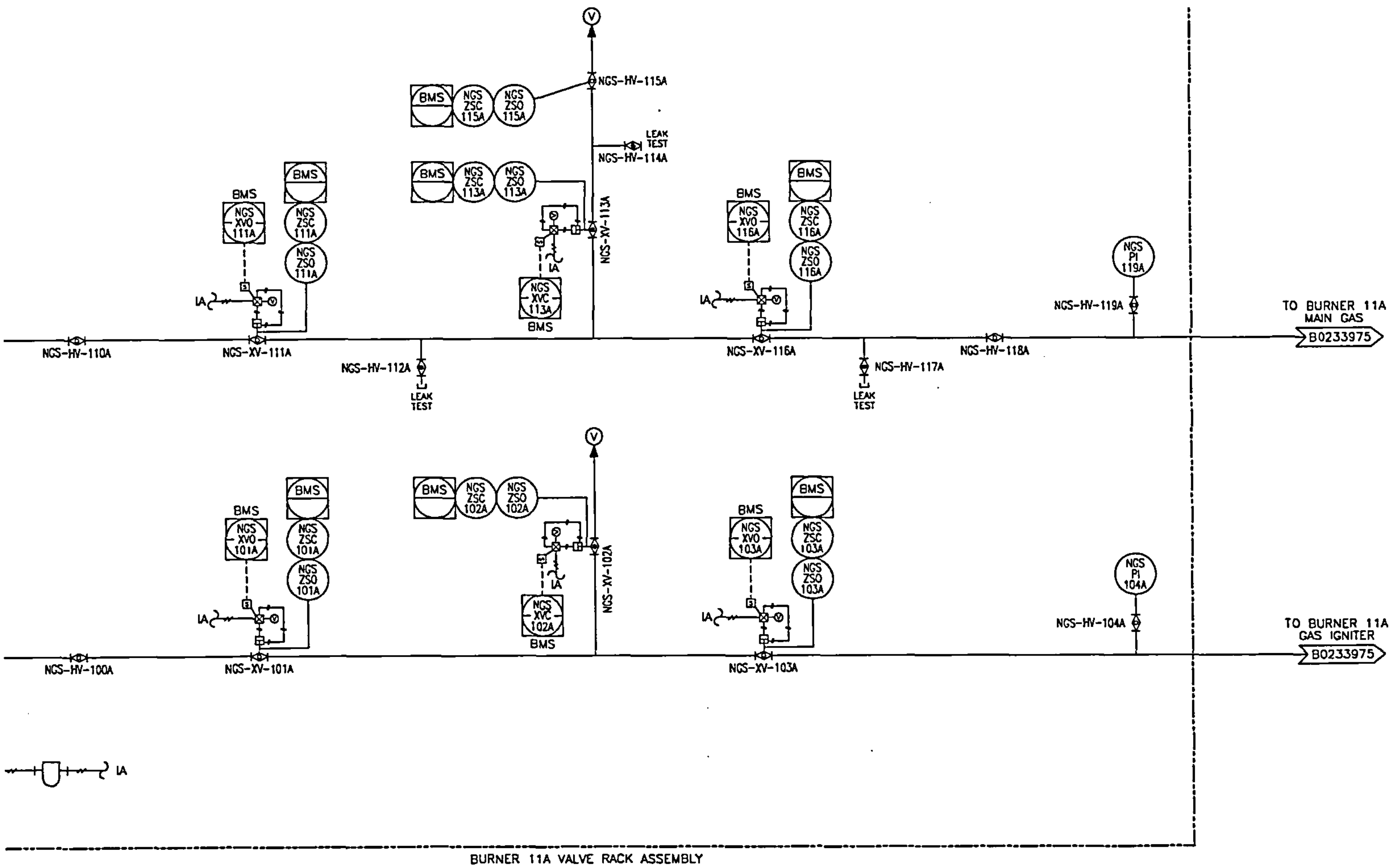
AE



ED)
OPEN)
CLOSED)
N)
SED)
)
ED)
)
FIELD MOUNTED
PRIMARY LOCATION NORMALLY ACCESSIBLE TO OPERATOR
AUXILIARY LOCATION NORMALLY ACCESSIBLE TO OPERATOR
PRIMARY LOCATION NORMALLY INACCESSIBLE TO OPERATOR
AUXILIARY LOCATION NORMALLY INACCESSIBLE TO OPERATOR
DISCRETE INSTRUMENTS
SHARED DISPLAY, SHARED CONTROL
PROGRAMMABLE LOGIC CONTROL
ALARM, LOCAL VISUAL
ALARM, LOCAL AUDIBLE
ORIFICE PLATE
MAGNETIC FLOW METER
CORIOLIS FLOW METER
VORTEX FLOW METER
TURBINE METER
FLOW NOZZLE
PITOT TUBE
AVERAGING PITOT TUBE
VENTURI TUBE
FLUME
WEIR
FLOW STRAIGHTENING VANE
POSITIVE-DISPLACEMENT FLOW METER
ROTAMETER
ULTRASONIC FLOW METER
DT
DX
NUCLEAR DENSITY METER
FLAME DETECTOR
ACTUATORS
CYLINDER (PISTON), PNEUMATIC
MOTOR ACTUATOR
SOLENOID ACTUATOR
HYDRAULIC ACTUATOR
DIAPHRAGM
VALVE FAILURE MODE ABBREVIATIONS
FO
GLOBE, GATE, BALL OR OTHER VALVE TYPE SYMBOL
FO FAIL OPEN
FC FAIL CLOSED
FIP FAIL IN PLACE
LIP LOCK IN PLACE
LOA LOSS OF AIR
LOS LOSS OF SERVICE
LINE LEGEND
PROCESS LINE
INSTRUMENT SUPPLY CONNECTION TO PROCESS OR AUXILIARY
EQUIPMENT BOUNDARY OR SKID
ELECTRICAL
E . . . . E
ELECTRIC HEAT TRACED & INSULATED PROCESS LINE
P . . . . P
PERSONNEL PROTECTION INSULATED PROCESS LINE
I I
PROCESS LINE WITH INSULATION (NOT HEAT TRACED)
CENTRIFUGAL PUMP
POSITIVE DISPLACEMENT PUMP
PROPORTIONING PUMP
SUMP PUMP
AXIAL FAN
POSITIVE-DISPLACEMENT BLOWER
CENTRIFUGAL BLOWER OR FAN
CENTRIFUGAL COMPRESSOR
RECIPROCATING COMPRESSOR
VFD
VARIABLE FREQUENCY DRIVE
VSD
DC VARIABLE SPEED DRIVE
MFC
MASS FLOW CONTROLLER
MAGNETIC SEPARATOR
PICK-UP TEE
CONTINUATION REFERENCE NUMBER
T
SPLIT OF RESPONSIBILITIES
CONVEYOR
SCREW CONVEYOR/FEEDER
ROTARY FEEDER
ACCUMULATOR
M
MOTOR
HEAT EXCHANGER
ELECTRIC HEATER
AIR FOIL
AGITATOR/MIXER
AMMONIA/AIR MIXER
AMMONIA INJECTION GRID
STATIC MIXING DEVICE
EDUCTOR
LOAD CELL
MILL
PRESSURE/VACUUM RELIEF MANWAY
M
AIR TO AIR HEAT EXCHANGER
CAP
SCREW
QUICK
HOSE
FLANG
REDUC
D
DRAIN
V
VENT
S
SAMPL
T
TRAP
F
PNEUM
L
LUBRIC
OPEN
EXPAN
DUPLE
SIGHT
STRAIN
DIAPHI
SIPHON
CERAM
ISO SI
FILTER
SILENC
ATTEM
VENT
SAFET
SPECT
LPA
LARGE ASH S
NOTES:
1. FOR PROCESS SEE B&W DR
2. FOR PROCESS & TAGGING, S
AE



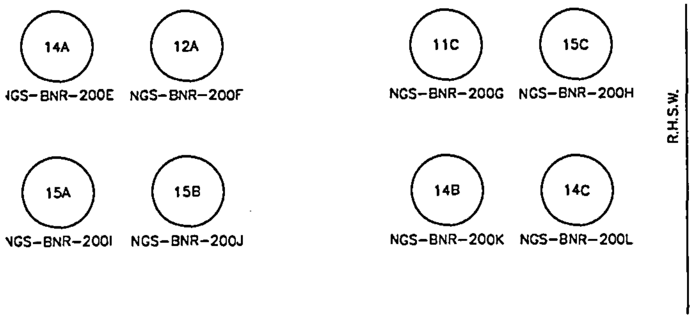
NGS-HV-032
NGS-XV-031
FO
IA
NGS ZSO 031
NGS ZSC 031
BMS
NGS-HV-036
NGS-XV-035
NGS ZSO 035
NGS ZSC 035
B0233974
TO BURNER 11A MAIN GAS HEADER
TO BURNER 11B MAIN GAS HEADER
TO BURNER 12B MAIN GAS HEADER
TO BURNER 12C MAIN GAS HEADER
TO BURNER 14A MAIN GAS HEADER
TO BURNER 12A MAIN GAS HEADER
TO BURNER 11C MAIN GAS HEADER
TO BURNER 15C MAIN GAS HEADER
TO BURNER 15A MAIN GAS HEADER
TO BURNER 15B MAIN GAS HEADER
TO BURNER 14B MAIN GAS HEADER
TO BURNER 14C MAIN GAS HEADER
NGS-HV-034
NGS-HV-038
NGS-HV-020
NGS-HV-021
NGS-HV-022
NGS PI 023
NGS-HV-023
NGS ZSC 024A
NGS ZSO 024A
NGS XVO 024A
NGS-XV-024A
NGS-HV-026
NGS-HV-025
LEAK TEST
NGS-HV-027
N2 PURGE
BCS
NGS FIT 027
NGS-HV-027A
NGS-HV-027B
NGS-FE-027
NGS PY 028A
NGS ZT 028A
NGS-PCV-028A
NGS PIT 028
NGS-HV-028
NGS PI 030
NGS-HV-030
NGS ZSC 024B
NGS ZSO 024B
NGS XVO 024B
NGS-XV-024B
CHARGING VALVE
NGS-HV-029A
NGS-HV-029B
NGS-PCV-029
MIN FIRE
BYPASS PRV
NGS XVC 060
NGS-XV-060
NGS ZSO 060
NGS ZSC 060
NGS XVC 062
NGS-XV-062
NGS ZSO 062
NGS ZSC 062
TO BURNER 11A IGNITER GAS HEADER
TO BURNER 11B IGNITER GAS HEADER
TO BURNER 12B IGNITER GAS HEADER
TO BURNER 12C IGNITER GAS HEADER
TO BURNER 14A IGNITER GAS HEADER
TO BURNER 12A IGNITER GAS HEADER
TO BURNER 11C IGNITER GAS HEADER
TO BURNER 15C IGNITER GAS HEADER
TO BURNER 15A IGNITER GAS HEADER
TO BURNER 15B IGNITER GAS HEADER
TO BURNER 14B IGNITER GAS HEADER
TO BURNER 14C IGNITER GAS HEADER
NGS-HV-050
NGS-HV-051
NGS ZSC 052
NGS ZSO 052
NGS XVO 052
NGS-XV-052
NGS-HV-053
NGS-HV-054
N2 PURGE
NGS FIT 055
NGS-HV-055A
NGS-HV-055B
1-NGS-FE-055
NGS-HV-056A
NGS-HV-056B
NGS-PCV-056
NGS PIT 057
NGS-HV-057
NGS PI 058
NGS-HV-058
NGS-HV-061
NGS-HV-063
NOTES
1. FOR PROCES
SEE B&W DR
2. FOR PROCES
& TAGGING,
3. FOR PROCES
NOMENCLATU
AE
BURNER AND IGNITER NATURAL GAS SUPPLY HEADER SKID



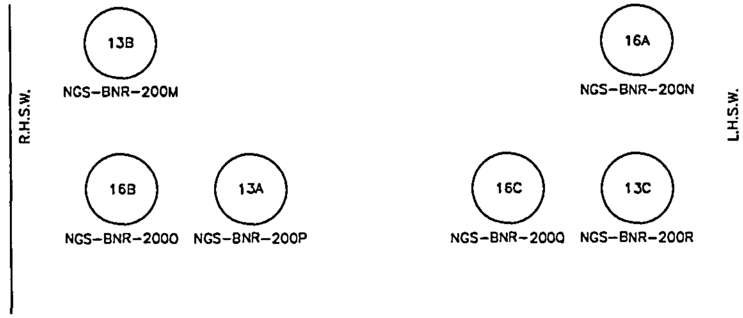
NOTES

1. FOR PROCES SEE B&W DR
2. FOR PROCES & TAGGING,
3. FOR PROCES NOMENCLATU
4. BURNER 11A 13A-C, 14A- NUMBER SUF

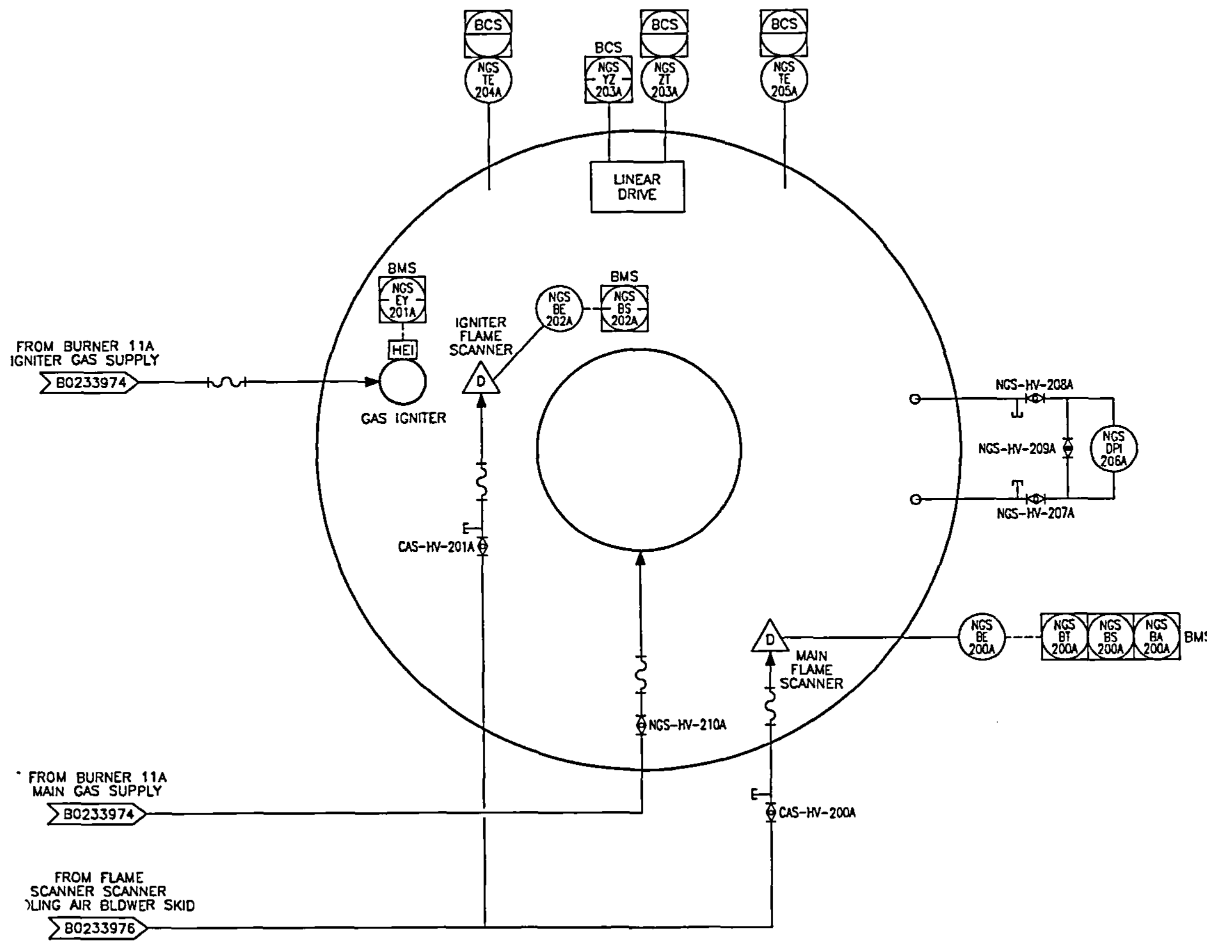
AE



FURNACE FRONT WALL
NATURAL GAS BURNERS



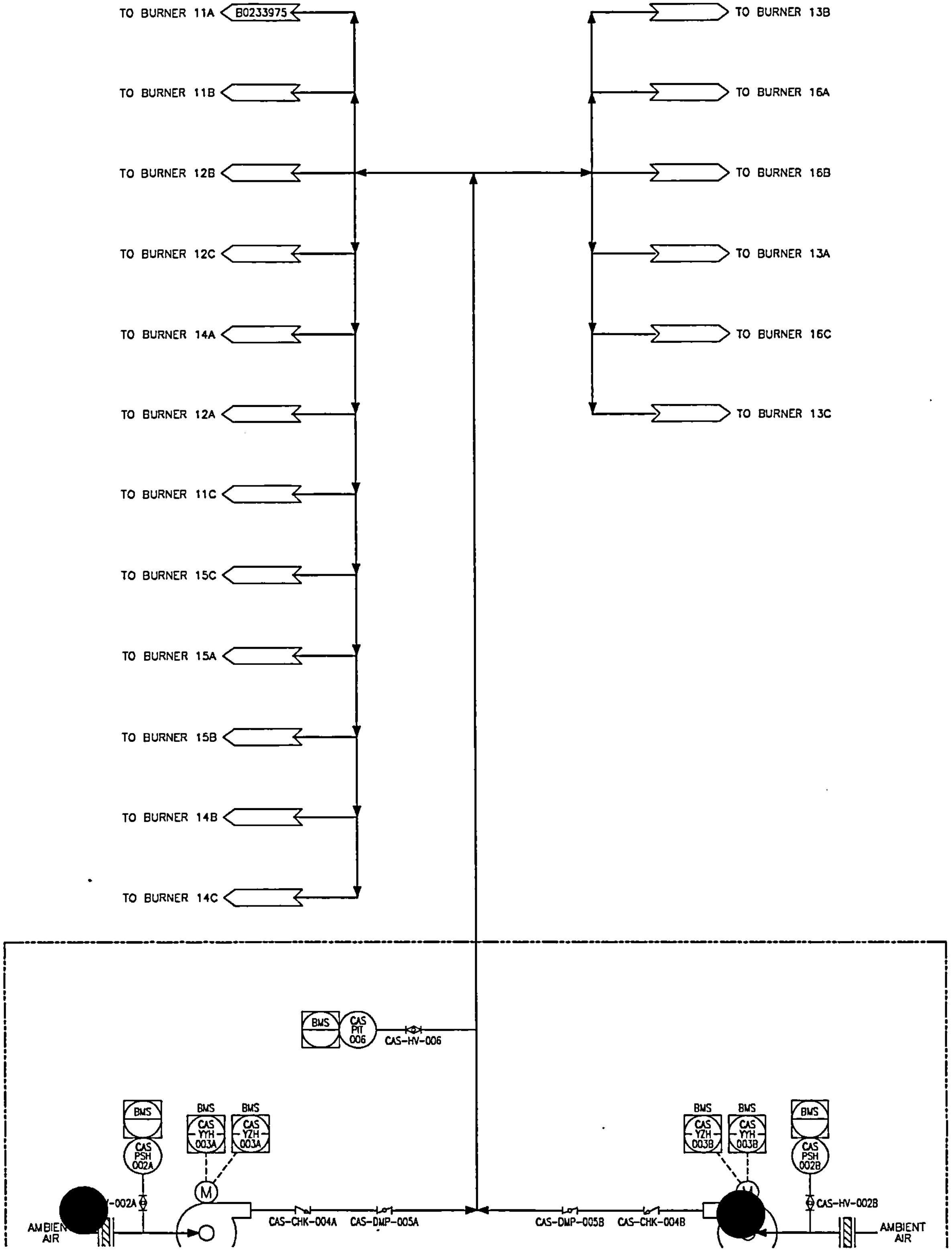
FURNACE REAR WALL
NATURAL GAS BURNERS



NOTES:

1. FOR PROCES
SEE B&W DR
2. FOR PROCES
& TAGGING,
3. FOR PROCES
NOMENCLATU
4. BURNER 11A
13A-C, 14A-
NUMBER SUF

AE



NOTES:

1. FOR PROCES
SEE B&W DR
2. FOR PROCES
& TAGGING,
3. FOR PROCES
NOMENCLATU

AEI

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EcoNomics

AMERICAN ELECTRIC POWER
BIG SANDY UNIT 1 GAS CONVERSION STUDY

Auxiliary Power Supply Study

Document: AEPBS-1-LI-EE-0001

Revision: B

Date: October 2012

WorleyParsons
2675 Morgantown Rd.
Reading, PA 19607
USA
Telephone: +1 610 855 2000
Facsimile: + 1 610 855 2001
www.worleyparsons.com

WorleyParsons
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AMERICAN ELECTRIC POWER
BIG SANDY UNIT 1 GAS CONVERSION STUDY
AUXILIARY POWER SUPPLY STUDY

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REV	DESCRIPTION	ORIGINATOR	REVIEWER	APPROVER	DATE
A	Issued for Review	Y. Tamayo	D. Keller	N. Zappone	October 5, 2012
B	For Use	Y Tamayo Y. Tamayo	N. Zappone N. Zappone	N. Zappone N. Zappone	October 19, 2012

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AMERICAN ELECTRIC POWER
BIG SANDY UNIT 1 GAS CONVERSION STUDY
AUXILIARY POWER SUPPLY STUDY

CONTENTS

APPENDICES

1. EXECUTIVE SUMMARY

The purpose of this study is to determine sources of power for the new loads for the Big Sandy Unit 1 Gas Conversion Project. New loads are listed in Appendix 1. New electrical equipment to power the new loads will consist of two 400A, 600V Flashguard MCCs (or MCC with similar features or better). These two MCCs will be powered from 600V Bus 11A, breaker 11A18 and 600V Bus 11B, breaker 11B10. The MCC low voltage switchgear feeder breakers will be retrofitted to include "Maintenance Bypass Switch" to enable the instantaneous setting of the breaker during maintenance mode.

All 120VAC loads in the plant shall be powered from new Distribution Panels powered from new 600V - 208/120V, 45KVA Transformers. These transformers will be powered from the new 400A, 600V MCCs.

The loads in the vicinity of the metering station including outdoor lighting shall be powered from a 208/120V Panel via 600V-208/120V transformer. This transformer is dual feed from both new MCCs through an automatic transfer switch. The transformer shall also power a Heat Tracing Panel in the metering station vicinity.

2. INTRODUCTION

The Big Sandy Plant is located in Lawrence County, Kentucky, approximately 5 miles north of Louisa, Kentucky and is composed of two coal-fired, steam-electric units. Big Sandy Unit 1 is rated 287 MW gross and was placed in service in 1962. Big Sandy Unit 2 is rated 840 MW gross and was placed in service in 1969. Both units exhaust their flue gas to a common stack. The stack was placed in service in 1969 along with Unit 2.

The Big Sandy Unit 1 Gas Conversion Project will evaluate the feasibility of converting the existing Unit 1 coal fired boiler to natural gas fired. A new Burner System is provided by B&W.

The purpose of this study is to determine sources of power for the new loads for the project.

3. DISCUSSION

3.1 Methodology

A. Because it was assessed earlier in the project that the existing 1750HP FD Fans can support the conversion of the Unit 1 boiler to natural gas firing and that there are no additional air compressors, air dryer or water system pumps needed, an ETAP Study is not required for Phase 1. There are no new medium voltage motors added; therefore, the short circuit requirement of the existing buses will not be impacted.

The following medium voltage and low voltage loads will be demolished, thereby reducing the loading on the existing unit auxiliary transformers:

1. Six 200HP Pulverizers
2. Six 250HP Pulverizer Fans
3. Two ash handling water supply pumps (1 x 300HP and 1 x 400HP)
4. Two Precipitators powered from 750 KVA and 500 KVA transformers
5. One 800HP Air Preheater Pumps
6. Four 250HP Ash Pond Recirc Pumps
7. One 200HP Conveyor #3 on Bus 11A
8. SO3 MCC

The list above is not a complete list of loads to be demolished for gas conversion. The one line diagrams of the existing MCC are not accurate and a walkdown of all existing MCCs is required to identify these loads.

Note that the removal of these many loads will affect the aux transformers taps, protective relay settings and arc flash analysis on the unit. For detail design, a Load Flow, Voltage Drop and Short Circuit Study, Relay Coordination Study and Arc Flash Study will be required.

B. Because of the nature of the new loads needed by the Burner System, it was determined that only MCC sources were needed. A walkdown was scheduled on

September 12, 2012 to determine possible power sources for the new MCCs. The results of the walkdown show that breakers 11A18 in Bus 11A and 11B10 in Bus 11B can be used to power the new MCCs.

C. The new MCCs will be Eaton Flashguard MCC or MCC with similar features or better to meet the required arc flash upgrade per AEP Fleet Electrical Design Criteria. The MCC low voltage switchgear feeder breakers will be retrofitted to include "Maintenance Bypass Switch" to enable the instantaneous setting of the breaker during maintenance mode.

