FutureGen 2.0 Oxy-Coal Combustion Carbon Capture Plant Pre-FEED Design and Cost

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ABSTRACT

This report summarizes the results of the Pre-Front End Engineering Design (pre-FEED) phase of a proposed advanced oxy-combustion power generation plant to repower the existing 200 MWe Unit 4 at Ameren Energy Resources' (AER) Meredosia Power Plant. AER has formed an alliance with Air Liquide Process and Construction, Inc. (ALPC) and Babcock & Wilcox Power Generation Group (B&W PGG) for the design, construction, and testing of the facility, and has contracted with URS Corporation (URS) for preliminary design and Owner's engineering services.

The Project employs oxy-combustion technology – combustion of coal with nearly pure oxygen and recycled flue gas (instead of air) – to capture approximately 90% of the flue gas CO_2 for transport and sequestration by another Project.

Plant capacity and configuration has been developed based on the B&W PGG-ALPC cool recycle process firing high-sulfur bituminous coal fuel, assuming baseload plant operation to maximize existing steam turbine capability, with limited consideration for plant redundancy and performance optimization in order to keep plant costs as low as practical. Activities and preliminary results from the pre-FEED phase addressed in this report include the following:

- Overall plant thermal performance
- Equipment sizing and system configuration
- Plant operation and control philosophy
- Plant emissions and effluents
- CO_2 production and recovery characteristics
- Project cost estimate and economic evaluation
- Integrated project engineering and construction schedule
- Project risk and opportunity assessment
- Development of Project permitting strategy and requirements

During the Phase 2 of the Project, additional design details will be developed and the Phase 1 work products updated to support actual construction and operation of the facility in Phase 3. Additional information will be provided early in Phase 2 to support Ameren-Environmental in finalizing the appropriate permitting strategies and permit applications. Additional performance and reliability enhancements will also be evaluated in Phase 2 to try to improve overall project economics.

ACRONYMS AND ABBREVIATIONS

AC	Alternating Current
ACI	American Concrete Institute
AER	Ameren Energy Resources
AL	American Air Liquide Holdings, Inc.
ALE	Air Liquide Engineering and Technology
ALLIUS	Air Liquide Large Industries US
ALPC	Air Liquide Process and Construction, Inc.
AQCS	Air Quality Control System
AR	Absorber Recirculation
Ar	Argon
ARRA	American Recovery and Reinvestment Act
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
ASU	Air Separation Unit
AVT	All Volatile Treatment
B&PV	Boiler and Pressure Vessel
B&W PGG	Babcock & Wilcox Power Generation Group, Inc (a wholly-owned subsidiary of The Babcock & Wilcox Company)
BACT	Best Available Control Technology
BAHX	Brazed Aluminum Heat Exchanger
BCS	Boiler Control System
BFP	Boiler Feed Pump
BMCR	Boiler Maximum Continuous Rating
BMS	Burner Management System
BOD	Biochemical Oxygen Demand
BOP	Balance-of-Plant
BWG	Birmingham Wire Gauge
CAPEX	Capital Expense
CCS	Carbon Capture and Storage
CCW	Closed Cooling Water
CEDF	Clean Environment Development Facility
CEMS	Continuous Emissions Monitoring System
CHS	Coal Handling System
Cl	Chlorine or Chloride
CM	Construction Manager
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COD	Chemical Oxygen Demand
COE	Cost of Electricity
CPU	Compression and Purification Unit
DC	Direct Current
DCCPS	Direct Contact Cooler – Polishing Scrubber
DCS	Distributed Control System

DOE	Department of Energy
DOR	Division of Responsibility
DSI	Dry Sorbent Injection
E&I	Electrical and Instrumentation
EHS&S	Environmental, Health, Safety and Security
EIS	Environmental Impact Statement
EIV	Environmental Information Volume
EI-XCL	B&W enhanced ignition burner design
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency
EPC	Engineer, Procure, Construct
EPRI	Electric Power Research Institute
FD	Forced Draft
FEED	Front End Engineering and Design
FEGT	Furnace Exit Gas Temperature
FeS	Iron Sulfide
FGA	FutureGen Alliance
FGD	Flue Gas Desulfurization
FRP	Fiberglass Reinforced Plastic
GOX	Gaseous Oxygen
GPS	Global Positioning System
GQCS	Gas Quality Control System
H_2	Hydrogen
H_2S	Hydrogen Sulfide
H_2SO_4	Sufuric Acid
HART	Highway Addressable Remote Transducer
HCl	Hydrochloric Acid
HF	Hydrofluoric Acid
Hg	Mercury
HGI	Hardgrove Grindability Index
HHV	Higher Heating Value
HMI	Human-Machine Interface
HP	High Pressure
HVAC	Heating, Ventilation, and Air Conditioning
HV-XCL	B&W High Velocity Dual Register Burner design
I&C	Instrumentation and Control
I/O or IO	Input/Output
I/P	Current to Pressure (Electropneumatic)
ID	Induced Draft or Inside Diameter
IGCC	Integrated Gasification Combined Cycle
IMS	Integrated Master Schedule
IP	Intermediate Pressure
L/G	Liquid-to-Gas
LCOE	Levelized Cost of Electricity
LOX	Liquid Oxygen
LP	Low Pressure

MACT	Maximum Achievable Control Technology
MBTU	Million British Thermal Units
MCC	Motor Control Center
MCR	Maximum Continuous Rating
ME	Mist Eliminator
MGD	Million Gallons per Day
MP	Medium Pressure
MTO	Material Take Off
N_2	Nitrogen
NAAQS	National Ambient Air Quality Standards
NEPA	National Environmental Policy Act
NFPA	National Fire Protection Association
NOx	Nitrogen Oxides
NPSH	Net Positive Suction Head
NSR	New Source Review
O_2	Oxygen
OD	Outside Diameter
OFA	Overfire Air
OPC	Open Process Control
OPEX	Operation Expense
OSHA	Occupational Health and Safety Administration
OTF	Over-the-Fence
P&ID	Piping and Instrumentation Diagram
PC	Pulverized Coal
PCS	Plant Control System
PFD	Process Flow Diagram
PHE	Potomac-Hudson Environmental, Inc.
PJFF	Pulse Jet Fabric Filter
PL	Powdered Limestone
PM	Project Manager
PM	Particulate Matter
PR	Primary Recycle
PRB	Powder River Basin sub-bituminous coal
PSD	Prevention of Significant Deterioration
QA/QC	Quality Assurance / Quality Control
RO	Reverse Osmosis
ROW	Right of Way
RTD	Resistance Temperature Detector
SCAH	Steam Coil Air Heater
SCR	Selective Catalytic Reduction
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
SPCC	Spill Prevention Control and Countermeasures Plan
SR	Secondary Recycle
STG	Steam Turbine Generator
T&D	Transmission and Distribution

TDH	Total Developed Head
TDS	Total Dissolved Solids
TOC	Total Organic Carbon
TPD	Tons per Day
TSA	Temperature Swing Adsorption
TS&M	Transport Store and Monitor
TSS	Total Suspended Solids
UF	Ultrafiltration
UPS	Uninterruptible Power Supply
URS	URS Corporation
VOM	Volatile Organic Matter
VSD	Variable Speed Drive
VWO-OP	Valves Wide Open, 5% Overpressure (STG Throttle condition)
WACC	Weighted Average Cost of Capital
WFGD	Wet Flue Gas Desulfurization
WFGD/DCC	Wet Flue Gas Desulfurizer-Direct Contact Cooler
WWTS	Wastewater Treatment System
ZLD	Zero Liquid Discharge

1.0 EXECUTIVE SUMMARY

Ameren Energy Resources (AER) has formed an alliance with Air Liquide Process and Construction, Inc. (ALPC) and Babcock & Wilcox Power Generation Group (B&W PGG) to design, construct, and test an advanced oxy-combustion power generation plant at their Meredosia Power Plant site, and has contracted with URS Corporation (URS) for preliminary design and Owner's engineering services. The Project will repower the existing 200 MWe Unit 4 steam turbine generator, capturing most of its CO_2 for transport and sequestration by another Project.

This report covers the first phase – Pre-Front End Engineering Design (pre-FEED) – of the four-phase Project. The Project is divided into separate islands, as follows:

- Boiler/Gas Quality Control System (GQCS) – by B&W PGG
- Air Separation Unit (ASU)/Compression & Purification Unit (CPU) – by ALPC
- Balance of Plant (BOP) – by AER/URS

Oxy-combustion is the combustion of coal with nearly pure oxygen and recycled flue gas (instead of air), resulting in a flue gas byproduct that is primarily CO_2 instead of nitrogen, facilitating capture of the CO_2 so that it can be sequestered.

Plant capacity and configuration has been developed using the B&W PGG-ALPC cool recycle oxy-combustion process firing a high-sulfur bituminous coal, and assumes baseload operation to maximize existing steam turbine capability, with limited consideration given to plant redundancy and performance optimization. Additional performance and reliability enhancements will be considered in Phase 2. Resulting plant performance is summarized in Table 1-1. Plant emissions and CO_2 production are summarized in Table 1-2. With the exception of carbon monoxide (CO), which is no higher than a new conventional coal-fired plant, the emissions of the criteria pollutants are expected to be very low.

Table 1-1
Overall Plant Thermal Performance Summary

Steam Turbine Gross Generation to 138 kV Grid	202,766 kW
Total Plant Auxiliary Power	80,100 kW
Plant Net Generation	**122,666 kW**
Plant Net Heat Rate, HHV	**16,211 kJ/kWh (15,365 Btu/kWh)**
Net Plant Efficiency, HHV	**22.2%**

Based on annual average baseload normal operating conditions, as follows, including estimated equipment degradation for existing plant equipment:

- Ambient Temperature: 11.7 ºC (53 ºF) dry bulb, 8.9 ºC (48 ºF) wet bulb
- Oxy-combustion operation of Boiler at maximum continuous rating on 100% design fuel (Illinois No. 6 bituminous coal), with 1% boiler drum blowdown.

Table 1-2
Project Air Emissions and CO_2 Production Summary

Emissions Constituent	kg/hr (lb/hr)	g/GJ (lb/MBtu), HHV Basis
CO	130.14 (286.90)	64.5 (0.15)
NO_x	≤ 12.80 (28.21)	≤ 6.32 (0.0147)
VOM	≤ 3.13 (6.89)	≤ 1.55 (0.0036)
PM (Total)	≤ 0.00026 (0.0006)	≤ 0.00013 (0.00000031)
SO_2	≤ 0.351 (0.774)	≤ 0.17 (0.0004)
Hg	≤ 0.0000027 (0.0000059)	≤ 0.0000013 (0.0000000031)

CO_2 Production	
CO_2 Recovery	90% (by mass)
Mass flow	159,211 kg/hr (351 klbs/hr) 3,820 tonnes/day (4210 tpd)
Pressure	145 barg (2,100 psig)
Temperature	21.7 °C (71 °F)
CO_2 content	≥ 99.7% (by mass, dry)

Based on operating conditions listed in Table 1-1, with all emissions from the CPU vent.

A Project Interface List and Division of Responsibility (DOR) document were developed to define the scope breaks between the islands. AER will own the entire repowered facility and will operate and maintain all systems within the plant except for possibly the ASU and the CPU, which may potentially be owned, operated, and maintained (in coordination with the remainder of the Plant) solely by AL under a services contract developed between AER and Air Liquide Large Industries US (ALLIUS).

With the exception of the ASU and CPU, plant design and operation are similar to a typical air-fired unit, with the following significant differences.

- The presence of highly concentrated O_2 and CO_2 streams within the plant require consideration of additional operational and safety issues.
- The ASU and CPU islands impose limitations on startup, shutdown, and load changing capabilities.
- Boiler, GQCS, and steam cycle are initially started and minimally loaded (to about 45% load) on air-firing, then transitioned to oxy-combustion when the ASU and CPU are ready.
- Heat integration between the steam cycle and other islands requires consideration of additional system design and operational limits.

A preliminary integrated schedule and cost estimate was developed for the overall power generation project, but excluding the pipeline and sequestration project. Estimates relied heavily on vendor quotations solicited specifically for this project. The total power generation project capital cost is estimated at $1.099 billion. AER is evaluating multiple economic scenarios using the Phase 1 performance and cost estimates, but results are not yet available.

A number of Project risks and potential enhancement opportunities have been identified during Phase 1 and will be further evaluated in Phase 2. Among the opportunities, specific performance improvements (e.g. auxiliary power) have been targeted to improve overall Project economics.

The Project continues to develop needed information on emissions, effluents, and consumables to support Ameren-Environmental in determining appropriate permitting strategies and completing permit applications. Information is also being provided to DOE’s Environmental Impact Statement (EIS) contractor, PHE, for use in developing the EIS.

2.0 INTRODUCTION/PROJECT DESCRIPTION

2.1 *Project Description*

Ameren Energy Resources (AER), a subsidiary of Ameren Corporation, has formed an alliance to construct and test an advanced oxy-combustion power generation plant (FutureGen 2.0) at their Meredosia Power Plant site. The oxy-combustion Project will repower the 200 MWe Unit 4 steam turbine generator, capturing most of its CO_2 for transport and sequestration by another Project. AER has executed a Cooperative Agreement with the Department of Energy (DOE) for a federal cost share of approximately $590 million of ARRA funding for the Project. AER has formed an alliance with Air Liquide Process and Construction, Inc. (ALPC) and Babcock & Wilcox Power Generation Group (B&W PGG) for design and construction of the major new equipment blocks to be installed and has contracted with URS Corporation (URS) to provide design services for the balance of plant (BOP), as well as Owner's engineering services.

The FutureGen 2.0 project will be designed for an expected 30 year life with respect to operability, maintainability and reliability. The oxy-combustion repowering project will utilize as much of the existing Unit 4 equipment and systems as possible, with the exception of the boiler (Boiler 6), which will be demolished. Due to the limited operating hours accumulated on Unit 4 since its construction in 1975, much of the existing equipment will be reusable.

2.2 *Project Schedule*

The Project is divided into four phases, as follows. This report addresses the results of Phase 1 only.

Phase 1: (October 1, 2010 – September 30, 2011) Pre-Front End Engineering Design (pre-FEED) work necessary to establish the initial plant performance, component sizes, preliminary specifications, and +/-20% Project cost estimate, along with initiation of Project permitting and NEPA processes. Completion of the following key documents/milestones is included in this Phase:

- Project Design Basis
- Process Flow Diagrams and Overall Mass and Energy Balances
- Project Cost Estimate and initial financial Pro Forma model
- Environmental information to support the NEPA process

- Integrated Phase 2 Project Schedule including Alliance Key Milestone Ties
- Phase 2 Project Management Plan
- Necessary commitments for Project Host Site
- Draft CO_2 off-take agreement with the Alliance
- Executed Cooperation and Technology Agreement with the Alliance

Phase 2: (October 1, 2011 – October 31, 2012) Completion of final FEED, NEPA process, and all major environmental permits needed for construction, along with +/-10% Project cost estimate.

Phase 3: (November 1, 2012 – April 30, 2016) Completion of required permitting, detailed engineering, procurement of materials and equipment, fabrication and delivery of materials and equipment to the site, construction of the Project, commissioning of equipment, plant start-up and initial plant operations.

Phase 4: (May 1, 2016 – December 31, 2018) Project testing, data collection and performance reporting.

2.3 *Project Scope Division of Responsibility*

In general, the project is divided into four islands:

- Boiler/Gas Quality Control System (GQCS) – by B&W PGG – with separate battery limits for Boiler and for GQCS.
- Air Separation Unit (ASU) – by ALPC
- Compression & Purification Unit (CPU) – by ALPC
- Balance of Plant (BOP) – by AER/URS

A Project Interface List has been developed and defines the general utilities and services provided between islands. These utilities and services are generally supplied to and from a single point at or within the battery limits of each island by the BOP, with distribution of those utilities beyond the interconnect point within each island by the individual island suppliers.

AER will own the entire repowered facility and will operate and maintain all systems within the plant except for possibly the ASU and the CPU, which may potentially be owned, operated, and maintained (in coordination with the remainder of the Plant) solely by AL under a services contract developed between AER and Air Liquide Large Industries US (ALLIUS). The benefits of this potential over-the-fence (OTF) arrangement with ALLIUS is discussed further in Appendix J.

2.4 *General Project Requirements and Design Philosophy*

Oxy-combustion is the combustion of coal with nearly pure oxygen and recycled flue gas (instead of air), resulting in a flue gas byproduct that is primarily CO_2 instead of nitrogen. Removal of nitrogen from the combustion process significantly reduces the flue gas mass flow and facilitates capture of high purity CO_2 from the flue gas so that it can be sequestered. The combustion oxidant (O_2) is supplied by the ASU, while the CPU purifies the flue gas.

Plant design is based on achieving successful oxy-combustion operation within project budget and schedule constraints, while achieving approximately the same summer design gross capacity (kW) as the existing Unit 4 design after accounting for existing turbine performance degradation. The engineering and design of the Project will ensure that all equipment and systems – regardless of scope of responsibility – are fully integrated systems, such that their function, operation, safety and performance are well coordinated and not impaired.

Boiler capacity and configuration has been generally set based on optimizing performance for the oxy-combustion operation mode, given the existing subcritical steam cycle. It should be noted that by reusing the existing subcritical cycle, the baseline heat rate (prior to oxy-combustion) is higher than a typical new conventional plant and will therefore detract from the oxy-combustion cycle performance that could otherwise potentially be achieved with a newer plant.

The ASU and CPU are each designed with a single 100% capacity train, sized to accommodate 100% boiler MCR load at summer design temperatures. Additional performance and reliability enhancements will be considered in Phase 2.

2.5 *Oxy-Combustion Process Description*

Figure 2-1 shows the oxy-combustion process schematic selected for the FutureGen 2.0 project. The combustion process employs the B&W PGG-ALPC cool recycle process firing a high sulfur bituminous coal. The entire system is integrated for maximum optimization, given the existing steam cycle and equipment. Heat from the ASU is incorporated into the condensate cycle, while heat from the steam cycle is used for flue gas reheating and other process heat loads. Because the FutureGen 2.0 application involves repowering an existing steam turbine, turbine design limits restrict the amount of heat which can be recovered from the oxy-combustion process and utilized in the power cycle to improve performance. Consequently, heat integration performance improvements that could be realized for a new oxy-combustion plant design will likely not be achieved for this Project, unless extensive steam turbine upgrades can be economically justified.

In the cool recycle process, hot gas leaves the boiler and passes through a regenerative advanced quad-sector (patent pending) secondary and primary recycle heater (aka airheater). This recycle heater is internally arranged to prevent any leakage of the oxidant fed from the ASU into the flue gas.

Following the dry sorbent injection for SO_3 removal, the flue gas passes through the pulse jet fabric filter (PJFF) where particulate matter (PM) is removed. From the PJFF the flue gas pressure is boosted by the induced draft fans and it enters the wet flue gas desulfurization (WFGD) absorber where most of the SO2 is removed.

Following the WFGD the saturated flue gas flow splits. One stream passes through a gas reheater to avoid downstream moisture condensation and its pressure is boosted by the secondary recycle (SR) fans. Oxidant (nearly pure oxygen) is introduced into the secondary recycle flow after the SR fans via Floxynators™ before re-entering the recycle heater for heating prior to the boiler windbox. The SR fans control the secondary flow to the boiler. The remaining flow leaving the WFGD passes through a direct contact cooler polishing scrubber (DCCPS) where moisture is reduced and most of the remaining SO_2 is removed.

The saturated gas leaving the DCCPS is reheated to avoid downstream moisture condensation and is again split with one stream flowing to the compression and purification unit (CPU), and the other supplying the primary recycle (PR) fans. The PR fans provide the flow required to dry and convey the pulverized coal to the burners. Oxidant is preheated and introduced into the primary recycle flow after the recycle heater via Floxynators™. A portion of the primary recycle bypasses the recycle heater to temper the hot primary to each pulverizer as needed to achieve the temperature required to dry the coal and achieve the desired pulverizer outlet temperature. The oxygen concentration in this stream is controlled to mitigate risk of combustion in the pulverizers or coal pipes. Oxidant is also injected directly into the burners to control combustion and the remaining oxidant is mixed into the secondary recycle as previously described.

When air firing (during start-up and shut-down), the secondary recycle stream is isolated by dampers and all of the gas leaving the WFGD flows to the stack as in a conventional air-fired design. The primary and secondary recycle control dampers are closed and, through their air intakes, the SR and PR fans provide fresh air to the recycle gas heater. The DCCPS and its outlet gas reheater are not in service in this mode.

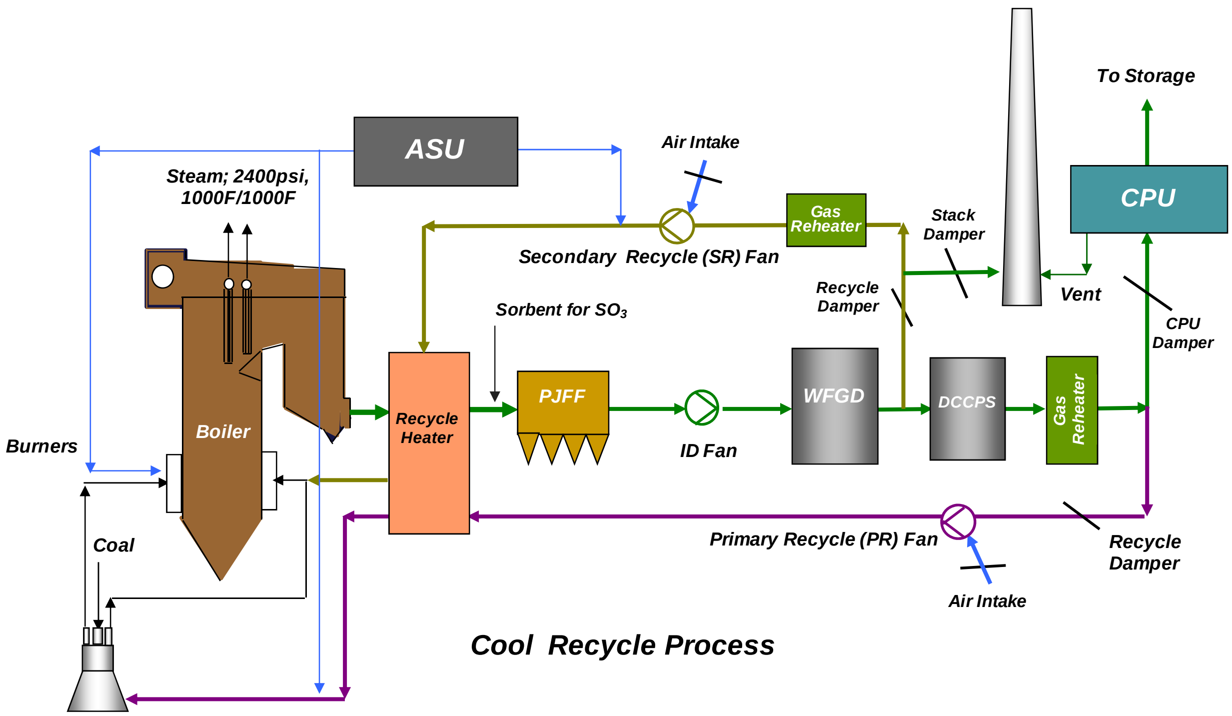


Figure 2-1
Oxy-combustion Cool Recycle Process Schematic

3.0 PROJECT DESIGN

This section describes the preliminary design and performance of Project as established during Phase 1. Preliminary plant equipment lists are provided in Appendix E. A preliminary overall plot plan of the repowered facility is presented in Appendix F.

3.1 *Plant Performance*

All performance is based on annual average operating conditions, as follows:

- Ambient Dry Bulb Temperature: 11.7 ºC (53 ºF)
- Ambient Wet Bulb Temperature: 8.9 ºC (48 ºF)
- Baseload operation of all islands, including the following
    - Oxy-combustion operation of Boiler at maximum continuous rating on 100% design fuel (Illinois No. 6 bituminous coal), with 1% boiler drum blowdown.
    - Steam turbine at VWO-OP conditions
    - ASU at 100% load, normal operating mode
    - CPU at 100% load, normal operating mode, discharging to the CO_2 pipeline
    - All heat integration between islands operating normally, per the conditions established in the Project Design Basis Document.

Plant performance is presented in Table 3-1. Heat and mass balances supporting this estimated performance are presented in Appendix A. Based on an evaluation of the limited Unit 4 performance data available, the Phase 1 performance figures reported here include an estimated 3.1% degradation from new and clean turbine performance reported on the original turbine heat balances. Section 5.0 discusses the underlying basis for this performance and potential changes in plant design which could significantly improve overall performance.

Table 3-1
Overall Oxy-PC Plant Thermal Performance

Steam Turbine Generator Output (gross)	203,580 kW
Generator Step-Up Transformer Losses	814 kW
Steam Turbine Gross Generation to 138 kV Grid	202,766 kW
Total Plant Auxiliary Power	80,100 kW
Plant Net Generation	**122,666 kW**
Boiler Heat Output	1,766 GJ (1,674 MBtu/hr)
Boiler Fuel Efficiency (HHV)	88.83 %
Fuel Heat Input (HHV)	1,989 GJ (1,885 MBtu/hr)
Coal Consumption	81,420 kg/hr (179,500 lb/hr)
Plant Net Heat Rate, HHV	**16,211 kJ/kWh (15,365 Btu/kWh)**
Net Plant Efficiency, HHV	**22.2%**

All performance based on following:

- Average Annual Ambient Dry Bulb Temperature: 11.7 ºC (53 ºF)
- Average Annual Ambient Wet Bulb Temperature: 8.9 ºC (48 ºF)
- Baseload operation of all islands, including:
  - Oxy-combustion operation of Boiler at maximum continuous rating on 100% design fuel (Illinois No. 6 bituminous coal), with 1% boiler drum blowdown.
  - Steam turbine at VWO-OP conditions
  - ASU at 100% load, normal operating mode
  - CPU at 100% load, normal operating mode, discharging to the CO_2 pipeline
  - All heat integration between islands operating normally, per the conditions established in the Project Design Basis Document.
- Estimated equipment degradation included for existing plant equipment.

3.2 *Plant Effluents and Emissions*

3.2.1 Air Emissions

Table 3-2 summarizes the air emissions for the Project under average annual operating conditions. With the exception of carbon monoxide (CO), which is no higher than a new conventional coal-fired plant, the emissions of the criteria pollutants (SO_2, NOx, PM, VOM, Hg) are expected to be very low.

Table 3-2
Project Air Emissions

Emissions Constituent	kg/hr (lb/hr)	g/GJ (lb/MBtu), HHV Basis
CO	130.14 (286.90)	64.5 (0.15)
NO_x	≤ 12.80 (28.21)	≤ 6.32 (0.0147)
VOM	≤ 3.13 (6.89)	≤ 1.55 (0.0036)
PM (Total)	≤ 0.00026 (0.0006)	≤ 0.00013 (0.00000031)
SO_2	≤ 0.351 (0.774)	≤ 0.17 (0.0004)
SO_3	≤ 0.753 (1.660)	≤ 0.374 (0.00087)
HCl	≤ 0.042 (0.092)	≤ 0.021 (0.000048)
HF	≤ 0.00029 (0.00065)	≤ 0.00015 (0.00000034)
Hg	≤ 0.0000027 (0.0000059)	≤ 0.0000013 (0.0000000031)

Current estimates for permitting purposes, based on average annual baseload operating conditions, with all emissions from the CPU vent.

3.2.2 Liquid and Solid Effluents

The major Project effluents at average annual operating conditions are summarized in Table 3-3. Detailed plant water balances are included in Appendix B.

Table 3-3
Project Effluents

Solid Effuents	Effluent Rate
Bottom Ash (wet)	1,860 kg/hr; 44.6 tonnes/day (4,100 lb/hr; 49.2 tpd)
Fly Ash (wet)	9,300 kg/hr; 223.2 tonnes/day (20,500 lb/hr; 246.0 tpd)
Gypsum (wet)	21,320 kg/hr; 512 tonnes/day (47,000 lb/hr; 564 tpd)
Water/Wastewater Treatment Solids	10.4 kg/hr; 250 kg/day (23 lb/hr; 552 lb/day)
Liquid Effuents (refer also to Water Balance)	**Effluent Rate**
Cooling Water (once-thru and tower blowdown)	21,833 lpm; 31,515 m^3/day (5,781 gpm; 8,325 kgal/day)
Process Wastewater	660 lpm; 950 m^3/day (174.3 gpm; 251.0 kgal/day)
Intake Screen Backwash	147 lpm; 212 m^3/day (38.8 gpm; 55.9 kgal/day)
Sanitary Sewage	7.2 lpm; 10.4 m^3/day (1.9 gpm; 2.74 kgal/day)
Waste Oil Disposal (off-site disposal)	3.8 m^3/day (994 gal/day), max design

Based on operation of Unit 4 only. Effluent rates including Unit 3 operation are provided in the water balances contained in Appendix B.

3.2.3 CO_2 Recovery, Production, and Quality

During average annual operating conditions, the expected CO_2 recovery and production for the Project, along with CO_2 product quality at the CPU battery limits are as indicated in Table 3-4.

Table 3-4
CO_2 Recovery, Production, and Quality

CO_2 Recovery (mass basis)	90%
Mass flow (CO_2)	159,211 kg/hr (351 klbs/hr) 3,820 tonnes per day (4,210 tpd)
Pressure	145 barg (2,100 psig) *
Temperature	21.7 °C (71°F)
CO_2 content	≥ 99.7% (by mass, dry basis)
Inerts (Ar, N_2)	≤ 0.04% (by mass, dry basis)
Water (H_2O)	≤ 1 ppmw (dry basis)
Oxygen (O_2)	≤ 110 ppmw (dry basis)
Total Sulfur (SO_x)	≤ 1 ppmw (dry basis)
Hydrogen Sulfide (H_2S)	Negligible
Nitrous Oxides (NO_x)	≤ 1,700 ppmw (dry basis)
Mercury (Hg)	≤ 2 ppbw (dry basis)

* Current pipeline delivery pressure specification is 145 barg (2,100 psig). However, CPU Process and performance calculations have actually been based on 152 barg (2,200 psig) for Phase 1.

3.3 *Plant Control*

3.3.1 Startup

ASU Startup

Cold Start-up (Liquid Levels Maintained)

If the ASU has been shut down for a short period of time, the plant will still be at cryogenic temperatures and maintaining liquid levels. In this case the plant can be restarted fairly quickly by starting the Main Air Compressor, establishing clean dry air flow to the cold box through the adsorbers, and pressurizing the cold box. Once the cold box is pressurized, the expander can be started to produce the temperature drop required for cryogenic separation, product purity and subsequent production. The cryogenic pumps are then started and the facility placed on line.

Warm Start-up (After a Derime)

Starting up the ASU after a derime is essentially the same as a Cold Start-up with the exception of the plant being warm and requiring a longer period of time for cooldown.

Steam Turbine and BOP Startup

To support operation and warmup of the ASU, the following balance of plant (BOP) systems and equipment will initially be placed in service:

- HP and LP Service Water pumps
- Auxiliary boiler (including auxiliary boiler feed pumps and deaerator)
- ASU steam supply and condensate return systems
- Plant air compressors (if not already in normal operation)
- ASU/CPU circulating water pumps (1 pump operation initially)
- ASU/CPU cooling tower fans (number dependent on ambient conditions)

Other BOP systems will remain in their normal shutdown configurations until the ASU startup nears completion and the remainder of the plant can be started. The following additional BOP systems and components will then be placed in service:

- Fuel oil system to support boiler lightoff
- Coal handling systems (as needed to refill the boiler coal silos)

- Closed cooling water system
- Main and DCCPS circulating water pumps (1 pump operation initially for each service)
- Main and DCCPS cooling tower fans (number dependent on ambient conditions)
- Steam turbine oil systems
- Makeup water system pumps and treatment equipment (pumps running but in recirculation mode, provided plant systems are already filled)
- Wastewater system pumps and treatment equipment (pumps in automatic)

To initiate flow to the boiler, the Condensate and Feedwater systems are placed in service. Initially, a single pump in each service will support plant operation, with flow recirculated to the condenser and deaerator as necessary. Additional pumps will be started as system flow warrants. The all-volatile treatment (AVT) chemical feed systems will be placed in service to establish and maintain feedwater chemistry.

Besides supplying the ASU steam requirements, the auxiliary boiler will also initially provide steam for main boiler sootblowing and air preheating (in the SCAH). As sufficient steam pressure is developed in the boiler to maintain the auxiliary steam system pressure, the auxiliary boiler can be shut down. Once the auxiliary steam system is running on its normal supply from the main boiler, seal steam is applied to turbine glands and pegging steam flow to the deaerator is initiated. With turbine seal steam established, the condenser vacuum system will be placed in service to begin drawing condenser vacuum.

When sufficient condenser vacuum is achieved, and as boiler steam pressure and temperature continue to increase, main steam turbine operation will be initiated. Turbine warmup will be controlled following existing turbine startup procedures. When rated turbine speed (3,600 rpm) has been reached, the generator will be synchronized and connected to the grid. The turbine will initially be loaded to its minimum stable level, and then gradually ramped up to full load in coordination with the boiler.

Feedwater heaters (except for the deaerator) will initially be bypassed. As turbine temperatures increase, HP heater steam extraction flows will be initiated and the heaters placed in service, followed by the LP heaters. Additional steam and feedwater supplies from the steam cycle to the GQCS, ASU, and CPU will commence as those systems reach their minimum operating limits for heat integration.

Boiler Startup

During the ASU startup process the boiler startup is initiated at the appropriate time to coordinate having the boiler ready for transition to oxy-combustion when the minimum acceptable oxidant purity is available. Boiler and steam cycle startup are essentially the same as with air firing up to the transition load. As indicated in Figure 2-1, the stack damper and PR and

SR fan air intake dampers are fully open, and the PR and SR recycle flow control dampers and CPU dampers are fully closed for air operation.

Boiler Startup – Air Firing

The following describes the major steps in boiler startup but is not intended to be a comprehensive description. Boiler feedwater treatment must be in operation and ready to supply the boiler with water and the steam drum must be filled to startup level. After verification that all boiler auxiliary systems are ready for starting and all vent and drain valves are in the required startup positions, the fans are started and the furnace purged with burner registers at their predetermined light-off position. Once the furnace purge is complete, the lighters for the first burner group can be ignited. The heat input from the lighters is raised and additional burner group lighters are brought into service until the required steam conditions for turbine roll are achieved. After the fuel flow increases to match the minimum purge air flow, the burner registers can be moved from the light-off position to the cooling position.

Once steam conditions for turbine roll are achieved, the steam turbine is rolled and warmed (soaked) to relieve thermal stresses due to initial temperature differences within turbine components. When the boiler and turbine components have reached the desired temperatures, the first pulverizer can be started and coal firing initiated.

Because the unit is designed to be able to achieve full boiler maximum continuous rating (BMCR) with the design, Illinois #6, coal with two pulverizers in service and the third as spare, care must be taken to reduce the lighter input as the coal input increases to avoid excessive upsets in boiler heat input. Air flow is controlled appropriately to maintain the desired excess air (oxygen) at the boiler outlet under these conditions. Once the pulverizer is started and coal flow increased to the minimum pulverizer load (about 30% of full pulverizer input), all lighters except those associated with the first pulverizer group are backed out, and the unit is operating in a stable condition, the process is ready for transition to oxy-combustion. The minimum heat input may be as low as 30% to 35% of BMCR heat input, but for initial purposes, 45% of BMCR heat input is being assumed as the transition load. Since flue gas emissions prior to oxy-combustion operation and CPU startup are discharged to atmosphere via the startup stack, it is advantageous to transition to the oxy-combustion mode at as low a load as practical to minimize overall air emissions. The final minimum transition load will be established during initial unit tuning.

Transition to Oxy-combustion

Once the boiler has achieved stable operation at the transition load, the transition from air firing to oxy-combustion can commence. With the ASU ready to supply oxidant at the minimum oxygen purity, the process can begin the transition by initiating flue gas recycling. Lower quality oxygen can be used during boiler startup to reduce startup time but may extend the time required to reach full load if the time required for the ASU to reach full purity is greater than the time required to ramp the boiler and steam turbine to full load. The actual quality and availability of oxidant flow depends on the ASU design, but the requirements are partially driven by the tolerance of the CPU to accept the additional argon and nitrogen concentrations in the flue gas during CPU startup. The full transition will also depend upon the readiness of the CPU to accept the flue gas and produce CO_2 to the required pipeline purity. Both the ASU and CPU use a cryogenic process so the startup time from cold is governed by the time required to achieve the necessary cold box conditions for oxygen separation in the ASU and CO_2 separation in the CPU. Overlapping the ASU, boiler, and CPU not only reduces the overall startup time but minimizes air emissions.

Prior to the initiation of the transition, the SR and PR fan air intake control and isolation (tight shut-off) dampers are fully open and the SR and PR flue gas flow control dampers are fully closed. The transition to oxy-combustion begins by first adding oxidant to the operating burners in order to maintain stable and attached flames throughout the process. The transition is initiated by opening the SR flow control damper gradually allowing flue gas to be drawn into the SR fan inlet. As the recycled flue gas flow increases, oxidant is added to the secondary stream to maintain a safe oxygen level at the boiler exit. Once the SR flow control damper is fully open, the SR fan inlet air control damper is gradually closed, increasing the recycled flue gas flow into the SR fan inlet flue.

Once the secondary stream has been fully transitioned, transition of the primary stream commences using the same procedure by gradually opening the PR flow control damper. As the primary stream composition transitions from air to recycled flue gas, the oxygen in the primary stream to the pulverizers (after the recycle heater, aka airheater) is maintained at a prescribed set point. When the PR flow control damper is fully open, the PR fan air intake control damper is gradually closed. Once both the PR and SR fan air intake control dampers are fully closed the boiler process is in full oxy-combustion mode and the PR and SR fan air intake isolation (tight shut-off) dampers can be closed.

If the desired recycle flue gas flow is not achieved when the SR and PR fan air intake control dampers are fully closed and the flue gas recycle dampers are fully open, the stack inlet damper can be gradually closed to force additional flue gas to the SR and PR fan inlets. Flue gas flow to the stack must be maintained until the CPU is in service and ready to accept the flue gas.

When operating in equilibrium, the flue gas flow to the CPU (or stack) is equal to the sum of the oxidant (air and/or oxygen) added, any air infiltration, and the products of combustion less the constituents removed by the WFGD and DCCPS.

Once the boiler process is in full and stable oxy-combustion mode, (estimated to require 30 to 45 minutes), and the CPU is ready, the flue gas can be transitioned from the startup stack to the CPU. This is accomplished by first opening the CPU isolation (tight shutoff) damper (the CPU flow control damper is closed). The CPU flow control damper is then gradually opened, which will draw flow into the CPU and away from the startup stack. The CPU will maintain appropriate conditions to avoid an upset to the boiler process or the pipeline. Once the CPU flow control damper is fully opened, the stack flow control damper is gradually closed redirecting all remaining flow from the stack through the DCCPS, PR gas reheater, and to the CPU. During the transition the steam flow to the PR gas reheater will be modulated to maintain the outlet temperature above the dew point.

Unit load demand controls the PR flue gas demand to satisfy the needs of in-service pulverizers and SR flow is controlled to satisfy total mass flow to the boiler for combustion and heat transfer. SR gas flow is also used to control reheat outlet steam temperature by varying furnace and convection pass absorption. The SR and PR flows are measured and temperature compensated based on the densities of the air and oxygen/recycle gas flow streams. This density compensation accounts for the changing constituents of the SR and PR streams with air, oxygenated flue gas, and a mixture of the two.

The ASU Demand is the oxidant flow (a function of oxygen purity) required to deliver the difference between the theoretical stoichiometric oxygen requirement corresponding to the total Btu input plus the target excess oxygen and the oxygen available from incoming air and oxygen in the recycled flue gas. The ASU Demand is trimmed to maintain the target excess oxygen at the boiler outlet.

The oxidant flow to the oxidant injectors, called Floxynators™, is controlled to maintain an oxygen concentration by volume in the SR and PR streams downstream of the injection points. The total oxidant to the in-service burners is a proportional function of the total oxidant demand on the unit. The oxidant flow to the individual burners associated with a pulverizer is a function of that individual pulverizer demand compared to the total firing rate demand. Distribution between burners is preset during commissioning using valves on each burner to optimize combustion.

The local concentration of oxygen in the recycle flue gas downstream of the Floxynator™ must remain below maximum oxygen concentration limits under all circumstances. The demand for Total Oxidant is coordinated between the boiler and the ASU.

CPU Startup

Cold Startup (CPU Cold Box is Warm)

The start-up procedure for the CPU when the Cold Box is initially warm involves a sequence of steps to allow time for the Cold Box to cool down prior to the final step when CO_2 is admitted to the pipeline.

Hot Startup (CPU Cold Box is Cold)

It should be noted that if the start-up follows a relatively short period of shutdown, the Cold Box may still be at or close to operating temperature. In this case, the Cold Box cooling is not necessary.

3.3.2 Load Changing

Starting an additional pulverizer under oxy-combustion conditions is similar to starting a pulverizer under normal air firing. The first step is to confirm that the burner registers associated with the pulverizer to be placed in service are at light-off position. The associated lighters are then placed in service on these burners. Oxidant flow demand is temporarily increased to help maintain flame stability. Primary flow through the pulverizer is established when its burner line shutoff valves are opened, increasing the required PR flow. The oxygen concentration in the PR stream is maintained to its prescribed setpoint which, along with the additional oxidant to the burners, will increase excess oxygen. The increased recycle demand results in a temporary decrease in flow to the CPU which maintains a backpressure equivalent to that which would otherwise be provided by the stack.

After the pulverizer and feeder are started, oxidant flow to the corresponding burners is initiated. The additional coal flow will automatically back down the other in service feeder(s) to maintain heat input and redistribute the oxidant to the in-service burners based on pulverizer load. As stable conditions are achieved at the new total heat input, oxidant to the burners is returned to its normal set point and excess oxygen at the boiler outlet is trimmed.

Recycled flue gas and oxidant flow demands will follow changes in boiler heat release demands similar to normal air-fired systems. Oxidant flow to the burners is temporarily increased during transient conditions until steady state load conditions are achieved. Recycle flue gas flow leads oxidant flow which leads fuel flow on load increases. The process is opposite for a load decrease with fuel flow decrease leading oxidant flow decrease which leads recycle flue gas flow decreases.

The individual load change capabilities for the boiler, GQCS, ASU, and CPU are sufficient to support the overall plant load change requirement.

3.3.3 Shut Down

Transition from oxy-combustion back to air firing is the reverse of the transition procedure described in Section 3.3.1. Load is reduced to the transition load point , the gas flow to the CPU is transitioned back to the startup stack, and the CPU is shut down. The PR stream is transitioned back to air first, followed by the transition of the SR stream. First the fan air intake isolation damper is opened while the fan air intake control damper remains closed. The air intake control damper is then gradually opened allowing air into the fan inlet flue. As air mixes with the recycled flue gas, oxidant demand to the corresponding Floxynator™ decreases, as will the total oxidant demand to the ASU. Once the fan air intake dampers are fully open, the recycle flue gas control damper is gradually closed until the fan is supplying only air to the process. At this point the oxidant demand to that stream will be zero and the associated Floxynator™ is shut down. Once both the primary and secondary streams have reverted to air and no oxidant is being injected into the recycle streams, the oxidant flow to the in-service burners is decreased and stopped. From this state the lighters for the in-service pulverizer are ignited as the pulverizer load is decreased to minimum and then shut down followed by the PR fans. Load is further decreased to turbine trip load and the turbine is shut down. The lighters are shut off and the furnace is purged using the SR and ID fans. Once the purge is completed these fans are also shut down, unless they are needed to increase the boiler cool down rate.

3.3.4 Major Trips

Master Fuel Trips

Master fuel trips occur when the interlock system detects an unsafe condition such as loss of ignition, loss of air or oxidant flow, high or low boiler steam drum level, or turbine trip. The operator may, at his discretion, also initiate a master fuel trip. In either case, all fuel flow and sources of ignition are stopped immediately, the CPU is bypassed to the stack, and the furnace is purged. All pulverizers are stopped, the PR fans are stopped, and oxidant flow to the burners and primary Floxynators™ is stopped. Oxidant to the secondary Floxynator is continued to maintain an O_2 concentration of 21% by volume while the SR fan air intake control damper is open and the SR flue gas flow control damper is closed. Once the SR stream has reverted to air the oxidant flow to the secondary Floxynator™ is stopped. The ID and SR fans continue to operate for furnace post-purge.

The control system will close all attemperator and sootblower supply valves. The air flow shall not be increased by deliberate manual or automatic control action. If the air flow is above the purge rate, it shall be permitted to be decreased gradually to the purge rate for a post-firing purge. If the air flow is below the purge rate at the time of the trip, it shall be continued at the existing rate for 5 minutes and then increased gradually to the purge rate air flow and held at this value for a post-firing unit purge. All other current NFPA 85 standards must also be satisfied. Usually the unsafe condition can be corrected and the fuel reignited with little delay following a furnace purge.

Forced Shutdown

Forced shutdown procedures are used to remove the unit from service as quickly as possible, but in a more controlled manner than with the Master Fuel Trip. This procedure requires that the turbine control valves be used to control the load down to the Transition load. Once at Transition the CPU flow is reverted to the stack and the CPU is shut down. Once the flow to the stack has been reestablished, the unit is reverted to air firing and the turbine load is further reduced to the turbine trip load. After the turbine is removed from service, all fuel is stopped and the unit is purged.

3.4 *Power Block Systems*

3.4.1 Boiler and Auxiliaries

The pulverized coal boiler plant is designed to provide the required steam flow to generate a nominal 200 MWe (gross) with the steam power cycle described in Section 3.7 below. The resultant boiler performance parameters are indicated in Table 3-5. The boiler and GQCS process schematic is shown in Figure 2-1 in Section 2.5. The boiler gas-side flow sheet is provided in Appendix A.

Table 3-5
Overall Boiler Performance

Main Steam Flow	644,150 kg/hr (1,420.1 klb/hr)
Reheat Steam Flow	555,920 kg/hr (1,225.6 klb/hr)
Feedwater Flow	650,540 kg/hr (1,434.2 klb/hr)
Main Steam Outlet Pressure	175.9 barg (2,550 psig)
Main Steam / Reheat Steam Outlet Temperatures	542.8 / 540.6 °C (1,009 / 1,005 °F)
Total Heat Output	1,766 GJ/hr (1,674 million Btu/hr)
Total Heat Input	1,989 GJ/hr (1,885 million Btu/hr)
Fuel Flow	81,420 kg/hr (179.5 klb/hr)

Boiler

The boiler is a pulverized coal (PC) fired 200 MW (gross) boiler. It is 9.45 m (31’-0”) wide, 11.58 m (38’-0”) deep, and the height from the bottom inlet headers to the roof is 38.94 m (127’-9”). It is a balanced draft Carolina type subcritical Radiant Drum Boiler designed for variable turbine throttle pressure operation. This unit has a series downpass arrangement, as depicted in Figure 3-1, and will vary the flue gas recycle rate for reheat steam temperature control. In addition a spray attemperator located at the inlet to the reheater will be used for reheat steam temperature control during boiler transient conditions as well as for emergencies. The boiler is designed to burn the specified range of Illinois #6 coal and will utilize #2 fuel oil for the igniters.

Feedwater enters the bottom header of the economizer. Water passes upward through the economizer tube bank, through stringer tubes which support the economizer and primary superheater banks, and discharges to the economizer outlet headers. From the outlet headers, water flows into piping which connects to the steam drum. By means of natural circulation, the water flows down through downcomer pipes and supply distributor tubes to the lower furnace wall headers. From the furnace wall headers, the water/steam mixture rises through the furnace tubes to the upper enclosure headers. The flow then passes through riser tubes back into the steam drum.

The water and steam mixture in the steam drum is separated by cyclone steam separators which provide essentially steam-free water in the downcomers and water-free steam to the drum outlet connections. The steam is further purified by passing through the primary and secondary steam scrubbers within the steam drum.

Steam from the steam drum flows through multiple connections to the headers supplying the furnace roof tubes and pendant convection pass sidewall tubes. From the furnace roof outlet headers steam passes to the enclosure of the horizontal convection pass. The steam flows down horizontal convection pass enclosure and into the outlet headers which are also the inlet headers to the primary superheater.

Steam flow rises through the primary superheater and discharges through its outlet header and through two (2) connecting pipes each equipped with a spray attemperator.

The steam then enters the secondary superheater inlet header and flows through the secondary superheater sections to the outlet header nozzle which connects to the main steam line.

Steam returning from the turbine passes through the reheat attemperator located in the inlet piping to the reheat superheater. It then flows through the pendant reheater sections and exits the reheater through the outlet header which has a single end outlet.

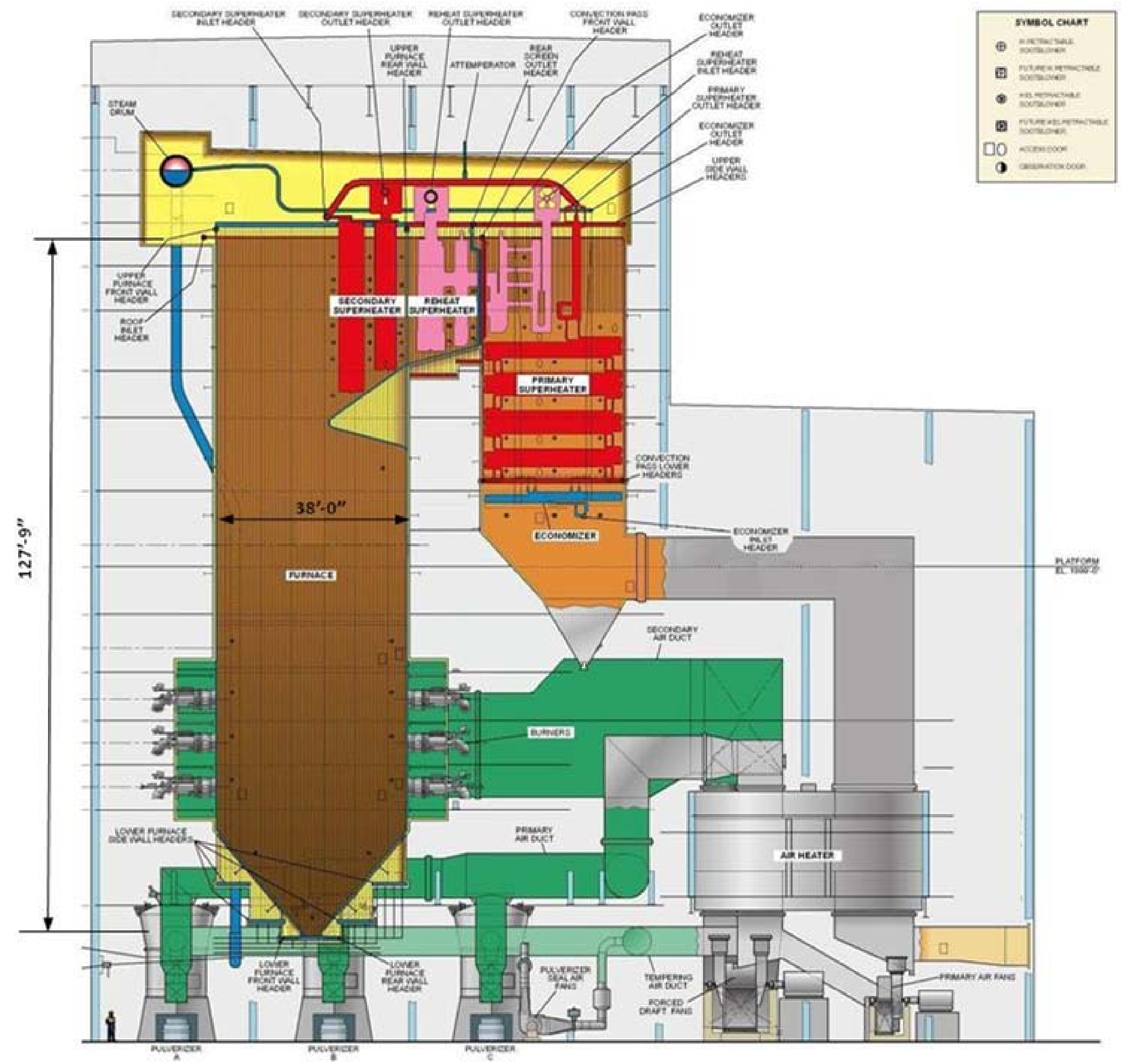


Figure 3-1
Carolina Radiant Drum Boiler with Series Downpass

Superheater and Reheater Material Selection

This unit has two vertical secondary superheater banks and the primary superheater is comprised of four horizontal banks in the downpass and one vertical outlet bank. Note that this unit does not have a platen superheater.

Several factors are considered in the selection of the superheater and reheater tube materials. The material and tube thickness must not only be adequate to meet the requirements of ASME Code, but gas side and steam side corrosion must also be considered in the selection of the tube materials.

Since the Illinois #6 coal contains a significant amount of sulfur and chlorine, both of which contribute to elevated corrosion potential in the superheater and reheater banks, the material selection should give careful consideration to gas side corrosion. As a result of B&W PGG's gas side corrosion analysis, higher grade materials (SA213TP310HCbN and SA213TP310H) were selected for the outlet portions of the secondary superheater and reheater banks.

Since all of the recycle gas has Trona injected to remove SO_3 and also passes through the wet scrubber (WFGD absorber) and the primary recycle gas also passes through the direct contact cooler/polishing scrubber (DCCPS), the concentration of SO_2 and SO_3 in the recycle gas is very low. Because the SO_2 and SO_3 have been removed from the recycle gas it dilutes the SO_2 and SO_3 concentration resulting from the combustion of the coal and oxidant in the furnace. This results in concentrations of SO_2 and SO_3 that are essentially the same as would be produced when firing the same fuel with air. Therefore corrosion rates are expected to be very similar to an air fired boiler burning this type of coal.

Due to the selection of SA213TP310HCbN and SA213TP310H (materials that also have a strong steam-side corrosion resistance) for the outlet portions of these banks, I.D. oxidation and exfoliation is not a concern.

Recycle Heater

One (1) quad-sector regenerative recycle preheater (aka air heater), size 31-VI-86, is provided. The recycle heater is sized to reduce inlet flue gas from approximately 321 °C (610°F) to approximately 177 °C (350°F), excluding correction for leakage, at the BMCR load when firing the typical Illinois #6 coal.

The arrangement of the sectors (patent pending) is used to prevent oxygen from leaking from the recycle gas side to the flue gas side. Oxygen is not only costly to produce in the ASU but it must also then be removed in the CPU.

As shown in Figure 3-2, the secondary sector is isolated from the gas sector by two primary sectors on either side. Since the primary recycle stream is at a higher pressure than either the secondary or the gas side, leakage occurs from the primary to secondary and from the primary to the gas side. As a result, no leakage occurs from the secondary to the gas side. Since the secondary recycle stream is the only stream that is oxygenated upstream of the recycle heater, no injected oxygen is lost to the gas stream. The oxygen for the primary stream is injected downstream of the recycle heater.

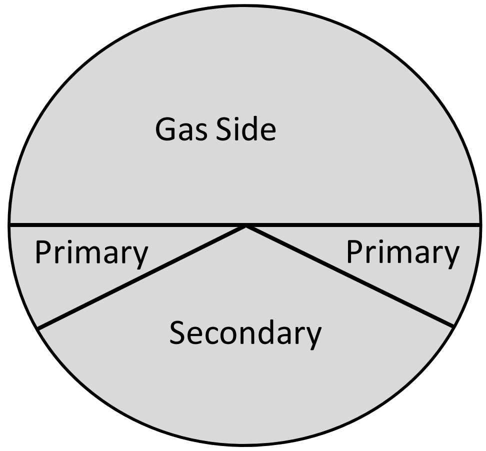


Figure 3-2
Recycle Heater (Plan View)

Although no injected oxygen is lost to the gas stream in this recycle heater sector arrangement, the overall leakage to the gas is increased due to the high pressure differential between the primary sectors and the gas sector. In addition, generally leakage rates are higher when in oxy-firing mode due to the higher densities of the gases as compared to air firing. Work is in progress to minimize the impact of this leakage on the capital and operating expense of the plant. It is believed that the oxygen loss resulting from use of a conventional trisector would be more costly than the impact of the leakage. Further evaluation for this plant will be made to confirm that during Phase 2.

Pulverizers

Three (3) B&W-89N pulverizers, depicted in Figure 3-3, with externally manually adjustable classifier vanes, are located along the boiler left side wall. These pulverizers are sized to meet the expected Boiler Maximum Continuous Rated (BMCR) load requirements with one mill out of service while firing the specified range of Illinois #6 coals. Each pulverizer feeds six (6) burners, which is one level of burners (front and rear wall). Coal is dried in the pulverizers and conveyed through the burner lines to the burners with recycle gas. Functionally, the coal pulverizers operate in the oxy firing mode the same way that they do in air firing mode.

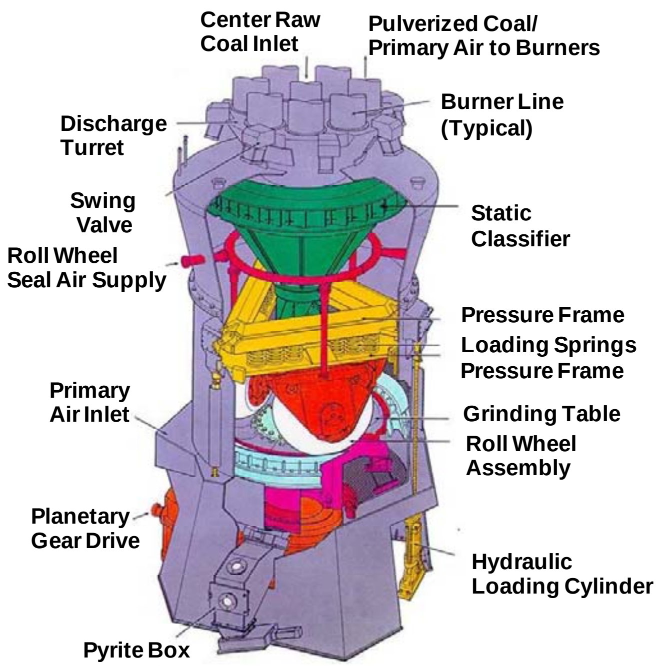


Figure 3-3
B&W Pulverizer

These pulverizers are also equipped with B&W's Auto-Spring^{TM} automatic wheel loading system which allows for variable adjustment of the spring load exerted down against the roll wheel assemblies. When operating the pulverizer at low coal flows, spring pressure is automatically reduced to minimize mill vibration. At high coal flows, spring pressure increases to improve grinding efficiency. This system was implemented due to the significant range of grindability (HGI) of the Illinois #6 coal. It also improves the turndown capability of the pulverizers which is beneficial at the air to oxy transition load.

Burners

There are eighteen (18) B&W HV-XCL^{TM} low NO_X burners, depicted in Figure 3-4, in three elevations on the front and rear walls of the furnace. It should be noted that each pulverizer supplies all of the burners on the front and rear wall of a given elevation, thus regardless of which pulverizer(s) is out of service, the burners in operation will always be directly opposed. This enhances combustion stability and encourages high combustion efficiency.