D. The new Beck 1/2HP, 120V damper drives will be powered from new 208/120V Distribution Panels powered from the new MCCs via 600V -208/120V transformers. These distribution panels will not power any lighting loads.

E. The loads in the vicinity of the metering station including outdoor lighting shall be powered from a 208/120V Panel via 600V-208/120V transformer. This transformer is dual feed from both new MCCs through an automatic transfer switch. The transformer shall also power a Heat Tracing Panel. See One Line Diagram AEPBS-1- SK-EE-206-002 in Appendix 4 for more details.

3.2 New Loads

A. New loads for the Project are listed in Appendix 1.

B. The conversion to natural gas will create new Hazardous Areas. Any existing electrical equipment that are in these areas shall be relocated or shall be replaced with equivalent Class I Div. 2 equipment. Appendix 2 identifies these devices and equipment.

3.3 Design Basis

A. AEP Drawings used for the study are

1. AEP Dwg. No. 1-1200A Rev. 18, "Auxiliary One Line"
2. AEP Dwg. No. 1-1200B Rev. 28, "Auxiliary One Line Unit #1"
3. AEP Dwg. No. 1-1200C Rev. 3, "Auxiliary One Line Unit #"

B. DC-ELEC-001-02, "AEP Fleet Plant Electrical Design Criteria" Dated May 10, 2010

C. AEPBS-1-SK-025-818-001 Rev. A, "Control System Architecture"

D. AEPBS-1-SK-561-302-001 Rev. B, 'Unit 1 Flue Gas System Piping & Instrumentation"

E. AEPBS-1-SK-600-002-001 Rev. B, "Unit 1 Enlarged Plant Plot Plan"

F. AEPBS-1-SK-600-002-002 Rev. B, "Unit 1 Metering Station Plot Plan"

G. The voltage for all new low voltage motors will be 575V.

H. Motor heaters for large demolished d motors are not considered in this study.

I. Gas Heater blowers are assumed 3HP. Thirty two (32) gas heater blowers are required for Unit 1.

J. The eighteen (18) 0.5HP damper drives are assumed Beck drives with integral starters and controller. For this study, the drives are assumed 120VAC.

K. Burner System Loads are listed in Appendix 3.

L. All power and control cables in the switchgear powering the loads identified in Section 3.1.A to be demolished will be determinated and pulled to the nearest tray.

M. To maintain air changes and velocity suggested by AEP, additional ventilation air across the burner fronts are required. Six fans are required and the fan motors are assumed 2HP each. Three (3) fans are required on the north wall and three (3) fans on the south wall. The air flow will be parallel to the burner front walls.

4. CONCLUSIONS

Based on the new loads identified in Appendix 1, two new 400A, 600V MCCs configured per sketch AEPBS-1-SK-EE-206-002 are required for the new loads. Because of arch flash requirements per Fleet Design Criteria, the MCCs will be Eaton Flashguard MCC or MCC with similar features or better. One MCC shall be powered from 600V Bus 11A, breaker 11A18 and the other shall be powered from 600V Bus 11B, breaker 11B10. The MCC low voltage switchgear feeder breakers will be retrofitted to include "Maintenance Bypass Switch" to enable the instantaneous setting of the breaker during maintenance mode. The existing loads on these breakers are not required for gas conversion and will be demolished. The trip units for these breakers will have to be replaced. The new trip units will be determined during detail design.

All 120VAC loads including the Beck 1/2HP, 120V damper drives shall be powered from new Distribution Panels powered via new 600V - 208/120V, 45KVA Transformers. These transformers are powered from the new 400A, 600V MCCs. The distribution panels that powers the damper drives do not power lighting loads.

The new MCCs shall be located at elevation 595'-0" Col K7-J11. New 45kVA Transformers and Distribution Panels powering the Beck 1/2HP, 120V damper drives and the new Burner System Control Panels shall be located at elevation 595'-0" Col K10-N10.

A new automatic transfer switch, 45kVA transformer, distribution panel and heat tracing panel will be installed in the vicinity of the metering station.

Existing electrical equipment in the newly classified hazardous areas will either be relocated or replaced with equivalent Class I Div. 2 equipment. This includes two existing 15HP Air Supply Fans powered from MCC 1BMF-A. The power source for this equipment will not change.

5. RECOMMENDATIONS

A. The study identified switchgear-supplied loads that will not be required after the implementation of the Gas Conversion. It did not identify MCC or Panelboard supplied loads that will not be required after the implementation of the Gas Conversion. WorleyParsons recommends doing a walkdown to identify these loads.

B. Power sources for the lights, receptacles, welding receptacles and other 120VAC loads in areas being changed from Unclassified to Hazardous Classification are not identified in panel drawings. WorleyParsons recommends doing a walkdown to determine their power sources during detail design.

C. WorleyParsons recommends performing the following studies during detail design:

1. Load Flow, Voltage Drop and Short Circuit Study,
2. Relay Coordination Study
3. Arc Flash Study

6. APPENDICES

Appendix 1 - New and Demolished Loads

Appendix 2 - Items Considered for Replacement Due to Hazardous Classification

Appendix 3 - B&W Load List

Appendix 4 - One Line Diagram Sketches

Appendix 1 - New and Demolished Loads

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AEP BIG SANDY UNIT 1 GAS CONVERSION PROJECT
PRELIMINARY NEW AND DEMOLISHED LOADS

AEPBS-1-LI-EE- 0001 Rev. B
PAGE 1 OF 1

Electrical Load													
Equipment Description	Unit HP	kW	KVA	V	φ	Eff	Unit kW	Number Installed	Installed kW	Number Operating	Demand Factor	Operating Load kW	Notes
Burner System													
Ignitors PAI Power Pack (Spark Circuit)		0.1		120	1	0.950	0.1	18	1.7	18	1.00	1.7	
Ignitors Sun Spot Flame Detectors		0.03		120	1	0.950	0.0	18	0.5	18	1.00	0.5	
Main Flaim Scanner		1.5		120	1	0.950	1.4	2	2.9	2	1.00	2.9	
Blowers	20			575	3	0.885	16.9	2	33.7	2	1.00	33.7	size 2 starters
Gas Valves		0.12		120	1	0.950	0.1	18	2.1	18	1.00	2.1	
Damper Drives	0.5			120	1	0.700	0.5	18	9.6	18	1.00	9.6	Similar to Beck Drives
Building Heating/Fans													
Gas Heater Fans	3			575	3	0.950	2.4	32	75.8	32	1.00	76	
Ventilation Fans	2			575	3	0.950	1.6	6	9.5	6	1.00	9	
Pressure Reducing Station/Metering													
Heat Tracing			20	208	3	0.950	19.0	1	19.0	1	1.00	19.0	Assumed
Control Panel		5		120	1	0.950	4.8	1	4.8	1	1.00	4.8	Assumed
Metering Station			10	208	3	0.950	9.5	1	9.5	1	1.00	9.5	Assumed
Water Bath Gas Heater Skid													
Bath Gas Fired Heater Blower	5			575	3	0.865	4.3	1	4.3	1	1.00	4	
TOTAL NEW LOADS									173.3			173.3	
DEMOED LOADS													
Pulverizer	200			4000	3	0.945	150.0	6	900.0	6	0.90	810.0	
Pulverizer Fans	250			4000	3	0.950	187.5	6	1125.0	6	0.90	1012.5	
Ash Handling Water Supply Pump 1M	300			4000	3	0.950	225.0	1	225.0	1	0.85	191.3	
Ash Handling Water Supply Pump 1W	400			4000	3	0.950	300.0	1	300.0	1	0.85	255.0	
Air Pre Heater Pump	800			4000	3	0.950	600.0	1	600.0	1	0.85	510.0	
Precipitator 1A Xfmr			750	4160	3	0.950	712.5	1	712.5	1	0.85	605.6	
Precipitator 1B Xfmr			500	4160	3	0.950	475.0	1	475.0	1	0.85	403.8	
Ash Pond Recirc Pump	250			575	3	0.950	187.5	4	750.0	4	0.85	637.5	
Conveyor #3	200			4000	3	0.945	150.0	1	150.0	1	0.85	127.5	
SO3 MCC				600	3								
TOTAL DEMO LOADS									5237.5			4553.1	

Appendix 2 - Items Considered for Replacement Due to Hazardous Classification

Tamayo, Yonie R. (Reading)

From:	Ferguson, Joel (Reading)
Sent:	Wednesday, September 19, 2012 12:45 PM
To:	Potteiger, Matthew (Reading); Tamayo, Yonie R. (Reading); Dasilva, Jose A (Reading)
Subject:	Big Sandy Electrical Considerations

Items to be considered for replacement due to Class I, Div II classification, Demo or Relocation:

Approx. 24 – Lighting Fixtures – Install new Class I, Div II
Approx. 6 - Comtrol Units (Paging) – Install new Class I, Div II
4 - Welding Receptacles – Relocate
Approx. 8 - 120vac Utility receptacles – Relocate
Approx. 5 - Air Damper Drives – Install new Class I, Div II (if req.)
2 - Ventilation Fans – Install new Class I, Div II (if req.)
1 - Unit Heater – Relocate (if req.)
2 - Ventilation Control Pnl's ? – Relocate (if req.)
Approx. 1 - Pulverizer Start-Up Alarm Horn – Demo
Approx. 1 - Pa/Alarm Horn – Relocate (if req.)

Joel Ferguson
Senior Electrical Designer | WorleyParsons
Tel: +1 (610) 855-2689
2675 Morgantown Rd. | Reading | PA | 19607 | United States of America
Joel.Ferguson@WorleyParsons.com | www.worleyparsons.com

Appendix 3 - B&W Load List

AEP Kentucky Power
Big Sandy Unit 1 – Natural Gas Conversion
Louisa, KY

Electrical Load List
Revision: 0
September 6, 2012

Ignitors
>> PAI power packs (spark circuit) – 18 X 0.1 kw
>> SunSpot flame detectors – 18 X 0.03 kw

Main Flame Scanner
>> Aux Power – 0.6 kw
>> Power Supply A – 1.2 kw
>> Power Supply B – 1.2 kw

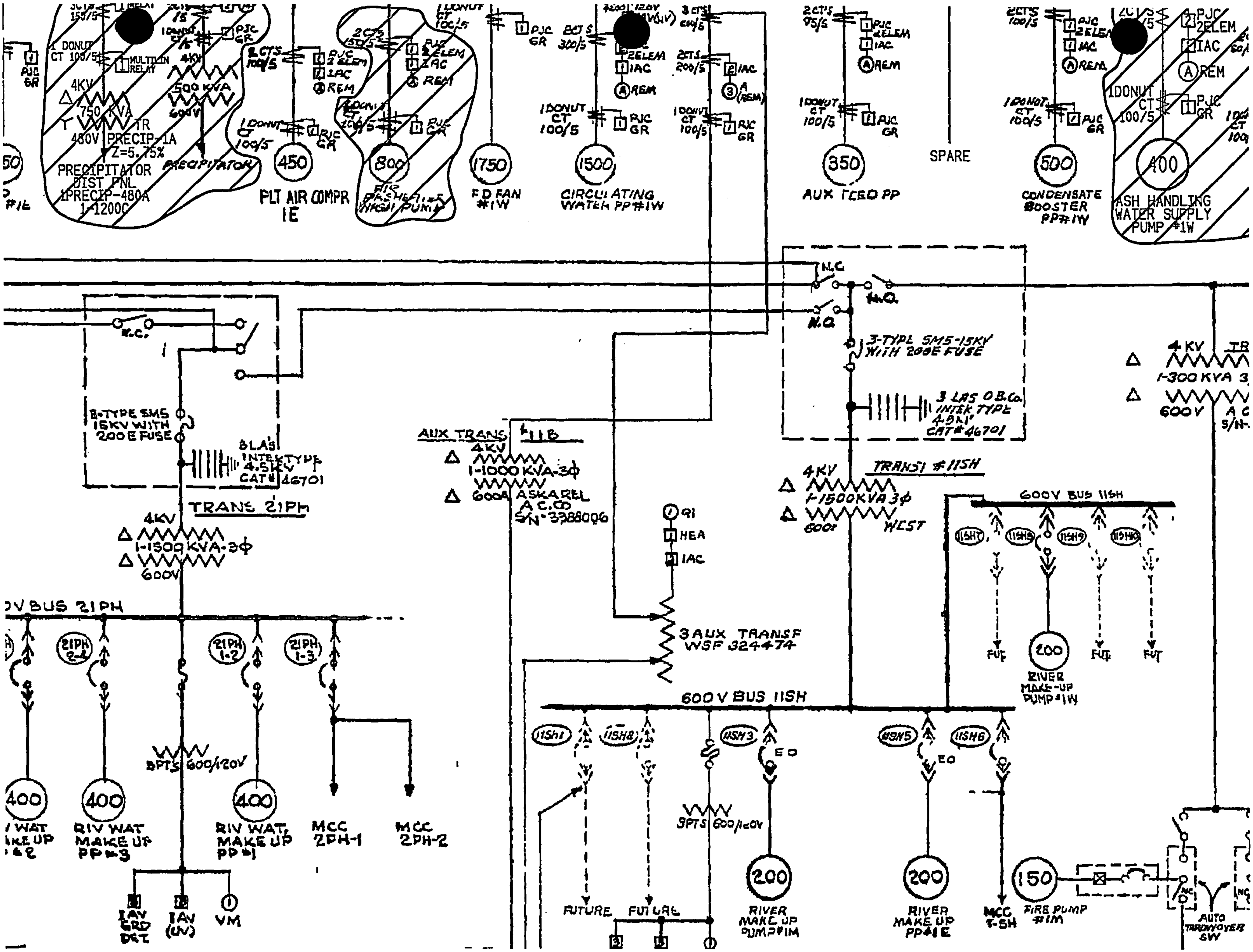
Cabinets
>> Covered in Ignitors & Main Flame Scanner sections

Blowers
>> 2 X 20 HP

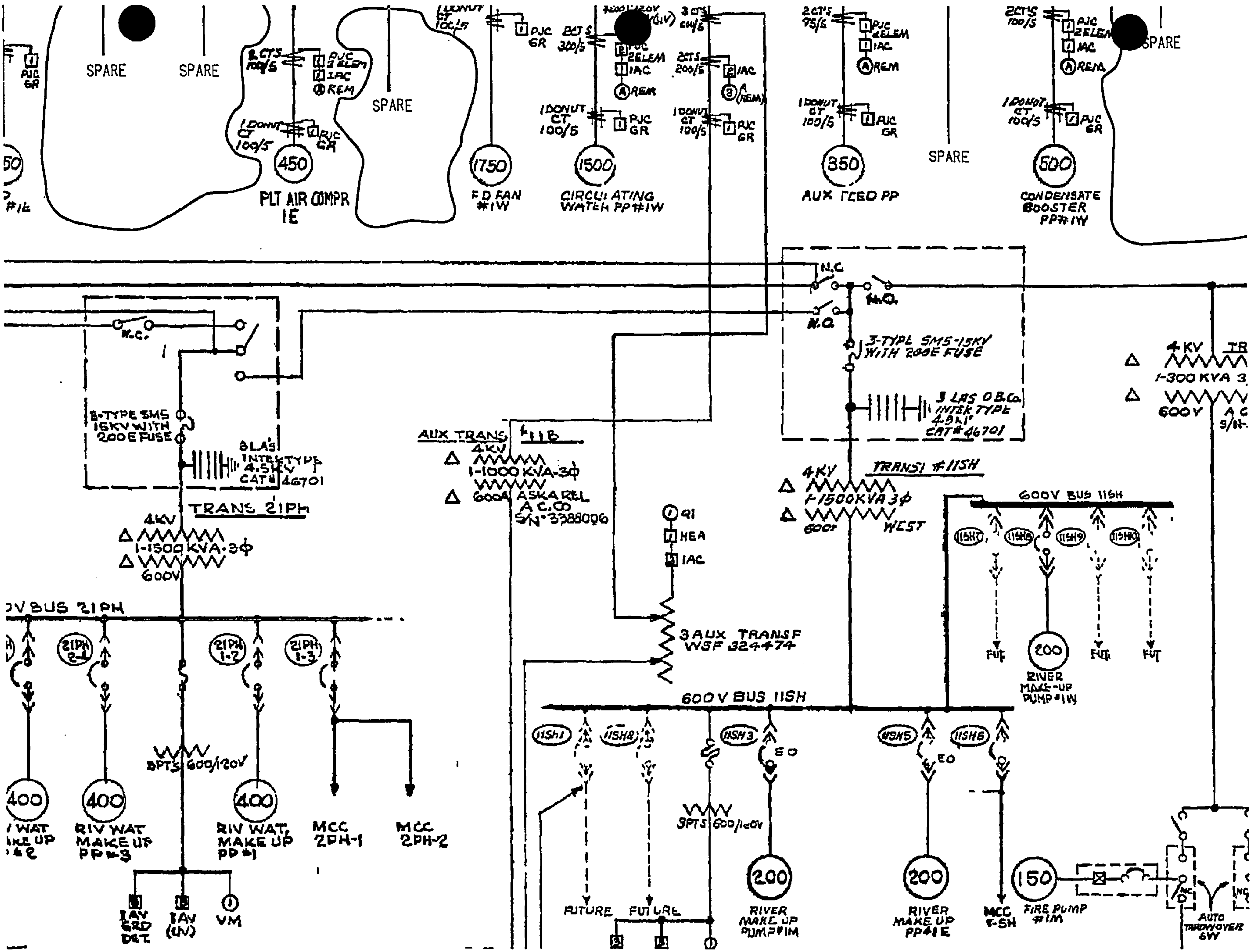
Gas Valves
>> 18 X 0.12 kw (0.12 kw is calculation for one set of burner & ignitor valves. 18 sets required)

Damper Drives
>> 18 X 0.5 HP

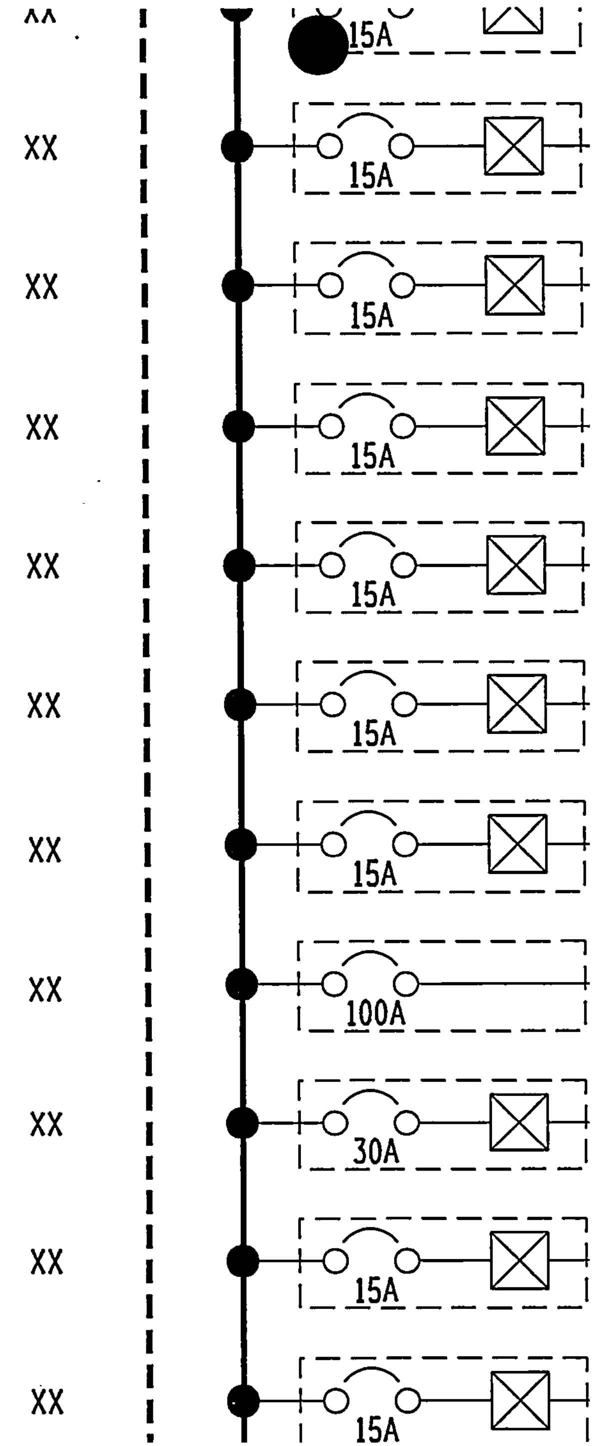
Appendix 4 - One Line Diagram Sketches



1 DONUT CT 100/5
MULTILIN RELAY
PJC GR
4KV
750 KVA
TR
480V PRECIP-1A
Z=5.75%
4KV
500 KVA
600V
PRECIPITATOR DIST PNL 1PRECIP-480A 1-1200C
PRECIPITATOR
2 CTS 100/5
PJC 2 ELEM
IAC
REM
1 DONUT CT 100/5
PJC GR
450
PLT AIR COMPR 1E
2 CTS 150/5
800
1 DONUT CT 100/5
PJC GR
1750
F D FAN #1W
2 CT'S 300/5
2 ELEM
IAC
REM
1 DONUT CT 100/5
PJC GR
1500
CIRCULATING WATER PP #1W
2 CTS 200/5
IAC
1 DONUT CT 100/5
PJC GR
2 CT'S 75/5
PJC 2 ELEM
IAC
REM
1 DONUT CT 100/5
PJC GR
350
AUX FEED PP
SPARE
2 CT'S 100/5
PJC 2 ELEM
IAC
REM
1 DONUT CT 100/5
PJC GR
500
CONDENSATE BOOSTER PP #1W
PJC 2ELEM
IAC
REM
1DONUT CT 100/5
PJC GR
400
ASH HANDLING WATER SUPPLY PUMP #1W
N.C
N.O.
N.O.
N.C.
3-TYPE SM5-15KV WITH 200E FUSE
3 LAS O.B.Co. INTER TYPE 4.5KV CAT# 46701
3-TYPE SM5 15KV WITH 200E FUSE
3 LA'S INTER TYPE 4.5KV CAT# 46701
TRANS 21PH
4KV
1-1500 KVA-3Φ
600V
AUX TRANS #11B
4KV
1-1000 KVA-3Φ
600A
ASKAREL A.C.CO S/N-3388006
IAC
3 AUX TRANSF WSF 324474
4KV
TRANS #11SH
1-1500 KVA 3Φ
600V
WEST
600V BUS 11SH
11SH7
11SH8
11SH9
11SH10
FUT
200
RIVER MAKE-UP PUMP #1W
4KV
1-300 KVA
600V
600V BUS 21PH
21PH 2-4
21PH 1-2
21PH 1-3
3PTS 600/120V
400
RIV WAT MAKE UP PP #3
400
RIV WAT. MAKE UP PP #1
MCC 2PH-1
MCC 2PH-2
IAV GRD DET.
IAV (UV)
VM
600V BUS 11SH
11SH1
11SH2
11SH3
11SH5
11SH6
E O
E O
3PTS 600/120V
FUTURE
FUTURE
200
RIVER MAKE UP PUMP #1M
200
RIVER MAKE UP PP #1E
MCC 1-SH
150
FIRE PUMP #1M
AUTO THROWOVER SW



SPARE
SPARE
SPARE
SPARE
SPARE
PJC GR
2 CT'S 100/5
PJC 2 ELEM
IAC
REM
1 DONUT CT 100/5
PJC GR
450
PLT AIR COMPR 1E
1750
F D FAN #1W
1500
CIRCULATING WATER PP#1W
350
AUX FEED PP
500
CONDENSATE BOOSTER PP#1W
2 CT'S 300/5
2 CT'S 200/5
2 CT'S 75/5
2 CT'S 100/5
N.C.
N.O.
3-TYPE SMS-15KV WITH 200E FUSE
3 LAS O.B.Co. INTEK TYPE 4.5KV CAT# 46701
4KV
1-300 KVA 3
600V
TRANS 21PH
4KV
1-1500 KVA-3φ
600V
3-TYPE SMS 15KV WITH 200E FUSE
3 LA'S INTEK TYPE 4.5KV CAT# 46701
AUX TRANS #11B
4KV
1-1000 KVA-3φ
600V ASKAREL A.C.Co
S/N 3388006
TRANS #11SH
4KV
1-1500KVA 3φ
600V
WEST
600V BUS 11SH
11SH7
11SH8
11SH9
11SH10
200
RIVER MAKE-UP PUMP #1W
FUT
Q1
HEA
IAC
3 AUX TRANSF WSF 324474
600V BUS 21PH
21PH 2-1
21PH 1-2
21PH 1-3
400
400
400
RIV WAT MAKE UP PP#2
RIV WAT MAKE UP PP#3
RIV WAT MAKE UP PP#1
MCC 2PH-1
MCC 2PH-2
3PTS 600/120V
1AV GRD DET.
1AV (LV)
VM
600V BUS 11SH
11SH1
11SH2
11SH3
11SH5
11SH6
EO
EO
3PTS 600/120V
FUTURE
FUTURE
200
RIVER MAKE UP PUMP #1M
200
RIVER MAKE UP PP#1E
MCC 1-SH
150
FIRE PUMP #1M
NC
AUTO THROWOVER SW



15A
XX
15A
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100A
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30A
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15A
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AMERICAN ELECTRIC POWER
BIG SANDY UNIT 1 GAS CONVERSION STUDY

Controls, Instrumentation, DCS and BMS Upgrade Study

Document: AEPBS-1-LI-EI-0001

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WorleyParsons
2675 Morgantown Rd.
Reading, PA 19607
USA
Telephone: +1 610 855 2000
Facsimile: +1 610 855 2001
www.worleyparsons.com

WorleyParsons
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AMERICAN ELECTRIC POWER
BIG SANDY UNIT 1 GAS CONVERSION STUDY
CONTROLS, INSTRUMENTATION, DCS AND BMS UPGRADE STUDY

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REV	DESCRIPTION	ORIGINATOR	REVIEWER	APPROVER	DATE
A	Initial Issue	J DaSilva	G Blair	N Zappone	Sept 28, 2012
B	Revised Gas Scrubber Section	J DaSilva	G Blair	N Zappone	Oct 17, 2012

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AMERICAN ELECTRIC POWER
BIG SANDY UNIT 1 GAS CONVERSION STUDY
CONTROLS, INSTRUMENTATION, DCS AND BMS UPGRADE STUDY

CONTENTS

1. EXECUTIVE SUMMARY

A. American Electric Power (AEP) is converting Big Sandy Unit 1 to burn natural gas instead of coal. The existing coal burners will be removed and replaced with new gas burners supplied by B&W.