Each burner has oxygenated recycle gas supplied to it. In addition, from 10% to 20% of the total oxidant flow (nearly pure oxygen) to the boiler is injected into the burner flames.

The combustion system on this boiler is un-staged to mitigate furnace corrosion. When firing bituminous coals, the combustion system has a significant impact on the degree of corrosion expected in the furnace. Medium to high sulfur coals can be expected to contribute to FeS deposition/corrosion and to some extent H_2S gas phase corrosion in the presence of a reducing and/or alternating reducing and oxidizing atmosphere. These conditions will exist in the furnace burner zone extending up to and through the OFA port elevation on a staged combustion system.

In order to avoid this hazard, an un-staged firing arrangement will be utilized on this boiler. This will eliminate the need for Inconel 622 weld overlay in the furnace. Eliminating staging is a corrosion mitigation strategy. B&W PGG recommends only spot protection with thermal flame spray of any local areas of corrosion should they occur in operation.

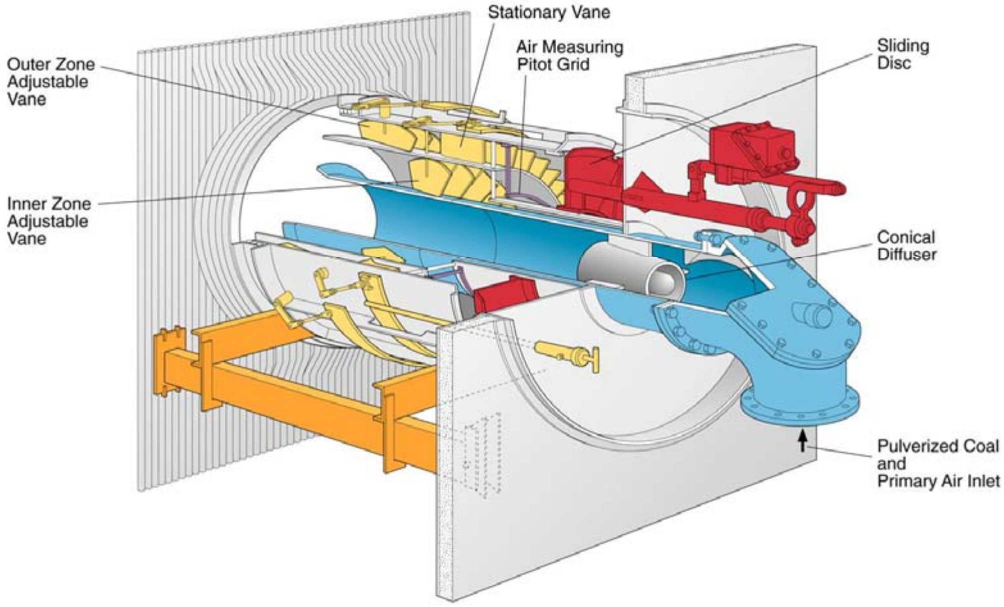


Figure 3-4
HV-XCL Burner

A single retractable #2 oil lighter with air atomization is installed in each burner for startup. Each lighter is capable of approximately 15% of the burner full load heat input (18 lighters at approximately 26.4 GJ/hr [25 MBtu/hr] based on 44,900 kJ/kg [19,300 Btu/lb] HHV and approximately 600 kg/hr [1,300 lb/hr] oil flow). Since this boiler is capable of full load firing with two-thirds of the burners in service (one pulverizer out of service), the total heat input capability with all oil igniters in service is approximately 22.5% of the boiler full load heat input.

Oxidant Injection

The oxidant is injected in three locations: the primary recycle stream after the recycle heater and before the pulverizers, the secondary stream before the recycle heater and thirdly, into the burner flame. In the primary stream oxidant is injected to maintain the O_2 concentration in the recycle gas at slightly less than the O_2 concentration in normal air. This is done to reduce the risk of fire in the pulverizers and coal lines. Capability is provided to inject from 10% to 20% of the total oxidant flow to the boiler directly into the burner flames. The remainder of the oxidant required for combustion is injected into the secondary recycle stream.

Fans and Air Intakes

There are three sets of 2 x 50% centrifugal fans for the oxy-fired boiler process; two primary recycle fans, two secondary recycle fans, and two induced draft fans. The primary recycle fans supply the recycle gas to the pulverizers for coal drying and to transport the pulverized coal from the pulverizers to the burners. They also supply sealing and cooling gas for the pulverizers, coal feeders and other equipment. The primary recycle fans are located between the direct contact cooler/polishing scrubber (DCCPS) outlet and the recycle heater. The secondary recycle fans supply recycle gas to the burner windbox. They are located between the WFGD absorber outlet and the recycle heater. The induced draft fans draw the flue gas leaving the boiler through the pulse jet fabric filter (PJFF) and forces it through the WFGD absorber and then either to the stack or to the DCCPS depending on whether or not the boiler is in carbon-capture mode. The induced draft fans are located between the PJFF and the WFGD absorber.

Both the primary and secondary fans have inlet ducts arranged so that either air or recycle gas can be supplied to them. The ducts have shut-off dampers so that only air is supplied to the fans when the boiler is in the air-firing mode and only recycle gas is supplied to the fans when the boiler is in oxy-firing mode. The inlet ducts also have control dampers for modulating the air and recycle gas flow during the transition from air-firing to oxy-firing and vice-versa. Located at the air inlet to the secondary fan is a steam coil air heater that is designed to protect the recycle heater from cold-end acid dew point corrosion when in the air-firing mode.

The fans are designed to minimize leakage from the ambient into the gas stream because air infiltration introduces nitrogen which adds flow to the gas path and the compression and purification unit (CPU) and increases power consumption. The fans for this project are capable of accommodating an expanded range of operating conditions due to operational uncertainties of the new oxy-fired technology and to allow some flexibility for research and testing. Several options for fan design and operation are considered to determine the most economical design that both covers the range of operating conditions and optimizes the fan performance at the expected normal operating points.

Sootblowers

The locations and quantities of sootblowers suitable for steam blowing are based on Diamond Power recommendations and B&W PGG standards for firing the specified range of Illinois #6 coal. Convection pass sootblowers are installed on one boiler side wall. The convection pass blowers are Diamond Power’s IK-700’s, the recycle heater blowers are IK-DM’s and the furnace will be steam cleaned by IK-4M’s which will function the same as Diamond Power’s typical furnace IR blowers. Special sealing methods are used to prevent air infiltration into the boiler or flue gas leakage into the building from the sootblower openings.

Bottom and Convection Pass Ash Removal

Bottom Ash

The bottom ash removal system will consist of a transition chute, submerged chain conveyor with water recirculation pumps, sludge pumps and heat exchangers. For the water recirculation pumps, the sludge pumps and heat exchangers, two of each will be supplied, one operating and one installed as a spare. The submerged conveyor will run from the furnace transition chute beneath the furnace hopper to the silo storage. The conveyor will include the maintenance rollout feature. This conveyor will completely clear the transition chute when in the rolled out position allowing for direct access to the boiler throat. An OSHA compliant maintenance access platform and staircase will be provided for inspection and service access to the head section.

A hydraulic conveying system is also provided for pyrites (mill rejects). The pyrites system will transport the pyrites from the pulverizers to the submerged chain conveyor system.

Convection Pass Ash

The economizer hopper ash will be removed from the hoppers via knife-gate valves and discharged onto a dry single strand collecting drag conveyor directly below the economizer. The conveyor will collect the convection pass ash from two hoppers and discharge the ash to a transfer conveyor. The transfer conveyor will transfer the ash from collecting ash conveyor to the submerged bottom ash conveyor.

Steam Coil Air Heater and Gas Reheaters

There are two gas reheaters in this process, the primary gas reheater and the secondary gas reheater. The function of both of these reheaters is to heat the gas leaving the WFGD absorber or the DCCPS, which is at saturation temperature, by 17ºC (30°F) to prevent condensation in the downstream flues and fans. The primary gas reheater is located in the DCCPS outlet flue before it splits to the CPU and the primary fans. The gas will leave the DCCPS at a typical temperature (depending on the season) of 21ºC (70°F) to 38ºC (100°F), and the primary gas reheater will heat this gas by about 17ºC (30°F). The primary gas reheater will use a condensate (water) extraction from the turbine as the source for the heating fluid.

The secondary gas reheater is located at the outlet of the WFGD absorber in the flue to the inlet of the secondary fans. The gas will leave the WFGD absorber saturated at a typical temperature between 71ºC (160°F) and 82ºC (180°F) and the secondary gas reheater will heat this gas by about 17ºC (30°F). The secondary gas reheater will also have the function of protecting the recycle heater from acid dew point corrosion at partial boiler loads. When it is serving in this function, the secondary gas reheater may raise the recycle gas temperature by significantly more than 17ºC (30°F). The secondary gas reheater will use a steam extraction from the turbine as the source for the heating fluid.

The locations of the steam and condensate extractions are selected to minimize the impact to the overall steam cycle efficiency while still having the capability to accomplish the required amount of gas heating.

The gas reheaters incorporate features to protect against corrosion, minimize the potential for gas side fouling and are designed to accommodate future sootblowers if operational experience indicates that they are needed.

The steam coil air heater (SCAH) was sized to protect the recycle heater from acid dew point corrosion while the boiler is in air firing mode. In addition, these air heaters serve the function of preheating the combustion air for the #2 oil igniters during boiler start-up.

3.4.2 Gas Quality Control Systems (GQCS)

The Gas Quality Control System (GQCS) consists of a Dry Sorbent Injection (DSI) System for the removal of sulfur trioxide (SO_3), a Pulse-Jet Fabric Filter (PJFF) for the removal of particulate matter, a Wet Flue Gas Desulfurization (WFGD) System for the bulk removal of sulfur dioxide (SO_2) and other acid gases and a Direct Contact Cooler Polishing Scrubber (DCCPS) with dedicated cooling tower for flue gas dehumidification and SO_2 polishing. The dehumidification is necessary to provide reasonably dry recycle flue gas to the pulverizers for coal drying and conveying and to reduce the amount of dehumidification required in the CPU. The additional SO_2 polishing of the flue gas in the DCCPS is necessary to minimize corrosion potential in the CPU. The overall GQCS system is depicted in Figure 3-5 below.

From the recycle heater, dry sorbent is injected and all of the flue gas is sent through the PJFF, where more than 99% of the fly ash is removed and approximately 96% of the incoming SO_3 is removed. The flue gas then flows through the ID fans which discharge to the WFGD System where 98% of the SO_2 is absorbed from the flue gas along with HCl and some mercury (Hg). After the WFGD, the saturated flue gas stream is split, with a portion being directed through the secondary gas reheater where it is heated to a margin above the moisture dew point. It then passes through the secondary recycle fans and is recirculated back through the recycle heater to recover energy prior to the boiler windbox. The remainder of the flue gas is sent to the DCCPS for dehumidification as well as polishing of SO_2, SO_3, and acid gases. The saturated flue gas leaving the DCCPS passes through a gas reheater where it is heated to a margin above the moisture dew point and then is split again. A portion is directed to the primary recycle fans to be recirculated back through the recycle heater for heating and to recover energy from the hot flue gas exiting the boiler. The hot primary recycle is then tempered with cooler primary flue gas before entering the pulverizers. The remainder of the flue gas is directed to the CPU for CO_2 purification and compression. A detailed GQCS Process Flow schematic is included in Appendix C.

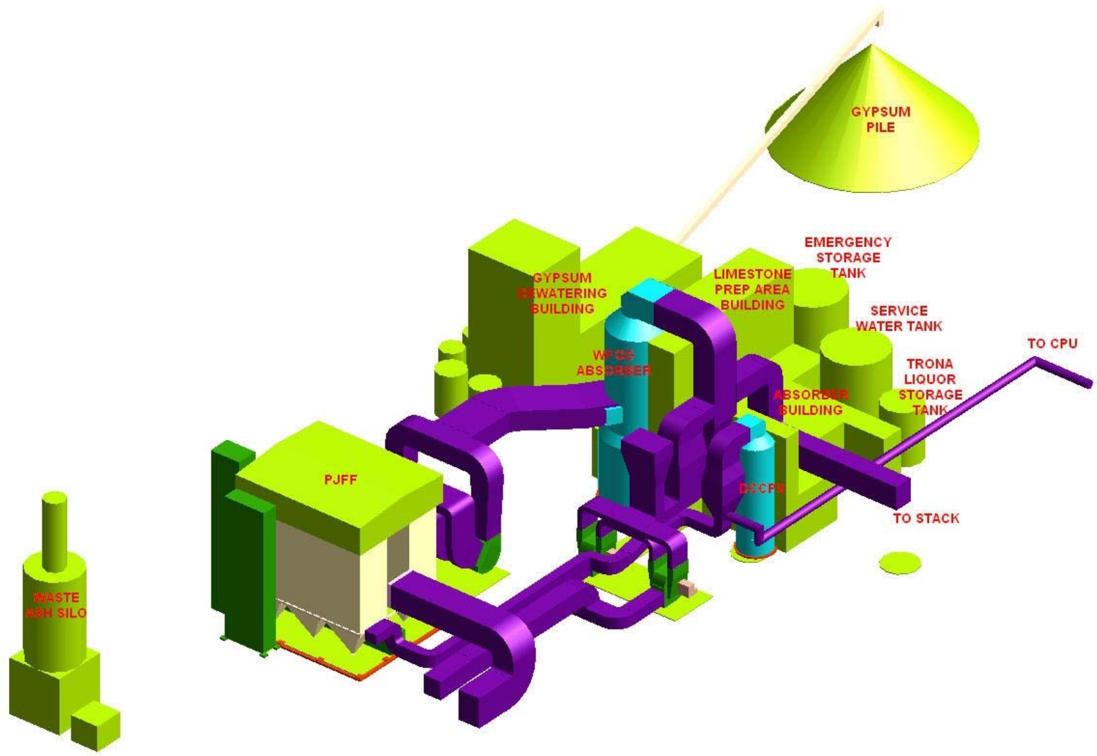


Figure 3-5
GQCS Equipment Arrangement

Pulse Jet Fabric Filter (PJFF) System and Auxiliaries

The single, 100% capacity six (6) compartment PJFF is designed to remove the particulate matter and SO_3/H_2SO_4 reaction products entrained in the flue gas discharged from the recycle heater. Since it is critical to prevent air infiltration into the oxy-firing process, the pulse gas system will use dry CO_2 from the CPU for filter bag cleaning when in the oxy-fired mode. A pulse air compressor and dryers will be used to generate clean, dry compressed air to clean the filter bags when the unit is in the air-fired mode. The fly ash removed by the PJFF will be sent to the waste ash storage silo by the waste ash system.

Pulse Jet Fabric Filter

The PJFF is a self-cleaning dust collector designed to remove particulate matter from the flue gas stream. The PJFF is designed to capture the majority of the fly ash/trona reaction products from the gas prior to it entering the WFGD absorber. The PJFF is an integral component of the system, assisting the trona in the removal of SO_3/H_2SO_4 contained in the flue gas. Figure 3-6 shows a typical hatch-style PJFF, similar to what is proposed for this project.

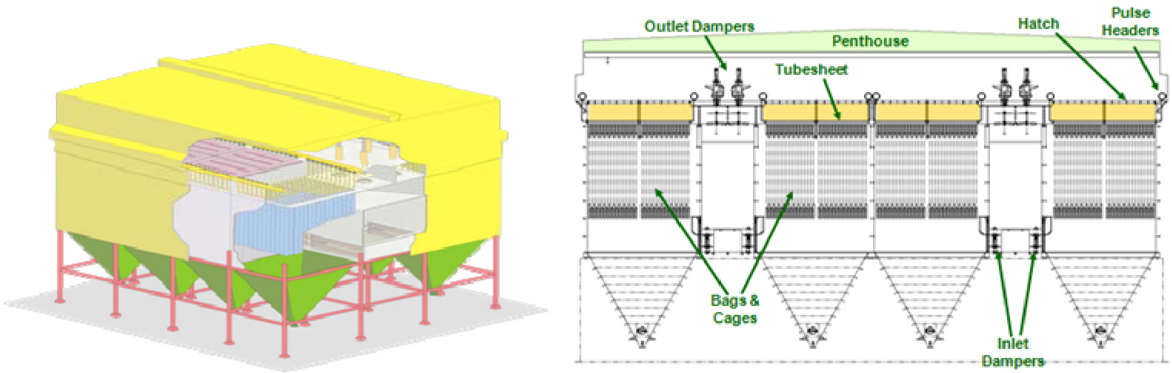


Figure 3-6
Typical Hatch-Style PJFF

The PJFF is located in the flue gas train downstream of the recycle heater and the trona injection point. Flue gas is directed into the individual compartments of the PJFF via the PJFF's inlet manifold. The particulate matter entrained in the flue gas is treated in the PJFF compartments, exits through the common outlet manifold, and then is directed to two (2) 50% capacity Induced Draft (ID) Fans which discharge to the WFGD absorber.

The PJFF consists of six (6) gas-tight filter bag compartments. Each filter bag compartment contains 720 filter bags. Each filter bag is 15.2 cm (6 inch) nominal diameter by 10 meters (32.8 ft) long. The air to cloth ratio with one (1) compartment out of service for maintenance is approximately 75.53 to 1 meters/hr (4.13 to 1 ft/min). The air to cloth ratio with all compartments in service is approximately 62.91 to 1 meters/hr (3.44 to 1 ft/min).

Flue gas laden with particulate matter enters each PJFF compartment below the filter bags, slowing down and changing directions prior to passing through the filter bags from the exterior to the interior of the filter bags. The mechanics of turning and slowing the gas results in some of the particulate matter falling directly into the hopper; the remainder is deposited on the outside surfaces of the filter bags.

Pulse Gas System

To keep pressure losses at an acceptable level, the filter bags are periodically cleaned. During oxy-fired operation, the PJFF filter bags are cleaned using a short pulse of dry compressed gas; air during air firing and CO_2 when oxy firing. The dry CO_2 comes from the CPU and is stored locally in the pulse gas receiver. During air-fired operation, dry compressed air is used to clean the filter bags. In both cases, the compressed gas enters the bag from the top via the blow pipe injection. The air and/or gas pulse expands the filter bag and releases collected dust cake on the outside surface of the filter bag.

The six (6) pulse gas header assemblies, including pulse valves and blow pipes, are designed to accept pulse gas from either the pulse gas system or the pulse air system. Air from the pulse air receiver or CO_2 from the pulse gas receiver is directed to the pulse air headers which are sized to supply a sufficient quantity of gas to each pulse valve with each cleaning pulse. The pulse gas header includes connections for each pulse valve, a drain valve, and a pressure gauge with isolation valve.

Start-up Pulse Air System

For operation in the air-firing mode during startup, clean, dry compressed air is used for filter bag cleaning until the boiler is in the oxy-firing mode and dry CO_2 is available from the CPU. Pulse cleaning air during startup is provided by one (1) pulse air compressor. The compressor has a reduced capacity compared to the amount of compressed CO_2 needed for the oxy-fired mode since only half of the compartments will be in operation.

The pulse air system consists of one (1) 100% capacity air compressor complete with inlet filter and after cooler, one (1) air receiver, two (2) 100% capacity air dryer trains complete with inlet and outlet filters. The compressed air produced by the compressor is discharged to either air dryer train which supplies dried compressed air to the common pulse air receiver.

Waste Ash System

The ash handling system transfers the fly ash collected by the PJFF to the waste ash storage silo for disposal. The free flowing ash from the PJFF is discharged from each of the collection hoppers into the waste ash transport system piping. The ash is conveyed by two (2) 100% capacity PJFF ash transport vacuum blowers. A vacuum-based system is preferred over a pressure-based one primarily due to the decrease in potential for air infiltration into the PJFF hoppers.

The waste ash system consists of a waste ash storage silo complete with bin vent and filter collector, a silo discharge fluidizing air system including two (2) 100% waste ash storage silo fluidizing air blowers (one(1) operating and one (1) spare), one (1) 100% capacity waste ash storage silo fluidizing air heater and one (1) 100% capacity pug mill.

The ash is conveyed pneumatically from the PJFF to the waste ash storage silo via the PJFF ash transport vacuum blowers which pull their vacuum through the silo filter collector. A bin vent is located on the roof of the silo for venting the fluidizing air introduced into the cone of the silo. The silo is sized to hold enough ash to maintain approximately seventy-two (72) hours of system operation when in the oxy-firing mode and burning the coal that produces the maximum ash quantity.

The stored ash in the presence of moisture, if settled, has a tendency to harden. To maintain a fluid state, the silo incorporates a heated fluidizing air system. The air discharged from either fluidizing air blower passes through a common fluidizing air heater before it is distributed to the silo cone by way of flexible hose assemblies. Each hose assembly is equipped with a manual valve and check valve for isolation.

The ash contained in the silo is mixed with either the chloride blowdown stream from the WFGD system or service water in the pug mill to achieve approximately a 20% by weight moisture content in the ash. This eliminates the possibility of dusting when the ash is loaded into trucks or railcars for disposal.

SO_3 Mitigation System and Auxiliaries

The flue gas exiting the recycle heater is at a temperature of approximately 171°C (340°F) at full load when in the oxy-combustion mode. The injection of the dry trona reagent occurs directly downstream of the recycle heater to ensure ample residence time inside the flue work prior to entering the PJFF. It is important to maintain a flue gas temperature below approximately 177°C (350°F) in order to minimize the potential for the formation of sodium bisulfate byproduct which tends to be a sticky salt that can plug injection lances and blind the PJFF bags. Furthermore, the flue gas temperature exiting the recycle heater will be close to the sulfuric acid dew point. When in the oxy-firing mode, the relatively high SO_3 concentration and high humidity results in a relatively high sulfuric acid dew point temperature when compared to a conventional air-fired boiler. To address this concern, a grid of thermocouples for flue gas temperature monitoring is located downstream of the recycle heater. To address the acid condensation potential at the low end of the temperature range, the flue from the recycle heater to the PJFF will be coated with an epoxy-type protective coating. The capture of SO_3 by trona injection will lower the SO_3 concentration in the flue as it makes its way to the PJFF.

Dry Sorbent Injection (DSI) System

The DSI system is installed for the removal of SO_3 and H_2SO_4. The injection lances are located at a suitable distance downstream of the flue gas temperature control water injection grid. This system is designed to use trona as the reagent, at injection rates up to 2 tonnes/hr (2.2 ton/hr). Trona reacts in the flue gas to form a solid compound that is removed in the PJFF. The injection location in the flue work was selected to allow the proper temperature distribution across flues, maximization of residence time and optimal flow distribution.

At optimal temperatures, trona will calcine in the flue to form sodium carbonate. During this calcination process, the trona experiences a “popcorn” effect in which the sorbent particle expands rapidly to form many small pores. The presence of these small pores will increase reactivity of the sorbent with the acid gases. At higher temperatures, sodium bisulfate can form as a secondary reaction product and can rapidly form sticky deposits in the flue and on the PJFF bags which can impede flue gas flow and greatly hinder PJFF performance.

Truck Offload / Silo Filling

The DSI system will be capable of receiving sorbent from self-discharging positive displacement trucks fitted with nominal 100mm (4 inch)diameter discharge connections. A single “truck fill” control panel is included and can be utilized as an information device allowing simple light-based indication of the silo fill status and permissives.

Trona is delivered with a particle size (D50) of 35 microns (1.4 mils). Trona is hydroscopic and tends to form agglomerations when exposed to free moisture. Material properties of trona can be altered above a free moisture content of 0.04%. For this reason, equipment is in place to allow a single PD truck to draw its conveying air from a dehumidification skid. This skid is designed to condition 17 m^3/minute (600 CFM) of ambient air to a dryness level of 1.4 g/kg (10 grains/lb). This is done by first sending the ambient air through a refrigeration unit for cooling and bulk water condensing. The air is then sent through a desiccant wheel dryer where the final dryness levels are achieved. Heated ambient air is used in the dryer to regenerate the desiccant. The dry outlet conveying air is maintained at a temperature below 49°C (120°F) due to the fact that if trona is exposed to temperatures greater than this, pre-calcination may occur which will reduce the reactivity of the product.

Trona Storage Silo

The trona storage silo is of a shop-fabricated, skirted design which reduces on-site construction. The silo is 4.3 m (14 ft) nominal diameter by 23.5 m (77 ft) overall height. This size allows for the storage of 143 tonnes (158 tons) of Trona, or roughly six (6) truckloads, which will allow for three (3) days of Trona storage at the maximum expected injection rate. The area directly beneath the silo will accommodate a single stack-up configuration.

The roof of the storage silo contains a filling target box, vacuum/pressure relief valve, bin vent filter, clean-air vent fan with automatic damper, and continuous handrail around the roof deck. The silo will have three (3) levels (low, high and high-high) of level switches for operational use as well as a continuous level monitor.

The storage silo skirt contains an exhaust fan and a heater for temperature control. During normal oxy-fired operations, dry CO_2 from the pulse gas receiver will be used as the conveying gas. Due to the possibility for conveying gas leakage inside the skirt area, a CO_2 monitor with alarm will also be installed inside the skirt for personnel protection.

Material Feed Stack-Up

Material stored in the silo is maintained in a free-flowing form by the bin activator located at the bottom section of the silo cone. The bin activator need only be activated during the initial start of the injection sequence. The bin activator discharges to a fixed speed rotary valve which discharges sorbent to the downstream material feed equipment.

The stack-up consists of a feeder hopper on load cells and variable speed screw feeder. The weigh bin operates on a loss-in-weight basis, whereby it is filled in a batch operation. The sorbent is delivered at a controlled rate by the screw feeder to a vent hopper and then on to a rotary airlock. Both the feeder hopper and vent hopper include a vent line which discharges back into the silo to capture any vent dust. The fixed speed rotary airlock discharges material into the convey pipe through a pick-up tee.

Conveying Gas and Trona Injection System

During oxy-fired operations, compressed CO_2 from the pulse gas receiver, which is fed from the CPU, will be used for trona conveying. This is necessary to minimize air infiltration into the system. During startup, compressed CO_2 will not be available for sorbent conveying. One (1) 100% trona injection blower will be used for this purpose and any other time that the unit is in the air-fired mode. The blower will come as a separate pre-piped and pre-wired skid including all accessories and instrumentation. The skid will be located outdoors next to the storage silo skirt.

The trona injection blower draws in ambient air through a filter and inlet silencer. A silencer and a relief valve are located on the outlet side of the blower. Upon leaving the blower, the convey air passes through an air-to-air cooler where it is cooled before coming in contact with the trona. This cooling prevents the sorbent from calcining in the convey line before entering the flue. The trona fed into the pneumatic pick-up tee is conveyed through a single pipeline until it reaches the vicinity of the flue. A splitter will be located close to the injection point. As sorbent passes through the splitter, it is divided equally into multiple branch connections, each of which leads to a dedicated injection lance. These injection lances ultimately deliver the sorbent into the flue gas stream to begin the acid gas mitigation reactions. Dispersion nozzles located at the tips of the lances provide necessary distribution of sorbent across the flue.

Flue Gas Desulfurization System and Auxiliaries

The WFGD system has been designed primarily to reduce the emissions of hydrochloric acid (HCl), hydrofluoric acid (HF), and sulfur dioxide (SO_2). The WFGD system is comprised of flue work from PJFF outlet to two (2) 50% capacity induced draft (ID) fans, flue work from the ID fans to the WFGD absorber, flue work from the WFGD absorber to the DCCPS or the stack. See the figure below for a typical WFGD absorber tower with dual trays. Auxiliary systems include a limestone unloading and storage system, limestone slurry preparation, storage and feed system, and a gypsum dewatering system.

Wet Flue Gas Desulfurization (WFGD) Absorber System

The 9.8 m (32 ft) diameter WFGD absorber tower with 11.6 m (38 ft) flared reaction tank is designed for 98% SO_2 removal. The tower is made of alloy A-255 (UNS S32550) above the inlet and has an alloy AL-6XN (UNS N08367) reaction tank. Limestone slurry feed to the absorber is controlled by the inlet and outlet SO_2 loading and the absorber slurry pH. Absorber slurry level, monitored by three (3) hydrostatic level transmitters, is controlled by adding reclaim and makeup water to the absorber. Absorber slurry density, measured in the absorber bleed pump discharge piping by a density meter, is controlled by bleeding absorber slurry to the dewatering system using a batching operation. The reaction tank provides a minimum of 15 hours of solids residence time and is equipped with a drain line and valve for emptying during maintenance periods.

As flue gas passes up through the absorber, it is quenched by the absorber slurry falling from the spray levels and then passes through two stages of perforated absorber trays. The alloy A-255

(UNS S32550) trays are sectioned into compartments by baffles which help to evenly distribute the slurry on top of the trays. Above the trays, the flue gas encounters the absorber spray zone. The absorber spray headers are constructed of abrasion resistant FRP. The absorber slurry is sprayed from silicon carbide spray nozzles.

The absorber module is equipped with two stages of mist eliminators which remove carryover mist by inertial contact. The primary stage captures large particles and the secondary stage captures wash water droplets and finer particles. The two-stage mist eliminator is kept free of slurry deposits by using a water wash system. Two (2) 100% mist eliminator wash water pumps (sized to wash both the WFGD absorber and the DCCPS simultaneously) direct wash water to both the upstream and downstream faces of the first stage and the upstream face of the second stage mist eliminator by an array of spray headers and spray nozzles. The mist eliminators shall be washed sequentially by section to optimize the wash flow rate. The mist eliminator blades, spray nozzles and spray headers shall be constructed of FRP.

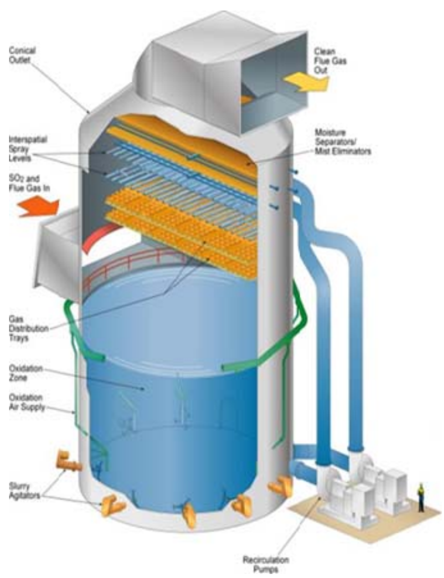


Figure 3-7
Typical B&W WFGD Absorber Tower with Dual-Trays

During oxy-combustion, treated flue gas exiting the WFGD absorber is split, with a portion being directed through the secondary fans. This stream exits the WFGD and is sent to the secondary gas reheater. The reheater raises the gas temperature sufficiently to ensure that the water is in the vapor phase before entering the secondary recycle fans. Following the secondary recycle fans, oxidant is added and the oxygenated secondary recycle then passes through the recycle heater where it is heated and sent to the boiler windbox to participate in combustion in the furnace.

The remainder of the flue gas is sent to the DCCPS for dehumidification and some SO_2 polishing. When in the air-firing mode, the CPU is also not in operation and the primary and secondary fans send ambient air back to the recycle heater instead of recycled flue gas. Because of this, the DCCPS is not in operation and all of the WFGD exit flue gas is sent directly to the stack. During and immediately after transition from air to oxy firing mode the flue gas continues to flow to the stack until it is transitioned to the CPU.

The integral WFGD reaction tank is equipped with four (4) side-entry oxidation air lance type agitators to provide the required mixing and suspension of solids in the tank. The agitator design is such that operation of the absorber system will not be adversely effected if one of the agitators is out of service. All wetted components of the agitators shall be constructed of a corrosion / abrasion resistant alloy suitable for the design level chlorides concentration. The side-entry agitators employ the use of a flush-less mechanical seal which can be replaced while the absorber is on-line.

An in-situ oxidation system forces calcium sulfite ($CaSO_3 \cdot ½H_2O$), formed by the SO_2 removal process, to be oxidized to calcium sulfate ($CaSO_4 \cdot 2H_2O$). The air required to carry out the oxidation reaction is supplied by two (2) 100% capacity oxidation air blowers (one (1) operating and one (1) spare). The air is introduced into the reaction tank via the oxidation air lance agitators. The lance agitators provide dispersion of the oxidation air, as well as agitation of the absorber slurry. Provision is made to keep the oxidation air from infiltrating the flue gas outlet stream. There are seven (7) oxidation air vents equally spaced around the absorber to allow the spent oxidation air to be discharged to the stack. These vents are piped together and routed to the stack flue (start-up flue) at a point downstream of the isolation dampers.

Three (3) 50% capacity Absorber Recirculation (AR) pumps (two (2) operating and one (1) spare) are used to supply the absorber spray headers with slurry from the reaction tank. The AR suction and discharge piping is 1066 mm (42 inch) diameter abrasion resistant FRP and contains a pneumatically actuated butterfly valve both upstream and downstream of the pump for isolation.

Two (2) 100% capacity absorber bleed pumps (one (1) operating and one (1) spare) transfer gypsum slurry from the reaction tank to the primary hydroclone for purposes of absorber slurry density control. The absorber bleed pumps are also capable of transferring slurry from the absorber reaction tank to the emergency storage tank.

One (1) 10.7 m (35 ft) diameter emergency storage tank is sized to hold the contents of the WFGD absorber. During periods of absorber maintenance, the absorber bleed pumps will send the majority of the absorber contents to the emergency storage tank. The final amount will be drained to the absorber area sump and pumped from there to the emergency storage tank. One (1) 100% capacity emergency storage tank transfer pump returns the absorber contents to the WFGD once maintenance is complete. The emergency storage tank can also be drained to the absorber area sump and returned to the WFGD by the absorber area sump pumps.

Limestone Unloading and Storage System

Powdered limestone (PL) is delivered to the plant site via trucks, equipped with onboard positive displacement (PD) blowers, to either of two (2) PL storage silos. Each silo is equipped with a dedicated 100% capacity PL storage silo rotary airlock feeder. Fluidizing air is used to ensure the continuous flow of limestone from the bottom of the silo through the rotary airlock feeder.

Each rotary airlock feeder delivers powdered limestone to a dedicated limestone slurry preparation and storage system.

Two (2) 6.9 m (22.5 ft) diameter PL storage silos provide a total of four (4) days of onsite storage when firing the design coal at the maximum continuous boiler rating. A dust filter is supplied on the roof of the silo for filtering and venting the transport air and displaced silo air during filling.

To maintain a fluid state, the PL storage silo incorporates a fluidizing air system. Three (3) 50% capacity PL storage silo fluidizing air blowers (two (2) operating and one (1) spare) provide fluidizing air to the fluidizing air system supply header and distributed to the silo cone by way of flexible hose assemblies. Each hose assembly is equipped with a manual isolation valve and check valve. Each hopper discharge is equipped with a dedicated 100% capacity rotary airlock feeder.

Limestone Slurry Preparation, Storage and Feed System

The limestone slurry preparation, storage and feed system consists of two (2) 100% capacity limestone slurry preparation and storage trains. Each train consists of a PL sluice bowl and a limestone slurry storage tank with agitator. The limestone slurry feed system consists of two (2) 100% capacity limestone slurry feed pumps (one (1) operating and one (1) spare) and a 100% capacity limestone slurry feed loop.

The powdered limestone that is discharged from each PL storage silo is combined with service water or WFGD reclaim water in a dedicated sluice bowl to a suspended solids concentration of approximately 28% by weight. The limestone slurry discharged from each sluice bowl flows by gravity into its dedicated limestone slurry storage tank. Additional water can be added through the non-operating sluice bowl if needed to correct the slurry density.

Two (2) 6.9 m (22.5 ft) diameter limestone slurry storage tanks provide a total of 16 hours of slurry storage at the maximum usage rate. The liquid slurry level in these tanks varies from the low level setpoint to the high level setpoint. The management of limestone slurry reserves within the system will enable the process to buffer temporary swings in boiler load and fuel sulfur content.

Two (2) 100% capacity limestone slurry feed pumps (one (1) operating and one (1) spare) draw suction from a crosstie that is common to both the limestone slurry storage tanks. Each of the limestone slurry feed pumps maintains a continuous flow of limestone slurry through the common limestone slurry feed loop. Only a fraction of the slurry entering the feed loop is delivered to the WFGD absorber which is necessary to maintain limestone pipe velocities within the proper range. The remaining slurry entering the feed loop is returned to either of the limestone slurry storage tanks. The actual flow of limestone slurry to the WFGD absorber is dependent upon the SO_2 concentration at the absorber outlet and absorber recirculation slurry pH.

Gypsum Dewatering System

Gypsum slurry from the absorber is fed to the primary hydroclones by two (2) 100% capacity absorber bleed pumps (one (1) operating and one (1) spare). The purpose of the primary hydroclones is to concentrate the solids of the gypsum slurry stream for secondary dewatering. The secondary hydroclones further decrease the solids content in the final chloride blowdown stream. Each hydroclone battery consists of multiple cyclones (with 20% minimum spare units) which operate at a constant flow rate. Flow is added involutedly to produce a swirling motion inside the hydroclone. This swirling motion produces a centrifugal force and affects solids separation.

Primary hydroclone overflow is sent to a standpipe which provides positive suction pressure for the two (2) 100% capacity secondary hydroclone feed pumps (one (1) operating and one (1) spare). These pumps draw off a portion of the slurry and deliver it to the secondary hydroclone. The remainder of the slurry that continuously overflows from this standpipe is sent by gravity to either of the reclaim water tanks and eventually is returned to the absorber reaction tank. The underflow from the primary hydroclone is gravity fed to either of the filter feed tanks for further dewatering.

Secondary hydroclone underflow is gravity fed to either of the reclaim water tanks while the overflow flows to the chloride blowdown tank. Two (2) 100% capacity chloride blowdown pumps (one (1) operating and one (1) spare) send blowdown to the waste ash pug mill for waste ash conditioning. This blowdown stream is necessary to limit build-up of chlorides and fine particulate matter in the absorber system.

Two (2) 4.9 m (16 ft) diameter filter feed tanks provide a total of 16 hours of storage capacity based on the primary hydroclone underflow production at the maximum rate. Two (2) 100% capacity filter feed pumps (one (1) operating and one (1) spare) are used to transfer the slurry via the filter feed loop to the vacuum drum filters. Two (2) 100% capacity rotary drum vacuum filters (one (1) operating and one (1) spare) are used to dewater the gypsum to approximately 80% by weight suspended solids. The gypsum cake is then transported from the drum filters by the gypsum conveyor to the gypsum storage pile for disposal.

The drum filter filtrate pumps (one per filter) direct the filtrate from the drum filters to either of the reclaim water tanks. Two (2) 4 m (13 ft) diameter reclaim water tanks provide a total of 16 hours of storage capacity based on the filtrate production at the maximum rate. Two (2) 100% capacity reclaim water pumps (one (1) operating and one (1) spare) recycle the filtrate back to the WFGD absorber for level control. Make-up water to the reclaim water tanks consists of either fresh service water or the DCCPS wet cooling tower blow down.

Flue Gas Dehumidification System

The dehumidification system is comprised of a DCCPS and a dedicated wet cooling tower (by URS). Two (2) 100% capacity DCCPS blowdown pumps (one (1) operating and one (1) spare) send reaction tank liquor to the cooling tower. Two (2) 100% capacity cooling tower recirculation pumps (one (1) operating and one (1) spare) (by URS) return cooled water from the cooling tower back to the DCCPS spray headers. Trona liquor reagent is added to the cooling water supply stream by the trona liquor feed pumps.

Direct Contact Cooler Polishing Scrubber (DCCPS)

After removal of most of the SO_2 in the WFGD absorber, the saturated flue gas is sent to the DCCPS. It is in this vessel that the flue gas is cooled below the adiabatic saturation temperature (to about 24 °C [75 °F] during normal conditions) to condense water, and the flue gas SO_2 concentration is further reduced to about 1 ppm (dry). The 6.3 m (20.75 ft) diameter DCCPS vessel is constructed of 316L stainless steel. The bottom of the conical reaction tank is equipped with a drain line and valve to aid in the complete emptying of the vessel during maintenance periods. The primary means of reaction tank draining is by the DCCPS blowdown pumps.

The gas entering the DCCPS passes through two (2) standard spray levels which are supplied with cool liquor from the cooling tower recirculation pumps. The spray headers are constructed of FRP and the supports are constructed of stainless steel. The absorber liquor is sprayed from silicon carbide spray nozzles.

Above the spray headers, the scrubber is equipped with two (2) stages of FRP mist eliminators which remove carryover mist by inertial contact. The primary stage is for bulk entrainment (large particle capture) while the secondary stage acts as a polishing stage (wash water droplet and finer particle capture). This two-stage mist eliminator is kept free of deposits by using an integral wash water system. Service water is directed to both the upstream and downstream faces of the first stage and the upstream face of the second stage mist eliminator by an array of spray headers and spray nozzles. The mist eliminators shall be washed sequentially by section to optimize the wash flow rate. The mist eliminator blades, spray nozzles and spray headers shall be constructed of FRP. By having the DCCPS in series with the WFGD, the gypsum carryover is greatly reduced due to effectively four stages of mist eliminators (two stages per vessel).

The dehumidified and polished flue gas exits the DCCPS and is sent to the primary gas reheater. The reheater raises the gas temperature sufficiently to ensure that the water is in the vapor phase before entering the CPU and primary fans, which are located downstream. Downstream of the reheater, a portion of the flue gas is sent through the primary fans back to the recycle heater, while the remaining flue gas is sent to the CPU for CO_2 purification and compression.

Trona Unloading and Solution Preparation, Storage and Feed System

Sodium sesquicarbonate (trona) is used in the DCCPS to reduce remaining pollutants such as SO_2 and other acid gases (HCl, HF, H_2SO_4) in the flue gas to desired levels at the CPU inlet. The trona reacts primarily with the SO_2, producing sodium sulfate and sodium bisulfate as reaction products. Those reaction products will steadily increase in concentration over time and therefore a blow down stream is required to maintain an allowable steady state concentration of the dissolved solids in the DCCPS circulating liquor. Eventually, the dissolved solids captured in the DCCPS leave the process via the liquid phase of the gypsum cake and via the chloride blow down stream that is used for flyash wetting.

Dry trona is delivered to the site via self-discharging positive displacement trucks to either of two (2) 100% capacity trona filter receivers. Each filter receiver is equipped with a collection hopper, a 100% capacity rotary feeder and a wetting box. Clean dry air is piped to the hopper to ensure the free flow of reagent into the downstream equipment.

Both 100% capacity filter receiver/rotary feeder/wetting box assemblies are mounted on top of a common 6.9 m (22.5 ft) diameter trona liquor storage tank. The water added in the wetting box is adequate to make a 12.5% by weight solution of trona liquor in the storage tank. The storage tank provides sufficient storage capacity for 1.5 truckloads, and is constructed of lined carbon steel. The tank is equipped with a dual impellor agitator to ensure the trona completely dissolves and two (2) immersion heaters to maintain a liquor temperature of 15.6 °C (60°F) or higher (which prevents liquor crystallization).

The trona liquor is added to the system by two (2) 100% capacity trona liquor feed pumps (one (1) operating and one (1) spare). The pumps tie into a common discharge loop which supplies reagent to the main cooling tower recirculation line. Since the reagent required during normal oxy-fired operation is minimal, the remainder of the feed liquor is recycled back to the storage tank.

3.5 *Air Separation Unit (ASU)*

3.5.1 Overview

The ALPC ASU will be an integrated component of the Oxy-Combustion Power Plant Facility. This ASU will supply oxygen for the Boiler Island, and the process is simply illustrated in Figure 3-8. A preliminary block flow diagram of the ASU process is provided in Appendix C.

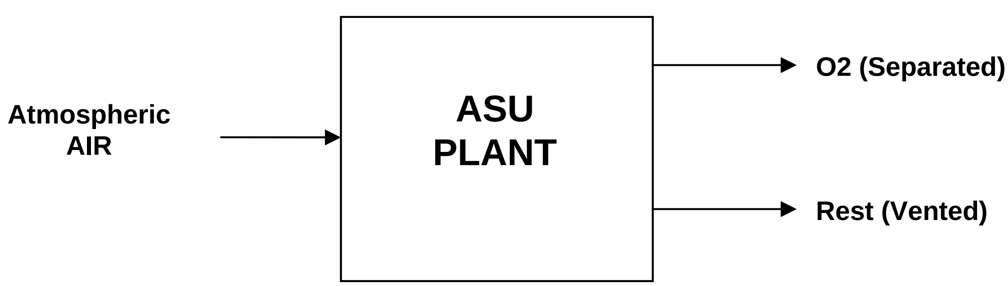


Figure 3-8
Basic Air Separation Process

ALPC has extensive experience with the air separation process, with over 3,500 plants built not only for 3rd party clients but also for our own operating facilities at over 550 locations around the world. Consequently ALPC can reference, and thus benefit from, a large amount of industrial operations data for the engineering and construction activities.

ALPC incorporates feedback from its operating facilities into new designs to continually improve and maintain its position as the world leader in gases for industry, health and the environment.

Being both a supplier and an operator of plants, ALPC selects the most suitable design for each project taking into account:

- Type and characteristics of product utilization
- Compression system
- Automation needs
- Availability of utilities
- Plant layout
- Overall power efficiency
- Safety
- Operability

3.5.2 Air Compression

Atmospheric air is the source or raw material for the ASU, the main components being oxygen and nitrogen.

Atmospheric air is drawn through inlet air filter (F01) to remove particulate matter before entering the suction of the Main Air Compressor (C01). The essentially particle-free filtered air is then compressed in the electrically driven Main Air Compressor thus beginning the air separation process.

3.5.3 Air Pre-Cooling

The heat of compression from this compressor is transferred to boiler feed water in the air/BFW heater (C01E). The air is further cooled in a 2-stage direct contact cooler (E07). The top stage uses chilled water from the nitrogen/water tower (E60) and the bottom stage uses cooling water.

3.5.4 Air Purification

The cold air enters a front-end temperature swing adsorption (TSA) purification system to remove moisture, carbon dioxide, and other impurities. The system is composed of two radial flow bed vessels (R01/R02) containing activated alumina and molecular sieve adsorbents. Waste nitrogen, heated by a low-pressure steam in a reactivation heater (E08), is used to regenerate the adsorbents.

3.5.5 Air Booster

Dry compressed air is pressurized prior to entering the main heat exchangers.

3.5.6 Cold Production

The refrigeration of the cold box is accomplished by expansion in a cryogenic turbine.

3.5.7 Distillation

The air streams then enter the distillation sections where air is separated into liquid oxygen (LOX) and gaseous waste nitrogen. LOX is pumped, vaporized, warmed and sent to the boiler.

3.5.8 Backup System

Two (2) liquid oxygen (LOX) storage tanks are included in the design for back-up. Liquid oxygen is pumped from the LOX storage tanks and is then vaporized and warmed in the LOX Vaporizer.

3.6 *Compression and Purification Unit (CPU)*

3.6.1 Overview

The ALPC CPU will be an integrated component of the Oxy-Combustion Power Plant Facility. Its function is to take low pressure (~1atm) Flue Gas from the GQCS and to compress (to ~145 barg [2,100 psig]) and purify (expected purity is 99.7% mass) it for subsequent transport and storage.

The CPU process is simply illustrated in Figure 3-9. A preliminary block flow diagram of the CPU process is provided in Appendix C.

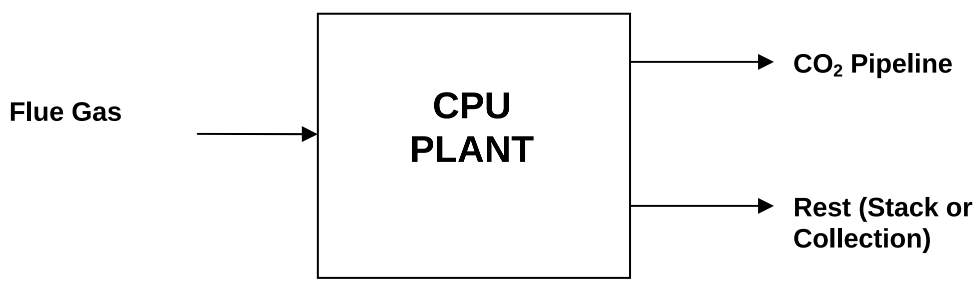


Figure 3-9
Basic Compression Purification Process

3.6.2 Air Liquide's CPU Development Roadmap

Air Liquide has been actively involved in the development of oxycombustion technologies for power generation with carbon capture for the past 10 years. Air Liquide has become a major player and is involved in several key projects in the field including FutureGen 2.0. An ambitious roadmap for bringing Oxycombustion technology for carbon capture to commercialization is being executed. The roadmap (Figure 3-10) aims to improve CPU design with respect to three key criteria:

- Risk mitigation for first industrial demonstrations
- OPEX reduction (particularly via specific energy reduction)
- CAPEX reduction

After an initial phase of lab-scale tests and process scheme development, Air Liquide is now focusing on integrating results from pilot plants into the CPU design in addition to performing preliminary studies for the FutureGen 2.0 plant.

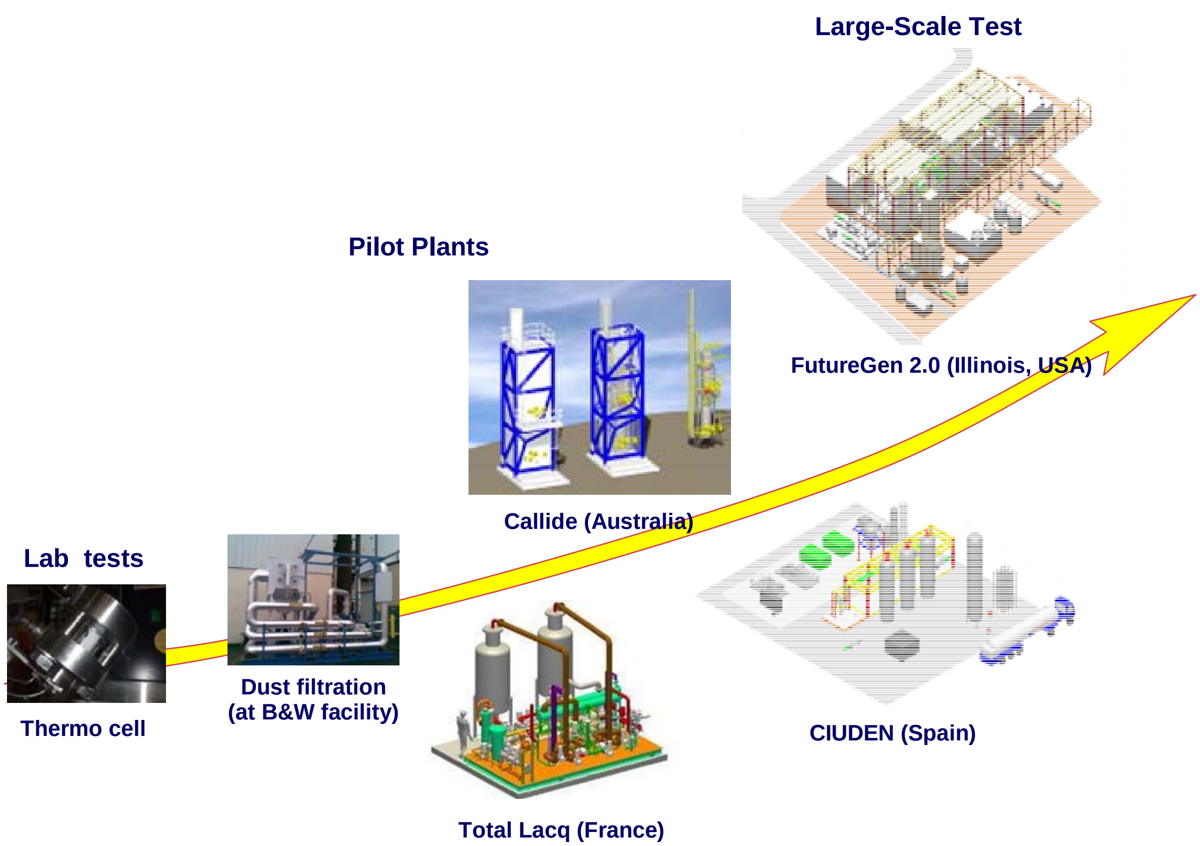


Figure 3-10
Overview of Air Liquide CPU Development Roadmap

High Performance Dust Filtration Pilot

Air Liquid has installed a pilot for testing high performance dust filtration technology at a Babcock & Wilcox test centre in the United States (Figure 3-11). Advanced dust filtration technology is tested on real flue gases from different boiler types. This system ran in 2009 and has given promising results. The Callide and CIUDEN pilots will also test high performance dust removal, building on the tests already completed.

Figure 3-11
Air Liquide's High Performance Dust Filtration Test Skid

Lacq Pilot Plant

The Lacq project is the first complete pilot of oxycombustion with carbon capture, transport and storage. CO_2 is captured from a 30 MWth natural gas oxycombustion boiler at TOTAL's Lacq site. Air Liquide provides the ASU, proprietary oxy burner technology and a flue gas drying unit. Once the CO_2 has been dried and compressed it is transported by pipe to injection in a depleted gas field.

The dryers (Figure 3-12) are specifically designed for the oxycombustion application. Therefore the tests being carried out on the dryers unit are of particular importance for the development of Air Liquide's CPU design. Furthermore, the FutureGen 2.0 CPU uses the same design for the dryers, upscaled accordingly.

The objectives of the tests are:

- Adsorbent qualification (ageing, performance)
- Study of emissions throughout cycle
- Vessel materials qualification

Tests are currently underway and and are giving promising results.

Figure 3-12
Lacq Dryers

Callide Pilot

The Callide pilot plant will treat 75 tpd of CO_2 from the 30 MWe Callide Oxyfuel plant and has been specially designed to test upscalable systems. Key design features include:

- Centrifugal compressors for the flue gas compression
- Brazed aluminum heat exchanger in the Cold Box
- High Performance dust filtration cartridges

The plant is currently under construction (Figure 3-13) with start-up planned for Q1 2012.

Figure 3-13
Callide Pilot – Site View September 2011

The CPU design for the FutureGen 2.0 project is strongly based on technologies that will be tested at Callide. In addition to using similar technologies (such as centrifugal compressors and brazed aluminum heat exchangers) to as great an extent as possible, the same process has been implemented. For example, an auto-refrigerated cycle is used for cooling the Cold Box in both projects. Differences between the FutureGen 2.0 project and Callide mainly stem from project specific constraints. For example, the Callide CPU does not include compression of the CO_2 product to supercritical pressure, because the final product that is required is liquid CO_2 for transport by truck. However, compression of pure CO_2 by centrifugal technology is already referenced in industry.

CIUDEN Pilot

In 2011, Air Liquide signed a contract to provide the CO_2 CPU for CIUDEN's Integrated CCS Technology Development Plant (TDP) located near Endesa's Compostilla power plant (Spain). The CIUDEN platform will be equipped with both a Pulverized coal (PC) and Circulating Fluidized Bed (CFB) boiler, both capable of burning a range of coals. Different flue gas purification options will also be available. Thanks to this flexibility, the CIUDEN CPU will be able to test key equipment on a wide range of different flue gases. In particular, similar dust filtration and brazed aluminium heat exchanger technology to that currently planned for the FutureGen 2.0 CPU design will be tested.

3.6.3 Process Description

Low Pressure Pre-Treatment

The flue gas is filtered down to a very low level of particulate matter. This very low dust load is required for reliable and efficient operation of the downstream process equipment of the CO_2 CPU (centrifugal machines in particular).

Flue Gas Compression

The flue gas is then compressed to the pressure of the cryogenic process in a multistage integrally geared centrifugal compressor. In terms of cost and energy efficiency, centrifugal integrally geared machines are the most suitable technology to compress very large flow rates of flue gas as required in the application of oxy-combustion.

Medium Pressure Pre-Treatment

Dryers

The chosen adsorption drying system is based on the design that is currently tested at Air Liquide’s Lacq pilot plant and will be further tested on the Callide pilot plant.

It consists of a Temperature Swing Adsorption (TSA) unit with an appropriate adsorbent. The flue gas is dried alternatively in each bottle.

Mercury Removal

Mercury in the flue gas is removed to avoid very rapid and critical corrosion of brazed aluminum heat exchangers used in the cold box section.

Cryogenic Section

Dry flue gas enters the cryogenic part where it will be purified, separating non-condensable gases like N_2, Ar, O_2 from CO_2.

The process is based on partial condensation and distillation.

Main equipments for this cryogenic section which are all packaged into two cold boxes are:

- Separation pressure vessels
- Distillation columns and associated piping
- Compact type multi-fluid Aluminum Brazed Heat Exchangers

Aluminum Brazed Heat Exchangers (BAHX) have been developed specifically for the multi-fluid heat exchange needs in industrial gas applications, such as cryogenic air separation or CO purification in Synthetic Gas streams for the chemical industry. This compact technology is particularly well suited in terms of footprint, cost and heat exchange efficiency.

Non-Condensables Expansion

The non condensable gases are expanded with power recovery and vented to the atmosphere. One turbine train treating 100% of the non-condensable gases has been chosen. This is done in order to minimize cost and footprint.

CO_2 Compression to Pipeline Pressure

The cold box produces low pressure gaseous CO_2 which must be compressed to the final pressure required by the pipeline.

CO_2 Transfer to Alliance Pipeline

Liquid CO_2 at the conditions specified in Table 3-4 will be delivered to the Alliance at an underground pipeline interface point (300 mm [12”] nominal) located near the east boundary of the Meredosia Plant. An isolation valve will be installed near the CPU battery limit (downstream of the CPU discharge interface point) to initiate or shutoff flow to the pipeline as required. Control of the CO_2 isolation valve will be managed by the Meredosia Plant, but operation of the CPU and the isolation valve must be a coordinated effort with the Alliance.

CO_2 flow, pressure, temperature, and quality will be monitored at the CPU discharge upstream of the pipeline isolation valve. Additional monitoring closer to the Alliance pipeline interface point, along with potential automated control of the isolation valve, will be evaluated during Phase 2 as design details are developed. Remote monitoring capability may also be implemented to allow the Alliance to directly monitor CO_2 conditions at the CPU discharge.

During operation, if CO_2 conditions do not meet the required specifications per Table 3-4, Ameren will notify the Alliance and a decision made as to whether the process upset can be accommodated or whether flow to the pipeline should be stopped. No specific allowance for out-of-spec CO_2 is provided for in the CO_2 offtake agreement, but minor upsets will likely be able to be accommodated by the CO_2 storage facility, since they will be diluted by the CO_2 inventory already in storage.

During CPU startup, shutdown, or other operating condition when the pipeline isolation valve is shut and no CO_2 delivery to the pipeline is occurring, CO_2 must be discharged elsewhere until pipeline deliveries can resume. While the startup stack and normal CPU vent will accommodate many such conditions, additional backup discharge points may be required to facilitate practical CPU operation during upsets. Details regarding such backup discharge points will be finalized in Phase 2, but may include on-site CO_2 storage or additional CO_2 venting capability downstream of the CPU battery limit.

Additional monitoring and reporting requirements will be developed and finalized during Phase 2.