B. This study evaluates and creates a basis for the controls upgrade at Big Sandy Unit 1. Installation of the new burners and associated equipment will require new control and monitoring equipment, including a new Burner Management System (BMS) which will be integrated with the existing Distributed Control System (DCS).

C. Main Control Room modifications will include removal of control board-mounted instruments and control devices which are no longer required.

D. Based on this study, all equipment and processes will be controlled from the control room via the existing Operator Workstations.

E. Recommendation

WorleyParsons recommends installing the necessary controls as described herein and as shown in the Control System Architecture, including an upgrade of the DCS to the latest version available. In addition, WorleyParsons recommends modification of the Control Panels as necessary to remove control devices that are no longer required.

2. INTRODUCTION

A. The Big Sandy Plant is located along the Big Sandy River near Louisa, Kentucky. The Plant is comprised of two coal-fired boilers; Unit 1 is rated at 287 MW gross and was placed in service is 1962; Unit 2 is rated at 840 MW gross and was placed in service in 1969. The present project consists of converting Unit 1 from coal to natural gas firing.

B. The existing plant control system consists of a combination of hardwired panel control, Programmable Logic Control (PLC), and DCS control. The new natural gas firing system will be DCS-controlled which will include the integration of a new BMS into the overall Unit 1 DCS network; the BMS will provide the necessary code protective functions. The existing Combustion Control drops will be used for any non-protection related control required as part of this project

C. The following modifications will impact instrumentation and control:

1. New Natural gas system and Burners
2. Removal of existing coal burners and associated coal pulverizers and feed system
3. Removal of existing sootblowers
4. Modification to existing ash removal system
5. Disable operation of existing precipitator
6. Control Room Panel Modifications
    a. Remove existing coal related control devices
    b. Remove sootblower HMI and associated devices
    c. Remove ash system control devices

D. The existing DCS for Unit 1 is an Emerson Ovation DCS version 3.0.4. The Ovation version being offered by Emerson is currently 3.3.1 (Note a newer version (3.5) should be available when this project is being executed). The new Ovation equipment cannot be added directly to the existing equipment due to version incompatibility. Two options are available for the addition of the new equipment:

1. Upgrading all existing Ovation equipment to the same version that will be installed with the new Ovation equipment

2. Installation of the new Ovation equipment as a separate network configuration.

E. This study defines the scope and presents a basis for a cost comparison of "options" associated with the DCS upgrade and other means of control and monitoring of installed equipment and processes. The purpose is to:

1. Define operator interface locations and types.

2. Determine the scope of the modernization portion of the project which may include the removal of miscellaneous support controls from the Main Control Room panels.

F. Determine the DCS control system upgrade

1. Addition of hardware required for Unit 1 natural gas conversion and associated equipment installation

3. DISCUSSION

3.1 Study Objectives

Determine a conceptual DCS design that will support natural gas firing of Big Sandy Unit 1, control and monitoring of associated equipment, and support expansion as new processes and equipment are identified for control by the DCS. For budgetary purposes, the overall cost for the DCS upgrade will be included in the Phase 1 cost estimate for the natural gas conversion project.

3.2 Project Design Details

The control system modifications presented herein are a result of the mechanical modifications being performed on Big Sandy Unit 1 to convert the unit to natural gas. These control system modifications consist of the following items:

A. Boiler Modifications

1. Demolish existing burners and associated equipment along the burner front and disconnect control and power from existing equipment such as the pulverizers and coal feeders.

2. Installing new gas burners and associated controls including all instrumentation and valves from the B&W terminal point (B&W will provide estimate for equipment, WorleyParsons will provide electrical and control wiring estimate).

B. Gas piping and associated Equipment

1. Check Metering Station

   Installation of new Check Metering Station; signals will be wired to the DCS for monitoring and trending. Material and installation estimate is provided by WorleyParsons.

2. Pressure Reducing Station

   Installation of natural gas pressure reducing station; signals will be wired to the DCS for monitoring and trending. Material and installation estimate is provided by WorleyParsons.

3. Gas Scrubber

   Gas scrubber will be part of the Gas Supplier's scope, however it is assumed the Plant will be required to maintain the gas scrubber (as discussed in weekly conference call). The gas scrubber instrumentation and control signals will be wired to the DCS for monitoring and trending.

4. Gas Chromatograph

   A gas chromatograph will be provided to check the composition of the gas. A datalink will be provided to the DCS for monitoring and trending. Material and installation estimate is provided by WorleyParsons.

5. Water Bath Gas Fired Heater

   A heater is provided to heat the supply gas to prevent possible freezing and ice buildup of pressure reducing stations and the burner trip valves. The heater will be PLC controlled and includes all the necessary instrumentation and control devices required for safe operation. A datalink will be provided to the DCS for monitoring and trending. Material and installation estimate is provided by WorleyParsons.

C. Control Board Modifications

1. Remove control switches, indicating lights and other control devices for equipment no longer required after conversion the natural gas firing:

   a. Pulverizers and feeders

   b. Sootblower

   c. ESP and ash removal

2. Add two new E-Stop Pushbuttons to the Control Board

   a. Emergency Shutdown - isolate gas to the plant

   b. MFT / Main Gas Trip Valve

3.3 Control Philosophy

A. The control system expansion project will upgrade existing plant Emerson Ovation DCS version 3.0.4 to the latest version available and add new BMS hardware to control the new equipment being installed as part of the Gas Conversion Project. The Main Control Room will remain the central location for plant control.

B. I/O Quantities

1. New I/O

The following I/O will be added as part of this project:

Table 1 - Gas Conversion I/O

	BMS						DCS						
	AI	AO	DI	DO	T/C		AI	AO	DI	DO	T/C		Total
B&W	20		326	136			23	19	2	2	36		564
BOP			4	2			9		16	4	2		37

Four new cabinets (two I/O cabinets and two marshalling) will be installed in the existing DCS room located next to the Unit 1 Control Room for the "BMS" I/O.

The existing DCS Combustion Control drops will be used for the "DCS" I/O.

2. Existing I/O

The following I/O will need to be removed along with the associated logic and graphics:

Table 2 - DEMO I/O

DCS						
AI	AO	DI	DO	T/C		Total
42	42			24		108

C. Network Switches

1. Based on provided network drawing, there appeared to be sufficient ports to add the new BMS drops to the existing Root switches (ES1 and ES2), however after a walk-down it was found that there are not enough ports and new Fanout switches (ES3 and ES4) will be needed. The Fanout switches will be added to the existing network cabinet located in the Control Room.

3.4 Study Basis

A. Determine the necessary DCS changes to provide monitoring and control of new gas burners and associated equipment.

B. Modify Main Control Room panels as necessary for equipment demolition and installation.

C. Install new DCS (BMS) equipment including new network switches.

3.5 Study Methodology

The following steps were taken in completing this study:

A. Identify applicable controls changes performed at other AEP plants and incorporate into Big Sandy Unit 1. The Clinch River Gas Conversion project was used as a guideline in this study.

B. Identify locations for new equipment installation.

C. Develop a conceptual DCS arrangement that provides at least the same level of functional control currently experienced by the plant and make improvements to operational control as opportunities arise.

D. Identify existing control equipment to be removed, replaced, or spared in place.

E. Document the above items in this report for management review and record.

F. Assumptions

1. Continuous Emissions Monitoring System (CEMS) estimate is based on Clinch River.

2. WorleyParsons has not provided an estimate for NERC CIP compliance related work which may be required. If estimate is needed, AEP will provide scope for WorleyParsons to estimate.

3. There is no requirement to upgrade Q-line I/O to R-line series I/O. If required, this will be determined later.

4. Simulator for this Project is not required.

3.6 Distributed Control System (DCS)

The DCS equipment is represented in Attachment 8.1, AEPBS-1-SK-025-818-001, Control System Architecture.

The new gas burners and associated equipment will be controlled from new modern micro-processor based DCS equipment. The BMS drops will provide the control and protection functions and interface with existing plant operating systems. Adding the BMS to the existing DCS allow for smoother integration between the new gas conversion related equipment controls and existing Unit controls.

A. I/O Counts by Node/Drop

The new DCS equipment will be partitioned in a manner that allows for a robust and fully redundant design down to the I/O bus level. Redundant field equipment will be assigned to different I/O cards in the DCS. The I/O counts are also affected by the number of I/O points that a processor in the DCS can handle. Thus, if a fault occurs in a DCS Drop (which is highly unlikely), the fault would only affect the equipment allocated on the Drop and cause a reduction in load, and not a complete loss of the Unit.

Based on Table 1 (Gas Conversion I/O) there will be approximately 244 I/O points per BMS drop.

B. Location of Equipment

1. Main Control Room Layout

The Main Control Room is to be maintained as the central control location for the plant and the new natural gas equipment.

Attachment 8.2 provides markups of the Control Boards showing control devices which will be removed and the holes covered and painted to match existing panel.

2. Cabinets for the new BMS Drops will be installed in the existing DCS room next to the control room.

C. DCS Upgrade versus Multi-Network

1. A version upgrade would allow the new Ovation Controller, I/O, and workstations for the BMS to tie directly into the upgraded existing Ovation network. The Unit would have the most current system that would require no major version changes in the near future. There would also be only one system to maintain and spare parts would be the same across the system. Due to the amount of equipment (new workstations, controllers, and communication hardware) and software that would need to be upgraded, however, this option is the most expensive.

2. Adding the new Ovation equipment with a Multi-Network configuration would allow the two different versions to operate with the same user interface while communicating over a set of redundant core switches. Points could be passed across the networks if needed for interface to the other version. This option would leave the existing Ovation DCS mostly unaffected except for a few modifications to add the required Multi-Network communications. The downside of this option is the Plant would need to maintain two separate DCS systems, including separate databases and different spare parts. Also, consideration will have to be given to the end of support concerns with the existing I/O and the fact that the existing Ovation version will become obsolete (and may need to be updated) before the new DCS equipment installed as part of the gas conversion project will require updating; thus there would be a continuous version mismatch for the life of the Unit.

3.7 Required Field Instrumentation and Control Modifications

As part of the mechanical equipment packages various instruments and control devices will be provided in accordance with AEP instrumentation specifications.

4. COST AND SCHEDULE

4.1 Summary

A. Estimate of work detailed herein is included in the Project cost estimate.

B. Cost estimate is based on the addition of new DCS equipment and upgrading the existing DCS to the latest version available. Estimate is based on brief discussions with Emerson Ovation representatives and comparison of Clinch River estimate.

C. Estimate for CEMS related materials is based on Clinch River Gas Conversion Project estimate.

5. CONCLUSIONS

Big Sandy currently has an Ovation DCS installed for control and monitoring of major plant systems. With the addition of a new natural gas burner and associated equipment, more controls will be installed at the Big Sandy plant that will use the DCS platform. Since the plant already has DCS control, there will not be any major differences for the operators to get accustomed to. The process system changes have been reviewed and a preliminary DCS architecture for the new control system developed. The proposed DCS architecture is shown in sketch AEPBS-1-SK-025-818-001, Attachment 8.1.

6. RECOMMENDATIONS

WorleyParsons recommends installing the necessary controls as described herein and as shown in the Control System Architecture including an upgrade of the DCS to the latest version available. In addition WorleyParsons recommends:

A. Modification of the Control Panels as necessary to removed existing controls which will no longer be required and the installation of the two E-Stop Pushbuttons.

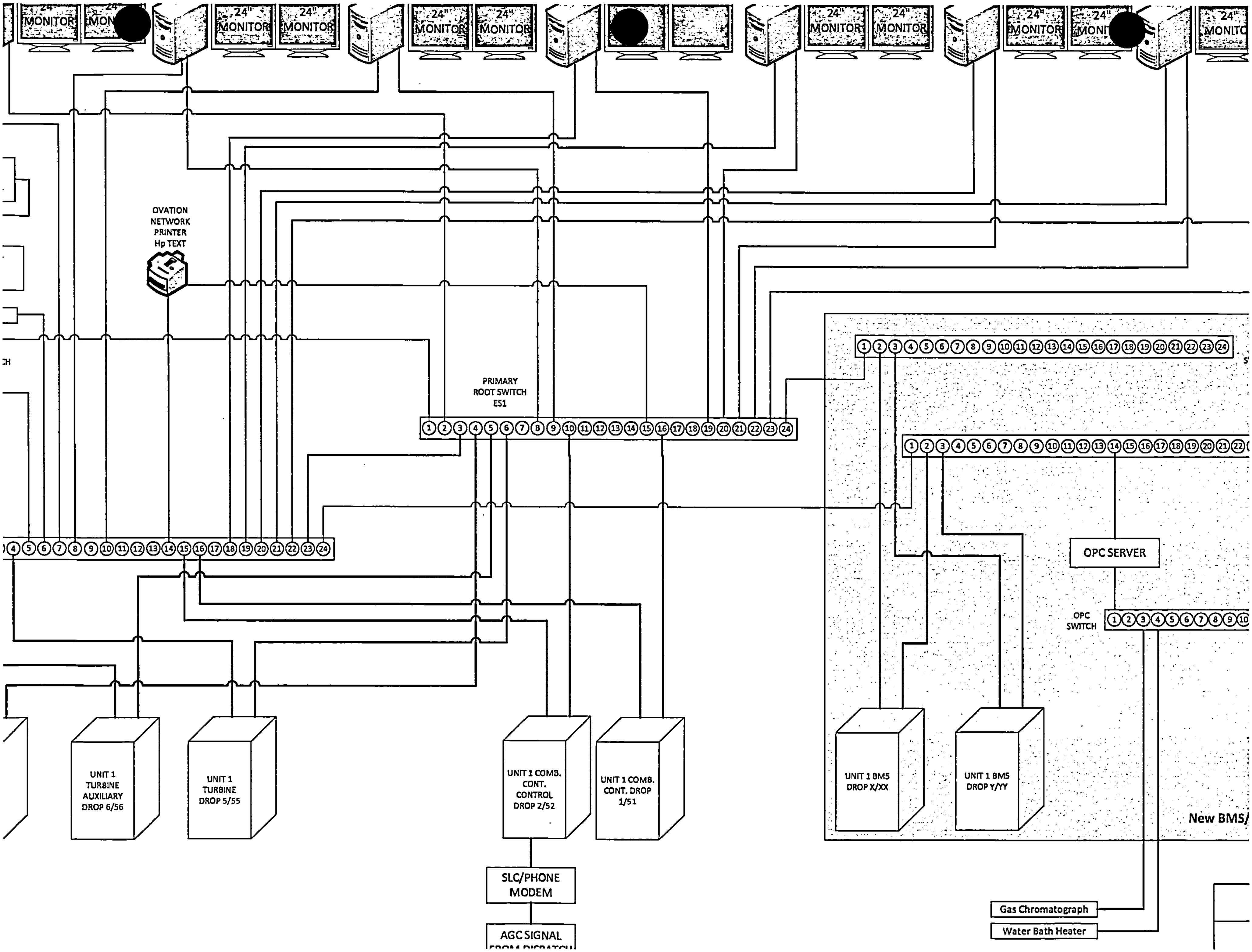
7. REFERENCES

Not Used

8. ATTACHMENTS

8.1 Sketch of Control System Architecture

(One page to follow)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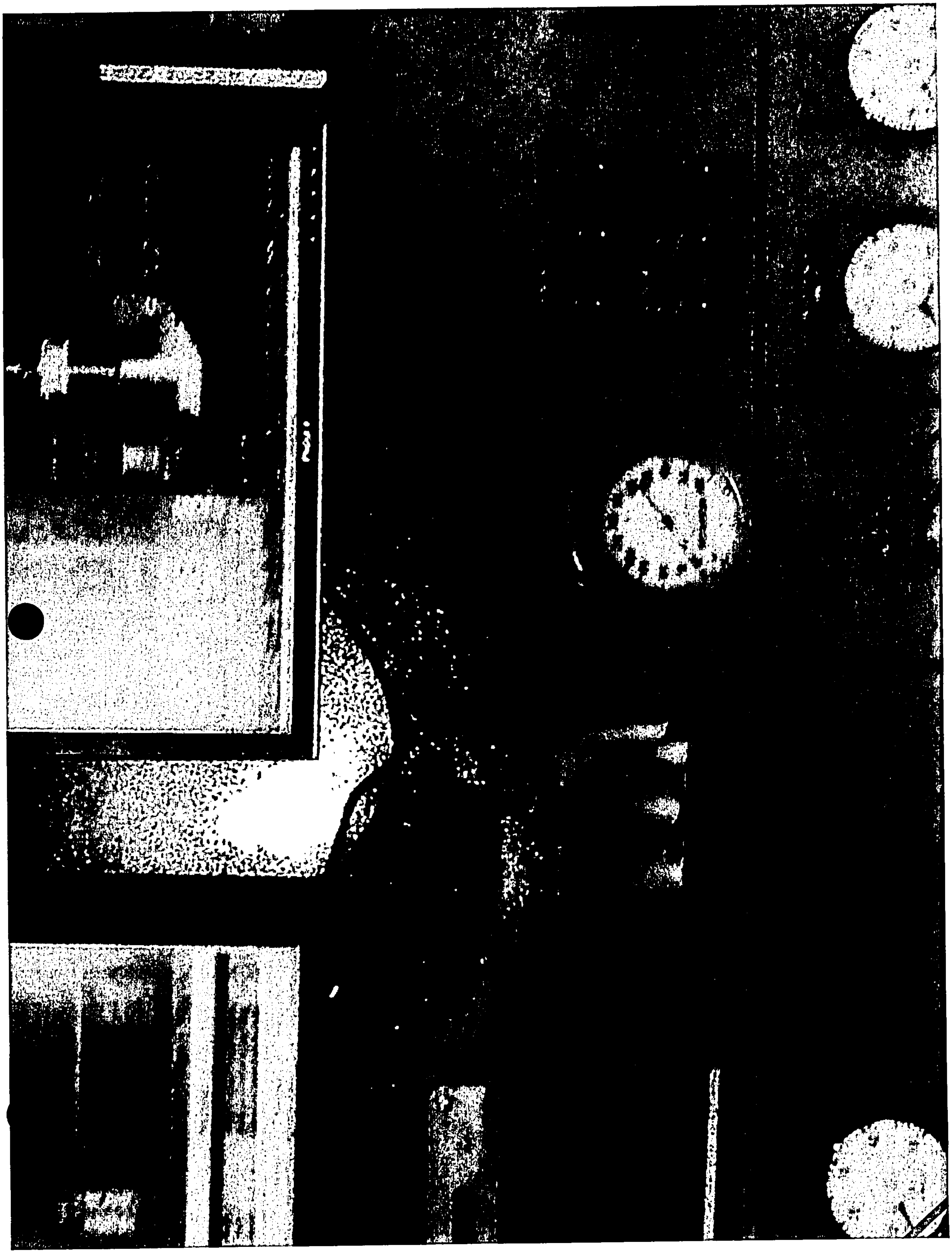
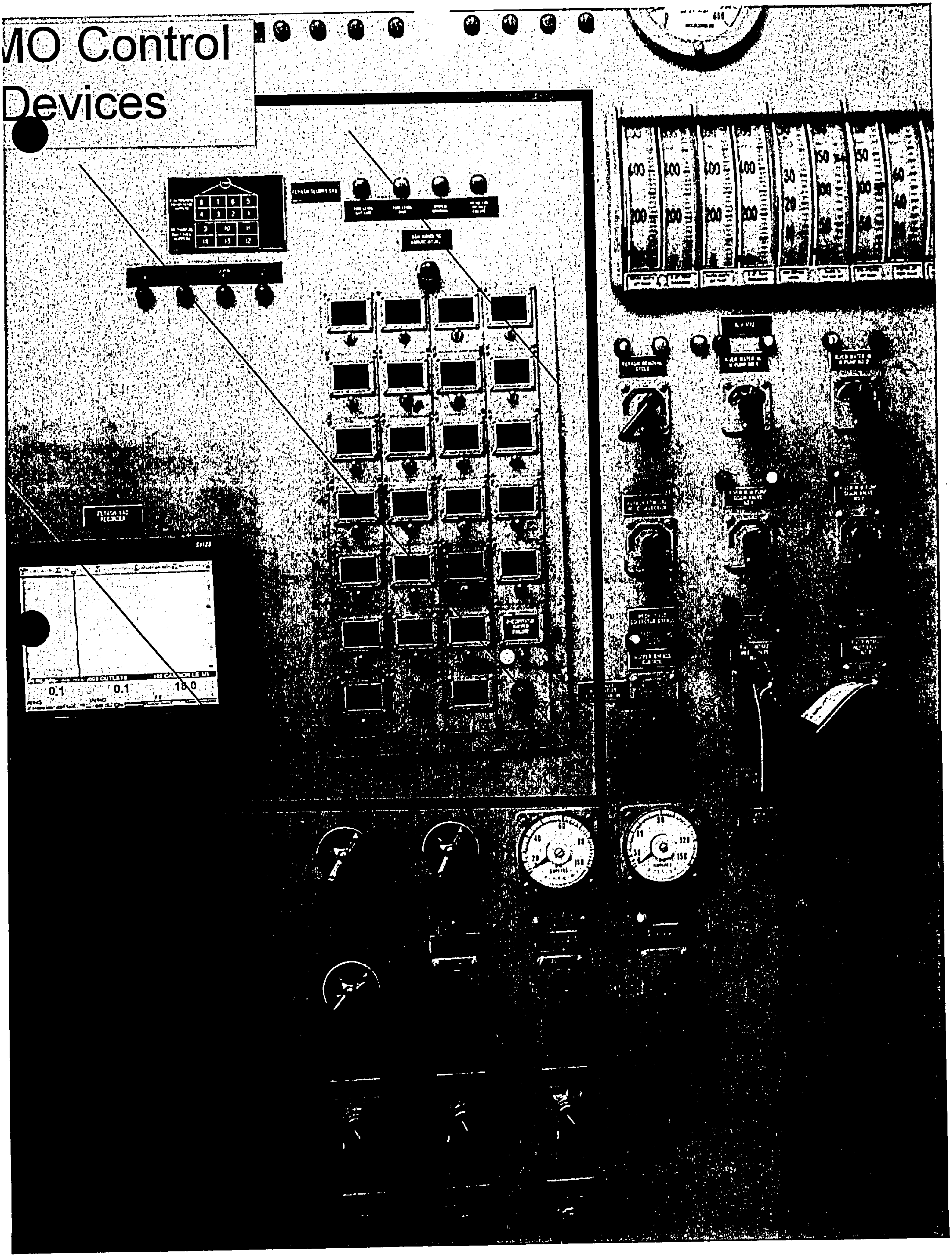
PRIMARY ROOT SWITCH ES1
OPC SERVER
OPC SWITCH
UNIT 1 TURBINE AUXILIARY DROP 6/56
UNIT 1 TURBINE DROP 5/55
UNIT 1 COMB. CONT. CONTROL DROP 2/52
UNIT 1 COMB. CONT. DROP 1/51
UNIT 1 BMS DROP X/XX
UNIT 1 BMS DROP Y/YY
New BMS/
SLC/PHONE MODEM
AGC SIGNAL
Gas Chromatograph
Water Bath Heater

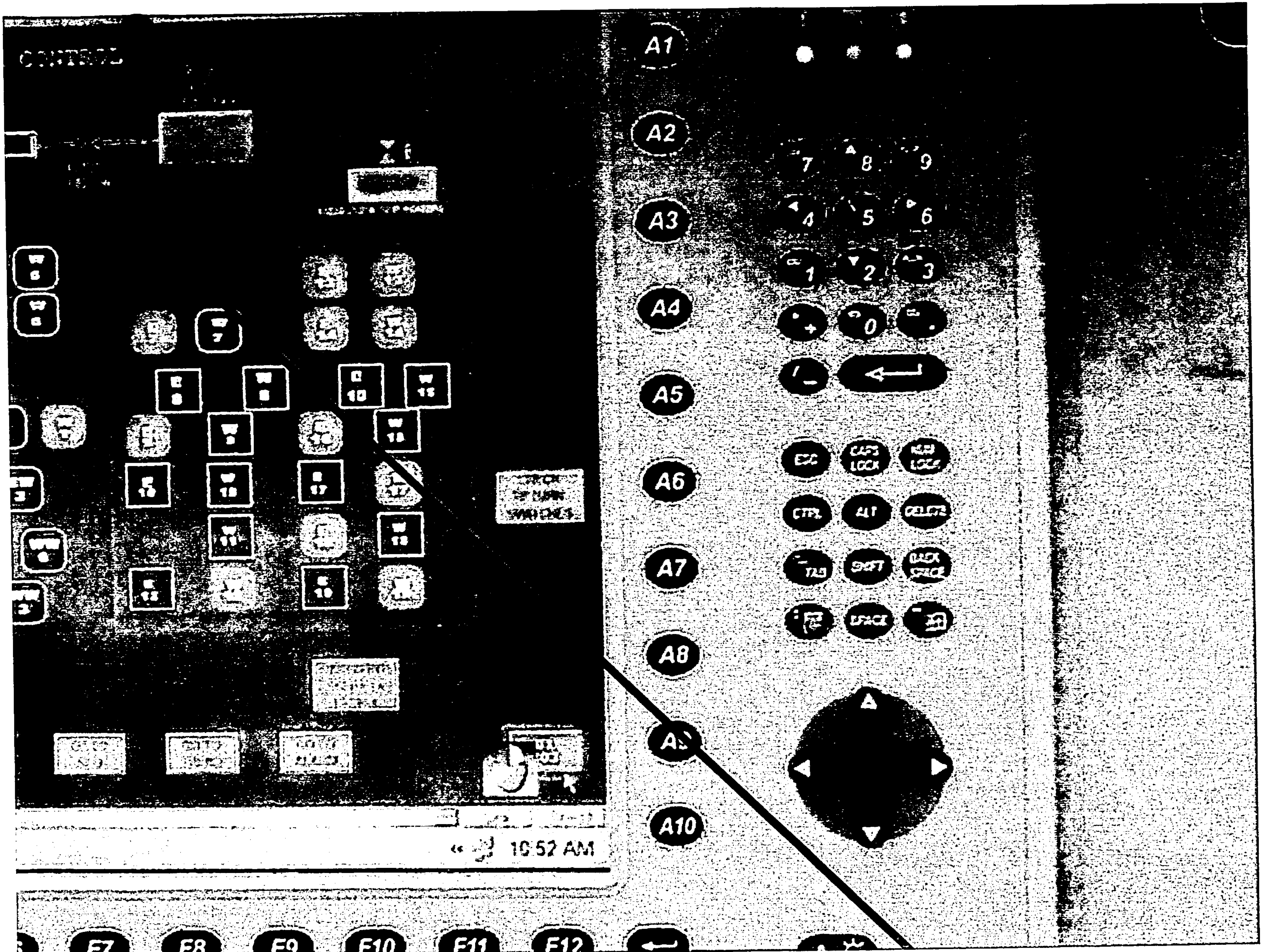
8.2 Markups of Main Control Room Panels

(Three pages to follow)



MO Control Devices





CONTROL
A1
A2
A3
A4
A5
A6
A7
A8
A10
7
8
9
4
5
6
1
2
3
0
ESC
CAPS LOCK
CTRL
ALT
DELETE
SHIFT
BACK SPACE
SPACE
10:52 AM
F7
F8
F9
F10
F11
F12

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AMERICAN ELECTRIC POWER
BIG SANDY UNIT 1 NATURAL GAS CONVERSION PROJECT

Water Study

Document: AEPBS-1-LI-EM-0001

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Date: October 2012

WorleyParsons
2675 Morgantown Rd.
Reading, PA 19607
USA
Telephone: +1 610 855 2000
Facsimile: + 1 610 855 2001
www.worleyparsons.com

WorleyParsons
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AMERICAN ELECTRIC POWER
BIG SANDY UNIT 1 NATURAL GAS CONVERSION PROJECT
WATER STUDY

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BIG SANDY UNIT 1 NATURAL GAS CONVERSION PROJECT
WATER STUDY

CONTENTS

ATTACHMENTS

1. EXECUTIVE SUMMARY

The purpose of this study is to determine the impact on the Station water supply, water discharge, and water treatment systems as a result of a fuel source conversion of Unit 1 from coal to natural gas for the Big Sandy Power Plant in Louisa, Kentucky. The study reviewed the changes and modifications based on Unit 2 being shut down and Unit 1 ash systems being abandoned.

The impact to the water and wastewater systems will be substantial. The river water that is required for plant operations will be reduced from approximately 19.41 MGD to approximately 6.08 MGD. The wastewater that is required to be discharged from the plant will be reduced from approximately 6.60 MGD to approximately 1.11 MGD.

The shutdown of Unit 2 will reduce the amount of demineralized water used and as a result help reduce the amount of wastewater generated for its production. The Unit 1 natural gas conversion will not significantly change the amount of demineralized water used and the wastewater generated in its production.

Converting Unit 1 to natural gas and shutting down Unit 2 will result in shutting down the wastewater to the fly ash pond. This requires that wastewater be removed from the system through discharge to a different location on the outfall receiving source. This location will potentially be from the reclaim pond directly to the Big Sandy River instead of indirectly through Blaine Creek as was done through the fly ash pond. The overflow on the reclaim pond will be modified to discharge to the Big Sandy River based on a continuous discharge requirement.

One new mixed bed system or modification of the existing Unit 2 condensate polishers from condensate polishers to mixed beds may be required.

The plant indicated that they would like to use the existing Unit 2 condensate polishers as mixed bed units. This will require an investigative study of the condensate polishers to confirm whether they can be modified for this purpose. The capital costs for upgrading the Unit 2 demineralized water and condensate systems so that they can continue to be used for the supply of condensate and demineralized makeup water for Unit 1 are part of and included in the Unit 2 Retirement Study AEPBS-1-LI-EM-0002.

For final design the water treatment and wastewater system designs will need to be evaluated in their entirety.

2. INTRODUCTION

The Big Sandy Plant is located along the Big Sandy River in Louisa, Kentucky. The Plant is comprised of two coal-fired, steam-electric units; Unit 1 and Unit 2. The present project consists of the conversion of Unit 1 to natural gas and the shutdown of Unit 2. The Unit 1 boiler conversion will be designed by Babcock and Wilcox, Inc.

The boiler feedwater rate will be approximately the same and the furnace seal troughs will be kept in place and in operation. The focus of this study is to determine the water system modifications if any that are required. Deliverables also include a preliminary plant water balance (see Appendix 1).

3. DISCUSSION

3.1 Study Basis

The study basis is as follows:

- The existing river water makeup supply for the Unit 2 system will remain in operation. The Unit 1 river water system will be retired.
- The reclaim pond will discharge to the Big Sandy River by modifying its overflow to reflect the new level requirements and the NPDES discharge permit will be updated to accommodate this change.
- The reclaim pond will be lined. The lined reclaim pond will become a wastewater pond once the units no longer burn coal.
- Two bottom ash ponds will be lined and two bottom ash ponds will be closed. The two lined ponds will become wastewater ponds once the units no longer burn coal.
- The coal pile runoff pond will not be changed and will continue to drain to the bottom ash ponds until the units no longer burn coal.
- Unit 1 ash systems will be shut down as applicable.
- Unit 2 will be shut down as applicable.
- Unit 2 condensate polisher will be able to be used as a mixed bed for reverse osmosis permeate cleanup. A study of the condensate polisher system will need to be done to investigate whether this is economically feasible.

3.2 Study Objectives

The primary objectives of this study are as follows:

Determine the impact on the plant water systems as a result of converting Unit 1 from coal to natural gas. This includes the abandonment of Unit 1 ash systems.

Determine the impact on the plant water systems as a result of shutting down Unit 2.

Provide a preliminary water balance to depict changes.

Identify any additional permits that may be needed. Specific permit changes are not part of this study. See section 3.8 below.

Provide a study report with recommendations.

3.3 Study Design Basis

The following presents the design basis for this study. It is compiled from a combination of operating information obtained through discussions with the plant, existing plant data, past study data, and project design criteria documents.

- The existing river water make-up system for Units 1 and 2 consists of three (3) existing 10,000 gpm pumps and two (2) existing 6,750 gpm pumps. The two (2) 6,750 pumps were installed with the original "old" system. The three (3) 10,000 gpm pumps were installed later for Unit 2 in an added pump caisson. Current practice is to run one of the 10,000 gpm pumps and one of the 6750 gpm pumps. The river water make-up system currently supplies water for Units 1 and 2 cooling tower make-up, bottom ash sluicing, and service water. It is also a backup for fly ash sluicing. All pumps currently have piping which allows them to be used to feed Units 1 or 2. All pump discharge pipelines have self-cleaning strainers. During stormy weather the self-cleaning strainers work well and the plant has not had a recent problem with them binding up.

- Two (2) existing 600 gpm L.P. service water pumps currently operate for Unit 1. These are used for seal trough supply, seal trough flushing, refractory weir supply, clinker grinder seals, the pyrites loop seal supply and observation window jets. These also fed the Unit 1 water treatment system before it was shut down. These pumps are normally fed from the river water header.

- Two (2) existing 2,000 gpm ash handling water pumps currently operate for Unit 1. These feed the fly ash system, bottom ash system, pyrites system, and the air preheater water washing device. These pumps are normally fed from the river water header but are also fed from cooling tower blowdown.

- One (1) existing 850 gpm air preheater ash water pump currently operates for Unit 1. This pump feeds the air preheater hose connection. This pump is normally fed from the ash handling water pumps discharge header.

- Two (2) existing 1,600 gpm fly ash pumps currently operate for Unit 2. These feed the fly ash hydroveyors and flow through to the Unit 2 slurry tank. These pumps are normally fed from the reclaim pond. An alternate feed to the pumps is river water.

- An existing 1,600 gpm spare pump is shared between the Unit 2 fly ash and Unit 2 bottom ash system below. This pump is fed from the river water header but can discharge to the bottom ash or fly ash system.

- Two (2) existing 1,600 gpm bottom ash pumps currently operate for Unit 2. These feed the economizer ash hydroveyors and flow through to the Unit 2 slurry tank. These pumps are normally fed from the circulating water system. An alternate feed to the pumps is river water.

- The existing sluicing from pyrites tanks for Unit 2 bottom ash operates intermittently as designed. This sluice water flows back to the reclaim pond. Overflow from the bottom ash hopper flows to the wastewater sump where it is returned to the reclaim pond.

- There are four existing 2,500 gpm ash pond recirculation (APR) pumps. These pumps run according to pond level. They feed the fly ash pumps and provide make-up to the slurry tank. They send the excess to the fly ash pond. Two or three out of four APR pumps for Unit 2 normally operate. Only Unit 2 equipment is fed from the APR pumps.

- There are two existing 2,000 gpm Unit 2 service water pumps. The service water pumps are being used to feed the bottom ash ring water header, cooling water coolers (as an alternate supply), evaporator blow down tank quench, water treatment plant, circulating water chemical injection, wastewater sump dilution ring, and as a backup for the ash pit sump ejector.

- The Unit 1 water treatment plant has already been shut down.

- There is one existing condensate tank for Unit 1. This tank has an approximate capacity of 300,000 gallons.

- There are two existing condensate tanks for Unit 2. One is for contaminated condensate and one is for clean condensate. The contaminated condensate tank has an approximate capacity of 500,000 gallons. The clean condensate tank has an approximate capacity of 750,000 gallons.

- There are three existing 3,000 gpm Unit 2 condensate cleanup pumps. These pumps are being used to pump contaminated condensate to the pre-coat filters and condensate polishers for system use or for return to the clean condensate tank.

- There are four existing Unit 2 condensate precoat filters and five existing Unit 2 condensate polishers. These filters and polishers cleanup the condensate from the contaminated condensate tank so it is suitable for use in the feedwater loop or for filling the clean condensate tank. The condensate polisher system flow rate is approximately 3000 gpm.

- There are two existing 3,000 gpm Unit 1 hotwell pumps.

- There are two existing 3,000 gpm Unit 1 condensate booster pumps. These pumps are used to feed the Unit 1 low pressure feedwater heaters.

- There are three existing 4,500 gpm Unit 2 hotwell pumps.
- There are three existing 4,500 gpm Unit 2 condensate booster pumps. These pumps are used to feed the Unit 2 low pressure feedwater heaters.
- The existing Unit 1 and 2 fire water pumps are set up to pull circulating water from the Units 1 or 2 cooling tower basins, respectively.

3.4 Water Requirements Evaluation

Table 1 below presents the demand for the gas conversion project with Unit 2 shutdown.

Table 1 - Water Demand

WATER REQUIREMENTS	FLOW (GPM - UNLESS NOTED OTHERWISE)	PRIMARY WATER SOURCE
UNIT 1 RIVER WATER		
24 Hour Average	4225	Big Sandy River
UNIT 1 DEMINERALIZED WATER		
Normal Maximum	25,000 GPD	Unit 1 Condensate Tank
Peak Maximum	50,000 GPD	Unit 1 Condensate Tank
UNIT 1 SERVICE WATER		
24 Hour Average	280	Unit 1 Service Water Pumps
UNIT 2 SERVICE WATER		
24 Hour Average	165	Unit 2 Service Water Pumps
UNIT 1 POTABLE WATER		
24 Hour Average	5	City Water

3.5 Water Evaluation

This section evaluates water requirements.

River Water

The water source for the plant is Big Sandy River water. Approximately 4200 gpm of river water will be used on an average 24 hour basis for plant operations. For the gas conversion project, the existing Unit 2 clean condensate tank is being considered for use as the firewater tank. This tank has a capacity of 750,000 gallons. See the Unit 2 Retirement Study AEPBS-1-LI-EM-0002 for more details. This tank would be filled from the river water header. Any of the Unit 1 river water pumps can individually support the plant water requirements.

Demineralized Water

The demineralized water demand will be reduced to approximately 25 gpm on a 24 hour average basis as a result of the Unit 2 shut down. The Unit 1 water treatment plant is shut down and not being used. Currently the Unit 2 water treatment plant supplies demineralized water for the Unit 1 system and will need to stay in operation. This system will have sufficient capacity to supply the Unit 1 demineralized water requirements. The Unit 2 demineralizer is a reverse osmosis (RO) system that has a capacity to provide approximately 120 gpm demineralized water continuously. After Unit 2 is shut down its run time will be reduced by about 80 percent.

Service Water

The Unit 1 service water demand will be reduced as a result of the abandonment of the Unit 1 ash systems. The unit 1 service water demand will be reduced to approximately 280 gpm on a 24 hour average basis as a result of the Unit 1 ash systems abandonment.

The Unit 2 service water demand will be reduced as a result of the shutdown of Unit 2. The Unit 2 service water system is required to be kept operational to provide water for the Unit 2 water treatment system that supplies makeup water for Unit 1 boiler makeup as well as filtered and softened water for other uses.

3.6 River, Demineralized, and Service Water System Modifications

This section provides the recommended modifications to the plant to meet the river, demineralized, and service water needs.

River Water

The Unit 2 river water pumps are more reliable and should be kept in operation. The Unit 2 river water pumps will be oversized and may need to be modified for the new flow requirements and this would be investigated during detailed design.

See the Unit 2 retirement study AEPBS-1-LI-EM-0002 for more details.

Demineralized Water

As stated above the Unit 1 water treatment plant is shut down and not being used so the Unit 2 water treatment plant which supplies the demineralized water for the Unit 1 system will need to stay in operation. As the system currently operates, the RO effluent water is not of sufficient quality to be directly blended with the clean condensate but must be sent to the contaminated condensate storage tank from where it is cleaned up by the Unit 2 condensate polisher system to an acceptable quality and then used as needed. The Unit 2 condensate cleanup pumps are 3000 gpm and are oversized for the current condensate cleanup demand and should be shut down. In order to allow the Unit 2 high flow condensate clean up pumps to be shut down new smaller demineralizer feed pumps must be provided for condensate cleanup. The RO can directly feed the contaminated condensate tank as it does now. These new demineralizer feed pumps will then take suction from the contaminated condensate storage tank and pump though modified condensate polishers (demineralizers) into the Unit 1 condensate storage tank. This arrangement is based on the premise that the condensate polishers (demineralizers) can be modified to condition the condensate at a much lower flowrate. The internals inside the condensate polisher vessels may need to be modified. The precoat filters will be shut down. If modifying the condensate polishers is not feasible then a new mixed bed system needs to be installed to meet the water quality requirements.

See the Unit 2 retirement study AEPBS-1-LI-EM-0002 for more details.

Service Water

It is recommended that the Unit 1 service water system be kept in service. The Unit 1 service water system that currently supplies water to Unit 1 will have sufficient capacity to provide water for Unit 1 operations.

It is recommended that the Unit 2 service water system be kept in service. The Unit 2 service water system that currently supplies makeup water to the Unit 2 water treatment plant has more than sufficient capacity to provide water to the Unit 2 water treatment system and for other uses. As a result of the Unit 2 shutdown the existing pumps (which are reported to be in poor condition and will also be oversized) need to be modified or replaced to get the turndown necessary to operate at the reduced flow rates.

For more details see the Unit 2 retirement study AEPBS-1-LI-EM-0002.

Service Water Pumps

If the existing Unit 2 pumps cannot be modified to meet the current flow capacity requirements two new 100% service water pumps would be installed to supply service water for the Unit 2 service water operations.

For more details on the Unit 2 service water pumps see the Unit 2 retirement study AEPBS-1-LI-EM-0002.

3.7 Condensate Cleanup Description

This section presents an evaluation of the existing condensate cleanup system and provides suggested modifications needed to update the system to meet the condensate requirements.

Currently Unit 2 RO permeate is sent to the Unit 2 contaminated condensate tank where it is used for makeup to the condensate system. The sodium content of the RO permeate water is higher than acceptable and the contaminated condensate is cleaned up using the Unit 2 condensate polishers and then the clean condensate is either used, fed to the Unit 2 clean condensate storage tank, or transferred to Unit 1. If Unit 2 is shut down it requires that the Unit 2 condensate polisher system be operated to make clean condensate for Unit 1. This requires running the Unit 2 condenser hotwell pumps, and the Unit 2 condensate cleanup pumps. In order to prevent this from being necessary, the condensate polishers need to be investigated to determine if they can be converted to mixed beds. The internals and other complex details of the polishers have to be investigated to determine if this is feasible. This would require a study of the system to determine if this is feasible. If it is not feasible then a mixed bed system will need to be installed. The evaluation of the condensate polisher system is beyond the scope of this report.

Assuming it is feasible, the condensate can be conditioned by pumping it through the modified mixed beds into the Unit 1 condensate storage tank. The system piping will need to be modified to treat the condensate by piping it from the Unit 2 contaminated storage tank to the inlet of the converted polishers (or mixed beds) and from the outlet of the polishers (or mixed beds) to the existing 4 inch cross-tie connecting to the Unit 1 condensate storage tank where it can then be used for Unit 1 operations.

Two new 100% capacity demineralizer feed pumps will be installed to forward the contaminated condensate through the modified condensate polishers (or newly installed mixed bed system) and into the Unit 1 condensate tank. Pumps will be of stainless steel construction and will each be capable of providing 220 gpm continuous condensate flow into the Unit 1 condensate storage tank.

For more details see the Unit 2 retirement study AEPBS-1-LI-EM-0002.

3.8 Permitting Requirements

This section discusses potential requirements for new permits and/or modifications to existing permits. Although this section was prepared without direct contact with regulatory agencies about this gas conversion project, it was prepared based on previous permitting experience gained from similar projects. The following table presents potential permits that may be required for the Big Sandy Gas Conversion Project:

Table 2 - Permitting

PERMIT/APPROVAL	AGENCY	ACTIVITY/COMMENTS
Kentucky Pollutant Discharge Elimination System (KPDES) Permit	Kentucky Department of Environmental Protection (KYDEP)	For changes to the wastewater flow diagram resulting from the conversion of the Unit 1 System (to natural gas) and the decommissioning of Unit 2.
Spill Prevention, Control, and Countermeasure (SPCC); Best Management Practices (BMP); Stormwater Pollution Prevention (SWPP) Plans	KYDEP	Update plans accordingly resulting from the Unit 1 Gas Conversion and the decommissioning of Unit 2.
KPDES Stormwater Discharge for Construction	KYDEP	For earth disturbances during construction
KPDES for Construction Dewatering Discharge	KDEP	For lowering water table during construction, more likely with underground highway and railroad crossings

Table 2 - Permitting		
PERMIT/APPROVAL	AGENCY	ACTIVITY/COMMENTS
Erosion and Sedimentation Control Plans	County Soil Conservation Service	For earth disturbances during construction
Activities Affecting Jurisdictional Waters	US Army Corps of Engineers	For new and/or modified crossing of streams or wetlands with new discharge structure to Big Sandy River from bottom ash pond
Endangered Species Analysis	US Department of Interior, KY Department of Natural Resources	For identifying project impacts on threatened and endangered species
Archeological, Historic, and Cultural Resources Survey	State Historic Preservation Office	For identifying project impacts on cultural resources
Potable Water System	Municipal Water Utility	For changes to potable water system and availability of potable water for new and modified plant water usage
Risk Management Plan, Community Right to Know, Toxic Release Inventory	US EPA/KYDEP/ Emergency Response Committee/Fire Chief	For handling, storage, and releases of hazardous materials
Site Plan Approval	County Planning Department	For plant site improvements
Closure of Fly Ash Ponds	KYDEP/US EPA	For the closure and long-term maintenance of the fly ash ponds
Solid Waste Permit	KYDEP/US EPA	For the disposal of excavated debris during construction

Discussion of specific permit changes and application preparation is beyond the scope of this study. However, early permitting discussions of this gas conversion project with regulatory agencies would confirm the need for the permit, potential permit requirements, the need for any additional supporting studies, the agency's review schedule, and public comment and public hearing requirements.

3.9 Costs

This section includes a description of the budgetary capital costs included for modifying the water system.

A total of 10,000 USD dollars was included in the cost estimate for modifying the reclaim pond overflow piping to operate at the required pond levels. No other costs for modifications are included in the cost estimate as a result of the water study. Other water system modifications are considered a result of the Unit 2 shutdown and these costs are included in the Unit 2 retirement study AEPBS-1-LI-EM-0002.

3.10 Impact on Schedule

The required modifications to the existing equipment and piping are limited to a few piping tie-ins and potential pump modifications. These must be done during a plant outage and must be scheduled during Unit 1 and 2 outages.

Modifications to the Unit 2 condensate polishers must also be made. Since it is anticipated that Unit 2 will be running while the conversion project is ongoing it may be required to rent mixed bed units until the existing condensate polisher units can be converted to mixed beds (condensate demineralizers).

Procurement and installation will be done based on a developed project schedule so that the project timeline can be maintained. Pumps will be the longest lead items to procure. The feasibility of converting the condensate polishers to mixed beds (condensate demineralizers) will require an evaluation and subsequent modifications. The evaluation could take up to eight weeks and the new internals/piping procurement and installation at least eight more weeks.

If a new mixed bed system is required it may take up to 24 weeks for specifications, procurement and installation. A new mixed bed system would also require an area for installation. The area where the current condensate polisher system is located could be used. This would require removal of the existing precoat filters, condensate polishers and their associated regeneration systems to facilitate installation of the new mixed bed system. Rental mixed bed units could be used to clean up the contaminated condensate until the mixed bed system could be put into service.

4. CONCLUSIONS

This section summarizes the results of the study for the river water, demineralized water, service water and other affected systems.

River Water

The abandonment of the ash systems and conversion of Unit 1 to natural gas and shutdown of Unit 2 will require less river water than is currently being used. The existing system has sufficient capacity to provide the necessary river water. According to AEP the Unit 2 river water pumps are more reliable than the Unit 1 river water pumps and should be kept in service. The Unit 2 pumps are oversized and the required modifications to them needs to be determined during detailed design. The Unit 1 pumps will be retired.

Demineralized Water

The abandonment of the ash systems and conversion of Unit 1 to natural gas and shutdown of Unit 2 will require less demineralized water than is currently being used.

The Unit 2 water treatment system will need to be maintained in operation. A new mixed bed system may need to be installed to provide the required water quality if the existing condensate polisher system cannot be converted to mixed bed units. A rental mixed bed system may need to be used until the condensate polishers can be converted to mixed beds or if the conversion is not feasible then a rental system may need to be used while the Unit 2 condensate polishers are shut down and removed and a new mixed bed system is installed in the space currently occupied by the precoat filter/condensate polisher system.

Service Water

The abandonment of the ash systems and conversion of Unit 1 to natural gas and shutdown of Unit 2 will require less service water than is currently being used.

The Unit 1 service water system and some aspects of the Unit 2 service water system will need to be maintained in operation. The Unit 2 system will need to be modified for the reduced flow resulting from the shutdown of Unit 2. See the Unit 2 retirement study AEPBS-1-LI-EM-0002 for more details.

Potable Water

The current Unit 1 potable water system will need to be maintained as currently configured.

Wastewater

The abandonment of the ash systems and conversion of Unit 1 to natural gas and shutdown of Unit 2 will produce less wastewater than is currently being produced. Refer to the water balance AEPBS-1-DB-EM-0001 for more details.