3.7 *Steam Cycle and Balance of Plant Systems*

In general, the design and configuration of the steam turbine power cycle is typical of any similar coal-fired Rankine cycle power plant designed in the late 1960s. As such, the following system descriptions provide only a general overview of each major system. Typical system design details are not discussed at length unless unique to the design of the plant. The overall integration between the BOP steam cycle and the other islands is generally depicted on the overall process flow diagram contained in Appendix C.

A detailed assessment of the existing plant equipment was completed by URS during Phase 1 to determine which existing components needed replacement or refurbishment to support the repowered oxy-combustion configuration of Unit 4. This section generally identifies existing plant components that will be reused vs. those components that will be replaced. Additional details regarding equipment reuse, refurbishment, or replacement are addressed in separate plant assessment reports developed by URS.

3.7.1 Steam Systems

Main and Reheat Steam

The main steam system transports high pressure and temperature steam from the steam generator secondary superheater outlet header to the inlet of the main stop valves of the HP turbine. The system also directs steam to the steam turbine seal system at low loads when there is insufficient steam supply from the normal extraction steam (IP-LP turbine crossover) supply.

The design pressure of the main steam system is equal to the lowest steam generator superheater safety valve set pressure. The maximum operating pressure is 175.9 barg (2,550 psig). The design temperature corresponds to the steam generator MCR superheater outlet temperature of 542.8ºC (1,009°F) plus a 5.6ºC (10°F) margin added to account for the accuracy of the temperature control. The piping system is designed in accordance with ASME B&PV Code Section I and ASME B31.1 rules for boiler external piping. The material for the main steam piping is a seamless ferritic alloy steel, SA 335 Grade P91, which provides superior stress and creep properties.

The cold reheat steam system transports steam from the outlets of the HP steam turbine to the steam generator reheater inlet headers. A portion of the cold reheat flow is also directed to the steam side of the No. 4-6 high pressure feedwater heater. The system is designed in accordance with the requirements of ASME/ANSI B31.1 rules for non-boiler external piping. Design pressure of the system is equal to the lowest set pressure for the safety valves on the reheater inlet. The maximum operating pressure is 39.9 bara (578.1 psia). Design temperature is equal to the HP turbine outlet temperature at VWO conditions plus a 13.9ºC (25°F) margin. The material for the cold reheat piping will be ASTM A335 Grade P22.

The hot reheat steam system conveys the heated steam from the steam generator reheater outlet headers to the inlet of the reheat stop valves of the intermediate pressure turbine. The system is designed in accordance with the requirements of ASME/ANSI B31.1 rules for non-boiler external piping. The design pressure of the system is equal to the design pressure of the reheater. The maximum operating pressure is 37.8 bara (548 psia). The design temperature is equal to the temperature at the reheater outlet at VWO plus a 8.3ºC (15°F) margin. The material for the hot reheat piping is seamless ferritic alloy steel, SA 335 Grade P91, which provides superior stress and creep properties.

Other system design criteria include:

- Piping sized for turbine generator VWO load case conditions.

- Maximum velocity at VWO conditions not to exceed 102 m/sec (20,000 ft/min) in main steam and hot reheat steam headers and 76 m/sec (15,000 ft/min) in cold reheat headers. Lower velocities may be required by the steam turbine vendor at the inlet to the steam turbine.

- Steam line drains supplied as required to meet the requirements of ASME TDP-1 “Recommended Practices for the Prevention of Water Damage to the Steam Turbines Used for Electric Power Generation.”

Extraction and Low Pressure Steam

The extraction and low pressure steam system transports steam from extraction steam points on the steam turbine and the cold reheat line to the closed feedwater heaters, the deaerator, the Secondary Recycle Gas Heater, oxygen heaters and the ASU and CPU "islands" for process heating.

Six (6) feedwater heaters are included in the steam power cycle design to heat condensate and feedwater from the condenser temperature to the design boiler feedwater inlet temperature of 247ºC (477 °F) at the performance condition. Feedwater heater performance is reflected on the steam cycle heat balance included in Appendix A.

The system is designed to meet the recommendations of ASME TDP-1 "Recommended Practices for the Prevention of Water Damage to the Steam Turbines Used for Electric Power Generation." In accordance with TDP-1 each extraction line has a motor operated isolation valve and power assisted non-return valve.

System components with design temperatures less than 399 ºC (750 °F) are generally fabricated from carbon steel (ASTM A106 Grade B). Components with design temperature above 399 ºC (750 °F) are fabricated in accordance with SA 335 Grade P91 or from 2 ¼ % Cr 1% Mo alloy steel material (ASTM A335 Grade P22).

The system is also designed in accordance with the following criteria:

- Piping sized for turbine generator VWO load case conditions and such that pressure of 165.5 barg (2,400 psig) will be delivered to the turbine steam chest.

- Maximum velocity at VWO conditions will not exceed 76 m/sec (15,000 ft/min) in extraction steam piping, except for extractions under vacuum, where velocity may be up to 102 m/sec (20,000 ft/min).

- Extraction steam piping design pressures are 115% of the turbine extraction pressure as shown on the VWO steam cycle heat balance. Design temperatures are determined based on the established design pressure and the extraction steam entropy as determined from the steam cycle heat balance.

Auxiliary Steam

The auxiliary steam system takes steam from the main steam system, conditions it through a pressure reducing and desuperheating station, and provides low pressure and temperature steam for the following uses:

- Deaerator pegging during start up and low load conditions when extraction steam is not available at sufficient pressure.

- Main steam turbine sealing steam during start up and low load conditions when the normal source of steam from the turbine HP gland leakoff is not sufficient.
- Chemical cleaning equipment and water treatment equipment
- Pulverizer inerting in the event of a pulverizer fire
- Process heating in the Boiler, GQCS, ASU and CPU “islands”
- Space heating in the existing Main Plant and for Unit 3 cross-tie
- Fuel oil heating at the barge unloading terminal, as required

An auxiliary boiler is included for startup.

3.7.2 Steam Turbine Generator

Steam Turbine Generator Design

The existing steam turbine-generator consists of one (1) Westinghouse, Tandem Compound, Double Flow Reheat turbine and one (1) hydrogen-cooled generator. The LP sections are downward exhaust.

The turbine-generator is rated at 194,175 kW gross with steam inlet conditions of 157.7 barg (2,286 psig) and 538 ºC (1,000 ºF), reheat to 538 ºC (1,000 ºF). The rated speed is 3,600 rpm.

Main steam from the boiler flows through the turbine’s main stop valves and control (governing) valves and enters the HP turbine. It expands through the HP section and exhausts as cold reheat to the boiler. Hot reheat steam from the boiler flows through the turbine’s reheat stop valves and intercept valves and enters the IP section. It expands through the IP and then enters the crossover piping, which transports the steam to the LP elements. LP steam is divided between the two LP elements and exhausts into the condenser.

The steam turbine was originally designed for fixed pressure, partial-arc operation. However, to optimize performance for the oxy-combustion plant, turbine operation will be modified to a hybrid sliding pressure operating mode.

The turbine provides for six (6) feedwater heater extraction points, as indicated in the steam cycle heat balance diagram, with full load extraction pressures. Final feedwater temperature at full load is 247 ºC (477 ºF).

The electrical generator is rated at 233 MVA, 60 Hz with a power factor of 0.90. The generator is a hydrogen-cooled design.

Steam Turbine Auxiliaries

Major turbine auxiliary systems and components include the following.

Gland Seal System

The gland seal system serves to prevent steam leakage through shaft penetrations at the ends of each turbine element and from the valve stems. It also prevents air in-leakage into the condenser through LP turbine shaft penetrations. The system is partially integrated with the BOP auxiliary steam system and consists of piping, pressure regulating valves, and a gland steam condenser with 2x100% capacity motor-driven exhausters.

Lubricating Oil System

Turbine bearings are lubricated by a closed-loop, water-cooled pressurized oil system. The system includes piping, oil reservoir, oil heaters, one (1) main and one (1) back up full-capacity AC oil pumps, one (1) emergency DC oil pump, 2x100% water-cooled lube oil coolers, a vapor extractor, oil purifier and duplex oil filter.

Turbine Governor System, Hydraulic Oil System, and Trip System

The turbine governor system controls turbine speed, load and throttle pressure over the full operational load range. Turbine start-up, shut-down, and load change are directed by the governor system.

The turbine stop valves, control valves, reheat stop valves, and intercept valves are positioned by the control system that is part of the governor system. The hydraulic oil system includes piping, fluid reservoir, two (2) independent, parallel, full-capacity AC fluid pumps, 2x100% water-cooled hydraulic oil fluid coolers and duplex fluid filter.

Generator Gas Cooling and CO_2 Purge Systems

The existing generator gas cooling system cools the generator utilizing hydrogen gas. The system includes a hydrogen manifold with integral pressure regulation, hydrogen purity instrumentation, dual tower hydrogen dryer and hydrogen-to-water coolers. The CO_2 purge system includes a CO_2 manifold with integral pressure regulation, along with a CO_2 vaporizer heater and purge control valves.

Hydrogen Seal Oil System

The existing hydrogen seal oil system provides containment of the hydrogen gas within the generator by maintaining the seal oil pressure at a small differential above the gas pressure. The system includes seal oil pumps and gas coolers.

Generator Excitation System

The existing excitation system provides the power to maintain the generator voltage.

3.7.3 Condensate and Feedwater

The existing feedwater and condensate systems of the thermal cycle consist of six feedwater heaters and two pressure levels of pumping. The feedwater system comprises the equipment and piping from the deaerator storage tank outlet to the boiler economizer inlet. The condensate system comprises the equipment and piping from the turbine condenser to and including the existing, relocated, deaerator and storage tank. The condensate/feedwater system process flow diagrams are included.

The condensate and feedwater system is also integrated with the GQCS, ASU, and CPU islands to provide heating and cooling requirements for those islands as required. The system configuration is generally depicted on the overall process flow diagram contained in Appendix C.

Feedwater System

The deaerator storage tank provides a suction reservoir for the feedwater pumps, which discharge through two existing high pressure shell and tube feedwater heaters (heaters no. 5 and 6). The high pressure feedwater heaters perform the final two stages of feedwater heating, with a nominal final feedwater temperature of 247ºC (477°F). Heater no. 5 receives steam from IP turbine exhaust and heater no. 6 is fed from cold reheat (HP exhaust). High pressure heater drains cascade through successive lower pressure heaters and normally directed to the deaerator.

The existing main feedwater pumps are motor driven using a hydraulic coupling to vary the flow. This arrangement allows efficient variable speed drive for these large pumps.

The feedwater heaters are capable of operating at any load condition and are capable of accepting increased extraction steam flow rates resulting from removing one or more heaters from service or from cascading the heater drains to the condenser.

Condensate System

Steam is condensed from the main turbine in an existing two-pass, shell and tube type steam surface condenser with divided water boxes, admiralty and stainless steel tubes and Muntz-metal tube sheets. Vacuum pumps are used to create and maintain condenser vacuum. System make-up will be vacuum drained from a new, 380 m^3 (100,000 gallon), lined-steel, condensate storage tank into the hotwell.

Two existing, 50% capacity, can-type vertical condensate pumps pump water from the condenser hotwell through an ion-exchange polishing system, a gland steam condenser, three existing conventional shell and tube feedwater heaters (heaters no. 1 through 3), to a direct contact deaerating feedwater heater (heater no. 4). Drains from heaters no. 2 and 3 are cascaded through heater no. 1 to the condenser.

The condensate pumps are designed to handle the condensate generated at the VWO rating. The pump cans are set to a depth that provides adequate NPSH at the suction flange at all conditions, including one pump runout. A common minimum flow recirculation system is designed to provide the required minimum flow for the pumps and/or the gland steam condenser. The pump total head requirement is 283 m (930 feet) TDH.

The low pressure heater shell side design pressure and temperature are based on the associated extraction steam line design pressure. The tube side design pressure is equal to the design pressure of the condensate piping, with the tube side design temperature based on saturation temperature for the shell side design pressure.

To maintain water chemistry within the limits required for the subcritical boiler design, an all-volatile treatment (AVT) chemistry program is used, employing ammonia for pH control and hydrazine for oxygen scavenging. Additionally, full condensate flow from the hotwell is polished, as required, to assure water quality is maintained.

3.7.4 Heat Rejection (Cooling Water) Systems

Main Circulating Water

The main circulating water system provides a continuous supply of cooling water for heat rejection from the main steam condenser. The circulating water system is designed to the following parameters:

- A condenser steam-side pressure of approximately 63.5 mm (2.5 in) HgA under average annual operating conditions (94.0 mm [3.7 in] HgA under summer design conditions).
- Cooling tower designed at summer conditions with 45.6ºC (114°F) inlet water temperature, 33.3ºC (92°F) outlet water temperature with an ambient 24.4ºC (76°F) wet bulb temperature.

Resulting steam cycle cooling system temperatures are reflected on the heat balance in Appendix A.

The system is a wet recirculating design that includes the following major equipment:

- One (1) steam surface condenser
- One (1) four-cell mechanical draft, crossflow cooling tower
- Two (2) x 50% capacity main circulating water pumps
- Two (2) x 100% capacity condenser vacuum pump skids

System main circulating water piping is arranged in a single common supply and single common return header configuration, with individual risers to each side of the cooling tower water deck and individual branches to the split condenser waterboxes. Underground existing main circulating water piping is coated and wrapped steel material.

Water chemistry within the circulating water system is maintained through chemical injection and system blowdown rates.

Condenser

An existing two-pass divided waterbox steam surface deaerating condenser is provided to condense exhaust steam from the LP turbine exhausts. The unit is constructed with 25.4 mm (1 inch) OD, BWG 18 Admiralty tubes and 25.4 mm (1 inch) OD BWG 20 Type 304 stainless steel tubes, primarily for air removal. Tube sheets are Muntz metal. Performance under normal base load operating conditions is reflected on the steam cycle heat balance.

Cooling Tower

The main cooling tower rejects cycle heat from the main condenser and closed cooling water system to atmosphere. The existing main cooling tower will be replaced with a new tower constructed on the existing basin. The new tower is a crossflow, induced-draft design comprising 4 individual cells, each equipped with a single speed 149 kW (200 hp) electric motor-driven fan. Tower design conditions are as stated above. Tower performance under normal base load operating conditions is reflected on the steam cycle heat balance and on the water balance.

The tower is built over a common concrete cold water basin, with a pump pit provided at one end. The tower structure is of fiberglass reinforced plastic (FRP) construction. The pump pit is a reinforced concrete structure, equipped with trash racks.

Main Circulating Water Pumps

The circulating water pumps are vertical motor-driven constant speed, mixed flow design pumps. The pumps are self lubricated and are provided with automatic air release systems to expel contained air from the pump column during pump starting. Each pump discharge is provided with a motor operated butterfly valve and expansion joint. The discharges from each pump are combined into one common supply header.

Both pumps are required to operate to achieve maximum plant performance as reflected in the steam cycle heat balance. Should one pump be out of service, plant operation can be continued with single pump operation. Limitations on steam turbine load during single pump operation are dependent on ambient conditions, but are partially mitigated due to the runout characteristics of a single operating pump.

Condenser Vacuum Pump Skids

Each existing condenser vacuum pump skid contains a single full capacity rotary type condenser vacuum pump and associated separator tank, seal water pump, and seal water cooler. During normal base load operation, a single operating skid will maintain condenser vacuum at the design point. During startup, both skids can be operated in parallel to shorten the time required to pull initial condenser vacuum.

ASU/CPU Circulating Water

ASU/CPU Cooling Tower

The cooling tower rejects cycle heat from the ASU and CPU “island” closed cooling water systems to atmosphere. The tower is built over a common concrete cold water basin, with a pump pit and pump enclosures provided on one side. The pump enclosure houses the ASU/CPU circulating water pumps. The tower structure is FRP. The pump pit is a reinforced concrete structure consisting of separate chambers for each pump, each equipped with bar screen trash racks.

Water chemistry within the ASU/CPU circulating water system is maintained through chemical injection and system blowdown rates.

ASU/CPU Circulating Water Pumps

The ASU/CPU circulating water pumps are vertical motor-driven constant speed, mixed flow design pumps. The pumps are self lubricated and are provided with automatic air release systems to expel contained air from the pump column during pump starting. Each pump discharge will be provided with a motor operated butterfly valve and expansion joint. The discharges from each pump are combined into one common supply header feeding two distinct piping loops.

Both pumps are required to operate to achieve maximum plant performance as reflected in the steam cycle heat balance. Should one pump be out of service, plant operation can continue with single pump service, but at a curtailed level.

DCCPS Circulating Water

DCCPS Cooling Tower

The cooling tower rejects cycle heat from the DCCPS closed cooling water system to atmosphere. The tower is a counterflow, induced draft design comprising 2 individual cells, each equipped with a single speed 186 kW (250 hp) electric motor-driven fan. Tower design conditions are 48.9ºC (120°F) inlet water temperature, 32.2ºC (90°F) outlet water temperature with an ambient 24.4ºC (76°F) wet bulb temperature. Because of the effects of high inlet water temperature on tower material, a significant portion of the cooled water from the basin is mixed with the inlet water. Net tower performance under normal base load operating conditions is reflected in the Project Design Basis Document and on the water balance.

The tower is built over a common concrete cold water basin, with a pump pit and pump enclosures provided at one end. The pump enclosure houses the DCCPS circulating water pumps. The tower structure is FRP. The pump pit is a reinforced concrete structure consisting of separate chambers for each pump, each equipped with bar screen trash racks.

Water chemistry within the DCCPS circulating water system is primarily a function of the GQCS/WFGD operating conditions, but can be controlled when necessary through additional chemical injection and blowdown. Refer to the Water Balance in Appendix B for further details.

DCCPS Circulating Water Pumps

The DCCPS circulating water pumps are vertical motor-driven constant speed, mixed flow design pumps. The pumps are self lubricated and are provided with automatic air release systems to expel contained air from the pump column during pump starting. Each pump discharge will be provided with a motor operated butterfly valve and expansion joint. The discharges from each pump are combined into one common supply header that feeds the DCCPS spray headers. DCCPS liquor is returned by the DCCPS Blowdown Pumps (see B&W PGG description) to the DCCPS Cooling Tower.

Both pumps are required to operate to achieve maximum plant performance as reflected in the steam cycle heat balance. Should one pump be out of service, plant operation can be continued with single pump operation. Limitations on DCCPS effective operation (also limiting steam turbine load) during single pump operation are dependent on ambient conditions, but are partially mitigated due to the runout characteristics of a single operating pump.

Closed Cooling Water

The existing closed cooling water (CCW) System provides condensate quality cooling water to various small duty heat exchangers throughout the plant, thereby acting as a heat sink for those components. Heat from the CCW System is rejected to the Service Water System.

The CCW system serves the following major equipment:

- Bearing cooling on the Motor-driven Boiler Feed Pumps
- Existing air compressor after coolers and intercoolers
- Existing condensate pump motor bearing coolers
- Electro-hydraulic oil coolers
- Sample coolers

The CCW System consists of:

- One shell and tube, two-pass heat exchanger sized to cool 56.8 m^3/hr (250 gpm) of water from 51.7ºC (125°F) to 40.6ºC (105°F)
- Two 56.8 m^3/hr (250 gpm) horizontal centrifugal pumps, one operating and one standby
- One Closed Cooling Water Storage Tank, 5.7 m^3 (1,500 gallons)

The CCW Storage Tank accommodates system volume variations due to changes in water temperature and ensures adequate suction head is available at the CCW pumps during all operating conditions.

Service Water Cooling

The existing service water cooling system provides filtered river water to various equipment heat exchangers throughout the plant via a once-thru arrangement, thereby acting as a heat sink for those components.

The service water cooling system serves the following existing and new major equipment:

- Service water strainer backwash system
- Main steam turbine oil coolers
- Hydraulic coupling oil coolers for motor-driven boiler feed pumps
- Hydrogen seal oil coolers, air and hydrogen sides
- Generator hydrogen coolers
- Generator exciter coolers
- Vacuum pumps heat exchangers
- CCW heat exchanger
- New Boiler interface point for new equipment cooling and miscellaneous uses
- New GQCS interface point for equipment cooling and miscellaneous uses
- ASU and CPU new interface points for miscellaneous uses

The service water cooling system consists of:

- One 400 mm (16 inch) strainer, twin basket, 1,136 m^3/hr (5,000 gpm), with manual backwash, to remove particles larger than 4.8 mm (3/16 inch)

- Two 1,136 m^3/hr (5,000 gpm) horizontal centrifugal pumps, one operating and one standby

Service water is pumped to individual equipment coolers in the Service Water Supply pipe, passes through each cooler and is collected in the Service Water Return pipe. The heated service water is discharged into the main cooling tower pump basin as makeup water. Excess water is discharge as tower blowdown to the river.

3.7.5 Compressed Air System

The existing compressed air system is not considered oil-free so a new instrument air and service air system is provided. The new system consists of:

- Three rotary screw, oil-free, 8.6 barg (125 psig) discharge pressure, 5,100 inlet m^3/hr (3,000 icfm) compressors

- Two heatless, 7,234 Nm^3/hr (4,500 scfm) air dryer skids, dewpoint of -40°C (-40°F).

- Two 4.26 m^3 (1,125 gallon) instrument air receivers

- One 4.26 m^3 (1,125 gallon) service air receiver

Two compressors will operate continually with the third compressor operating in load/unload modes as system demand dictates. The system will be cross-tied to the existing compressed air system through a controlled interface to prevent air with oil entering the new piping system.

Instrument air and service air will be distributed to the collective interface points at the Boiler, GQCS, ASU and CPU "islands." Instrument air piping will be ASTM A312 TP 304 stainless steel. Service air piping will be ASTM A106 Gr. B carbon steel pipe.

3.7.6 Stack

A new 137.5 m (451 ft) tall concrete chimney will be provided. The stack is designed to discharge monitored volumes of flue gas during unit startup and the transition to oxygen-fired status and to discharge flue gas and carbon dioxide during normal shutdown. In addition the stack will discharge small, monitored volumes of non-condensable gases during normal operation.

The stack will consist of:

- Outer reinforced concrete shell (27.6 MPa [4,000 psi] design) per ACI-307
- FRP inner shell liner per ASTM D5364
- FRP breeching duct
- Two, 360-degree test platforms with one hoist
- Test, CEMS and opacity ports, FRP construction
- One full concrete roof platform with Type 316L stainless steel hatch
- Aviation lighting, two levels of three medium intensity strobe lights
- Chimney electrical system
- Lightning protection

3.7.7 Coal Handling System

Existing Coal Handling System

Process diagrams of the existing coal handling system (CHS) are provided in Appendix C. The existing CHS currently serves Unit 3 (Boiler 5) burning 100% PRB coal. Unit 3 will continue to burn only PRB coal for any future operations.

PRB coal is currently delivered to the plant by river barges, while bituminous coal is delivered by truck. No provisions for accurate blending of bituminous and PRB coal are presently provided in the existing system.

PRB coal is unloaded from the barge via a clamshell bucket into the barge unloading hopper. A belt feeder installed below the hopper transfers the coal to the 91.4 cm (36”) Conveyor E rated at 454 tonne/hr (500 ton/hr). Conveyor E transports the coal to the Breaker Building where it discharges to Belt Feeder F. This feeder releases coal to a two-position flop gate diverter that can send the fuel to either the granulator or to the tail of Conveyor D, which discharges to the Yard Hopper.

The granulator inlet is furnished with a grizzly classifier that directs oversize coal to the granulator while the finer particles bypass the granulator and are mixed with the sized product, then discharged onto the 454 tonne/hr (500 ton/hr) Conveyor B. Conveyor B elevates the coal to the Tripper Gallery where it is discharged from Conveyor B onto the Tripper Conveyor C. The Coal Tripper Car unloads coal from Conveyor C into the boiler coal bunkers.

The Yard Hopper that is fed by Conveyor D provides surge capacity to allow scraper type earth moving equipment to load out coal for transfer to the yard stockpile.

Reclaiming of coal from the Coal Yard is performed through the Reclaiming Pit/Hopper that is furnished with a grate on ground level and an underground belt feeder. This feeder discharges onto Conveyor A that transports the reclaimed coal to the Breaker Building where it is unloaded onto Belt Feeder F for further processing as described above.

Repowered Plant Coal Handling System Configuration

The existing CHS will continue to be used to serve Unit 3 (Boiler 5) and Unit 4 (new Boiler 7). Unit 3 will be supplied with only PRB coal. Unit 4 will burn primarily bituminous coal, but will be able to accommodate a limited blend of PRB coal as well.

Besides providing coal directly to Unit 3, the barge unloading system will be also used for maintaining the PRB coal pile inventory and for on-line blending of PRB coal with bituminous coal for Unit 4. Supply of PRB coal from the yard pile to Unit 3 Boiler 5 could be provided also through the existing reclaim hopper, if required.

Bituminous coal for Unit 4 will be delivered to the plant by trucks and a pile of bituminous coal will be formed by yard machines. Yard machines (dozers, scrapers) will be used to transfer the coal from this pile to the existing reclaim hopper.

Concurrent operation of Unit 4 on either 100% bituminous coal or bituminous coal/PRB coal blend, and Unit 3 on 100% PRB coal, will require additional operating hours for the coal handling system.

Processed coal will be transported by the existing Conveyor B to the area of the existing Conveyor C tail section. A new transfer chute and gate arrangement will be provided in this area for transfer of coal to a new Belt Conveyor G that will transport the fuel to the new transfer house constructed at the new Boiler 7 building.

Construction of the new transfer chute and gate in the Conveyor C tail section will require the extension of the Conveyor B head section. This is necessary to provide sufficient headroom to feed the new transfer chute and gate and for the transfer of PRB coal onto existing Conveyor C for Unit 3.

Routing of the new Conveyor G will be provided above the existing turbine building roof. Coal will be discharged by Conveyor G onto Unit 4 tripper/cascading conveyor.

The new Conveyor G will be enclosed by hood covers. An outside walkway will be provided along the enclosed Conveyor G for service and maintenance purposes.

Blending of bituminous coal and PRB coal for Unit 4 will be provided by two (2) scenarios as follows:

Blending Scenario A (more accurate)

Appropriate conveyor belt scales will be furnished on existing conveyors as required to monitor the flow rates of bituminous and PRB coals. Combining the flow rate signals with the existing variable speed reclaim and barge unloader belt feeders will provide control parameters necessary to produce an accurate blend. Bituminous coal will be transferred from the reclaim hopper belt feeder onto existing Conveyor A, which discharges to the existing Belt Feeder F. The PRB coal will be transferred from the barge to the Feeder F by the existing Conveyor E. Blended Feeder F fuels will be discharged to the existing Coal Granulator and processing will continue as described above.

Scenario B (less accurate)

When loading coal from a barge is not available, yard machines will transfer both bituminous coal and PRB coal from their respective piles into the existing yard reclaim hopper. The blending coal ratios will be controlled by the number of scraper loads of PRB coal blended together with bituminous coal as it is pushed into the reclaim hopper . Blended coal will be transported by the existing Conveyor A to the Breaker Building and processing will continue as described above.

3.7.8 Water and Wastewater Treatment

Refer also to the plant water balances in Appendix B.

Makeup Water

Sources of Makeup Water

The Illinois River is the primary source of makeup water, supplying water for the following uses:

- Screen and strainer backwash
- Cooling tower makeup (main cycle and GQCS)
- GQCS makeup (WFGD, DCCPS, ASU/CPU)
- Equipment cooling
- Equipment washdown
- Coal handling dust suppression
- Bottom ash and fly ash handling

The River Water analysis is shown in Table 3-6.

Table 3-6
River Water Analysis

Analysis Parameter (all mg/l unless noted otherwise)	**Typical**	**Range**	
		Min	**Max**
pH	7.9	7.1	8.2
Specific Conductivity, µS/cm	630	530	810
Total Dissolved Solids (TDS)	418	372	478
Total Suspended Solids (TSS)	95	11	226
Silica, dissolved	4	1.1	9.2
Chloride (total)	57	39	73
Fluoride (total)	<1	< 0.25	< 1
Sulfate (total)	78	61	95
Nitrate (total) as CaCO3	< 3	< 3	< 3
Phosphorus (total) as CaCO3	< 1	< 1	< 1
Sodium (total)	34	21	52
Potassium (total)	5 est	2 est	10 est
Calcium (total) as CaCO3	171	146	190
Magnesium (total) as CaCO3	114	78	150
Copper (total)	< 0.01	< 0.01	< 0.01
Iron (total)	1.5	0.4	3.8
Aluminum (total)	2.0	1.67	2.4
Barium (total)	no data	est 0.2	est 0.5
Manganese (total)	0.1	0.04	0.15
Total Hardness as CaCO3	271	246	340
Alkalinity (Carbonate), ppm as CaCO3	< 1	< 1	< 1
Alkalinity (Bicarbonate), ppm CaCO3	196	159	222
Dissolved Oxygen	7	7	7
Turbidity, NTU	no data	est 30	est 90
Total Organic Carbon (TOC) - estimated	5	2	7
Biochemical Oxygen Demand (BOD)	<4		
Chemical Oxygen Demand (COD)	6.6		
Oil & Grease	<3		
Water Temperature, °C (°F), estimated	21 (70)	1.7 (35)	32 (90)

Well water is used directly (without treatment) for:

- Steam cycle demineralizer influent
- Coal handling dust suppression
- Fire protection (some outside hydrants)
- Potable water

City water is used directly (without treatment) for:

- Fire protection makeup
- Unit 4 floor wash

Treatment of Makeup Water

As noted above, well water and city water are used directly, without additional treatment. River water, on the other hand, is subject to several processing steps, depending on the final use:

- All of the river water passes through intake screens. The screens are backwashed using their own inlet water. The backwash water is then discharged directly back to the river.
- The Unit 3 condensers use some of the screened water, without additional treatment.
- The balance of the river water, downstream of the screens, is pumped through various strainers, for use in high pressure service water (coal handling dust suppression, pyrite sluicing, air compressor cooling, floor washing), low pressure service water (equipment cooling, main cooling tower supplemental makeup, bottom ash seal, and Unit 4 GQCS), and ash sluicing water (Unit 3 ash handling, Unit 3 condenser vacuum ejectors) systems. The strainers are backwashed using their own inlet water.
- The Unit 4 GQCS system uses low pressure service water for various purposes and the treatment requirements vary, as indicated below:
    - No Additional Treatment - WFGD makeup (ME wash, gypsum dewatering, humidification water)
    - Clarification - ASU/CPU cooling tower
    - Clarification and Softening - DCCPS ME wash, DCCPS reagent prep, and DCCPS cooling tower supplemental makeup
    - Clarification, Ultrafiltration, and Reverse Osmosis - CPU process water

- The Unit 4 GQCS water treatment process main equipment components, chemical reagents, and byproducts are briefly presented below:
    - Clarification
        - Equipment: Reaction tank, solids contact clarifier, sludge recirculation and forwarding pumps, filter presses for sludge dewatering, pumps for sludge recirculation and filter press feed.
        - Chemical reagents: Ferric chloride (coagulant), polymer (flocculant/coagulant aid)
        - Byproducts: Filter cake (approximately 50% solids, chemically “fixed”, expected to pass Toxicity Characteristics Leaching Procedure test).
    - Softening
        - Equipment: Ion exchange softener
        - Chemical reagents: Salt solution for regeneration
        - Byproducts (possibly use as WFGD makeup): Regenerant waste
    - Ultrafiltration and Reverse Osmosis
        - Equipment: Cartridge filters, ultrafiltration units, tanks, reverse osmosis feed pumps, and booster pumps, reverse osmosis units.
        - Chemical reagents: Possible reagents are sodium hypochlorite, acid, caustic, antiscalant, sodium bisulfite, detergent
        - Byproducts (use as WFGD makeup) : Ultrafiltration backwash, reverse osmosis reject (concentrated river water)
        - Byproducts (offsite processing): Rinses from chemical cleaning of reverse osmosis units.