The Unit 1 boiler room and turbine room sumps should be kept in operation. Any other Unit 1 sumps should be kept in operation unless they can be shut down as part of the Unit 1 ash system abandonment. Sumps such as the Unit 1 ash pit sump should be abandoned only after operational experience has demonstrated that they no longer have to be kept in operation. This can be done on a field trail basis before they are permanently shut down.

No change to the waste water system on Unit 2 is anticipated. It will need to remain in service after Unit 2 is retired.

Modifications to the common (Unit 1 & Unit 2) existing wastewater system will need to be made. The existing reclaim pond overflow will need to be modified to perform within the new discharge level requirements. Two bottom ash ponds may need to be shutdown and two bottom ash ponds may need to be lined. The reclaim pond may need to be lined.

As a worst case scenario a new wastewater treatment facility may be needed due to permitting requirements.

Any new wastewater treatment equipment required as a result of new discharge permit requirements is outside the scope of this study.

Sanitary Drains

No modifications to the existing sanitary sewer system will need to be made as a result of the gas conversion. Mobile tank-type trailers can be used to provide a clean, comfortable, cost effective system during the construction period operation. Mobile tank-type trailers should be provided in accordance with the expected extra construction personnel and the number of personnel a trailer has the capacity to treat.

Chemical Feed System

If it is feasible to convert the existing condensate polishers to mixed beds (condensate demineralizers) capable of supporting the reduced flow rate and capable of meeting the water quality requirements, it is not anticipated that the type of regeneration or regeneration chemical feed systems will need to be changed. This needs to be confirmed by the manufacturer of the system or other party qualified to make this determination.

5. RECOMMENDATIONS

This section provides WorleyParsons recommendations for the river, service and demineralized water systems.

The following items are recommendations based on this study:

The existing Unit 1 river water pumps should be retired. The Unit 2 pumps should be kept in service and modified if necessary so that the operational characteristics of the pumps are in line with the gas conversion flow requirements.

The Unit 1 service water system should be kept operational.

The Unit 2 service water system provides water to the Unit 2 water treatment system. This system should be kept in service since it currently supplies water to the demineralized water system. The Unit 2 service water system should be kept operational but the system flow capacity should be downsized to accommodate the lesser flow requirements by either modifying the existing pumps or supplying new smaller pumps.

The Unit 2 water treatment system should be kept operational since it supplies clarified, filtered and softened water to Unit 1 users. One of these users is the demineralized water system that currently supplies demineralized water for boiler makeup to both Unit 1 and Unit 2.

The Unit 2 condensate cleanup system is currently used to condition the condensate for both Unit 1 and Unit 2. In order to prevent having to maintain the condensate cleanup system in its current operation which relies heavily on Unit 2 operation it is preferred to use the existing condensate polisher vessels for Unit 1 only. In order to do this they must be capable of being converted to mixed bed units that can handle a reduced flow of approximately 220 gpm. This requires an analysis of the current system by the system manufacturer or by Other's that are capable of making this analysis. After the feasibility of this conversion has been ascertained the decision should be made as to whether it is more cost effective and efficient to make the conversion or if the installation of a mixed bed system would be more advantageous.

Keep the Unit 1 potable water system in operation as configured.

Keep the existing sewage treatment plant (STP) as configured. During construction periods, mobile tank-type trailers should be used if needed.

See the Unit 2 retirement study AEPBS-1-LI-EM-0002 for details on the Unit 2 water systems shutdown ramifications.

6. REFERENCES

A. AEP - Engineering Services, Mechanical Design Criteria, DC-MECH-001

B. Project Specific Design Criteria, AEPBS-2-DB-EU-0001-RA

C. Water Supply Study, Big Sandy Unit 2 DFGD-NID & ACI Retrofit Project - AEPBS-2-LI-EM-0006

D. Kentucky Power Company - Big Sandy Plant Water Usage Flow Diagram

E. Unit 2 Retirement Study, Big Sandy Gas Conversion Project - AEPBS-1-LI-EM-0002

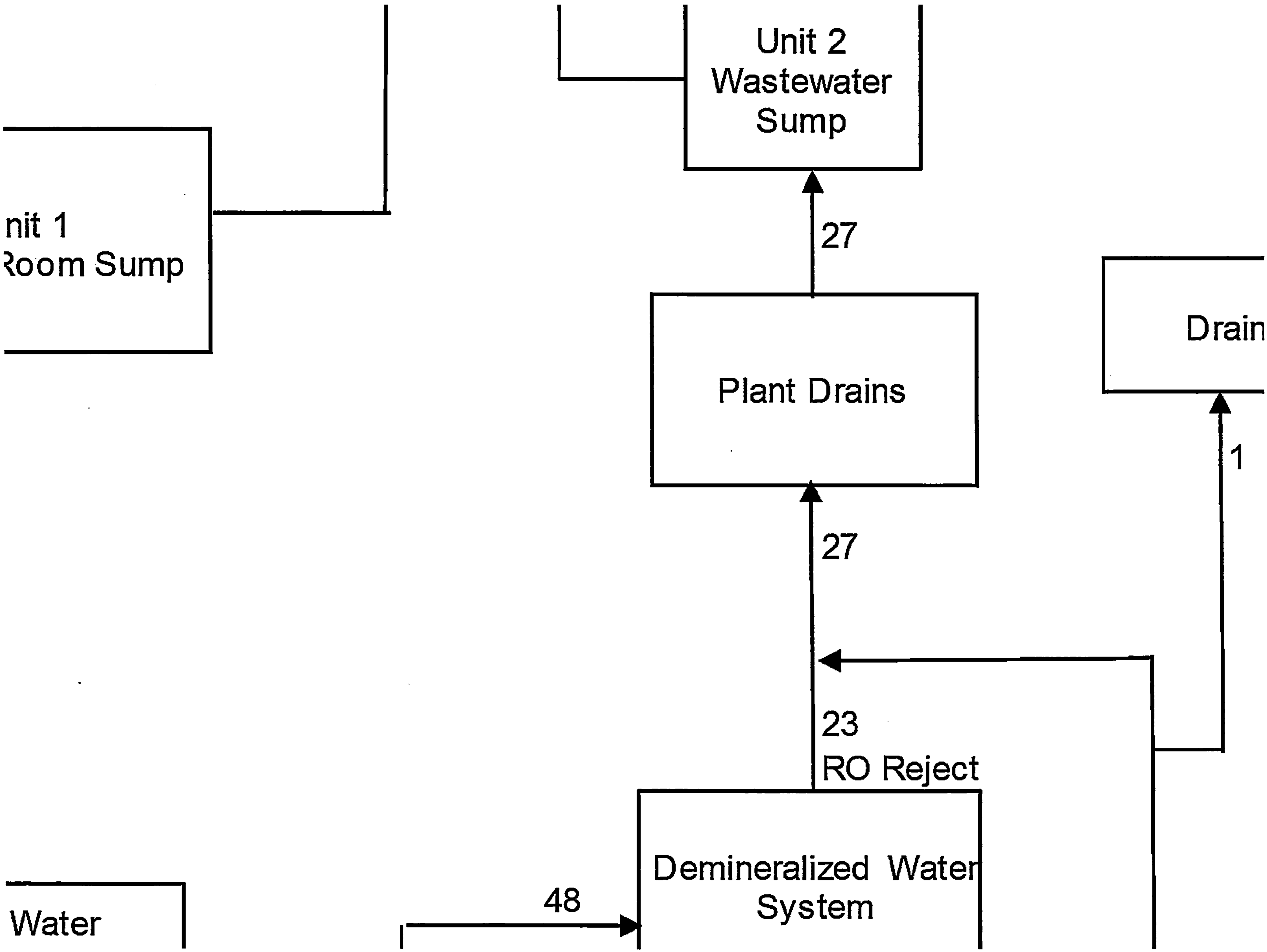
F. Big Sandy Plant Drawings MSK-200, MSK-202, 1-5007-17, 1-5013-18, 1-5016-12, 1-5092-5, 2-5004-5, 2-5007-23, 2-5013-23, 2-5014-40, 2-5016-17, 2-5027-16, 2-5078-12, & 12-5335-4

7. APPENDICES

Appendix 1 - Plant Water Balance

Appendix 2 - Kentucky Power Company - Big Sandy Plant - Water Usage Flow Diagram

Appendix 1- Plant Water Balance



Unit 2
Wastewater
Sump
27
nit 1
Room Sump
Plant Drains
Drain
1
27
23
RO Reject
Demineralized Water
System
48
Water

Appendix 2 - Kentucky Power Company - Big Sandy Plant - Water Usage Flow Diagram

APPENDIX 2

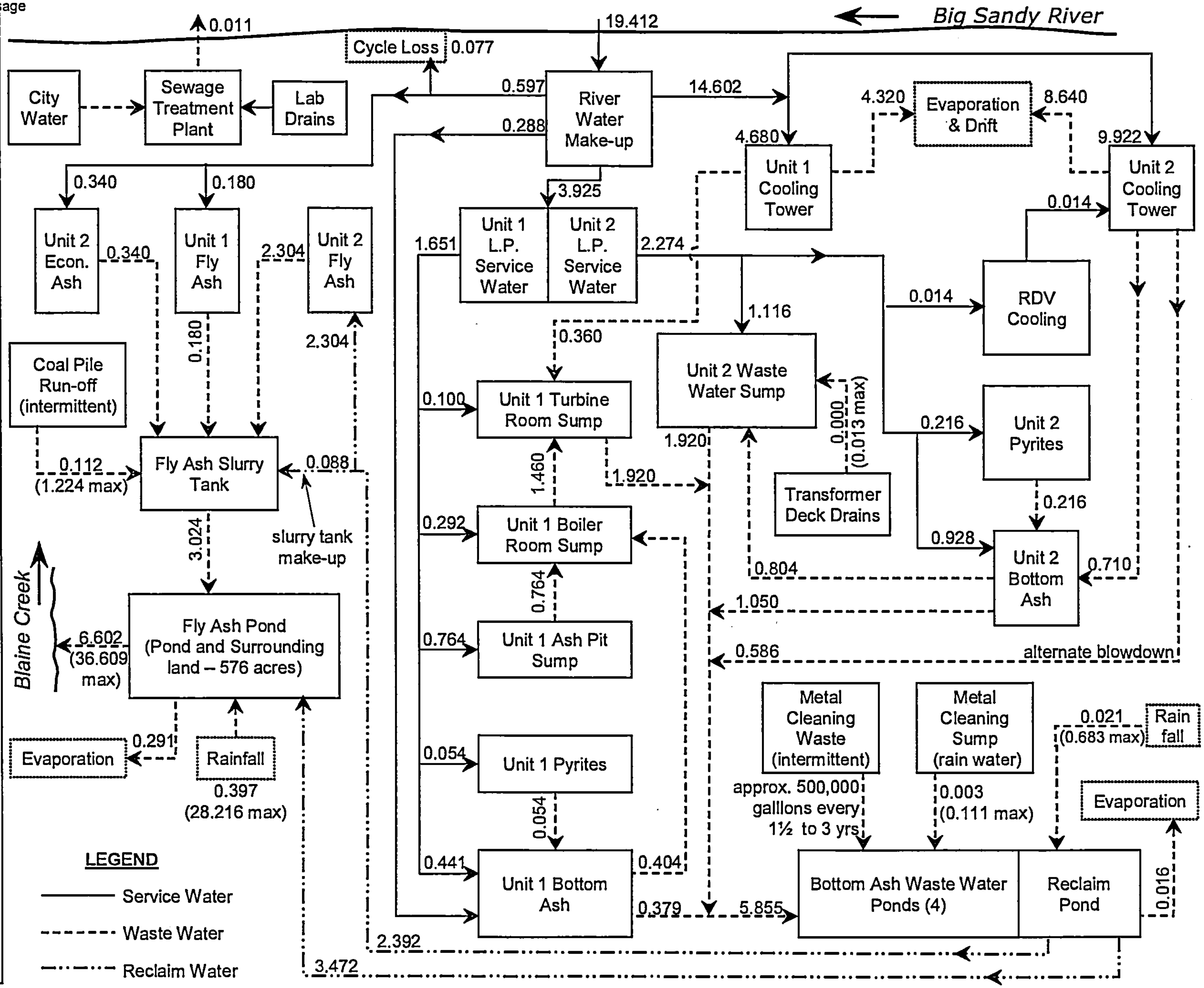
10.26.01 BS waterusage

NOTE:
1. Flows represent actual water usage with both units operating at full load.
2. Normal rainfall values based on avg. annual rainfall of 46.36 In/yr. Maximum rainfall includes rainfall for a 10yr – 24 hr event (4.1 in/day).

ALL FLOWS MEASURED IN MILLION GALLONS PER DAY (MGD)

AEP Water & Ecological Resource Services

Kentucky Power Company
Big Sandy Plant
Water Usage Flow Diagram



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AMERICAN ELECTRIC POWER
BIG SANDY UNIT 1 GAS CONVERSION PROJECT

Unit 2 Retirement Study

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WorleyParsons
2675 Morgantown Rd.
Reading, PA 19607
USA
Telephone: +1 610 855 2000
Facsimile: + 1 610 855 2001
www.worleyparsons.com

WorleyParsons
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EcoNomics

AMERICAN ELECTRIC POWER
BIG SANDY UNIT 1 GAS CONVERSION PROJECT
UNIT 2 RETIREMENT STUDY

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BIG SANDY UNIT 1 GAS CONVERSION PROJECT
UNIT 2 RETIREMENT STUDY

CONTENTS

1. EXECUTIVE SUMMARY

The purpose of this study is to identify the scope of work and cost necessary to retire Unit 2 in 2015 without compromising the ability of Unit 1 to operate after being converted from coal to natural gas firing.

Results of the study indicate that retirement of Unit 2 will have only a small impact on the overall capital cost of converting Unit 1 to fire natural gas. Specifically:

- Due to the condition of the auxiliary boiler, an investment in natural gas fired unit heaters will be necessary to allow the station to be heated when Unit 1 is not in service.
- There is a greater risk of a black station after Unit 2 is retired. It is suggested that AEP consider maintaining the existing cross-tie to the Unit 2 battery and that this battery be maintained in the future.
- While there is no reason to believe that loss of the Unit 2 Reserve Auxiliary Transformer would trip Unit 1, AEP may wish to maintain the existing Unit 2 GSU and Auxiliary Transformers since they would provide an alternate source of power for some of the common loads and allow Unit 1 to continue to operate if the Unit 2 Reserve Auxiliary Transformer were to fail.
- Unit 2's retirement may require an investment in the fire water protection system to maintain reliability in this area. Converting the existing Unit 2 Clean Condensate Storage Tank to a fire water tank is a logical solution to minimize the cost of losing the Unit 2 cooling tower basin as a source of fire water.
- The existing common Water Treatment Plant is not capable of independently producing demineralized water suitable for Unit 1 since Big Sandy has historically relied on the Unit 2 condensate polishers to produce water for both units. It will be necessary to polish the reverse osmosis unit permeate to allow the Unit 2 condensate system to be permanently shut down. For study and cost estimating purposes, it was assumed that new demineralizer feed pumps, supplied by the existing Unit 2 Contaminated Condensate Storage Tank, would be added and that piping modifications would be made to allow one of the existing two-vessel polishing trains to function as a mixed bed demineralizer for the make-up water to Unit 1 in the future.
- It will be necessary to maintain live medium voltage buses (2A, 2B and 2C) at Big Sandy to accomplish the objective of converting Unit 1 to natural gas with minimal investment.

Further details on the cost estimate associated with retiring Unit 2 are contained in the cost estimate submittal made to AEP in a separate document.

2. INTRODUCTION

2.1 Background

The Big Sandy Plant is located between Route 23 and the Big Sandy River near Louisa, Kentucky. The plant is comprised of two coal-fired, steam-electric units, Unit 1 and Unit 2. AEP is considering converting Unit 1 to fire natural gas. A consent decree will require that Unit 2 be retired in 2015 since AEP has determined that retrofitting this unit with air pollution control equipment would be prohibitively expensive.

Since the two units share some common systems, the impact of retiring Unit 2 on the continued operation of Unit 1 as a peaking unit must be examined.

2.2 Scope of Work

WorleyParsons was asked to prepare a scoping study to determine the modifications necessary to allow Unit 2 to be retired with the expectation that Unit 1 will be converted to fire natural gas. The study was to look at both the electrical and mechanical implications of retiring Unit 2.

The second part of WorleyParsons' scope was to estimate the cost of these modifications necessary to allow Unit 2 to retire without impacting operation of Unit 1 on natural gas.

While the study does not specifically address how Unit 2 will be retired, it was assumed that there would be a period of time following shut-down of Unit 2 where it would be maintained in cold reserve status. Subsequent decisions (and costs) regarding salvage of the plant and equipment associated with Unit 2 were beyond the scope of this study.

2.3 Approach and Key Assumptions

It was necessary to make several key assumptions as a basis for the study. First, it was assumed that any capital investment should be kept to a minimum, consistent with safe and reliable operation, since it is expected that Unit 1 will be operated as a peaking unit with a capacity factor of only 10 or 15 percent following its conversion to natural gas firing. This limits the amount of investment that can be justified.

Based on the foregoing, it was assumed that any action to salvage Unit 2 plant and equipment would result from a separate decision made only after it had been retired for a long enough period of time that a completely new air permit would be required were market conditions and/or current regulations to change dramatically from the present and cause AEP to reconsider the decision to discontinue the operation of Big Sandy 2 on coal. It was further assumed that any costs necessary to completely dismantle Unit 2 and salvage some of its equipment would be a separate decision justified by the value to be gained from salvage. In other words, any costs associated with repowering equipment common to the two units would need to be justified by the expected revenue associated with salvaging the Unit 2 equipment.

As a consequence of this, it was assumed that the existing Unit 2 138 kV-4.16 kV 20 MVA reserve transformer TR 102 would remain in service and be used to power certain common loads supplied by breakers located on the 2A, 2B and 2C buses. While none of the common loads remaining on these buses appear to be critical to the safe and orderly shutdown of Unit 1 (or even necessary to prevent an immediate trip of Unit 1) should TR 102 fail in the future, the existing Unit 2 950 MVA generator step-up transformer TR 2 and the auxiliary transformers TR 2A, TR 2B, TR 2C and TR 2D could also be maintained if AEP wishes to have a second source of power for some of the common loads supplied by Unit 2.

Retirement of Unit 2 will eliminate the need for the reserve bus 2D-R that supplies the forced draft fans. The best way to safely and permanently isolate this bus needs to be investigated.

The two 138-13.8 kV SCR Reserve Transformers will also be unused following retirement of Unit 2. While disconnects are available to isolate them from the 138 kV system, proper preservation and/or salvage of these transformers and the relatively modern electrical equipment that they feed needs to be considered by AEP. This subject was not considered as part of this study since de-energizing these transformers should not impact safety or reliability following the conversion of Unit 1 to natural gas.

Based on the above, the following specific medium voltage (MV) and low voltage (LV) loads necessary (or desirable) for the future reliable operation of Unit 1 on natural gas (or for the short-term preservation of high value Unit 2 equipment) were assumed to continue to be supplied by buses 2A, 2B and 2C:

- Various Unit 2 air compressors (MV)
- Large river water make-up pumps (LV)
- Water Treatment Plant loads (LV)
- Sewage Treatment Plant loads (LV)
- High demand Unit 2 fire water pump (MV)
- Low demand Unit 2 fire water pump (LV)
- Lighting (LV)
- Unit 2 battery charger (LV)

- Unit 2 air dryers (LV)
- Unit 2 generator seal oil system (LV)
- Unit 2 stator cooling system (LV)
- Unit 2 turbine turning gear, lube oil and jacking oil pumps (LV)
- Unit 2 turbine lube oil vapor extractors (LV)

A site visit made in April 2012 to identify specific areas of concern associated with common systems was helpful to better understand the potential issues associated with retiring one of the Big Sandy units. AEP provided people with many years of operating experience and a wealth of knowledge about the plant to answer WorleyParsons' questions and escort the WorleyParsons team on a station walk down which was very helpful to understanding operations at Big Sandy and deciding which areas effort should be focused on.

AEP personnel were questioned about the following systems as a basis for identifying areas of concern:

- Boiler Chemical Cleaning
- Ash Sluice Water
- Ash Sluice Water Return
- Atomizing Air
- Auxiliary Boiler
- Auxiliary Cooling Water
- Auxiliary Steam
- Boiler Chemical Cleaning
- Break Rooms
- Building Heat
- Carbon Dioxide Storage and Piping

- Caustic Bulk Storage and Forwarding
- Chlorine Storage
- Circulating Water
- Closed Cooling Water
- Coal Crushing
- Coal Receipt and Unloading
- Coal Reclaiming
- Coal Sampling
- Coal Stack Out
- Coal Thawing
- Control Rooms
- Corrosion Inhibitor Storage and Forwarding
- Demineralized Water Storage Tank
- Demineralizer Regeneration
- Dust Suppression
- Elevators
- Emergency Diesel Generator
- Filtered Water Storage Tank
- Fire Water Pumps and Piping
- Fire Water Storage

- Flue Gas Conditioning
- Fuel Oil Piping
- Fuel Oil Storage
- Fuel Oil Unloading
- HVAC
- Hydrogen Storage
- Hydrostatic Test Pump
- Instrument Air
- Laboratories
- Lighting (shops, warehouse, administration, labs, break rooms, control room, yard)
- Locker Room
- Metal Cleaning Waste Treatment
- NaOCl Bulk Storage and Forwarding
- Neutralization Tank
- Nitrogen Blanketing
- Oxygen Scavenger Storage and Forwarding
- Boiler Water Chemicals Storage and Forwarding
- Plant Scales
- Potable Water
- R.O. Permeate Storage Tank

- Raw Water Storage Tank
- Raw Water Supply
- Rest Rooms
- Service Air
- Service Water
- Sewage Treatment Plant
- Soda Ash Bulk Storage, Mixing and Forwarding
- Sootblowing Air
- Station Battery
- Sulfuric Acid Bulk Storage and Forwarding
- Sump Pumps
- UPS
- Urea Storage, Handling and Conversion
- Waste Oil Storage
- Waste Water Storage Tank
- Waste Water Treatment
- Water Treatment Plant, Demineralized Water
- Water Treatment Plant, Filtered Water

Based on the results of discussions in the areas identified above, as well as a subsequent site visit made to Big Sandy in September 2012, AEP was able to help the WorleyParsons team determine the common areas that will be impacted if Unit 2 is retired and Unit 1 is converted to a peaking unit firing natural gas.

3. DISCUSSION

3.1 Auxiliary Steam for Start-up

Auxiliary steam is currently produced at Big Sandy from Unit 1, Unit 2 or a single oil-fired auxiliary boiler.

Auxiliary steam at a pressure of approximately 200 psig is critical to operation of Big Sandy Unit 1. It is essential for start-up since it is used for steam seals on both the main steam turbine as well as the turbine-driven boiler feed pump. It is also used to preheat combustion air, peg the deaerator at low loads, warm the reheat lines and drive the turbine-driven boiler feed pump until turbine extraction pressures are high enough to perform these functions.

While Unit 2 is dependent on steam from another source to start-up, Big Sandy Unit 1 is currently equipped with a motor-driven auxiliary boiler feed pump that can be used to provide feedwater to the boiler before auxiliary steam is available. This pump, which is driven through a gear box, is shown below. It allows the boiler to be started up and drum level maintained until auxiliary steam is available to start-up

UNIT 1 MOTOR DRIVEN AUXILIARY BOILER FEED PUMP

the turbine-driven boiler feed pump. Steam from the primary superheater outlet of Unit 1 can be reduced in pressure and attemperated to accomplish this. This steam can also be used to peg the deaerator, warm up reheat lines and furnish steam to the seals on both the boiler feed pump turbine and the main steam turbine so that vacuum can be pulled prior to turbine roll. Unit 1 relies on a vacuum pump to draw and maintain condenser vacuum so that auxiliary steam is not required for either a hogger or an air ejector during start-up.

In conclusion, while auxiliary steam is, and will remain, vital to the production of electricity at Big Sandy Unit 1, the presence of a motor-driven auxiliary boiler feed pump dedicated to this unit does not make the continued operation of Unit 1 dependent on auxiliary steam from other sources. This ensures that retirement of Unit 2 should not impact the future start-up and operation of Unit 1 since Unit 1 can create its own auxiliary steam.

It also ensures that problems with the existing auxiliary boiler (or retirement of it if AEP elects to do so) will not impact the capability of Big Sandy Unit 1 to start-up unassisted by other sources of auxiliary steam.

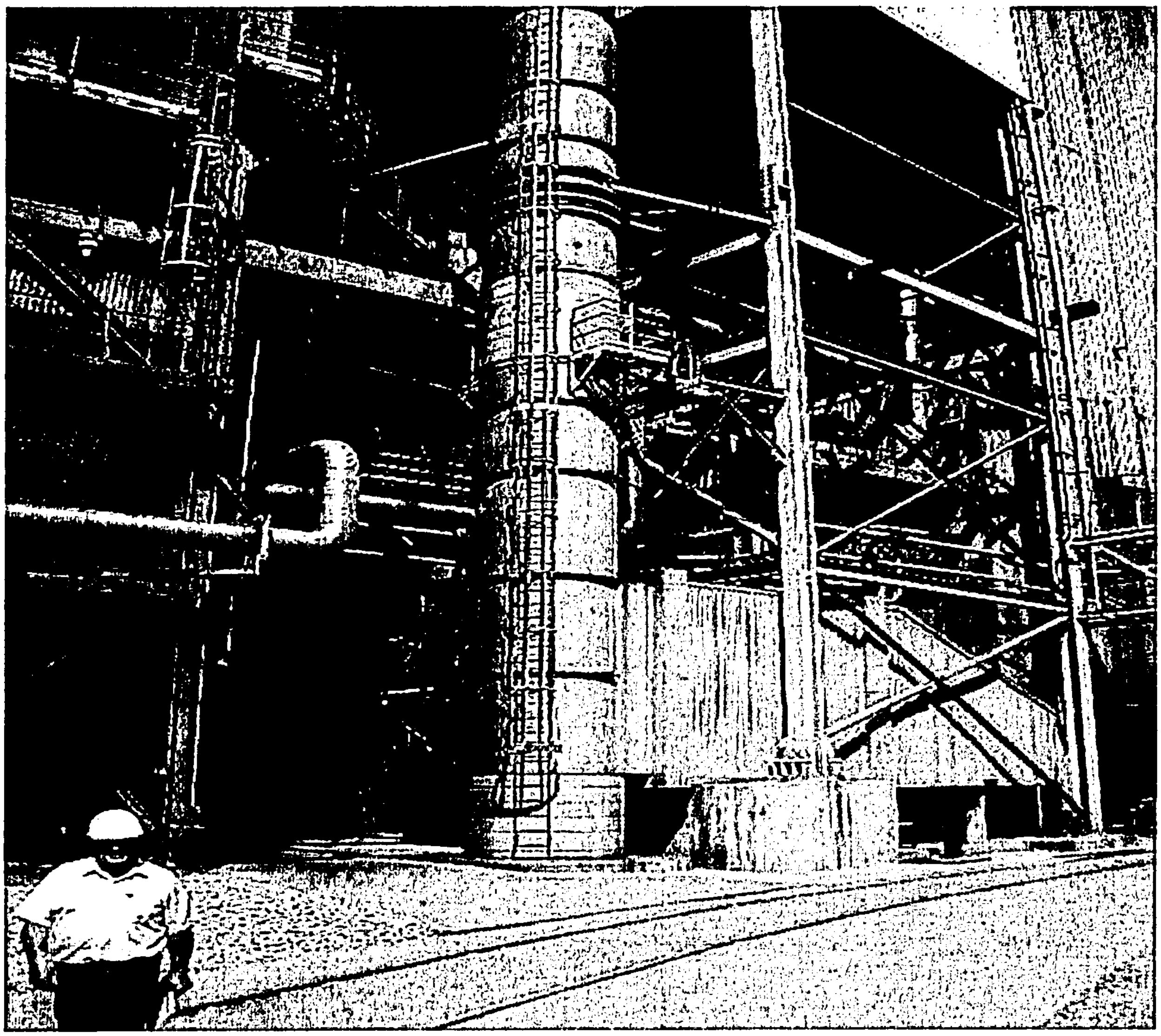
3.2 Auxiliary Steam for Building Heat

Auxiliary steam is also used to heat the station during cold weather. The station estimates that approximately 20,000-25,000 pounds per hour of auxiliary steam is currently used to heat both units. This equates to approximately 20 to 25 MMBtu per hour of heat. Further study would be necessary to determine how much this heat load could be reduced if the Unit 2 boiler is permanently drained and heat is no longer required in the coal handling and ash handling areas.

Auxiliary steam for building heat is currently provided to Big Sandy from Unit 1, Unit 2 or a single Foster Wheeler oil-fired auxiliary boiler that is used when neither of the two coal-fired boilers is available.

The boiler tubes in the auxiliary boiler are in poor condition and the station feels that they would all need to be replaced for the auxiliary boiler to be reliable on a going forward basis.

The auxiliary boiler at Big Sandy was constructed adjacent to Unit 2 before power plants were required to have all the air quality control equipment that current regulations mandate. Approximately 10 years ago, a selective catalytic reduction system was added to Unit 2. The impact of this was to surround the existing auxiliary boiler with structural steel, ductwork and other interferences. A picture of the auxiliary boiler is shown on the next page to illustrate the tight conditions around it which would prohibit future replacement of it in its existing location and make any major repair work to it expensive.



BIG SANDY AUXILIARY BOILER

The ductwork exiting the boiler and its stack are in the foreground. The forced draft fan for the boiler is in the background and to the left of the stack. The auxiliary steam line which is fed from the auxiliary boiler and Unit 1 (on left) and Unit 2 (on right) is also in the foreground of the picture.

The existing auxiliary boiler has a maximum allowable working pressure of 300 psig and is equipped with a superheater to raise the temperature of the steam from it to 600 F. It is rated at 355,000 pounds per hour.

The unreliable auxiliary boiler coupled with the proposed retirement of Unit 2 effectively eliminates two out of the three potential sources of building heat at Big Sandy. So when Unit 1 is out of service in cold weather, provisions must be made to heat the station. Our cost estimate included the cost of installing and furnishing natural gas unit heaters throughout the station. We assumed that once the Unit 2 boiler is drained and the coal and ash handling equipment is abandoned, that it would be possible to heat the station with less capacity than the current demand estimated by AEP to be 20 to 25 MMBtu per hour. Our cost estimate included the purchase and installation of permanently mounted hard-piped unit heaters having a total capacity of only 13.4 MMBtu per hour. The precise capacity and number of heaters required would need to be better estimated during preliminary engineering to confirm its adequacy. The fact that the Water Treatment Plant is on the Unit 2 side of the station significantly increases the heat load relative to what it would be if Unit 1 was "self-contained" with respect to water treatment.

While draining the Unit 2 boiler is expected to reduce the overall demand for building heat, the filtered water storage tank area located at elevation 95' on the existing Unit 2 boiler structure must continue to be protected from freezing using unit heaters.

For purposes of the cost estimate, a 3-inch dedicated welded steel natural gas heating main operated at 5 psig was assumed to be fed from a point immediately upstream of the main automatic isolation valve for the gas supply to the Unit 1 boiler just north of the north wall of the boiler house. The 3-inch line would run the length of Unit 1 (north south) and then a tee would be provided to allow it to run east to the Unit 2 water treatment area. Several vertical risers would originate from this main line with numerous small-bore laterals (1 to 1 1/2 inch diameter) feeding the groups of heaters on Unit 1, the lower elevations of Unit 2 in the vicinity of the water treatment area, the filtered water storage tank area, and the Unit 1 Service building.

In addition to the above, our estimate included the installation of ten 20 kW heaters and ten 10 kW heaters to provide an allowance for some areas of the plant where a relatively small amount of heat may be desirable for freeze protection, but the cost of running the natural gas piping to the area would be prohibitive. Examples of outbuildings where such supplemental electric heat may be desirable include the River Water Make-up Pump Houses and the Unit 2 fire protection water pump pit. These heaters would add another 1.0 MMBtu per hour of heat to the station.

Electric heat is presently used to heat the Unit 2 Service Building.

While the proposed means of heating the station should work well when Unit 1 is shut down, the initial start-up of Unit 1 during cold weather poses a problem due to the strong flow of ambient air through the boiler building when a forced draft fan is started up to purge the boiler in preparation for light off. At this time, and for the subsequent hours that it takes for Unit 1 to be able to produce auxiliary steam, it will not be possible to preheat combustion air using the heating coils designed to warm the air entering the Unit 1 boiler building. For this reason, the cost estimate includes an allowance to heat trace and insulate small bore lines in the boiler building basement area that would otherwise be prone to freeze up. This includes the small bore piping associated with providing cooling water to the air compressors on the ground floor.

Our estimate also included a modest allowance for insulation and heat tracing of piping elsewhere in the station since there may be a few critical areas in the plant that need extra heat if indoor temperatures in the station are maintained at lower levels in the future.

Because the natural gas-fired unit heaters are expected to be very reliable, no provision was made for spending any money on the existing auxiliary boiler or for making provisions to accommodate a rental package boiler.

There is no reason to retire the existing steam heaters throughout the station. It is anticipated that most of them will continue to be used in the future when Unit 1 is in operation since the use of turbine extraction steam is a more efficient means of supplying heat than direct-fired unit heaters.

3.3 Battery Rooms

Both Units 1 and 2 rely on 250 VDC battery banks to provide power to critical loads such as the DC turbine lube oil pumps. Failure of such a pump to operate when called upon to do so would have devastating consequences for the Unit 1 steam turbine-generator and likely lead to a multi-month outage. While multiple transmission lines at different voltages supply power to the substations at or near Big Sandy, the station does not have an Essential Power System (with diesel generator) to supply critical loads such as the turbine lube oil pumps and the battery chargers as required by the AEP Fleet Plant Electrical Design Criteria (DC-ELEC-001-02) dated May 10, 2010.

While WorleyParsons did not investigate the capability of the station batteries for Units 1 and 2 to determine if they are consistent with the AEP requirements for DC systems spelled out in DC-ELEC-001-02, the absence of an Essential Power System at Big Sandy and the retirement of the Unit 2 generator suggest that, at a minimum, it may be prudent to continue to maintain the existing Unit 2 battery and battery chargers to bolster the reliability of Unit 1 by reducing the possibility that the station could be black for long enough to discharge the existing Unit 1 battery and damage the steam turbine.

A disconnect was retrofit between the Unit 1 and Unit 2 batteries many years ago to take advantage of the combined capacity of the batteries for the two units. Based on discussions with station staff, no changes would be necessary to allow this disconnect to continue to be used as it has been.

While there are many differences between the design of AEP's Mountaineer and Big Sandy Stations, it is worth noting that Mountaineer has both a normal and a back-up battery.

Maintenance of the existing Unit 1 battery is not a substitute for having an Essential Power System. But it should help reduce the risk of not having one and this risk would appear to be higher for Unit 1 after Unit 2 is retired.

3.4 Diesel Generator

As noted above, Big Sandy does not have an Essential Power System with a diesel generator. See Section 3.3 for further discussion of this subject.

Big Sandy has experienced very few instances where it has been without power from the grid over the last 26 years and AEP may elect to do without a diesel generator in the future as well. But the lack of both a diesel generator and the Unit 2 generator in the future will put greater reliance on the station battery as well as the DC turbine lube oil pump as discussed in Section 3.3.

Given the relegation of Unit 1 to peaking status and the few instances where off-site power has been lost over the years, it is unlikely that the addition of a diesel generator at the station could be justified. Accordingly, no funds have been included in the cost estimate for the addition of a diesel generator.

3.5 Water Treatment Plant

This is an important area associated with retirement of Unit 2 since the existing Big Sandy Water Treatment Plant is common to both units. While the production of both filtered and softened water for various uses is one function of water treatment, no material modifications in these areas are anticipated to allow this to continue after Unit 2 retires.

However, the Water Treatment Plant is presently incapable of producing demineralized water suitable for Unit 1 unless the Unit 2 condensate polishers are in-service. Since Unit 1 has historically relied on the Unit 2 condensate polishers to produce boiler quality demineralized water for both units, modifications will be required to allow the Unit 2 condensate system to be shut-down with the anticipated retirement of Unit 2.

To understand the problem and the conceptual engineering basis for a solution to it, a general overview of the present process for producing boiler make-up water at Big Sandy is necessary.

River water from the station river water header is pumped to water treatment using one of two 100 percent capacity Unit 2 service water pumps.

In the Water Treatment Plant, water from the service water pumps first passes through coagulators where its pH is increased so that suspended solids can be removed. A gravity filter then further reduces the water turbidity. Water pumped from the clearwell downstream of the gravity filters is then softened to remove dissolved solids.

Downstream of the softeners, a recently installed multimedia filter and reverse osmosis unit (RO) is used to remove most of the dissolved solids necessary to prepare the water for use as boiler make-up. The RO is rated at 120 gpm of permeate. RO permeate and condensate from the two operating 250 HP Unit 2 hotwell pumps is stored in a 500,000 gallon Contaminated Condensate Storage Tank which is currently an integral part of the existing Unit 2 condensate system.

Two operating 400 HP Condensate Clean-up Pumps take their suction from the existing Contaminated Condensate Storage Tank. These pumps move a large volume of water through the existing Unit 2 polishing demineralizers, the effluent of which is suitable for boiler make-up on either unit.

Presently, a very small portion of the polished water from the Unit 2 condensate system is sent over to the 300,000 gallon Unit 1 Condensate Storage Tank and Unit 1 hotwell through an existing 4-inch cross-tie between the two units. Normal demand by Unit 1 is limited to roughly 25,000 gpd although a boiler tube leak can increase this to approximately 50,000 gpd until repairs can be scheduled and the Unit 1 boiler shut down.

The above-referenced service water pumps are reported to be in poor condition. They will also be much larger than necessary in the future after Unit 2 is retired taking into account other demands for service water. Due to their condition, as well as the fact that the demand for Unit 2 service water for other uses will be substantially less in the future, the two existing pumps and motors were assumed to be replaced with units rated at only half their present design flow rate of 2000 gpm.

The RO permeate is unsuitable for direct use in the Unit 1 boiler at Big Sandy due to unacceptably high levels of sodium.

Because of this fact, and the present physical configuration described above, it will be necessary to run the reverse osmosis unit permeate through a mixed bed demineralizer to allow the Unit 2 condensate system to be permanently shut down. For study and cost estimating purposes, it was assumed that the existing 500,000 gallon Unit 2 Contaminated Condensate Storage Tank would remain in service as a storage tank for the RO permeate. Two new 100 percent capacity Demineralizer Feed Pumps were added to the existing Water Treatment Plant to permit RO permeate from this tank to be forwarded to the two-vessel polishing train that presently functions as a polisher for the Unit 2 condensate system.

The two new demineralized water feed pumps were assumed to be located in the existing Unit 2 pump pit at approximately elevation minus 12.' The existing Condensate Clean-up Pumps and motors were assumed to be removed from their pedestals and replaced by the smaller Demineralizer Feed Pumps. These new pumps would be rated at approximately 220 gpm and 140 feet of head.

A 6-inch suction line would be run from the existing condensate line connected to the Contaminated Condensate Storage Tank to supply the two new pumps. Water from them would be pumped to the inlets of the two-vessel polisher train through a new 4-inch line and then exit the vessels and be piped to the existing 4-inch cross-tie that is used to transfer boiler make-up water to Unit 1.

Because the Contaminated Condensate Storage Tank might sit idle for long periods of time during the winter months if Unit 1 is down, a 100 kW immersion tank heater was also included in the scoping study and associated cost estimate.

Implicit in the assumptions above is the hypothesis that two of the existing polisher vessels could function as mixed bed demineralizers at a flow well below design. This would need to be verified with the manufacturer or confirmed by the station through testing to see if there are performance issues associated with low-flow operation. There is no strong reason to believe that this would cause problems, but further work may be necessary to confirm the validity of the suggested approach. A means of increasing flow (if this should prove necessary) would be to simply increase the proposed rating of the new Demineralizer Feed Pumps since their rating is de-coupled from the RO permeate design flow rate due to the presence of the Contaminated Condensate Storage Tank between the existing RO and the proposed pumps. If larger pumps were to be required, the limiting factor would then become the size of the existing 4-inch line used to transfer condensate to Unit 1.

The station presently relies on two 12,000 gallon sulfuric acid storage tanks (one for each unit) to maintain the pH in the circulating water drawn from the cooling tower basins. A relatively small quantity of sulfuric acid is also used for controlling pH of the water supplied to the reverse osmosis (RO) unit and for regeneration of demineralizer resin. With the retirement of Unit 2, and the relegation of Unit 1 to peaking status, the demand for sulfuric acid is likely to be dramatically lower than at present. Due to the age, perceived condition and potential liability of the Unit 2 sulfuric acid tank and piping, it is recommended that the feasibility of retiring this tank be evaluated during the preliminary engineering stage of this project. While beyond the scope of this study, such an evaluation could consider the addition of a new (smaller) tank to supply only the common water treatment area located on the Unit 2 side of the plant. If a safe routing could be identified, the installation of a double wall transfer line from the Unit 1 tank to the water treatment area could also be evaluated to avoid the cost of replacing the existing tank. Since any such expenditures are viewed as discretionary, they were not included in the cost estimate.

No other changes to the existing acid, caustic and waste water systems required to regenerate the demineralizers are anticipated.

The existing Water Treatment Plant is monitored and controlled by two PLC's. To better enable the Water Treatment Plant to be monitored remotely, the cost estimate for the retirement of Unit 2 included the installation of a new fiber optic cable between the water treatment PLC's and the Unit 1 Control Room. The number of HMI's was assumed to remain unchanged and an existing HMI in the field was assumed to be simply relocated to the Unit 1 Control Room.

3.6 Fire Protection

Retirement of Unit 2 may trigger an investment in the plant fire water protection system to maintain reliability in this area under all reasonable scenarios. While the two units have separate fire water protection systems, the water lines are cross-tied. Unit 1 has two 1500 gpm motor-driven vertical pumps and a single 1500 gpm diesel-driven vertical pump which take their suction from the Unit 1 cooling tower basin. No change to this part of the fire water protection system is foreseen.

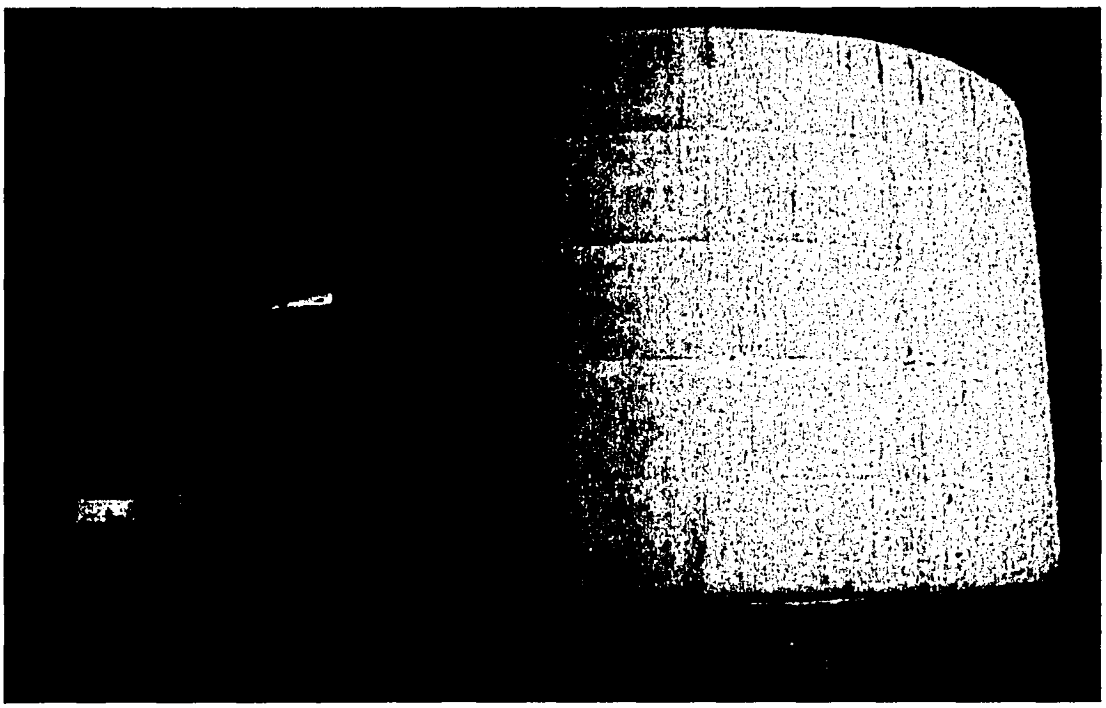
Unit 2 has two horizontal 2000 gpm high demand fire water pumps (one motor-driven and one diesel-driven) as well as a 500 gpm low demand motor-driven fire water pump. All three pumps are supplied from a common 14-inch suction header which draws water from the Unit 2 cooling tower basin.

There are three significant concerns with the existing Big Sandy fire water protection systems according to AEP's fire protection professionals. First, the existing fire pumps for Units 1 and 2 are undersized when one tower basin is dewatered since maximum water demand is seen to be as high as 3933 gpm and the required fire pump redundancy is not present when a basin is dewatered. Note that this demand is for the entire station as it presently exists and it is possible that this demand will be lower in the future with the retirement of Unit 2.

Second, retirement of Unit 2 eliminates one of the two sources of fire water available at Big Sandy under normal circumstances since the Unit 2 fire pumps draw their water from the Unit 2 cooling tower basin. (This assumes that dealing with stagnant water in the basin in the summer, ice formation during the winter and debris from above the basin would be unacceptable.) Since the other source of water is the Unit 1 cooling tower basin, failure to address this issue would render the plant without the means to fight a fire when Unit 1 is down for maintenance and the Unit 1 basin dewatered.

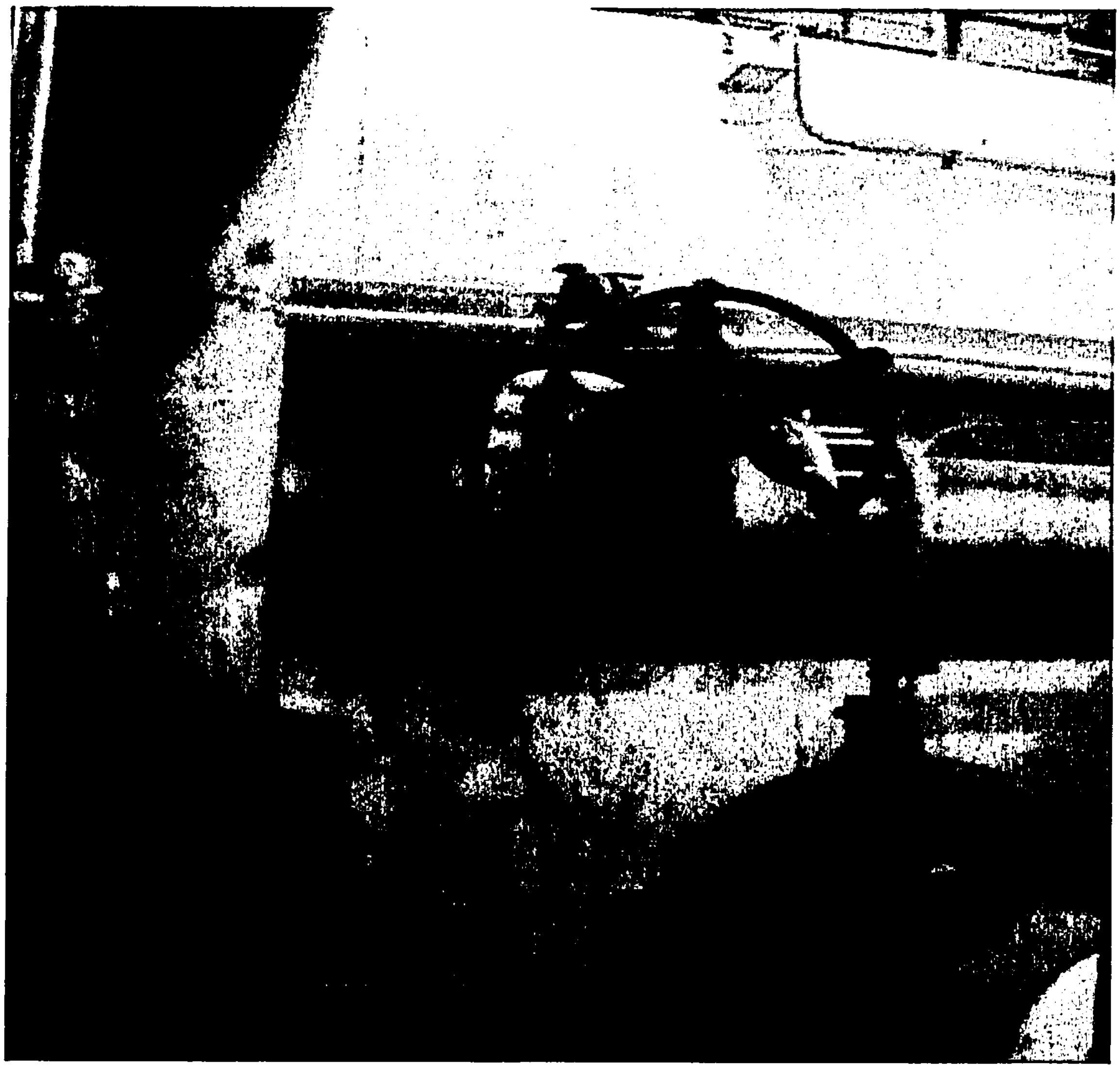
Third, and not directly related to the retirement of Unit 2, is the amount of sediment in the fire system since make-up water is unfiltered river water that has only been through a strainer.

To address the first of the three issues above, AEP's fire protection professionals have opined in the past that a storage tank of approximately 500,000 gallons should be installed to provide an additional source of water for firefighting. Since (1) the Unit 2 Clean Condensate Storage Tank (shown below) will not be needed once Unit 2 is retired, and (2) this tank is very close to the existing Unit 2 fire pump house, the Unit 2 Retirement study assumed that the subject tank would be converted to a fire protection water tank coincident with the retirement of Unit 2 by running an underground 14-inch line from it to the existing 14-inch Unit 2 fire pump suction header that is common for the three Unit 2 fire pumps. Pictures showing the 14-inch root valve in this existing header as well as construction access hatches necessary to complete this portion of the piping project are shown on the following pages.