Wastewater Treatment

Liquid effluent limitations for discharge to the Illinois River are identified in Table 3-7. The Unit 4 liquid effluents will not be discharged to the existing on-site ash ponds. Most of the Unit 4 WFGD and associated DCCPS system liquid waste will be recycled for fly ash wetting or reevaporated in the flue gas to the maximum possible extent to minimize high chloride waste streams requiring external treatment. Some Unit 4 streams, such as the main cooling tower and the ASU/CPU cooling tower blowdown, will be directed without further treatment to the discharge flume. These streams consist primarily of river water which has been concentrated due to evaporation in the cooling towers, with some small amounts of various circulating water feed chemicals (e.g. antiscalant, biocide, sulfuric acid, etc.) present. The ASU/CPU cooling tower makeup water portion of this stream will also have been softened, thereby exchanging sodium for calcium and magnesium ions. The other Unit 4 wastewater streams will be treated prior to release to the discharge flume.

Table 3-7
River Discharge Limits

Analysis Parameter (mg/l unless noted otherwise)	**Criteria**
Chloride	< 250
Sulfate	< 250
Fluoride	< 1.4
Phosphate	< 1.0
Ammonia, as N	< 4.54 (summer) < 2.03 (winter)
pH	6.0 – 9.0 standard units
Total Dissolved Solids	< 500
Oil & Grease	< 10 average < 15 max instant.
Total Suspended Solids	< 15 average < 30 max instant.
Aluminum	< 0.087
Antimony	< 0.006
Arsenic	< 0.05
Barium	< 1.0
Beryllium	< 0.004
Boron	< 1.0
Cadmium	< 0.012
Chromium, total	< 0.05
Cobalt	< 1.0
Copper	< 0.021
Iron	< 1.0
Lead	< 0.05
Manganese	< 0.15
Mercury	< 0.000012
Nickel	< 0.0963
Selenium	< 0.01
Silver	< 0.1
Thallium	< 0.002
Zinc	< 0.1426
Nitrate-Nitrogen, as N	< 10.0
Cyanide	< 0.1
Phenols	< 0.001
Hardness Dependent Metals Assumed	< 200 as $CaCO_3$

Two distinct wastewater treatment processes are currently proposed for Unit 4 operations. The collection method, main equipment components, chemical reagents, and byproducts for each process are briefly presented below.

CPU Wastewater Treatment System (CPU WWTS)

The CPU WWTS includes pH adjustment and mercury polishing for the CPU Process Wastewater.

- Collection method: pumped directly from the CPU process systems
- Equipment: Cartridge filters, ion exchange vessels charged with specialized mercury polishing media, pumps
- Chemical reagents: Sodium Hydroxide (NaOH) for pH adjustment
- Byproducts:
    - Media backwash (only to occasionally "fluff" the media)
    - Removal of spent media for offsite regeneration and replacement

Unit 4 Wastewater Treatment System (Unit 4 WWTS)

The Unit 4 WWTS includes physical-chemical treatment of multiple wastewater streams.

- Collection method: Wastewater is pumped to an equalization tank from the DCCPS cooling tower, the CPU WWTS, and from the following other Unit 4 processes: steam cycle (sampling, condensate, blowdown, and miscellaneous drains), demin sumps, and coal handling dust suppression. Oily wastes are treated in an oil/water separator prior to being combined with other process wastewater streams.
- Equipment: Equalization tank, reaction tank(s), solids contact clarifier, sludge recirculation and forwarding pumps, filter presses for sludge dewatering, pumps for sludge recirculation and filter press feed.
- Chemical reagents: Ferric chloride (coagulant), organosulfide (metal precipitation), polymer (flocculant/coagulant aid).
- Byproducts: Filter cake (approximately 50% solids, chemically "fixed", expected to pass Toxicity Characteristics Leaching Procedure test) and waste oil, both of which are trucked off-site for final disposal.

Condensate Polishers

The repowering project will provide new condensate polishers, to maintain the purity of the condensate. Deep bed ion exchange vessels will be provided, to replace the existing out-of-service pre-coat type condensate polishers. Regeneration of the polishing resin will be done off-site under a service contract.

3.8 *Electrical and Control Systems*

3.8.1 Overall Plant Electrical Design

The FutureGen 2.0 electrical one line drawings are included in Appendix D. The BOP Electrical Equipment List in Appendix E also includes information on individual equipment ratings. Equipment locations are shown in the general plot plan included in Appendix F.

The 138 kV switchyard will be expanded to provide a new overhead distribution line to supply power to a new Unit #4 Aux Transformer. The switchyard expansion, overhead line, and Aux load primary metering is designed and supplied by Ameren T&D. Additionally, a number of existing overhead transmission and distribution lines need to be re-routed to free up plot space for new project equipment. These re-routes will be handled also by Ameren T&D.

One two-winding mineral oil-filled 100MVA auxiliary transformer will be provided to step down the voltage from 138kV to 13.8kV. A 4,000A, 63kA non-seg bus duct will connect the transformer secondary to new outdoor 13.8kV switchgear for distribution to the ASU, CPU, Boiler, and GQCS islands via 2,000A underground duct bank feeders.

Power to the new ASU/CPU Cooling Tower will be feed from an ASU island 4,160V Motor Control Center (MCC). A small electrical power distribution room containing a 4,160V MCC and 480V MCC located near the cooling tower will supply electrical power to the cooling tower loads.

Power to the new DCCPS Cooling Tower will be feed from a CPU island 4,160V MCC. A small electrical power distribution room containing a 4,160V MCC and 480V MCC located near the cooling tower will supply electrical power to the cooling tower loads.

The remaining new BOP equipment will be fed from a single new 4,160V MCC located in a new BOP electrical power distribution room. The MCC will be supplied from an existing 4,160V switchgear breaker that derives its electrical power from the existing Unit #4 main auxiliary transformer. The 4,160V MCC will distribute power to the medium voltage motors for the main cooling tower and the instrument air compressors, as well as three step-down transformers that supply 480V MCC's. One of the 480V MCC's is devoted to essential service loads, and is backed up by a 1,600kW diesel generator currently available for use at the plant. This essential service 480V MCC will also feed the essential service MCC's supplied with each island.

Existing BOP equipment will continue to receive power from their existing sources. New BOP loads will be fed from new electrical distribution equipment as described above. The new BOP UPS loads are minimal and therefore will be fed from the existing UPS system.

3.8.2 Instrumentation and Control (I&C) Systems

I&C Philosophy

The I&C control philosophy will be applied to all systems comprising the new unit configuration and will include:

- Common/consistent units of measure application
- Standardized HMI display formats, text, color and display methods
- Common/consistent logic and functional control designs
- Standardized alarm management techniques, rationalization and alarm summary displays
- Common signal/equipment segregation and partitioning techniques
- Consistent signal, processor, communication and power supply redundancy approaches
- Consistent interrogating voltages and signal formats
- Consistent methods, materials and accessories for instrumentation installation and mounting
- Consistent instrument and control element vendor/models
- Hardwired signal exchange of critical signals among the unit control systems and equipment packages
- Active participation by plant staff in the development of HMI displays

Boiler and Combustion I&C

A Distributed Control System (DCS) is provided for the plant control system (PCS) which serves as the main control system and human-machine interface (HMI) for regulatory control, monitoring, data acquisition, storage and display. The PCS is comprised of the Boiler Control System (BCS), Burner Management System (BMS), Gas Quality Control System (GQCS), Turbine Control and Balance of Plant (BOP) with interface to the independently controlled ASU and CPU control systems. The PCS also interfaces with all other control sub-packages provided as part of the operation of the Boiler and GQCS systems.

The PCS utilizes a common control platform while using existing I/O hardware for the Turbine and BOP systems. The ASU and CPU control systems are interfaced via an OPC server connection for data exchange to the PCS. Critical interlocks, control signals, and alarms required between any of the control packages employ hard-wired I/O for maximum reliability. Hardwired emergency trips (e.g. Boiler Master Fuel Trips, and Turbine Generator trips) are implemented at the PCS central HMI location. Non-critical signal exchanges between control packages and between the PCS employ soft communication techniques (e.g. ModBus, OPC, Ethernet). In order to maximize system reliability, rendundancy is provided for control processors, data highways, interface controllers and power supplies. The conceptual system architecture is shown in Figure 3-14.

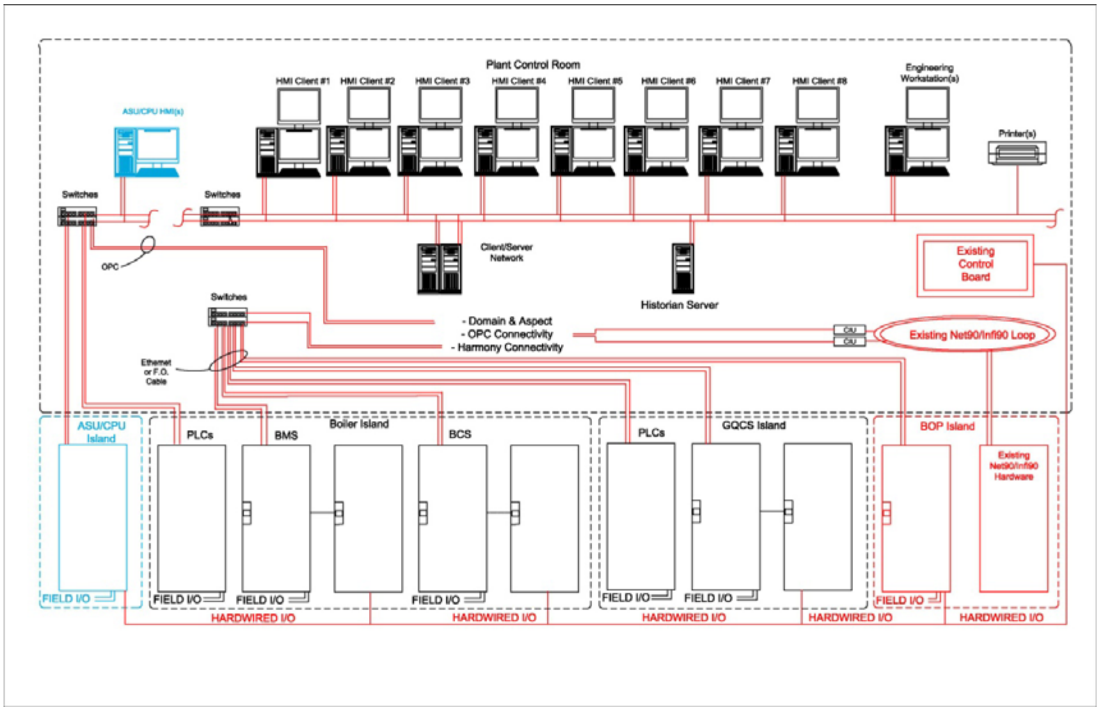


Figure 3-14
Plant Control System Architecture

Instrumentation manufacturers and model numbers/series are standardized as much as possible. Process measuring instruments are of microprocessor-based (Smart) design utilizing HART protocol.

The plant instrumentation and the PCS are designed to achieve the following:

- Maximize the integration of control sub-packages resulting in a comprehensive PCS that optimizes staffing levels.
- Apply a consistent control and instrumentation philosophy to the maximum extent possible throughout the plant.
- Standardize approaches to operating functions such as protection, automatic control manual control and monitoring.
- Utilize operating logic that minimizes operator action.

- Collect all information essential to plant operation, performance and maintenance in a central location.
- Provide performance monitoring subsystems that evaluate overall plant and major equipment performance.
- Apply techniques to prioritize alarms and suppress nuisance alarms.
- Minimize operator interaction through application of automation techniques (e.g., startup sequence blocks).
- Minimize the likelihood that any single failure results in a plant trip.

A high-fidelity simulator is also provided to facilitate operator training and increase operation proficiency. The simulator integrates the various dynamic models of the plant with the programmed control strategies of the PCS, ASU, and CPU control systems. The simulator environment including HMI's, consoles, and hardware is designed to duplicate the plant control room. The simulator emulates and provides accurate real-time responses for start-up, shutdown, varying operating loads and abnormal conditions of the plant.

ASU and CPU I&C

The ASU and CPU facilities will be designed for minimal but full time on-shift staffing. The operator will be able to start, control and stop all major pieces of equipment in the Facility from the Seller supplied control room. The Facility is equipped with suitable electronic instruments, process analyzers, and control devices to ensure safe and efficient Facility operation.

Equipment protection monitoring signals as well as Facility performance variables will be monitored and logged. This will allow the operators to monitor and trend the performance of the Facility over time and be able to make predictive maintenance calculations of the equipment. This enables the operating staff to better plan, coordinate and schedule any required maintenance.

Facility shutdown interlocks shall be designed for safety and to protect the equipment. If a shutdown interlock is activated, the Facility will automatically shutdown in a safe mode. Once the cause of the shutdown has been identified and fixed, the interlock will be cleared and the Facility can be restarted.

Balance of Plant I&C

The new unit configuration significantly increases the amount and variety of equipment, controls, alarms and monitoring items to be managed by the unit Operator. As such, emphasis must be placed on:

- Migrating the existing unit control, alarm and monitoring points to a single platform and interface

- Maximizing training and familiarization of unit personnel with the new systems.

To that end, much of the BOP I&C scope is focused upon migrating existing stand-alone systems into the common plant distributed control system (DCS) platform and supporting the development and provision of a high fidelity simulator for the project. Activities included in the BOP I&C modifications are:

- Migration of the existing unit sequence of events and alarm lamp box points to the DCS. The sequence of events points for the unit will be implemented in the DCS and applies a GPS clock for time stamp synchronization.

- Migration of unit-specific Main Control Board (MCB) indicator, recorder and indicating light values and statuses to the DCS

- Replacement of the hardwired motor controls with motor control logic and IO integrated into the DCS

- Provision of new Operator consoles for interface to the DCS

- Modification to existing BOP DCS process control and IO cabinets and hardware for integration into the new unit DCS platform

- Addition of new BOP DCS cabinets for migrated and new functions in support of the new unit configuration

- Replacement of the existing DCS loop (network) cabling for integration into the new platform

- Migration of the turbine water induction protection system into the DCS, including the addition of redundant feedwater heater level transmitters

- Migration of existing, key local control loop functions into the DCS

- Addition of redundant sensors/transmitters for critical control functions, such as deaerator storage tank level

- Replacement/refurbishment of existing unit instrumentation and control elements

- Integration of new vendor package programmable logic controllers via screen emulation in the DCS

- Development of steam turbine-generator and BOP dynamic models for a new high fidelity simulator

- Provision of simulator consoles for both training and configuration testing purposes that are essentially identical to the new DCS consoles

4.0 COST ESTIMATE AND SCHEDULE

4.1 *Project Cost Estimate*

The Project Cost Estimate was developed from the ground up, with each island supplier providing the costs for their respective island scope. The Project Division of Responsibility (DOR) was used as the guiding document to define scope splits between the participants. The specific estimating methods used varied between the islands, based on each participant's standard work processes, but generally encompassed the following.

- Preliminary equipment designs were prepared based on the Design Basis Document and other key process information contained in the Phase 1 engineering deliverables. In the majority of cases equipment was quoted by Vendors normally utilized by each island supplier in response to extensive technical/commercial request for bid packages. These quotes were validated against recent purchase information and tuned to reflect the best estimate of final price paid in a "real purchase" scenario.

- Where vendor quotes were not obtained, costs were estimated based on experience and internal cost database information.

- Material take offs (MTO's) for bulk items, including site preparation, piping, electrical, structural steel (pipe racks) and concrete foundation work, were prepared. These MTOs were used to feed cost estimate build-ups utilizing labor rates and productivity assumptions tuned to site-specific conditions. In many cases, local area Contractors who have serviced Ameren on recent large projects were used to independently develop estimates as validation.

- For those items not covered by vendor quoted subcontracts, engineering and installation labor was estimated based on the DOR, MTO's, and schedule using in-house information for each island supplier.

- Integrated project-wide (all islands included) engineering and construction schedules were developed and were utilized to assist with understanding work coordination and site density assumptions.

- Craft labor rates were based on labor survey information gathered from the local union halls.

- Management reserve was included based on a Monte Carlo analysis, with inputs from each participant for their respective cost items.

Table 4-1 presents a summary of the capital cost estimate results. Further discussion of the estimating methods and buildup is provided in Appendix H.

Table 4-1
Project Capital Cost Estimate Summary

Cost Category	Total Cost ($1,000's)
Direct Costs	$ 617,048
Indirect Costs	$ 124,147
Design Engineering	$ 103,024
G&A	$ 8,914
Fee	$ 14,975
Ameren Costs	$ 80,198
Escalation	$ 51,612
Construction/Startup Power	$ 2,462
Total EPC Costs	$1,002,378
Management Reserve	$ 83,693
Total Phase 2, 3, 4 Costs	$1,086,071
Phase 1 Costs	$ 12,554
Total Project Costs	$1,098,625

4.2 *Preliminary Schedule*

A preliminary Integrated Master Schedule (IMS) was prepared for the Project, built up and synchronized from individual schedules for each participant, including both engineering and construction activities and inputs. Interface milestones between the islands and participants were created based on information needed to complete each major design aspect or construction package within each island. These milestones were integrated into the IMS so that the associated activities are logically tied, but final agreement on key dates is still under discussion and the schedule will continue to be updated during subsequent Project phases.

The schedule does not include the Alliance pipeline and sequestration project schedule in detail, but selected Alliance milestones have been added to the IMS. Schedule integration with the Alliance is accomplished by contacting them on a monthly basis to review the status of their milestones and those selected activities that are carried in and impact the IMS.

The current revision of the full IMS contains approximately 14,000 individual activities identified through Phase 4 of the Project. Based on the IMS, the corresponding Level I Program Schedule has been provided in Appendix G.

5.0 PROJECT RISK AND OPPORTUNITY ASSESSMENT

5.1 *Project Risks*

A Risk Management Plan has been developed for the Project, based primarily on AER's internal risk management procedures. Pursuant to those procedures, a risk matrix has been developed identifying known project risks.

A number of issues have been identified during Phase 1 that require further evaluation in Phase 2 to better quantify and mitigate Project risks and to allow the Project to take advantage of potential opportunities. Most of these issues are related to plant performance, cost, and operability.

5.2 *Plant Performance Enhancements*

5.2.1 Auxiliary Power

This section is intended to describe some of the steps that may be taken in Phase 1B or Phase 2 (FEED) to reduce the aux power and thereby improve overall plant performance.

Table 5-1 shows the current auxiliary power prediction compared to the proposal estimate, based on performance coal and average ambient conditions. At the conclusion of the pre-FEED, an additional 15.7 MW of aux power has been identified when compared to the proposal.

Table 5-1
Auxiliary Power Comparison

	Current kW	Proposal kW	Increase kW	Phase 2 Target kW
Total	80,100	64,384	15,715	74,000 to 77,300

Basis of the Proposal Estimate

Boiler and Auxiliaries (includes GQCS)

<u>Fan Power:</u> The ID, Secondary and Primary fan power for the proposal was calculated using the proposal heat and mass balance flows assuming 80% fan efficiency and 95% motor efficiency. In addition, no margins were included in the proposal to cover any differences between calculated (theoretical) and actual fan performance.

Pulverizers: The preliminary design selected four B&W PGG 67G pulverizers with three in service at full load. During pre-FEED the comparison of current to proposal power it was discovered that the pulverizer power shown in the proposal table was erroneously based on two pulverizers in service instead of three. This represents a 200 kW underestimate (error).

GQCS: The GQCS estimate includes ash handling, baghouse (PJFF), wet scrubber and slurry prep system, gypsum system (WFGD), and the Polishing WFGD/DCC (now called DCCPS). The power estimate was factored from a previous project to account for scale but no design calculations were made due to limited time. The estimate for the Polishing WFGD/DCC was based on scaled down estimates for B&W PGG-AL's 800 MWe Integration Study and work in progress on a 700 MWe Reference plant design co-funded by EPRI.

ASU

The ASU power consumption for the proposal did not include any miscellaneous loads such as line/transformer losses, HVAC, lighting, etc.

CPU

The CPU power consumption for the proposal did not include any miscellaneous loads such as line/transformer losses, HVAC, lighting, etc.

Balance of Plant (existing equipment)

The balance of plant for the remaining existing equipment was estimated based on a percentage of gross power. No site information was available at the time. The proposal estimate is about 2.8% of the gross power. It was assumed that the auxiliary power for a new air-fired plant is about 8% of the gross power. The boiler and AQCS were assumed to be about 65% of that power leaving about 35% for the BOP. It was also assumed that the existing BOP would be refurbished to achieve modern performance.

Balance of Plant (additional due to oxy-combustion)

The ASU and CPU cooling were a very rough estimate scaled down from previous studies for greenfield plants. The cooling for the Polishing WFGD/DCC was considered as part of that system and included in the GQCS estimate.

Pre-FEED Predictions and Comparison with Proposal

Process Heat and Mass Balance

Several issues have changed the process heat and mass balances. In the following discussion, performance conditions assume typical coal analysis and average ambient conditions.

- The performance (design) coal properties selected early in Phase 1 are different from those used for the proposal. The shaded columns show the current typical coal analysis and the typical analysis used for the proposal. The impact of the differences on equipment sizing and auxiliary power will be discussed on a component basis.

- After initially providing recycle heater performance that was consistent with proposal assumptions, the vendor advised that their internal leakage calculation was erroneous and it was increased from 6.9% to 9.5%.

- It was decided that worst and best coals would be considered and a blend of up to 30% PRB was checked and found to be acceptable with minimal cost impact.

- The design would focus on low capital cost to maximize the ability to achieve the cost targets, which generally results in lower efficiency as well. This is particularly relevant to the large flue gas fans in which the lower cost single speed centrifugal fans selected in the pre-FEED are less efficient than variable-pitch axial fans that would give the higher efficiencies assumed in the proposal aux power estimate.

Some of these factors will be addressed in Phase 2 to reduce cost and auxiliary power as much as possible.

Boiler and Auxiliaries (includes GQCS)

Several factors have contributed to the increase in boiler auxiliary power. These factors are detailed below.

<u>Fan Power:</u> The reduction in heating value for the typical coal and the increase in recycle heater leakage produced flows under performance conditions that are significantly increased compared to the proposal. In addition, the fans operate at a lower efficiency under performance conditions (about 65% compared to 80% assumed in the proposal). The fan efficiency of 80% reflects either a centrifugal fan with a variable speed drive (VSD) or an axial fan with variable blade pitch, both of which are generally not considered low capital cost options. The low capital cost option considered in Phase I for the fans is two speed centrifugal fans with variable inlet vanes. These fan designs typically have a fan efficiency of approximately 65% at the full load operating point. Since the fans are operating down on their efficiency curve, experience has shown that fan vendors are less accurate in meeting their predicted performance so margin has been applied to their predicted power values compensate for vendor inaccuracy. The combination of these factors increased fan power by about 3,355 kW compared to the proposal estimate.

<u>Pulverizers</u>: The reduction in fuel heating value for the typical coal requires 11.4% more fuel to be handled by the pulverizers. This fuel difference along with an increase in coal fineness requirements (to improve combustion efficiency) result in an additional 350 kW in pulverizer power consumption over the proposal estimate.

<u>GQCS:</u> The total GQCS aux power came out about the same as the estimate in the proposal. The factors mentioned above that have impacted the other areas such as the difference in fuel

properties, increase in recycle heater internal leakage, and the sizing of equipment to accommodate a wider range of properties (i.e. worst coal and 30% PRB blend) also impacted the GQCS aux power estimate. However, the scaled down estimate for GQCS aux power put in the proposal appears to have been conservative enough to absorb these factors and so the Phase 1 (pre-FEED) aux power is relatively close to the proposal estimate.

Balance of Plant (existing equipment)

The original existing BOP aux load was simply estimated for the proposal, based on an assumed typical percentage of gross output. During Phase 1, a more rigorous analysis of the existing auxiliary loads was completed by URS, based both on historical performance as well as an individual load list buildup, and results in the higher final BOP aux load figure shown in Table 5-1. Besides being the result of more rigorous evaluation, the increase in auxiliary load can also be partly attributed to the following factors:

- The Meredosia site is a multiple unit site, with a number of miscellaneous components planned for reuse, but designed to serve the entire common plant. Since these loads are not optimized for Unit 4 operation only, auxiliary power consumption will be higher than expected for a new plant.

- Many of the existing auxiliary loads are original equipment that are planned for reuse without refurbishments that would improve performance. The original proposal estimate was based on modern new and clean performance.

- Because the original Unit 4 boiler was oil-fired, the original proposal assumption of 8% of gross output for total existing aux load appears reasonable. In fact, existing Unit 4 performance indicates that actual baseload auxiliary power has been around 7% of gross output. However, with the new Boiler 7, additional loads for equipment associated with coal-fired applications (e.g., coal handling, ash handling, etc. – existing equipment, but currently only associated with Units 1, 2, and 3) must be included, and were likely not adequately accounted for in the proposal estimate.

Balance of Plant (additional due to oxy-combustion)

The additional auxiliary power estimated for new BOP equipment related to oxy-combustion was limited to cooling of the ASU and CPU in the proposal stage. It was based on scaled down estimates from previous studies for larger plants that used adiabatic compression with the heat integrated into the steam cycle to produce additional gross power. During Phase 1 it was determined that the existing turbine-generator design is limited to about 210 MWe maximum (non-degraded) gross power so the degree of integration of the ASU and CPU heat was found to be defined by the amount of heat needed to compensate for the steam required for oxidant heating and the flue gas reheaters. Thus the heat added to the steam cycle is essentially equal to the heat used, and that was determined to be less than the ASU and CPU heat available, therefore resulting in more waste heat and cooling than the proposal estimated. Additionally, the small scale of the unit and the desire to minimize capital led to the selection of isothermal compressors in the CPU (heat integration done in the ASU) which produce more unrecoverable waste heat than adiabatic compression and are less efficient (see ASU and CPU discussions). These factors resulted in overall higher ASU and CPU cooling loads and therefore higher auxiliary power loads for the resulting BOP cooling water components, contributing to the overall aux load increase by approximately 2,943 kW.

Beyond the cooling water issue above, several additional new loads were identified in Phase 1 that were not expected when the proposal was prepared. These include the following:

- Air compressors – the ASU has a significant instrument air demand that cannot be accommodated by existing compressors or by the ASU compressors which are at too low a pressure.

- Water and wastewater treatment equipment – due to permitting requirements and the increased makeup water requirements associated with the oxy-combustion process (mainly increased ASU/CPU cooling), additional equipment is required for treating both makeup water and wastewater.

Phase 2 FEED Steps to Reduce Auxiliary Power

The following describes work anticipated to be done early in Phase 2 of the Project to evaluate various design issues that may improve overall auxiliary power consumption. These issues are part of a larger scope than encompasses performance optimization or "value engineering" in general.

Boiler and Auxiliaries (includes GQCS)

Fans: Since the difference in coal properties is not likely to be changed and it is desirable to provide test flexibility and capacity for a wider range of coals than considered in the proposal, those effects cannot be reduced. However, there are options that can be pursued in Phase 2 that could result in a reduction in fan power as much as 2 MW with additional capital expenditure. The key items are:

- Work with the recycle heater vendors to reduce internal leakage.

- Consider fan configurations and drives to improve fan efficiency (e.g. centrifugal fans with variable speed drives and/or axial fans with variable blade pitch).

- Work with the selected fan vendor to reduce margins.

- Optimize flue design and arrangement as well as equipment design to reduce pressure losses which will decrease the pressure rise required by the fans.