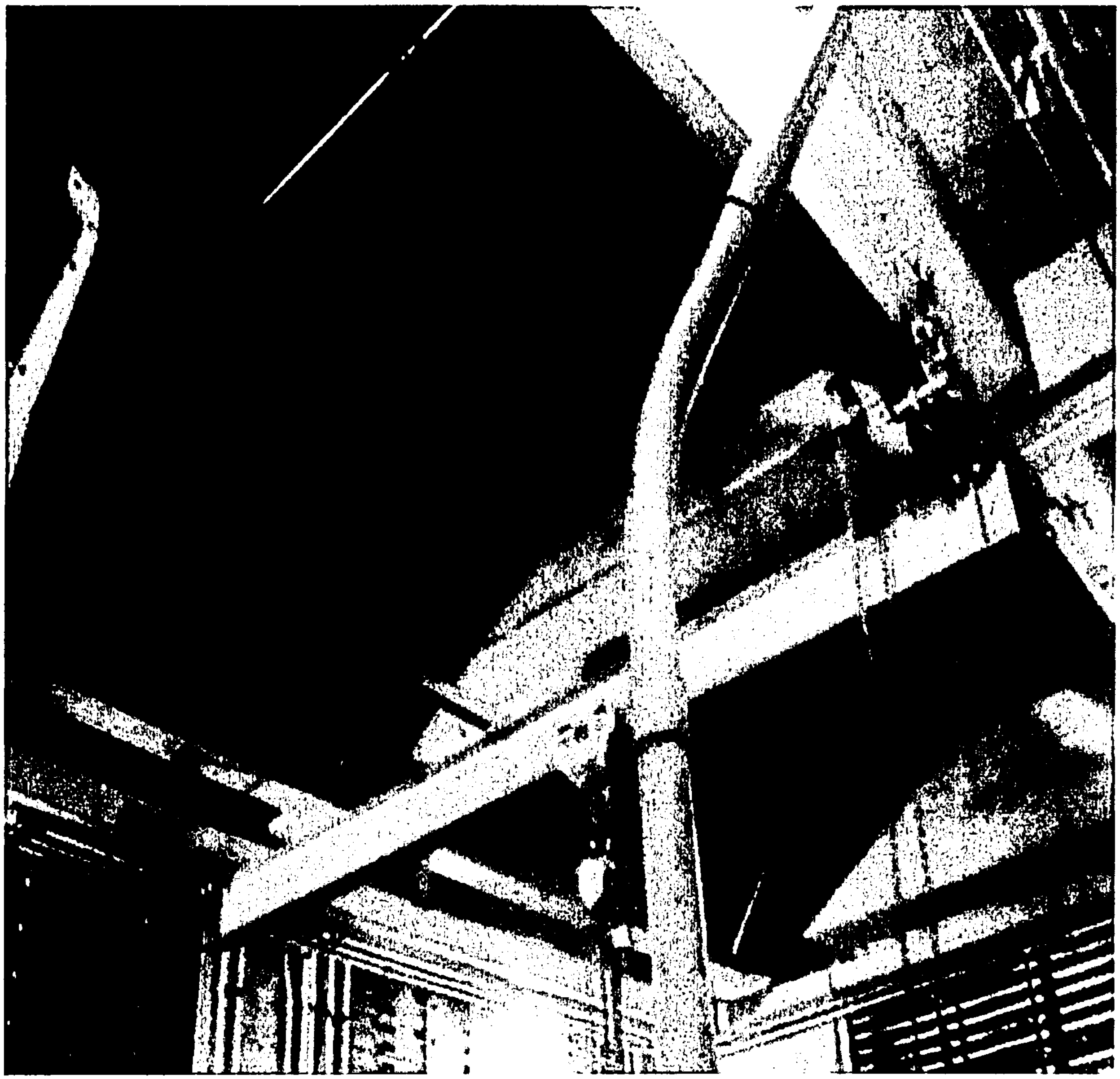
750,000 GALLON UNIT 2 CLEAN CONDENSATE STORAGE TANK (IN FOREGROUND)

VIEW LOOKING NORTH



14-INCH COMMON SUCTION LINE ROOT VALVE IN UNIT 2 FIRE PUMP PIT

(HIGH DEMAND FIRE PUMP IS AT BOTTOM OF PICTURE)



UNIT 2 FIRE PUMP PIT CONSTRUCTION ACCESS (NOTE HATCHES ABOVE MONORAIL)

While estimating the demand for fire protection water subsequent to retirement of Unit 2 was beyond the scope of the study, it was assumed that the capacity of these pumps would be adequate given the availability of all the Unit 2 fire pumps regardless of the status of the cooling tower basins. It is suspected, but not confirmed, that the retirement of Unit 2 would also reduce the maximum demand for fire protection water at the station since ultimately, it will no longer be necessary to consider the possibility of putting out a fire associated with a lubricating oil leak on the Unit 2 steam turbine.

The third issue (sediment in the fire system) is unrelated to the retirement of Unit 2. However, if AEP elects to convert the existing Unit 2 Clean Condensate Storage Tank to a fire protection water tank, a standpipe could be retrofit in the tank to better enable sediment to be blown down from the tank and also to ensure adequate NPSH for the existing Unit 2 fire pumps so long as the elevation of the standpipe allows sufficient tank capacity for fire protection. The cost of retrofitting a standpipe in this tank was included in the cost estimate.

Because the proposed new fire protection water storage tank (presently the Clean Condensate Storage Tank) may sit idle for long periods of time during the winter months, a 100 kW immersion tank heater was also included in the scoping study and associated cost estimate.

The modifications suggested above would represent a significant improvement in the station's flexibility to fight a fire without the cost associated with any new pumps or tanks.

The cost estimate also assumed that wires would be run from the Unit 2 Control Room to the Unit1 Control Room to provide a "Unit 2 Fire Protection System Trouble" alarm in the Unit 1 Control Room. An operator would be required to check the existing fire protection control panel for Unit 2 to determine the nature of a problem with this approach.

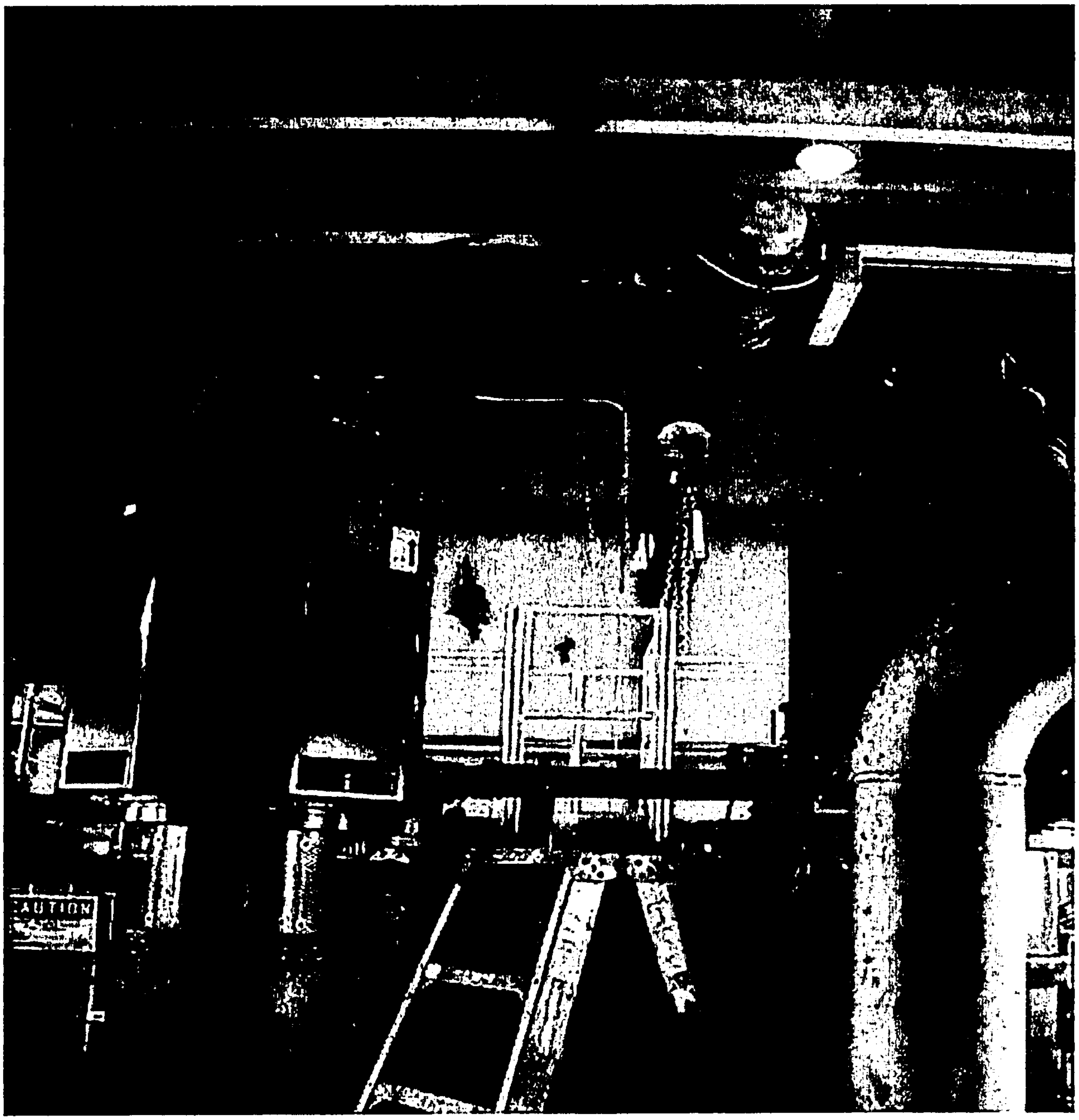
3.7 River Water Make-up Pumps

Currently, maximum demand for make-up water from the Big Sandy River is approximately 19 million gallons per day according to sources at the station. The retirement of Unit 2 will likely reduce this figure to approximately six million gallons per day.

The plant currently has five vertical river water make-up pumps in two adjacent pump houses that supply a common header. Three of these pumps (collectively referred to as the Unit 2 pumps) are rated at 10,000 gpm and 130 feet of head. They are driven by their original 400 HP 575 V motors and are shown on the following page.

BIG SANDY 3 X 10,000 GPM/ 130' TDH UNIT 2 RIVER WATER MAKE-UP PUMPS

The two smaller pumps in the second pump house (collectively known as the Unit 1 pumps) which are shown on the following page are now rated at 6750 gpm and 130' of total dynamic head (TDH). This is a relatively recent upgrade from the original design (which was 100' TDH) and all five pumps now have the same rated TDH as a result of the upgrade. The two smaller pumps are now driven by 300 HP 575 V motors which replaced the original 200 HP motors.



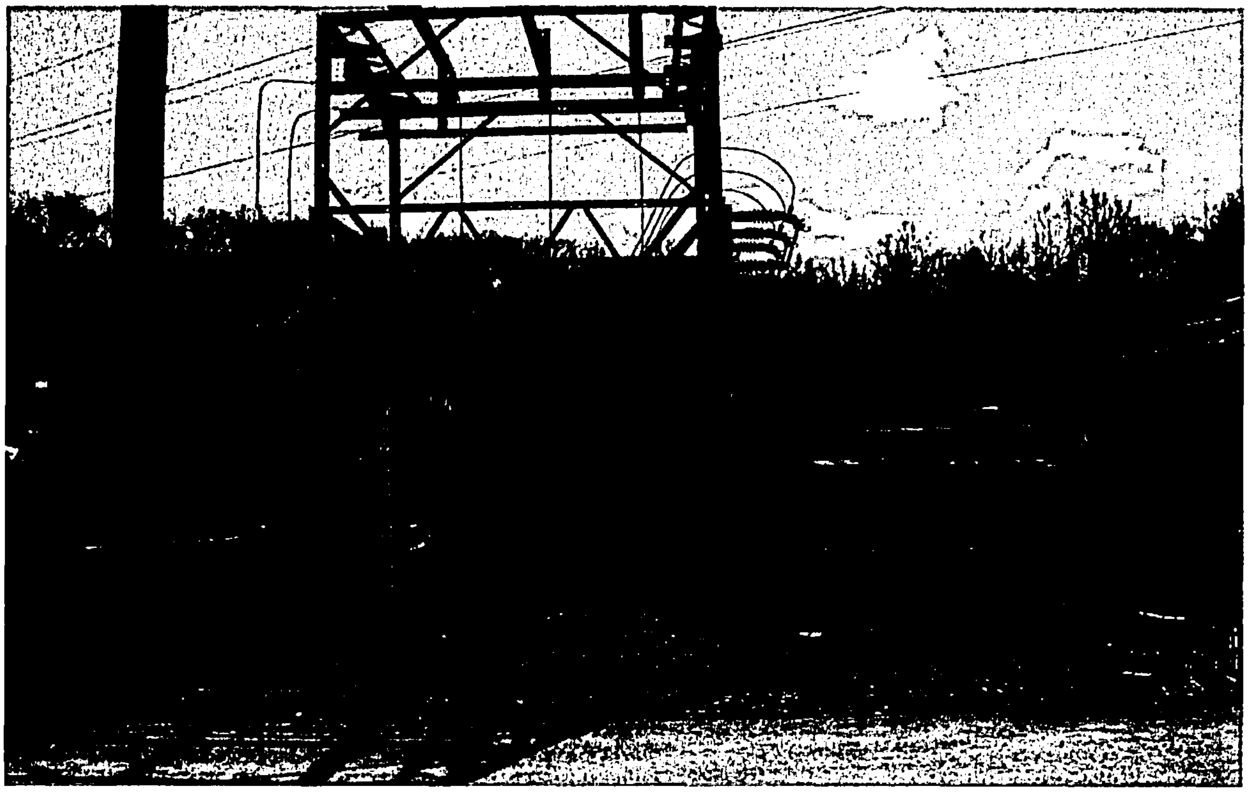
BIG SANDY 3 X 6750 GPM/ 130' TDH UNIT 1 RIVER WATER MAKE-UP PUMPS

Instrument air and seal water are both provided to the pump houses from Unit 1 so no modifications should be necessary for these utilities. The head tank assuring the desired seal water pressure to the pumps is also located on the Unit 1 structure so it should not be impacted by Unit 2's retirement. The seal water system for the pumps is cross-tied to the Unit 1 condensate system for flexibility in the event that emergency maintenance must be performed. Softened water for the seal water head tank is produced in the Water Treatment Plant that is common for the two units. No changes to the softeners in the water treatment area are anticipated.

The two pump houses each have their own 4160 V-600 V 1500 kVA transformers. The transformer for the three larger Unit 2 pumps is currently fed from Unit 2 through breaker 2C-17. With the anticipated retirement of the four 250 HP Ash Pond Recirculation Pumps, it should be possible to feed the pump house containing the larger river water make-up pumps from Unit 1 in the future. This flexibility does not currently exist due to the need to run at least some of the Ash Pond Recirculation Pumps when coal is burned at Big Sandy.

The transformer for the smaller river water make-up pumps is normally fed from Unit 1. It can be fed from either the medium voltage bus 1A (the normal source of power) through circuit breaker 1A11 or from the secondary side of the Unit 1 reserve transformer TR 101 through circuit breaker 101A.

The picture on the next page illustrates the 1500 kVA transformer 21PH (which provides power to the larger pump house) as well as the disconnects that allow it to be fed from either Unit 1 or Unit 2.



The river water make-up pumps are equipped with strainers to remove the larger sediment drawn in from the river. The strainers are manually backwashed when differential pressure across them reaches 5 psid.

The pumps are manually started and stopped remotely from the Unit 1 Control Room and so no control system modifications are anticipated in this area. The pumps are only started with an operator present in the pump houses. The operator lines up the valves necessary to flush the pumps to the river upon start-up and then swaps the valves so that the pumps are supplying water to the plant.

Manual control of the pumps is based on plant river water header pressure. Normal pressure is 35 to 40 psig with a low alarm set point of 30 psig.

Current practice is to operate one of the 10,000 gpm pumps and one of the 6750 gpm pumps simultaneously whenever possible.

One of the two smaller 6750 gpm pumps should be sufficient to meet Big Sandy's demand for water in the future since water demand should be considerably reduced following the retirement of Unit 2.

Maintenance of more than one river water pump house in the future to provide additional flexibility would be a purely discretionary decision since the two smaller pumps alone would constitute a 2x100 percent capacity system.

One advantage of retaining only the two existing smaller pumps is that both of these pumps and motors have been upgraded. Furthermore, the presence of a crane in the smaller pump house makes it a more maintenance-friendly place to work when the presence of high voltage lines above the pump houses is considered. However, the station has expressed a preference to retain the larger Unit 2 pump house containing the three 10,000 gpm pumps because the piping in this pump house has been recently replaced and the strainers are also more reliable.

A disadvantage of retiring either pump house is that they are each fed by their own 4160 V-600 V transformers. In the event of a transformer failure, maintenance of both pump houses would allow the plant to continue to run without a shut-down.

Since AEP plans to retain only the existing Unit 2 river water make-up pump house containing the three 10,000 gpm pumps, consideration should be given to making Unit 1 the normal source of power to this pump house to provide maximum operating flexibility in the event that the Unit 2 reserve transformer fails.

Other than building heat, no investment is expected in the common river water make-up pumps houses following Unit 2's retirement.

3.8 Unit 1 and 2 Control Rooms

The plant has separate control rooms for Unit 1 and Unit 2. There are a few common areas that will be impacted by an assumption that the Unit 2 Control Room will eventually be unmanned. Many of the common systems are presently controlled by the Unit 1 Control Room and should not be impacted by abandonment of the Unit 2 Control Room. Specifically:

- The screens for the plant security cameras are located the Unit 1 Control Room so no changes are anticipated in this area.

- All five available River Water Make-up Pumps are currently started and stopped from the Unit 1 Control Room. A header pressure transmitter and alarm associated with these pumps is also present in the Unit 1 Control Room.

- Although the control panel for the Unit 1 fire protection system is in the Unit 1 Control Room, it will be necessary to have a Unit 2 fire protection system trouble alarm present in the Unit 1 Control Room and the cost estimate includes money for doing this.

- Since the relay panel containing the Unit 2 Reserve Transformer TR 102 protective relays is not located in the Unit 1 Control Room, an alarm that will indicate a relay operation on this panel needs to be present in the Unit 1 Control Room.

- Control of the Main Gate is currently from the Unit 1 Control Room and no changes are expected in this area.

- Control of the gate at the Guard House is also currently from the Unit 1 Control Room and this function is also expected to remain as-is.

- Control of the Big Sandy auxiliary boiler is presently from the Unit 2 Control Room. While it is anticipated that this auxiliary boiler will be retired (owing to the condition of its boiler tubes, the decision to include natural gas unit heaters in the cost estimate and the fact that Unit 1 is capable of starting without a separate source of auxiliary steam), if AEP decides to invest in the auxiliary boiler to make it a reliable piece of equipment, an additional expenditure will be necessary to allow the auxiliary boiler to be monitored and controlled from the Unit 1 Control Room since this capability does not presently exist.

4. CONCLUSIONS

The retirement of Unit 2 need not adversely impact the reliability of Unit 1 when firing natural gas.

The retirement of Unit 2 should have only a minimal impact on the cost of converting Unit 1 to natural gas.

When the condition and reliability of the existing auxiliary boiler is considered, the capital investment to heat the station is likely to have the single largest impact on the cost associated with retiring Unit 2 and relegating Unit 1 to peaking status. New gas-fired unit heaters, electric space heaters in the outbuildings, immersion heaters to prevent water tanks from freezing, and heat tracing and insulation will all be necessary to accomplish the objective of protecting the station when it is down for extended periods of time in winter.

In addition to addressing the loss of a source of fire protection water (the Unit 2 cooling tower basin), it should be possible to improve the reliability of the plant fire protection systems at reasonable cost if the existing Unit 2 Clean Condensate Storage Tank is converted to a fire protection water storage tank to supply the existing Unit 2 pump house.

5. RECOMMENDATIONS

- AEP should consider maintaining the Unit 2 battery for use by Unit 1 in the event of a black station since Big Sandy will only have a single generator after Unit 1's retirement. A disconnect switch between the batteries for the two units is already in place so no capital investment in this area is anticipated.

- It would appear to make sense to retire the Big Sandy oil-fired auxiliary boiler at the same time Unit 2 is retired since (1) its capacity is over ten times the estimated requirement for building heat, (2) it is unnecessary for start-up of Unit 1, and (3) it is reportedly in need of replacement of all of its boiler tubes which would be prohibitively expensive for this type of boiler when one considers the lack of construction access to it. More stringent limitations on hours of operation (for environmental reasons) are also expected according to the station.

- Once a decision to proceed with the project is made, a building heat design basis should be agreed upon and a survey conducted to provide the inputs necessary to better estimate building heat requirements by performing calculations.

- The feasibility of converting a pair of the Unit 2 condensate polisher vessels to a mixed bed to polish the relatively low quantity of reverse osmosis permeate needs to be further examined through experimentation, consultation with the equipment vendor or both.

- A decision should be made on whether to pursue an improvement to the station fire water protection systems by adding a tank to supplement the existing Unit 1 tower basin as a source of water for the station. If it has not already been done, a new design flow for the station based on Unit 2 being retired should be determined to confirm that there are no pump capacity issues if the storage issue is addressed. If there is a consensus opinion (AEP and its insurance company) that a cold (ice-prone) Unit 2 cooling tower basin is an acceptable source of fire protection water, then perhaps the tank option forming the basis of this study can be discarded in favor of an alternative that will be even less costly.

- Further thought should be given to alternatives that would allow the Unit 2 sulfuric acid storage tank to be retired since sulfuric acid use at the station will be dramatically lower in the future. Retirement of this tank would be a discretionary decision based on the liability of continuing to maintain a tank that is far larger than it needs to be for the existing water treatment area.

6. REFERENCES

The contributions of AEP's Jamie Burton, Ken Borders, Kim Huff, and Chuck Stapleton from the Big Sandy Plant who spent time with the WorleyParsons team at the station and/or on follow-up questions are acknowledged and very much appreciated.

While not directly related to the Unit 2 retirement study, helpful thoughts and direction were also received in the past from AEP's Jim Beller and Dan Lampke in the area of fire protection engineering and their contributions to this study are also acknowledged.

The following AEP reference documents and drawings were also consulted to prepare the Unit 2 Retirement Study:

AEP Fleet Plant Design Electrical Criteria (DC-ELEC-001-02) dated May 10, 2010

Auxiliary One Line Diagram, Unit 2 (2-1200A-17)

Auxiliary One Line Diagram, Unit 1 (1-1200A-18)

Flow Diagram; Fire Protection Piping, Unit 2 (2-5018-18)

Flow Diagram; Service Water, Bottom Ash and Fly Ash, Unit 2 (2-5014-40)

Flow Diagram; Station Drainage, Units 1 and 2 (2-5013-23)

Flow Diagram; Condensate Clean-up System, Unit 2 (2-5027-16)

Flow Diagram; Condensate, Unit 1 (1-5007-17)

Flow Diagram; Condensate, Unit 2 (2-5007-21)

Flow Diagram; River Water Filtering & Softening, Unit 2 (2-5016-17)

Condensate Storage Tank and Piping, Unit 1 (1-5092-5)

Demineralizer & Water Treatment Area and Pump Pit (MSK-200)

Study of Contaminated & Clean Condensate Storage Tanks & Piping to Pump Pit, Unit 2 (MSK-202)

Study of Circulating Water Pump Building, Unit 2 (MSK-414)

Condensate Tanks & Piping & Filtered Water Piping, Unit 2 (2-5078-12)

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AMERICAN ELECTRIC POWER
BIG SANDY UNIT 1 GAS CONVERSION PROJECT

Fire Protection Study

Document: AEPBS-1-LI-EM-0003

Revision: B

Date: October 2012

WorleyParsons
2675 Morgantown Rd.
Reading, PA 19607
USA
Telephone: +1 610 855 2000
Facsimile: +1 610 855 2001
www.worleyparsons.com

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AMERICAN ELECTRIC POWER
BIG SANDY UNIT 1 GAS CONVERSION PROJECT
FIRE PROTECTION STUDY

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REV	DESCRIPTION	ORIGINATOR	REVIEWER	APPROVER	DATE
A	Review and Comment	P. Adams	B. Danko	J. Nicolas	October 4, 2012
B	For Use	P. Adams	10-18-12 B. Danko	J. Nicolas	October 19, 2012

CONTENTS

1. EXECUTIVE SUMMARY

AEP is considering conversion of Big Sandy Unit 1 from coal to natural gas. The purpose of this study is to determine the hazardous area classification zones, modifications of existing equipment required within the hazardous zones, and building modifications needed due to the presence of fuel gas within the boiler building.

Electrical classification is an important consideration when firing natural gas, especially in a building. This study also provides clarification of how current, applicable codes and guidelines relevant to electrical classification may be interpreted for the future gas firing scheme. When classifying an enclosed building and its electrical components, the structure's ventilation system must also be evaluated.

Review of current, applicable codes, regulations and guidelines reveals that a gas supply system rating of less than 275 psig located outdoors with potential leak sources (e.g. vents, flanges, threaded fittings or valve packing) will require electrical classification within a "bubble" of 15 foot radius and 25 foot height above the source. Outside of this bubble, no electrical classification is required.

For indoor service, leak sources such as gas piping vents, must be routed outdoors. Other potential leak sources such as flanges, fittings or valves, may result in classified areas equal to the "bubble" size noted above, but could be applied to an area up to and including the entire building. WorleyParsons believes that a conservative approach based on increased adequate building ventilation (24 air changes per hour) will avoid classifying the entire building. As a result, the extent of classification should be the "bubble" zone. In the event of reduced ventilation rates, venting and purging of the indoor gas mains should be performed. WorleyParsons recommends that the recommended strategy be reviewed with and approved by AEP's Risk Team and Insurance Provider as well as the Authority Having Jurisdiction (AHJ).

AEP is currently working on a deterministic approach to hazardous area electrical classification. The results of their work will be evaluated during final design and may impact the conclusions of this study. However, the recommendations in this study should be conservative.

The existing ventilation system has adequate capacity to meet the air change requirements described above. In the areas of the boiler house where the natural gas piping, valves and burners (for main boiler firing) will be located, a walk-down of electrical systems in expected hazardous areas was performed and a cost estimate was developed based on replacement due to hazardous classification. These items are addressed in the Auxiliary Power Supply Study. Fire protection system modifications resulting from the Unit 2 retirement are addressed in the Unit 2 Retirement Study.

A fixed gas detection system is recommended for this project, in accordance with AEP's Mechanical Design Criteria.

2. INTRODUCTION

With converting Big Sandy Unit 1 from coal to natural gas, a review of applicable codes and guidelines is needed to assess the impact on electrical classification inside the boiler building. The impacts of heating the boiler house with natural gas unit heaters are also assessed. The primary codes and guidelines reviewed are:

A. NFPA 70, National Electrical Code

B. NFPA 54, National Fuel Gas Code

C. API RP505, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Zone 0, Zone 1, and Zone 2

D. NFPA 497, Recommended Practice for the Classification of Flammable Liquids, Gases, or Vapors and of Hazardous (Classified) Locations for Electrical Installations in Chemical Process Areas

The classification process, if required, upgrades standard electrical components to appropriate rating. For a natural gas piping system, an electrical component's proximity to potential leak sources such as flanges, threaded connections, vents, etc. may require classification. Consideration is also given to whether the leak source is outdoors or indoors. For the latter, an enclosed building's ventilation system (based on air changes per hour) may mitigate the extent of the classification. The existing ventilation was evaluated and the results were used to support our recommendations in this study.

3. DISCUSSION

3.1 Hazardous Area Classification

A. Electrical classification is driven by the NFPA 70, National Electrical Code; NFPA 54, National Fuel Gas Code; API RP505, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Zone 0, Zone 1, and Zone 2; and NFPA 497, Recommended Practice for the Classification of Flammable Liquids, Gases, or Vapors and of Hazardous (Classified) Locations for Electrical Installations in Chemical Process Areas. Several factors impact the electrical classification; two primary ones are the rate of the leak and the ventilation rate. Since natural gas is lighter than air, with proper ventilation, it dissipates rather quickly.

B. In order to ensure safety and minimize changes/costs, it is assumed that all components that could be expected to vent fuel gas under normal operations (e.g. relief valves, gas powered valve operators, etc.) will have a vent that is piped to the outside the building. The location of these vents will comply with AEP's requirements. Only potential leak sources (e.g. flanges, valve packing, threaded connections, etc.) that are not expected to leak under normal operation will be permitted inside the building. For these potential leak sources in a system with a design pressure less than 275 psig, the classified area would be Class I, Zone 2, Group IIA, except leak sources 5 psig and less (building heat) which will be discussed later. Note that only potential leak sources generate an electrically classified area (e.g. welded piping, without valves, flanges or similar devices, does not generate an electrically classified area). The classified area should be a 15 foot radius ("bubble") from the leak source and 25 feet above as indicated in Figure 24 from API RP505. Similar dimensions are indicated in Figure 5.10.9(a) from NFPA 497. These dimensions are for an outdoor application.

C. These documents do not indicate this, but it is intuitive that as buildings get large enough with enough ventilation that it would be equivalent to an outdoor environment. In order to ensure safety and avoid possibly classifying the entire Boiler building, the ventilation approach discussed below should be considered to allow treating the Boiler building as an outdoor environment. This will permit classifying only the area around the potential leak source (15 ft. radius and 25 ft. above).

D. Adequate ventilation is required to ensure that a buildup of an explosive mixture does not occur. Adequate ventilation can be achieved by natural or artificial means. API 505 and NFPA 497 both indicate that 1 cubic foot of air volume flow per minute per square foot of floor area, but at least 6 air changes per hour should be provided to ensure adequate ventilation. Using this ventilation rate would classify the entire enclosure as indicated in Figure 23 from API RP505 and Figure 5.10.9(a) from NFPA 497. API 505 6.6.2.4.5 indicates a safety factor of 2 resulting in 12 air changes per hour for natural ventilation, but only on buildings of 1000 cubic feet or less. Again, this ventilation rate would classify the entire building. We, therefore, would recommend doubling the ventilation rate by a factor of two resulting in 24 air changes per hour to avoid any gas above the lower explosive limit (LEL) beyond the classified area. The ventilation should be provided with adequate safeguards against failure (e.g. sail switches, etc.) as described in NFPA 497 5.4.2(3). The ventilation should have inlets as low as possible and outlets as high as possible to help flush gas out of the building. Also, special care should be made to ensure that overhead obstructions (e.g. checkered plate) are minimized to ensure gas does not collect.

E. For potential leak sources located outdoors and less than 275 psig, the classified area should be a 15 foot radius from the leak source and 25 feet above. For higher pressures, the classified area is increased to a 25 foot radius from the leak source in all directions as described in Figure 104 from API RP505.

F. The use of gas fired unit heaters should not impact the electrical classified areas, since gas piping is mostly welded and the pressure will be 5 psig or less. It is inferred from NFPA 54 that gas piping at these low pressures will not create an electrically classified area because the leakage rate is so small.

4. CONCLUSIONS AND RECOMMENDATIONS

4.1 Ventilation

A. The current Boiler building ventilation system provides the capability of 44.8 air changes per hour at minimum load which greatly exceeds the 24 air changes per hour recommended. However, the Authority Having Jurisdiction and the Insurer should be consulted to confirm that this overall approach is adequate. When the Boiler building ventilation system is not providing the minimum ventilation rate of 24 air changes per hour, the piping system, within the building should be vented and purged with inert gas to ensure no potential leak sources are in the building (excluding the 5 psig gas to the unit heaters). The piping should be isolated outside the Boiler building with either a double block and bleed or a similar arrangement to prevent leakage into the Boiler building piping system. This will ensure an explosive mixture does not migrate to any electrical equipment that is not properly rated. Once the ventilation system is operating at or above the recommended rate, the gas system can be charged and operations can resume. Safeguards should be added as necessary to ensure the recommended ventilation is provided while the piping system is charged with fuel gas.

B. The concept of not classifying the low pressure unit heater gas piping should be confirmed with the Authority Having Jurisdiction and the Insurer.

C. As part of this work, a plant walk down occurred. Electrical devices in the expected hazardous areas were noted and a cost estimate was developed. The cost estimate priced either moving the component, if not properly rated, or modifying it as required to remain in the classified area. Also, the existing ventilation was reviewed. The minimum 24 air changes per hour can easily be accomplished with the existing exhaust fans only. The current capacity of the ventilation system using only exhaust fans (no combustion air, supply, or FD fans) is nearly 692,000 CFM. Only approximately 428,000 CFM is required to achieve 24 air changes per hour. WorleyParsons can help develop control schemes to ensure adequate ventilation is provided, but is not required at this time. This work would occur during the detailed design phase of this work.

D. For added safety fixed gas detection systems will be provided in areas with potential gas leaks. Gas detection would initiate local alarms not alert personnel. It also will provide indication in the control room of the problem. During detailed design the location and operating design basis will be determined for the detectors.

4.2 Fire Protection

The unit has an existing fire protection system for the boiler burner front. There is a fire alarm in the area and a push button in the control room to activate the system. This system was designed to protect against an oil fire at the burner front. Since the current project will be gas fired only (no oil), WorleyParsons would suggest that the plant consider either tagging the system out of service or removing it. This should be discussed and approved by the Insurer and the Authority Having Jurisdiction (AHJ). This suggestion is to prevent a potential gas fire being extinguished by the fire suppression system (even though this is unlikely) prior to isolating the gas source. This situation could result in a gas explosion, which could be more dangerous and cause more damage than the original gas fire. The appropriate way to fight a gas fire is to let the fire burn and shut off the supply of gas. During review of this study AEP indicated they would like the system to remain place. They indicated that the sprinkler system is unlikely to put out the gas fire and they would like to control the heat from a gas fire with the sprinkler system.

APPENDIX 1
Boiler Building Air Changes

Boiler Building Air Changes per Hour (ACH)

The following is a list of ventilation system components that have an impact on the Boiler Building air changes per hour ventilation rate.

Boiler Building

- Roof exhaust fans: Eight (8) at 40,000 CFM each
- Combustion air supply fans: Thirteen (13) at 42,400 CFM each
- Wall Openings: Nine (9) at 9 SF each

Heater Bay Building

- FD Fans (Exhaust): Two (2) at maximum flow of 266,000 CFM each
- Roof exhaust fans: Three (3) at 40,000 CFM each
- South wall exhaust fans: Two (2) at 40,000 CFM each
- South wall supply fans: Four (4) at 42,400 CFM
- South wall exhaust fans: Three (3) at 42,400 CFM
- West wall supply fans: Four (4) at 42,400 CFM

Area Below Coal Bunker

- North wall exhaust fans: Three (3) at 14,900 CFM
- North wall supply fans: Four (4) at 42,400 CFM
- East wall supply fan: One (1) at 42,400 CFM
- West wall supply fan: One (1) at 42,400 CFM

The following is a summary of the supply and exhaust CFM based upon the ventilation system components described above and assuming all fans are operating.

- Maximum Total Exhaust (FD Fan @ 100%): 1,223,900 CFM
- Minimum Total Exhaust (FD @ 20%): 798,300 CFM
- Maximum Total Supply (Combustion Air Fans @ 100%): 1,144,800 CFM
- Minimum Total Supply (Combustion Air Fans @ 20%): 703,840 CFM

Building Volume

The following is the approximate unoccupied volumes of the Boiler Building, Heater Bay Building, and the Area Below Coal Bunker.

- Boiler Building 80 feet x 83.5 feet x 156 feet x 0.5 = 521,040 CF
- Heater Bay Building 80 feet x 60 feet x 139 feet x 0.6 = 400,320 CF
- Area Below Coal Bunker 80 feet x 40 feet x 77 feet x 0.6 = 147,840 CF
- Total Unoccupied Volume: 1,069,200 CF

Air Changes per Hour (ACH)

- Minimum Boiler Load ACH = CFM x 60/Volume = 798,300 CFM x 60/1,069,200 CF
- Minimum Boiler Load ACH = 44.8
- Maximum Boiler Load ACH = 1,223,900 CFM x 60/1,069,200 CF
- Maximum Boiler Load ACH = 68.7

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AMERICAN ELECTRIC POWER
BIG SANDY UNIT 1 GAS CONVERSION PROJECT

Ash Handling Study

Document: AEPBS-1-LI-EM-0004

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WorleyParsons
2675 Morgantown Rd.
Reading, PA 19607
USA
Telephone: +1 610 855 2000
Facsimile: +1 610 855 2001
www.worleyparsons.com

WorleyParsons
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BIG SANDY UNIT 1 GAS CONVERSION PROJECT
ASH HANDLING STUDY

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A	Review and Comment	B. Danko	R. Letarte	J. Nicolas	October 3, 2012

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AMERICAN ELECTRIC POWER
BIG SANDY UNIT 1 GAS CONVERSION PROJECT
ASH HANDLING STUDY

1. DISCUSSION

The purpose of this study is to determine what needs to be done in order to shut down the Unit 1 bottom and fly ash handling systems while keeping the bottom ash seal system in operation.

AEP is considering fuel source conversion of Big Sandy Unit 1 from coal to natural gas. Unit 2 will be shut down and Unit 1 ash systems will be abandoned. The Unit 1 bottom ash and flyash system will be isolated and disabled.

The Unit 1 electrostatic precipitator will remain in place with power disabled, and the ash free flue gas resulting from natural gas conversion will continue to flow through the precipitator to the stack. The flyash hoppers will be isolated from the retired ash handling system by either shutting the isolation knife gates under the hoppers and/or blanking off the hopper discharge flanges.

The space between the boiler and the ash hopper is sealed by a water seal trough. The water seal permits downward thermal expansion of the boiler while allowing the ash hopper to be supported from below. A series of weir boxes permits the overflow of a continuous curtain of cooling water over the ash hopper refractory lining thereby keeping the refractory wet. The ash hopper drains to the ash pit then to the boiler room sump, which is sent to the turbine room sump then to the bottom ash waste water ponds.

Unit 1 has two (2) existing 600 gpm L.P. service water pumps currently in operation, taking suction from the river water header. One pump is sufficient for the required services; the second pump is a spare. A third pump has been taken out of service for parts. These pumps are currently used for seal trough supply, seal trough flushing, refractory weir supply, clinker grinder seals, the pyrites loop seal supply and observation window jets (P&ID 1-5013-18). The normal flowrate of 280-350 gpm will need to be maintained for seal trough and refractory weir supply after the Unit 1 conversion to natural gas.

2. CONCLUSION

The Unit 1 L.P. Service Water Pumps will remain in service in order to maintain seal trough and refractory weir water supply to the Unit 1 ash hopper.

Balance of plant impacts on ash handling system shut-down are addressed in the Water Study (AEPB-LI-EM-0001) and the Unit 2 Retirement Study (AEPB-LI-EM-0002).

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AMERICAN ELECTRIC POWER
BIG SANDY UNIT 1 GAS CONVERSION PROJECT

Fuel Gas Supply System Description

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WorleyParsons
2675 Morgantown Rd.
Reading, PA 19607
USA
Telephone: +1 610 855 2000
Facsimile: + 1 610 855 2001
www.worleyparsons.com

WorleyParsons
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AMERICAN ELECTRIC POWER
BIG SANDY UNIT 1 GAS CONVERSION PROJECT
FUEL GAS SUPPLY SYSTEM DESCRIPTION

REV	DESCRIPTION	ORIGINATOR	REVIEWER	APPROVER	DATE
A	For Review	B. Danko	R. Letarte	J. Nicolas	October 4, 2012
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BIG SANDY UNIT 1 GAS CONVERSION PROJECT
FUEL GAS SUPPLY SYSTEM DESCRIPTION

CONTENTS

1. INTRODUCTION

American Electric Power (AEP) is considering the conversion of Big Sandy Unit 1 boiler fuel from coal to natural gas. A new natural gas supply will be provided by the Gas Company. The existing coal burners will be replaced with new gas burners supplied by B&W. This document contains System Descriptions for the piping and equipment for the Fuel Gas Supply System in support of a Phase 1 budgetary estimate, including:

- Fuel Gas Supply Piping
- Fuel Gas Check Metering Station
- Water Bath Gas Fired Heater
- Fuel Gas Pressure Reducing Station

For reference to this document, Metering Station Plot Plan sketch AEPBS-1-SK-600-002-002 is a preliminary plot plan showing the gas supply from the gas company to the terminal point in the boiler house. Piping and Instrument sketch AEPBS-1-SK-561-302-001 is a preliminary P&ID for the Fuel Gas System.

2. DESIGN CRITERIA

AEP Project Specific Design Criteria, AEPBS-2-DB-EU-0001, and other AEP criteria documents specified therein are used for this project. Technical requirements, when appropriate for the Unit 1 Gas Conversion Project, were used from AEP Specifications for Fuel Gas Supply Specifications developed for the Clinch River Project by AEP: TPSE-009/010/011/012/013 all Rev.0.

Information regarding operating conditions at the natural gas tie-in was obtained from the Gas Company. Design/operating requirements at the tie-in to the burner skid located in the boiler house were supplied by B&W.

3. SYSTEM DESCRIPTIONS

The System Descriptions for the Fuel Gas System and equipment are provided in the sections below. These system descriptions are summary descriptions developed for Phase 1. Individual detailed system descriptions will be developed for each system during Phase 2.

The scope for this system begins at the electrical isolation joint provided by the Gas Company and ends at the skid connection in the boiler house supplied by B&W.

Supply of natural gas for this project will come from the Gas Company, with an above ground connection just north of the railroad tracks, near the abandoned Unit #1 rail car coal unloading electrical building. The Gas Company will have a receiver, filter-separator, condensate tank, metering station and gas chromatograph at this location. The Fuel Gas Supply System equipment will be located just downstream of the Gas Company metering station,. The scrubbed, heated, metered, and pressure reduced gas piping will run above grade, parallel to the abandoned Unit #1 coal conveyor.

Near the southwest corner of the Unit 1 boiler, a short section of the gas line will be routed underground, under a sidewalk and come up above grade near the north wall of the boiler house. The gas pipe will rise along the outside wall, and then penetrate the north side of the boiler house wall at the coal feeder elevation. The gas pipe will tie into the gas control skid provided by B&W at this level.

3.1 Fuel Gas Supply Piping

3.1.1 Functional Requirements

The Fuel Gas Piping system will deliver natural gas from the gas supply company tie-in to the B&W terminal point in the boiler house. Within the piping system, the major components listed below will be installed to deliver the natural gas to the boiler at the required conditions. The natural gas analysis below is a typical hydrocarbon analysis from a series of samples that have been taken by the Gas Company. At this time we have four samples and all are similar to each other. The normal flowrate is 2,544,160 scfh (per B&W at full boiler load).

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Natural Gas Analysis (hydrocarbon):

		Vol. %
Methane	CH4	76.62
Ethane	C2H6	16.61
Propane	C3H8	4.26
Butane	C4H10	0.90
Pentane	C5H12	0.21
Hexanes Plus	(C6+)	0.10
Nitrogen	N2	1.21
Carbon Dioxide	CO2	0.09
Specific Gravity	0.70	
Molecular Wt.	23.3	

Conditions of Gas Delivered from Gas Company:

	Minimum	Maximum	Normal
Inlet Line Pressure, psig	Not available	360 (MAOP)	168
Inlet Line Size, inches	----	---	16", Std Wt.
Inlet Gas Temperature, °F,	40	80	65
Moisture Dew Point (fuel), °F	----	----	Not available
Hydrocarbon Dew Point (fuel), °F	----	----	Not available
Ambient Temperature, °F	-24	108	80
Gas Moisture Content, lbs H20 / MMSCF	----	----	4.1
Gas Consumption, lb/hr	1,107	149,776	136,160
LHV, Heating Value @ 60 F, Btu/lb	----	----	22,752

3.1.2 Description of Equipment

A. The Fuel Gas Supply Piping for the WorleyParsons scope begins downstream of an electrically isolated pipe joint downstream of the gas supplier's isolation valve. Major components within the piping system include a check metering station, water bath gas fired heater, gas chromatograph, and pressure reducing station. The terminal point is a single connection on a gas skid supplied by B&W located inside the boiler house. The piping system will be designed in accordance with AEP's Mechanical Design Criteria.

B. The natural gas will be supplied from the Gas Company at a normal operating pressure of 168 psig. Maximum allowable operating pressure is 360 psig. The gas temperature range is from 40 to 80°F. The gas flow rate used by B&W is 2,544,140 scfh (approximately 136,000 lb/hr) for full load operation.

C. The piping from the gas supplier will be 16" diameter carbon steel. All piping from the gas supplier to the B&W terminal point will be ASTM A106 grade B seamless carbon steel, designed in accordance with ASME B31.1. The piping downstream of the pressure reducing station located by the river, up to the B&W skid terminal point inside the boiler house will be 20" diameter. The piping will be above ground from the gas company tie-in, up to the boiler house area, where it will go underground, under a sidewalk and will come above ground again to enter the boiler house.

D. The piping will have an air actuated full size ball valve just downstream of the gas company connection in order to shut the main gas supply off to the plant.

E. The piping will have an emergency shut-off valve (ESV) , to close in less than one second, located in close proximity to, and outside of the boiler house.

F. The piping will also have an automatic vent valve that will open when the shutdown valve is closed. This is to purge natural gas between the shutdown valve and the down-stream burner and igniter trip valves located on the B&W skid inside the boiler house.

G. A pressure relief valve is located between the shutdown valve and the B&W tie-point to protect equipment supplied by B&W. The relief valve set pressure is 60 psig. There are no valves or obstructions between the relief valve and the B&W equipment tie-point.

H. To supply control air, an instrument air line (2") will run from the plant air compressor area, adjacent to the gas line, to the gas scrubbing, metering, gas heater and pressure reducing equipment.

3.1.3 Description of Control and Operation

A. Downstream of the Gas Company tie-in, there will be a pneumatic driven ball valve to shut the gas supply off from within the control room via an E-stop pushbutton located in the control room.

B. Upstream and relatively close to the boiler house, there will be a pneumatic, fail-safe shutdown valve capable of closing in less than one second, by E-stop in the control room. There will also be a pneumatic, fail safe vent valve which will automatically open when the shutdown valve is closed. The vent valve will vent gases above the boiler house, between the shutdown valve and trip valves located on the B&W burner skid inside the boiler building.

C. The building heat supply gas piping includes isolation and regulating valves for isolation and pressure control. The pressure is controlled by a self-contained pressure regulator while the isolation valve is controlled via a pushbutton in the control room.

3.2 Fuel Gas Check Metering Station

The Fuel Gas Check Metering Station will be located downstream of the Gas Company metering station..

3.2.1 Functional Requirements

The metering station will be capable of measuring the gas flow with an accuracy of +/- 0.25% of full flow. The flow information will be transmitted to the DCS system. The instrumentation will provide pressure, temperature, mass flow, and total flow output signals. The metering station will have a measurable range of from 1,100 to 149,800 lb/hr (345 - 46,640 scfm).

3.2.2 Description of Equipment

A. The gas supply will have a parallel (bypass) check meter lane, unidirectional, and supplied with along radius elbows and extended pipe spools. The lane will have a flow conditioner upstream of the meter. The meter lane assembly pressure drop will be less than 3 psi flange to flange.

B. Electrical components will meet Class I, Division II, Group D, requirements for hazardous locations per NEC.

C. There will be a gas chromatograph downstream of the metering station to monitor the fuel gas composition and heating value.

3.2.3 Description of Controls and Operation

The flow information will be transmitted to the DCS system. The instrumentation will provide pressure, temperature, mass flow, and total flow output signals, including gas chromatograph output. Instrumentation and control signals will be wired to the DCS for monitoring and trending.

3.3 Water Bath Gas Fired Heater

The Water Bath Gas Fired Heater will be located downstream of the Fuel Gas Check Metering Station.

3.3.1 Functional Requirements

The Water Bath Gas Fired Heater will be capable of adding 40°F to the natural gas supply. The preliminary design is for heating approximately 2.5 MMscfh, with a heat duty of 3.75 MMBtu/hr.

3.3.2 Description of Equipment

A. The heater shell is a horizontal indirect fired water bath heater designed in accordance with API 12K requirements. The heater unit has an external expansion reservoir tank for the glycol/water mixture. The heater has a U tube firing chamber flue stack and process coil assembly designed to meet process design conditions.

B. The heater is a vessel filled with a transfer media of water/glycol. The combustion chamber (firetube) and process coil are submerged in the media. The firetube transfers the heat released by the burner to the media which then transfers the heat to the natural gas being heated through the process coil.

3.3.3 Description of Controls and Equipment

The heater will be controlled by a dedicated local PLC type controller and will be supplied with all the instrumentation and control devices needed for safe and reliable operation. A datalink to the DCS will be provided for monitoring from the control room.

3.4 Fuel Gas Pressure Reducing Station

The Gas Pressure Reducing Station will reduce pressure from Gas Company supply pressure (less scrubber and metering station pressure drop) to the pressure required to meet the requirements of the B&W gas burner system.

3.4.1 Functional Requirements

The gas pressure will be reduced from 168 psig to 45 psig in order to meet the pressure requirement of 40 psig for the new burner system skid supplied by B&W. Maximum delivered pressure is 50 psig. The design pressure of B&W equipment is 60 psig, for which a relief valve at this set pressure is installed on the gas supply pipe line to the boiler house.

3.4.2 Description of Equipment

A. The Gas Pressure Reducing Station will reduce pressure from gas company supply pressure to the pressure required to meet the requirements of the B&W gas burner system. The pressure reducing station is to be engineered as a skid package with all interconnecting piping, valves, filters, tubing, instrumentation and wiring.

B. Overpressure protection of the pressure reducing station will be accomplished with the use of pressure limiting regulators in series with the main regulators. In the event of failure of the main regulator/s the monitor regulator will function as the pressure control device and main valves will fail in the open position.

C. The pressure reducing station will have redundant pressure reduction valves and equipment for uninterrupted on-line maintenance capability, monitor regulators for overpressure protection, and inlet filtration for component protection.

3.4.3 Description of Control and Operation

The pressure will be controlled with "worker-monitor" regulators. Pressure transmitters will be provided for monitoring and trending the header pressure via the DCS.