ASU & CPU

Further optimizations that have the potential to lower the ASU and CPU power consumption will be done in Phase 2. Key examples include:

- Continuing process optimization studies to further improve energy efficiency (this would potentially involve some additional investment)

- Implementing heat integration between the boiler steam cycle and the CO_2 compressor. This is premised on the assumption that the steam turbine would be upgraded to accept more low pressure steam and generate more output since we are at the limit of integration for the existing turbine. Unfortunately, CPU heat integration for this project is unlikely due to the use of an existing turbine, but in a new plant this would be done and some MWe gained.

- Working with B&W PGG to optimize the split of the MP and LP O_2 flowrates.

- Recovery of the LOX purge refrigeration loss by means of an efficient heat exchange.

- Use of low pressure drop equipment to minimize friction losses and corresponding auxiliary power requirements, primarily for the ASU.

Balance of Plant (existing equipment)

The existing BOP equipment was extensively evaluated during Phase 1, and with few exceptions was found to be of appropriate capacity and in good condition for reuse in the repowered facility. Consequently, there is little value expected to be gained by replacing or upgrading existing components, so further evaluation during Phase 2 is expected to be minimal. In general, Phase 2 will only address component upgrade or replacement when and if existing equipment design is discovered after detailed design to be insufficient to supply the required utility conditions. Otherwise, the only specific evaluation issue planned specifically to target lower auxiliary power consumption is a study of the benefits of replacing existing motors with new high efficiency motors.

Balance of Plant (additional due to oxy-combustion)

In general, design efforts during Phase 2 are expected to result in somewhat lower BOP auxiliary power consumption, just due to better defined design criteria and the consequent reduction in design margins applied to final equipment sizing calculations. Beyond this, optimization of the DCCPS cooling tower and circulating water pump design will be evaluated, targeting a lower flow, higher temperature cooling tower design, which could reduce system auxiliary loads by as much as 500 kW.

5.2.2 Additional Performance Opportunities

Besides auxiliary power, several other plant performance related issues were identified during Phase 1 as potential opportunities for improvement. The following issues are expected to be addressed during Phase 2:

- Further optimization of heat integration between BOP and other islands. While additional heat integration may be difficult – as explained in Section 2.5 – further optimization (pressures, temperatures, etc.) may be possible.

- Additional steam turbine refurbishment or upgrades to improve plant performance and potentially allow additional heat integration. Note that estimated turbine performance degradation alone translates into approximately 1.2 percentage points in overall plant efficiency. Much of this performance loss could likely be recovered just from a turbine overhaul.

- Optimize boiler fan design and evaluate redundancy on boiler fan trains. Elimination of redundancy may improve both the cost and performance of the plant.

- Further evaluation of the benefits of overhauling/refurbishing existing equipment to improve performance. While the plant assessment report provided recommendations based on achieving and maintaining plant service life and reliability goals, additional performance benefits were not quantified.

5.3 *Plant Cost, Reliability, Operability, and Maintainability Enhancements*

While not specifically related to plant performance, many issues were identified during Phase 1 as potential opportunities for improvement in overall plant cost, reliability, operational flexibility, and maintainability. Further evaluation of the following issues may be addressed in subsequent Project phases.

- **Additional redundancy for systems which currently have non-redundant equipment:** To keep capital cost to a minimum, equipment redundancy was minimized in the Phase 1 design. The additional capital cost required for increased redundancy in some systems may be offset by the expected plant reliability improvement.

- **Additional features to allow extended and more efficient plant turndown:** The nature of the oxycombustion process and the goal of the Phase 1 design to minimize capital cost where possible resulted in limited plant turndown range. The ASU, CPU, and Boiler/GQCS designs could be modified to accommodate a wider turndown range, provided the additional capital cost could be justified by improved plant performance, reliability, and O&M costs.

- **Transient analysis of LOx switchover (if ASU trips) and ability to continue uninterrupted oxy-combustion operation:** If uninterrupted operation is not achievable with the Phase 1 design, the impact of continued operation (vs. trip or shutdown, followed by restart) on plant economics will be evaluated vs. the additional capital cost required to modify the boiler and ASU design to accommodate such operation.

- **Increase ASU O_2 storage to accommodate extended ASU outages:** Additional capital cost of modifying the ASU design will be evaluated vs. the benefits (revenue, emissions impacts) of increased plant availability in oxycombustion operation.

- **Increase in onsite CPU CO_2 storage to accommodate brief pipeline outages:** Additional capital cost of modifying the CPU design will be evaluated vs. the benefits (revenue, emissions impacts) of extended range of plant operations and increased plant availability in the oxycombustion mode during pipeline upsets.

- **Cost and design impacts for eliminating boiler air-firing capability (SCR accommodations) entirely:** Future retrofitting of the new boiler to accommodate full load (or near full load) air firing is not likely to be considered a viable option under the FutureGen 2.0 program. Therefore the current provisions (space and structural design of the boiler/GQCS to accommodate future installation) included in the design provide no significant benefit. The capital cost savings, along with any potential performance improvements, realized by redesigning the boiler without consideration for future SCR installation will be evaluated.

- **Main boiler startup and auxiliary boiler fuel source - No. 2 fuel oil vs. natural gas:** Existing site natural gas system cannot support new plant requirements without significant upgrades. Capital cost impact for making the necessary natural gas system modifications will be evaluated vs. emissions/permitting benefits.

- **Plume abatement for new main cooling tower, as well as ASU/CPU and DCCPS cooling towers:** Due to site layout constraints, potential issues with cooling tower plume dispersion and drift are a concern (ice buildup on plant electrical equipment, fogging of in-plant areas). Options for alleviating or eliminating these concerns will be evaluated with respect to capital and operating cost impacts.

- **Existing steam turbine limitations and potential upgrades required to accommodate wider range of oxy-combustion plant operation:** The existing turbine steam path limitations regarding flow, pressure, and temperature changes to be accommodated with the oxycombustion cycle are uncertain. Additionally, equipment degradation has not been adequately quantified. Further investigation and confirmation of these issues with the turbine OEM is planned. If and where constraints exist, potential equipment upgrades to alleviate such constraints will be identified and economically evaluated.

- **Auxiliary boiler capacity - whether to include building heating and other potential loads in capacity:** While not directly impacting the operability of plant in oxycombustion mode, combining other miscellaneous plant heat loads into the new auxiliary boiler may provide overall capital cost and operating cost benefits for the Meredosia facility.

- **Elimination of copper from the feedwater system (includes replacement of LP feedwater heaters as well as change of ASU/CPU heat exchanger materials) to improve boiler water chemistry:** The additional capital cost of replacing existing equipment components and materials to eliminate copper may be justified by the long term savings in O&M costs, as well as potential plant availability improvements.

- **Upgrades of existing CHS equipment (additional crusher, feeders, etc.) and the impacts to main boiler design and coal handling system (CHS) to accommodate PRB coal blend. Boiler and CHS can currently accommodate limited mix of PRB, but will confirm in Phase 2 and will more thoroughly assess cost impacts for accommodating this blend:** Existing equipment is deemed adequate for the purpose required to support the new plant. However, operability benefits (less manual operation) and long term reliability improvements (new equipment) realized from upgrading the existing CHS, will be economically evaluated.

- **GQCS (WFGD and DCCPS mainly) materials of construction:** Reliability, maintainability, cost issues to be evaluated.

- **Use of dry limestone injection vs. wet limestone slurry:** Performance, cost, reliability, and maintainability issues to be evaluated.

- **Purchase of spare pumps (or rotating elements) and motors in lieu of overhauling existing equipment to minimize downtime after equipment failures. Mainly to be considered for large pumps (feedwater, condensate, circulating water, etc.):** Capital cost vs. reliability/availability impacts to be evaluated.

- **Scope and function of high-fidelity plant simulator:** Capital cost vs. potential performance improvements (via monitoring and optimization) and training benefits (operating cost reduction) to be evaluated.

- **Additional underground piping installation (vs. current general aboveground plan, especially in ASU/CPU areas):** Potential design and operability impacts vs. potential construction cost savings and improved plant access issues to be evaluated.

- **Removal of CPU and ASU compressor buildings, with use of noise hoods for noise abatement:** Capital cost reduction vs. plant noise emissions and operability/maintainability impacts to be further evaluated.

- **Use of truck storage (vs. permanent silo storage) for Trona, limestone, and other non-fuel consumables:** Potential capital cost savings realized by eliminating on-site permanent storage to be further evaluated.

- **Alternative landfill sites for ash/gypsum other than Duck Creek:** Permitting and cost issues to be further evaluated.

- **Installation of a new elevator to serve new Boiler 7:** Operability and plant access issues to be further evaluated to determine if existing Unit 3 elevator is sufficient or if a new elevator is warranted.

6.0 PRELIMINARY PERMITTING AND NEPA

6.1 *Permits*

URS continues to work with the B&W PGG, ALPC and the URS design teams to develop needed data regarding air emissions, solid waste generation, water usage, and wastewater discharges, including toxic and hazardous constituents contained therein. These data are needed so Ameren-Environmental may determine the appropriate permitting strategy and what types of permits will be required. Ameren is writing permit strategy white papers for air, water, and solid wastes to provide management with options and potential impacts associated with those options. Ameren and URS are gathering data to determine the applicability of regulatory requirements under US EPA, Illinois EPA, Illinois DNR, and the U.S. Army Corps of Engineers. It is anticipated that the proposed facility's operation will be consistent with current regulatory requirements. Specific regulatory emission limits will be met through the use of operational controls, process design limitations, and implemented control technologies and these will be specifically identified in the permit applications and assumed will be incorporated into the issued permits.

A permitting action plan (permit matrix) has been developed and is presented in Appendix I.

6.2 *Environmental Information Volume*

Based on direction from DOE at the January 26, 2011 meeting at Ameren, URS is not developing an EIV document, but is providing information to DOE's Environmental Impact Statement (EIS) contractor, PHE. URS will provide the information as it becomes available for PHE's use in developing the EIS. Also, in accordance with DOE direction, PHE will conduct the field work needed to support the EIS, based on input from URS and Ameren.

URS has also provided data to PHE for the EIS to include the following:

- A technical memorandum with site-specific information needed to conduct field studies for ambient noise measurements

- Maps showing locations of impacts in and around the facility

- Map of the probable location of a natural gas line and ROW width if the project determines that one is needed; narrative descriptions of the existing plant and proposed modifications

- General arrangement plan

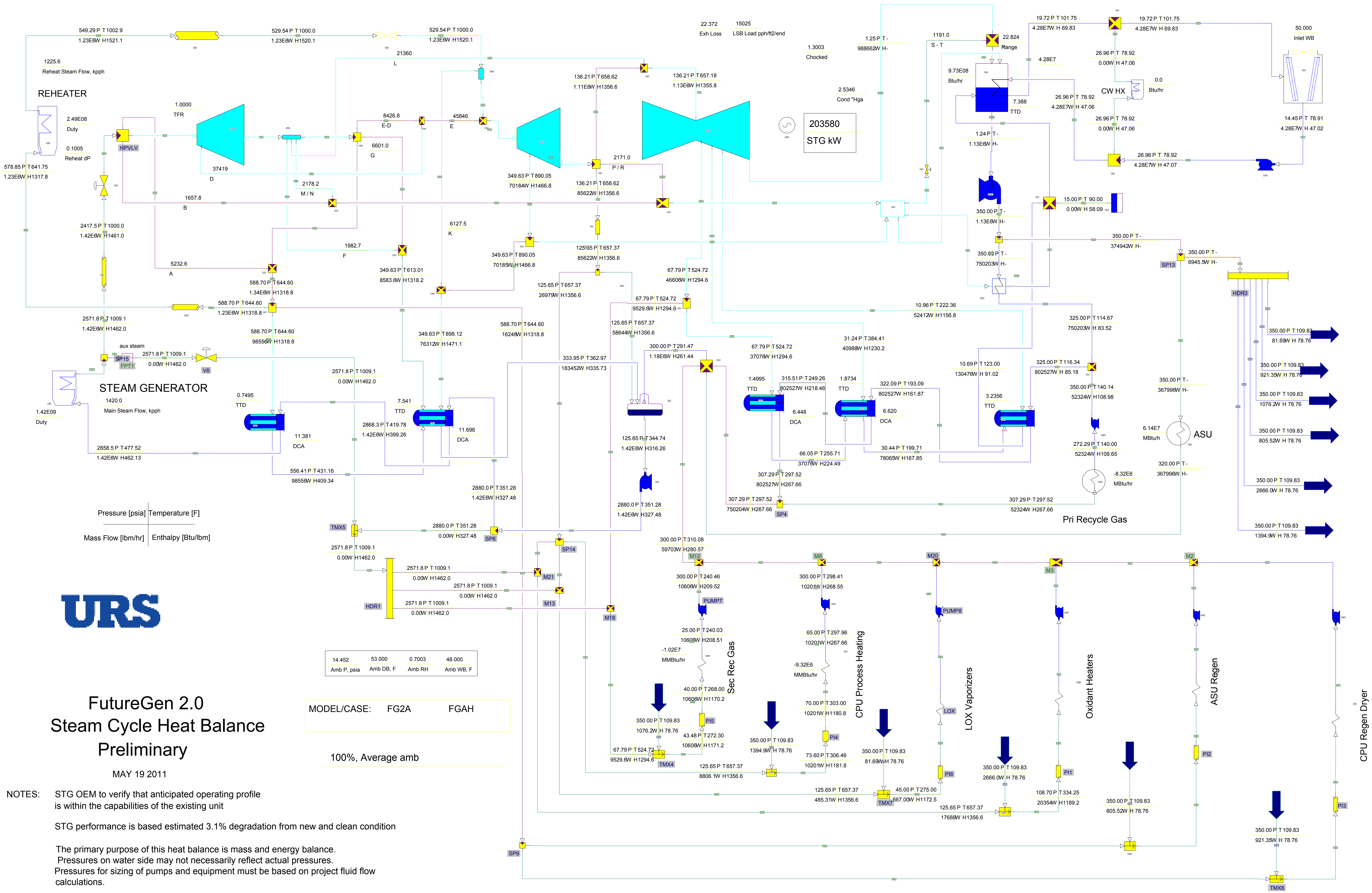
- Selected air permits

- Information on descriptions of processes, process inputs and outputs, and construction estimates.

Ameren has coordinated with PHE to conduct initial field work for the Ordinary High Water Mark, wetland delineations, traffic counts, noise measurements, and initial field survey for threatened and endangered species in and around Meredosia.

URS is working with Ameren to provide PHE with siting criteria for a potential off-site landfill, information on existing information regarding the facility's current operation to include permits, discharge reports, and operating procedures. Ameren will be discussing potential impacts to aquatic life in the river with the regulatory agencies to determine if field studies will be required in addition to obtaining clarification of regulatory requirements for barge unloading at Meredosia.

A APPENDIX – HEAT AND MASS BALANCES



REHEATER
1225.6
Reheat Steam Flow, kpph
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Duty
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Reheat dP
HPVLV
1.0000
TFR
STEAM GENERATOR
1420.0
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Duty
aux steam
SP15
FPT1
V6
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Exh Loss
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LSB Load pph/ft2/end
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Chocked
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STG kW
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Btu/hr
22.824
Range
7.388
TTD
CW HX
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Btu/hr
50.000
Inlet WB
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HDR3
ASU
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MBtu/h
-8.32E6
MBtu/hr
Pri Recycle Gas
Pressure [psia]
Temperature [F]
Mass Flow [lbm/hr]
Enthalpy [Btu/lbm]
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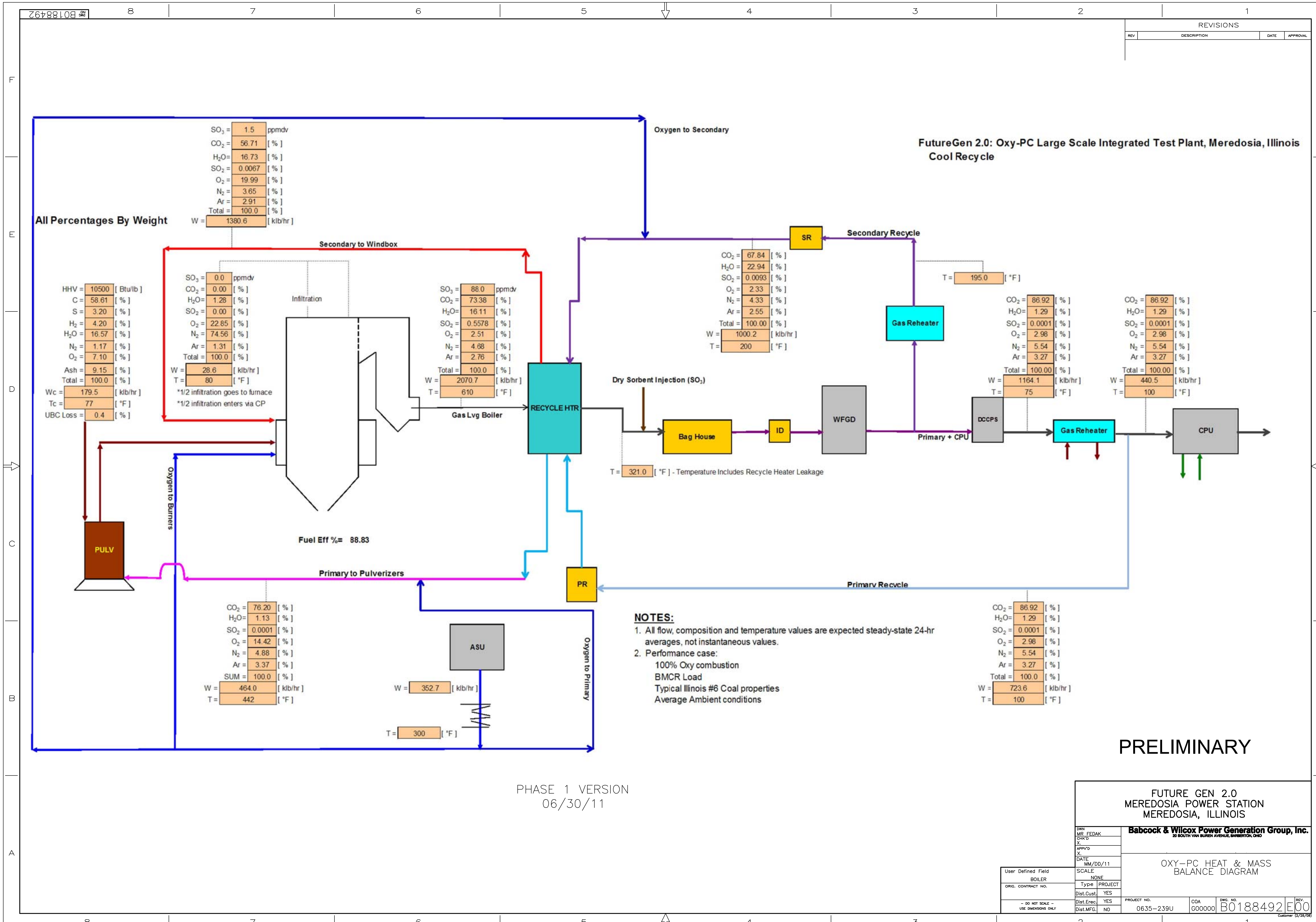
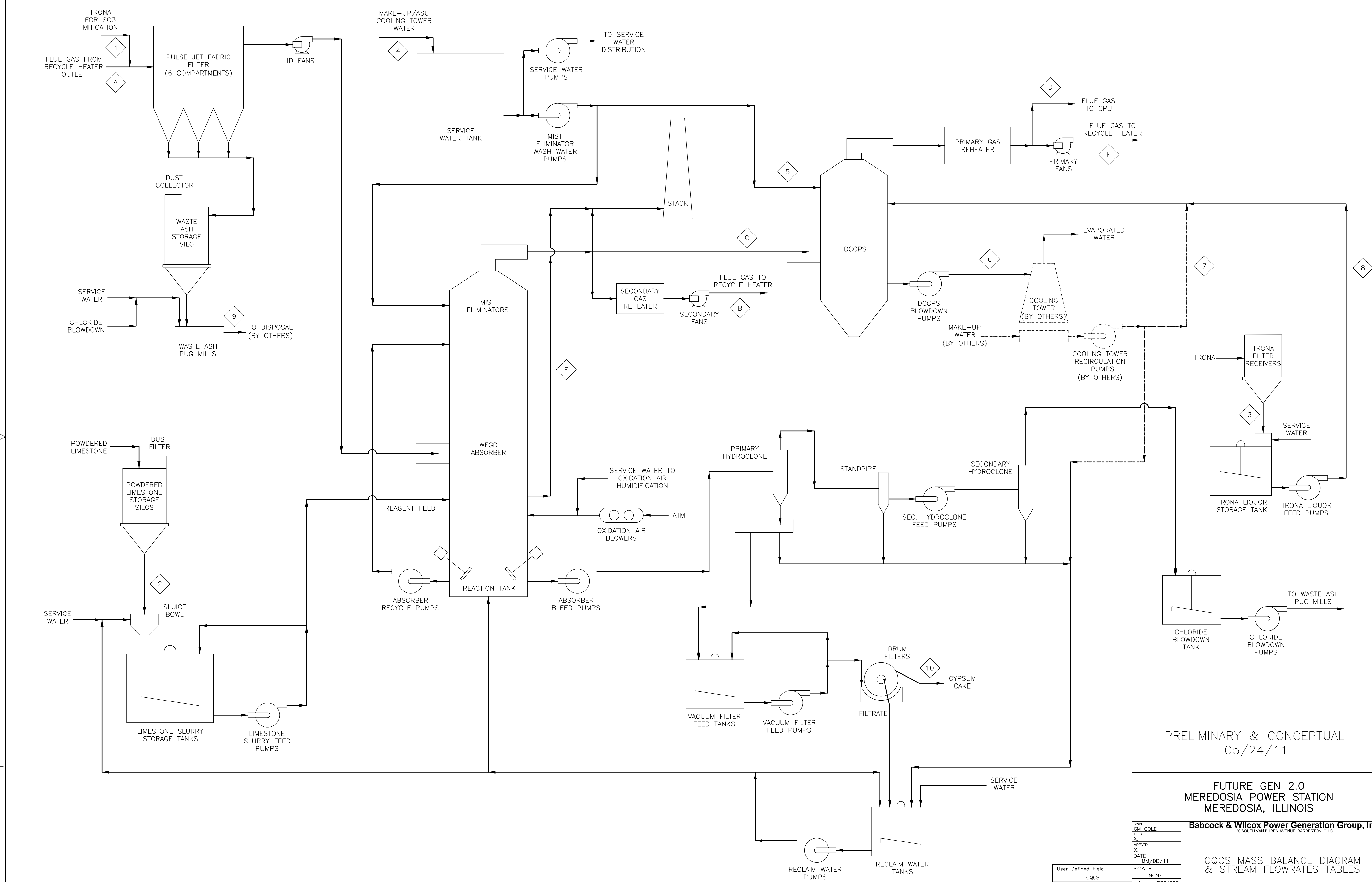
SP6
SP14
M21
M13
M18
HDR1
M12
M8
M20
M3
M2
PUMP7
PUMP8
Sec Rec Gas
CPU Process Heating
LOX Vaporizers
Oxidant Heaters
ASU Regen
CPU Regen Dryer
LOX
PI5
PI4
PI6
PI1
PI2
PI3
TMX4
TMX7
TMX6
SP9
14.452
Amb P, psia
53.000
Amb DB, F
0.7003
Amb RH
48.000
Amb WB, F
URS
FutureGen 2.0
Steam Cycle Heat Balance
Preliminary
MAY 19 2011
MODEL/CASE: FG2A FGAH
100%, Average amb
NOTES: STG OEM to verify that anticipated operating profile is within the capabilities of the existing unit
STG performance is based estimated 3.1% degradation from new and clean condition
The primary purpose of this heat balance is mass and energy balance.
Pressures on water side may not necessarily reflect actual pressures.
Pressures for sizing of pumps and equipment must be based on project fluid flow calculations.



FutureGen 2.0: Oxy-PC Large Scale Integrated Test Plant, Meredosia, Illinois
Cool Recycle
All Percentages By Weight
Oxygen to Secondary
SO3 = 1.5 ppmdv
CO2 = 56.71 [%]
H2O= 16.73 [%]
SO2 = 0.0067 [%]
O2 = 19.99 [%]
N2 = 3.65 [%]
Ar = 2.91 [%]
Total = 100.0 [%]
W = 1380.6 [klb/hr]
Secondary to Windbox
SR
Secondary Recycle
CO2 = 67.84 [%]
H2O = 22.94 [%]
SO2 = 0.0093 [%]
O2 = 2.33 [%]
N2 = 4.33 [%]
Ar = 2.55 [%]
Total = 100.00 [%]
W = 1000.2 [klb/hr]
T = 200 [°F]
T = 195.0 [°F]
Gas Reheater
HHV = 10500 [Btu/lb]
C = 58.61 [%]
S = 3.20 [%]
H2 = 4.20 [%]
H2O = 16.57 [%]
N2 = 1.17 [%]
O2 = 7.10 [%]
Ash = 9.15 [%]
Total = 100.0 [%]
Wc = 179.5 [klb/hr]
Tc = 77 [°F]
UBC Loss = 0.4 [%]
SO3 = 0.0 ppmdv
CO2 = 0.00 [%]
H2O= 1.28 [%]
SO2 = 0.00 [%]
O2 = 22.85 [%]
N2 = 74.56 [%]
Ar = 1.31 [%]
Total = 100.0 [%]
W = 28.6 [klb/hr]
T = 80 [°F]
*1/2 infiltration goes to furnace
*1/2 infiltration enters via CP
Infiltration
SO3 = 88.0 ppmdv
CO2 = 73.38 [%]
H2O= 16.11 [%]
SO2 = 0.5578 [%]
O2 = 2.51 [%]
N2 = 4.68 [%]
Ar = 2.76 [%]
Total = 100.0 [%]
W = 2070.7 [klb/hr]
T = 610 [°F]
Gas Lvg Boiler
RECYCLE HTR
Dry Sorbent Injection (SO3)
Bag House
ID
WFGD
Primary + CPU
DCCPS
CO2 = 86.92 [%]
H2O= 1.29 [%]
SO2 = 0.0001 [%]
O2 = 2.98 [%]
N2 = 5.54 [%]
Ar = 3.27 [%]
Total = 100.00 [%]
W = 1164.1 [klb/hr]
T = 75 [°F]
Gas Reheater
CO2 = 86.92 [%]
H2O= 1.29 [%]
SO2 = 0.0001 [%]
O2 = 2.98 [%]
N2 = 5.54 [%]
Ar = 3.27 [%]
Total = 100.00 [%]
W = 440.5 [klb/hr]
T = 100 [°F]
CPU
T = 321.0 [°F] - Temperature Includes Recycle Heater Leakage
Oxygen to Burners
PULV
Fuel Eff %= 88.83
Primary to Pulverizers
PR
Primary Recycle
CO2 = 76.20 [%]
H2O= 1.13 [%]
SO2 = 0.0001 [%]
O2 = 14.42 [%]
N2 = 4.88 [%]
Ar = 3.37 [%]
SUM = 100.0 [%]
W = 464.0 [klb/hr]
T = 442 [°F]
ASU
W = 352.7 [klb/hr]
T = 300 [°F]
Oxygen to Primary
NOTES:
1. All flow, composition and temperature values are expected steady-state 24-hr averages, not instantaneous values.
2. Performance case:
100% Oxy combustion
BMCR Load
Typical Illinois #6 Coal properties
Average Ambient conditions
CO2 = 86.92 [%]
H2O= 1.29 [%]
SO2 = 0.0001 [%]
O2 = 2.98 [%]
N2 = 5.54 [%]
Ar = 3.27 [%]
Total = 100.0 [%]
W = 723.6 [klb/hr]
T = 100 [°F]
PRELIMINARY
PHASE 1 VERSION
06/30/11
REVISIONS
FUTURE GEN 2.0
MEREDOSIA POWER STATION
MEREDOSIA, ILLINOIS
Babcock & Wilcox Power Generation Group, Inc.
OXY-PC HEAT & MASS BALANCE DIAGRAM
DWN MR FEDAK
SCALE NONE
PROJECT NO. 0635-239U
COA G00000
DWG NO. B0188492
REV. E00

FUTURE GEN 2.0 – MEREDOSIA POWER STATION – OXYCOMBUSTION



PRELIMINARY & CONCEPTUAL
05/24/11

REVISIONS			
REV	DESCRIPTION	DATE	APPROVAL

FUTURE GEN 2.0
MEREDOSIA POWER STATION
MEREDOSIA, ILLINOIS

Babcock & Wilcox Power Generation Group, Inc.
20 SOUTH VAN BUREN AVENUE, BARBERTON, OHIO

GQCS MASS BALANCE DIAGRAM & STREAM FLOWRATES TABLES

DWN	GM COLE
CHK'D	X
APP'D	X
DATE	MM/DD/11
SCALE	NONE
Type	PROJECT
Dist.Cust.	YES
Dist.Erec.	YES
Dist.MFG.	NO

User Defined Field: GQCS
ORIG. CONTRACT NO.
– DO NOT SCALE – USE DIMENSIONS ONLY

PROJECT NO. 0635-239U | COA G00000 | DWG. NO. B0186736 | REV. E00

Customer (2/24/06)

DWG NO B0186736

Design Coal Analysis	
M1A - Performance Case	
Component	wt %
Moisture	16.57
Carbon	58.61
Hydrogen	4.20
Nitrogen	1.17
Sulfur	3.20
Ash	8.99
Oxygen	7.10
Chlorine	0.16
Fluorine	0.01
Heating Value	10,500

Trona Analysis	
For DSI System	
Component	wt %
$Na_2CO_3 \cdot NaHCO_3 \cdot 2H_2O$	97.00
Free Moisture	0.03
Inerts	2.97
For DCCPS Reagent	
Component	wt %
$Na_2CO_3 \cdot NaHCO_3 \cdot 2H_2O$	93.50
Free Moisture	0.01
NaCl	0.10
Insoluble	6.40

Limestone Analysis	
Total $CaCO_3$	93.80%
Total $MgCO_3$	2.20%
Total Inerts	4.00%

FLOW RATES SHOWN ARE 24 HOUR AVERAGE FLOWS

Gas Stream ID →		A	B	C	D	E	F
Item	Units	Recycle Heater Outlet Flue Gas	Secondary Gas to Recycle Heater	DCCPS Inlet Flue Gas	CPU Inlet Flue Gas	Primary Gas to Recycle Heater	WFGD Vent to Stack
Total Flow (Wet)	ACFM	652,197	276,143	352,796	77,812	119,506	17,180
Temperature	°F	340	300	170	130	160	170
Flue Gas Pressure	in.wg.	-7.0	25.0	10.0	1.0	50.0	1.0
Total Flow (Wet)	lb/hr	2,287,679	1,003,873	1,492,562	441,309	723,814	59,734
CO_2	lb/hr	1,693,385	680,945	1,012,431	383,446	628,910	9,270
H_2O	lb/hr	337,995	230,295	342,402	5,737	9,409	11,754
SO_2	lb/hr	11,421	93	139	1	1	0
N_2 + Ar	lb/hr	172,066	69,169	102,840	38,967	63,912	31,874
O_2	lb/hr	58,098	23,361	34,733	13,155	21,576	6,836
HCl	lb/hr	299	2	4	0	0	0
HF	lb/hr	10	0	0	0	0	0
H_2SO_4	lb/hr	356	4	6	2	3	0
Ash	lb/hr	14,049	4	7	2	3	0
Molecular Weight	lb/lbmol	35.14	32.19	32.19	41.32	41.32	27.05

Solids Stream ID →		1	2	3
Item	Units	Trona Feed To Flue Gas	Powdered Limestone To System	Trona Feed To DCCPS System
Mass Flow	lb/hr	3,748	20,421	361
Moisture	%	0.03%	0.00%	0.10%
Trona	lb/hr	3,636	-	337
NaCl	lb/hr	-	-	0.4
$CaCO_3$	lb/hr	-	19,155	-
$MgCO_3$	lb/hr	-	449	-
Inerts	lb/hr	111	817	23

Liquid Stream ID →		4	5	6	7	8	9	10
Item	Units	Make-Up Water To System	DCCPS Mist Eliminator Wash Water	DCCPS Blowdown To Cooling Tower	Cooling Tower Recirc To DCCPS	Trona Liquor Feed to DCCPS	Waste Ash To Disposal	Gypsum Cake To Disposal
Volumetric Flow	GPM	181	32	15,418	14,462	5	-	-
Mass Flow	lb/hr	90,569	15,804	7,740,734	7,261,937	2,886	17,577	41,351
Suspended Solids	%	0.0%	0.0%	0.0%	0.0%	0.0%	80.0%	80.0%
Moisture	%	100.0%	100.0%	100.0%	100.0%	100.0%	20.0%	20.0%
Dissolved Solids	%	0.05%	0.05%	0.53%	0.55%	12.5%	5.2%	5.2%
Water	lb/hr	90,525	15,797	7,699,924	7,222,215	2,524	3,465	8,176
Na_2SO_4	lb/hr	1	0	TBD	TBD	0	0	0
Na_2SO_3	lb/hr	0	0	TBD	TBD	0	0	0
$NaHSO_3$	lb/hr	0	0	TBD	TBD	0	0	0
Na_2CO_3	lb/hr	0	0	TBD	TBD	36	0	0
$NaHCO_3$	lb/hr	0	0	TBD	TBD	301	0	0
NaCl	lb/hr	11	2	TBD	TBD	1	200	469
$CaSO_4 \cdot 2H_20$	lb/hr	0	0	TBD	TBD	0	33	30,196
$CaSO_3 \cdot ½H_20$	lb/hr	0	0	TBD	TBD	0	1	68
$CaCO_3$	lb/hr	17	3	TBD	TBD	0	4	1,280
$MgSO_4$	lb/hr	10	2	TBD	TBD	0	0	0
$MgCO_3$	lb/hr	5	1	TBD	TBD	0	3	337
Inerts	lb/hr	0	0	TBD	TBD	23	12	817
Ash	lb/hr	0	0	TBD	TBD	0	13,860	8
Cl	ppm	73	73	TBD	TBD	103	35,000	34,809
SG Liquor		1.00	1.00	1.00	1.00	1.11	N/A	N/A

NOTE 1: ALL FLOWRATES ARE EXPECTED FLOWRATES (AVERAGED OVER 24 HOURS AND NOT INSTANTANEOUS).

NOTE 2: PERFORMANCE CASE, 100% OXYCOMBUSTION AT FULL LOAD.

PRELIMINARY & CONCEPTUAL
05/24/11

REVISIONS			
REV	DESCRIPTION	DATE	APPROVAL

FUTURE GEN 2.0
MEREDOSIA POWER STATION
MEREDOSIA, ILLINOIS

Babcock & Wilcox Power Generation Group, Inc.
20 SOUTH VAN BUREN AVENUE, BARBERTON, OHIO

GQCS MASS BALANCE DIAGRAM & STREAM FLOWRATES TABLES

DWN	GM COLE
CHK'D	X
APPV'D	X
DATE	MM/DD/11
SCALE	NONE
Type	PROJECT
Dist.Cust.	YES
Dist.Erec.	YES
Dist.MFG.	NO

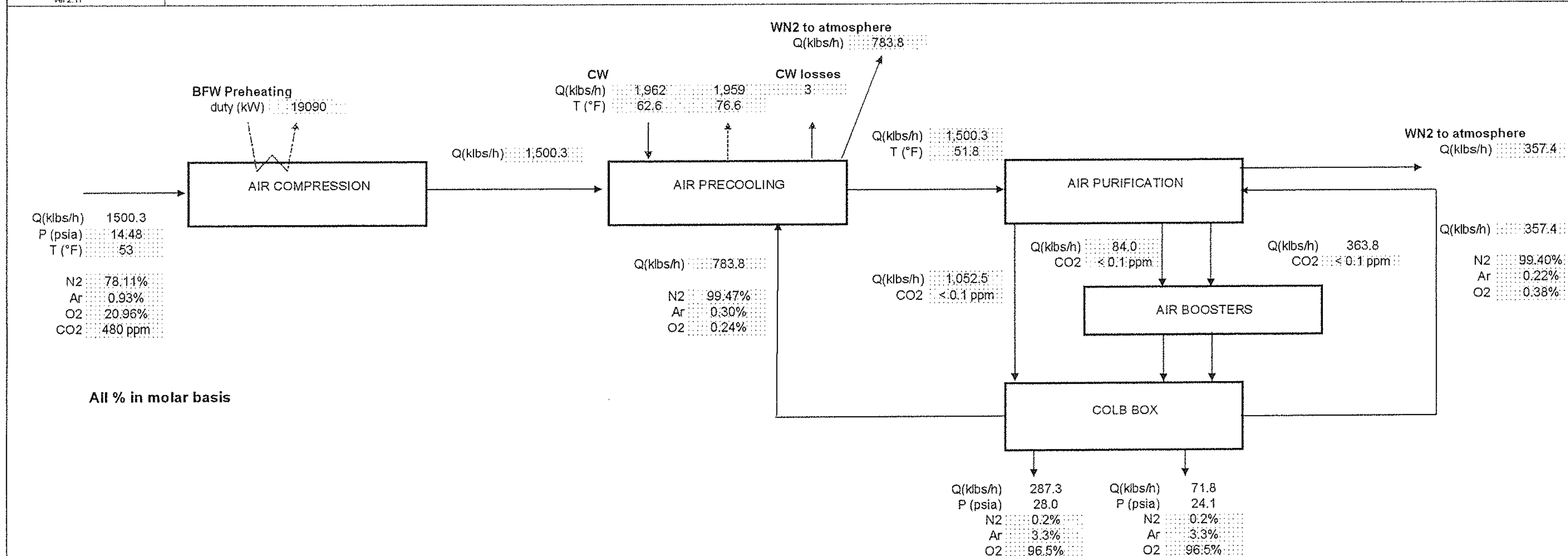
User Defined Field: GQCS
ORIG. CONTRACT NO.
– DO NOT SCALE – USE DIMENSIONS ONLY

PROJECT NO. 0635-239U | COA G00000 | DWG. NO. B0186736 | REV. E00

Customer (2/24/06)

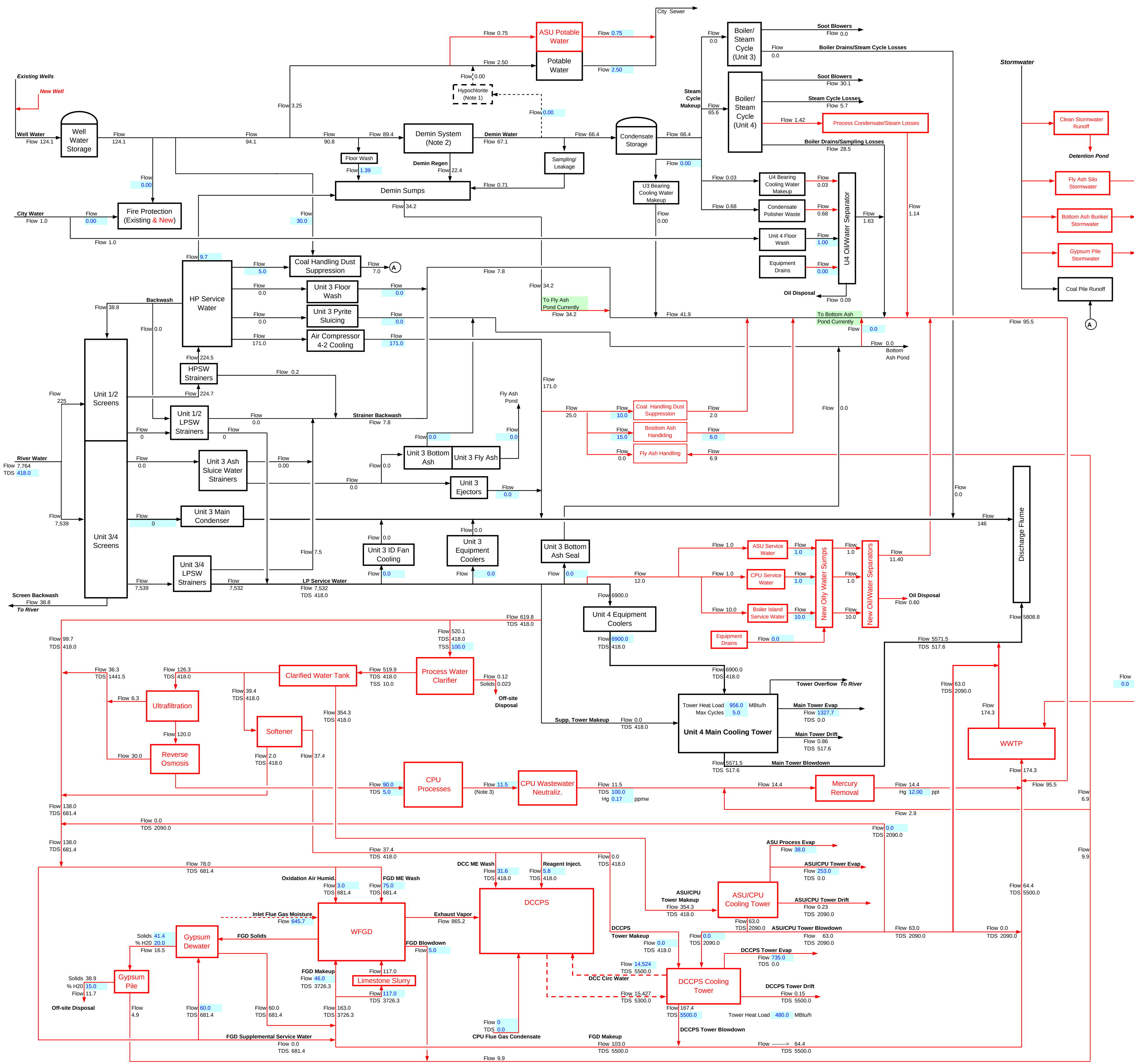
DWG NO. B0186736

AIR LIQUIDE	Job nbr : 7978 Name : FUTUREGEN 2.0	PRELIMINARY	Document number 7978-020-ASU PDS-102
PROCESS DATA Ver 2.11	HEAT AND MASS BALANCE		UR



Revision	a	b	c	d	0	1	2	3	Page
DATE	4/5/2011								1/1
BY	HM								
SIGN	HM HM								
FOR	Preliminary								

B APPENDIX – WATER BALANCES



All Flows are liquid flows in gallons per minute (gpm) at 60 °F under long-term average operating conditions

Where solids are indicated, figures are flow rates in klb/hr (wet) under average operating conditions

All TDS (total dissolved solids) are in ppm

Black indicates existing systems. Red indicates new or modified systems.

Notes:

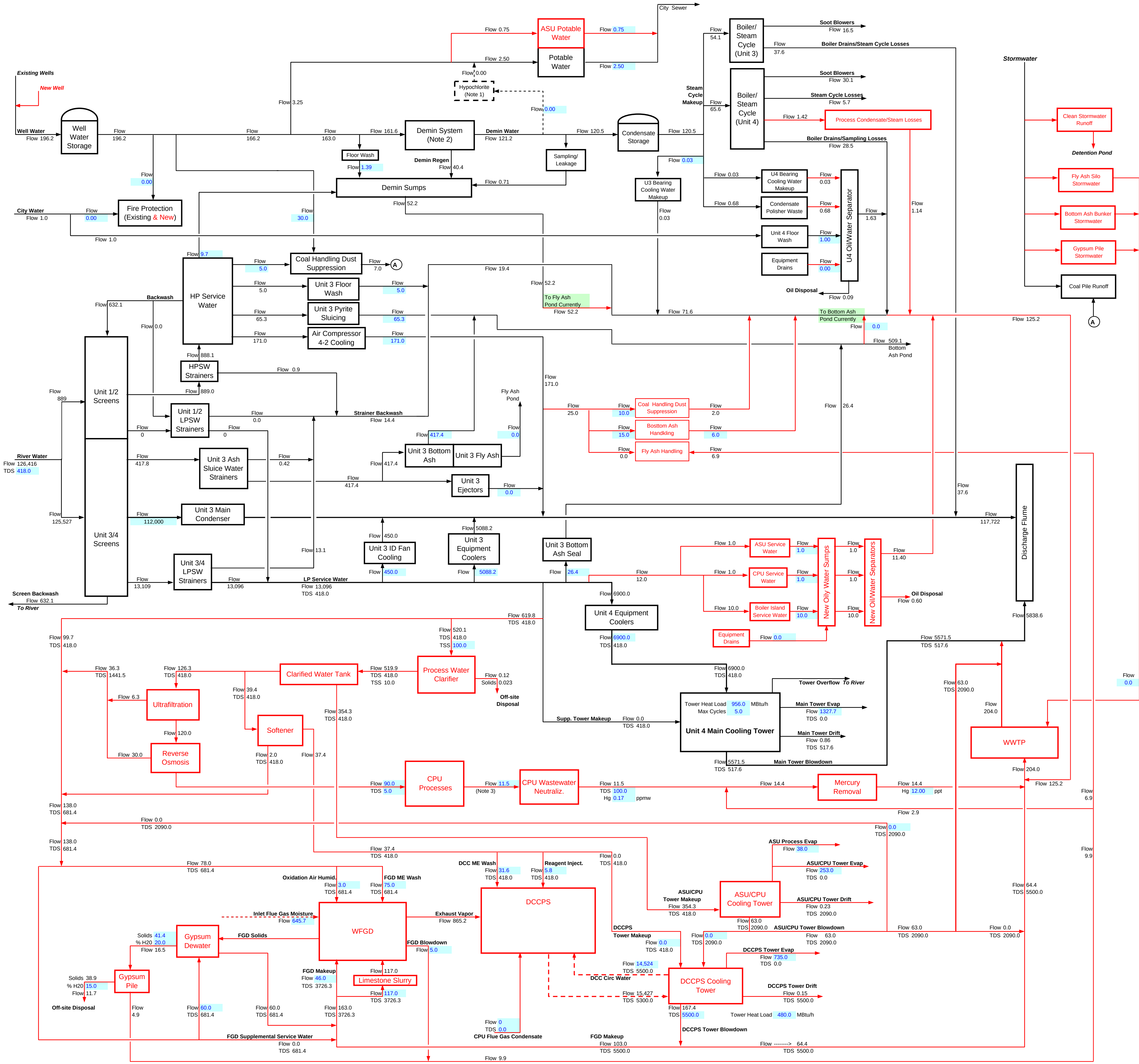
1) Hypochlorite not currently used, but still permitted.
2) Existing demin system currently limited to approximately 150 gpm effective average capacity due to frequent regeneration
3) CPU process wastewater will have pH of 1-2 and will need to be neutralized

FutureGen 2.0 - Preliminary Water Balance

Unit 4 Only Operating

Revision: D

Date: 20-May-2011



All Flows are liquid flows in gallons per minute (gpm) at 60 °F under long-term average operating conditions

Where solids are indicated, figures are flow rates in klb/hr (wet) under average operating conditions

All TDS (total dissolved solids) are in ppm

Black indicates existing systems. Red indicates new or modified systems.

Notes:

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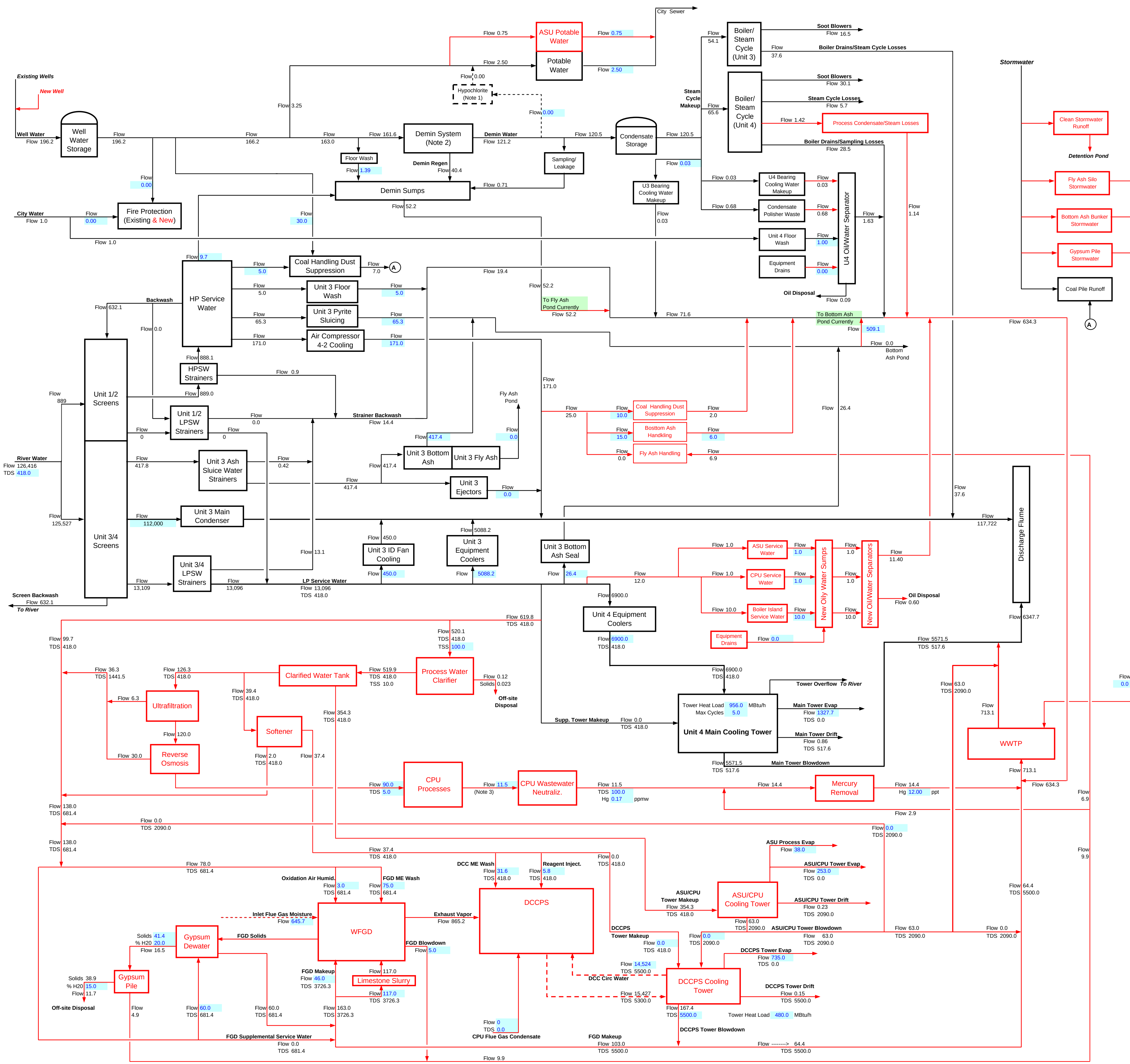
2) Existing demin system currently limited to approximately 150 gpm effective average capacity due to frequent regeneration
3) CPU process wastewater will have pH of 1-2 and will need to be neutralized

FutureGen 2.0 - Preliminary Water Balance

Unit 3 and 4 Operating, with U3 Discharges to Bottom Ash Pond

Revision: D

Date: 20-May-2011



All Flows are liquid flows in gallons per minute (gpm) at 60 °F under long-term average operating conditions

Where solids are indicated, figures are flow rates in klb/hr (wet) under average operating conditions

All TDS (total dissolved solids) are in ppm

Black indicates existing systems. Red indicates new or modified systems.

Notes:

1) Hypochlorite not currently used, but still permitted.

2) Existing demin system currently limited to approximately 150 gpm effective average capacity due to frequent regeneration

3) CPU process wastewater will have pH of 1-2 and will need to be neutralized

FutureGen 2.0 - Preliminary Water Balance

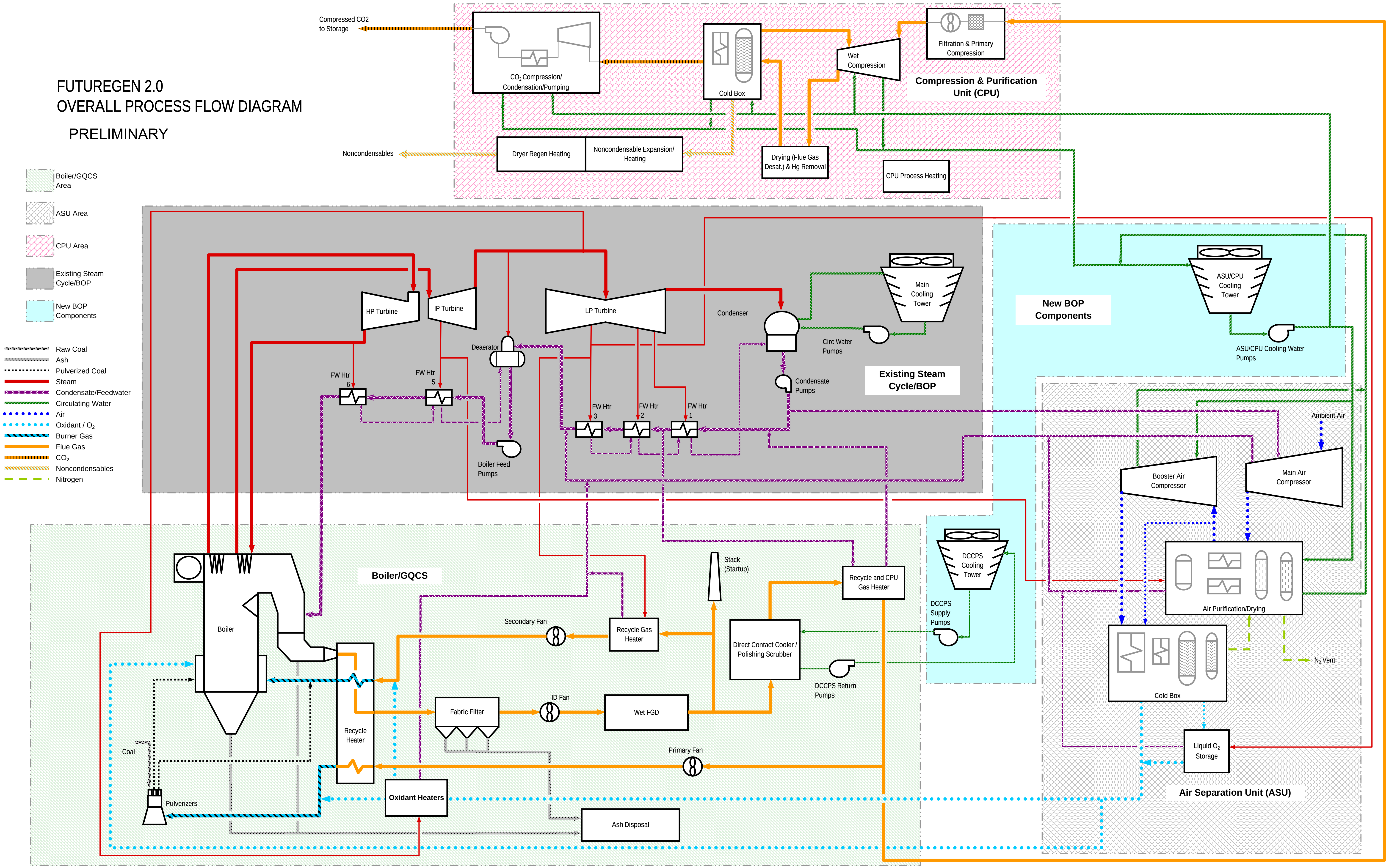
Unit 3 and Unit 4 Operating, no Bottom Ash Pond Discharge

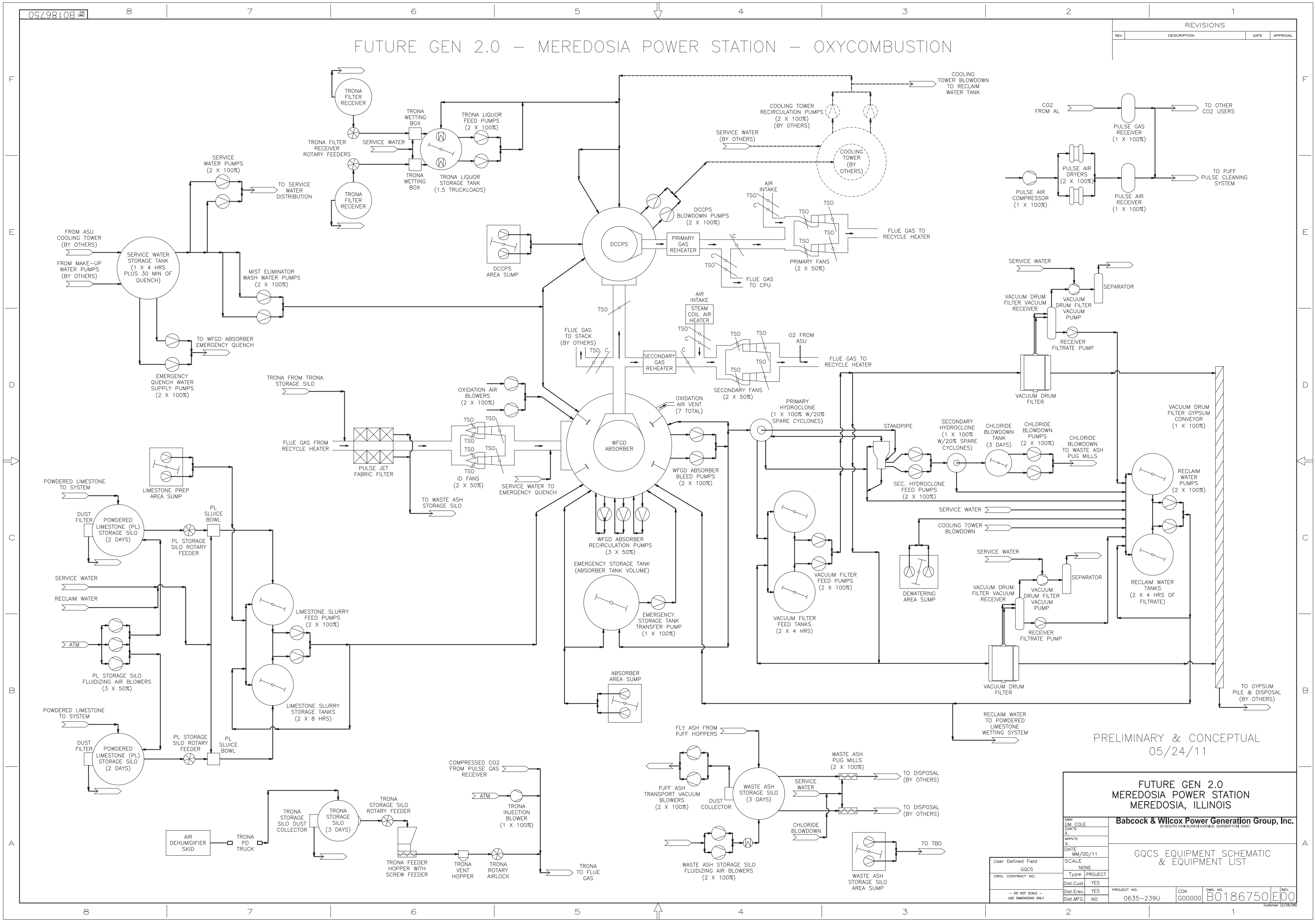
Revision: D

Date: 20-May-2011

C APPENDIX – PROCESS FLOW DIAGRAMS

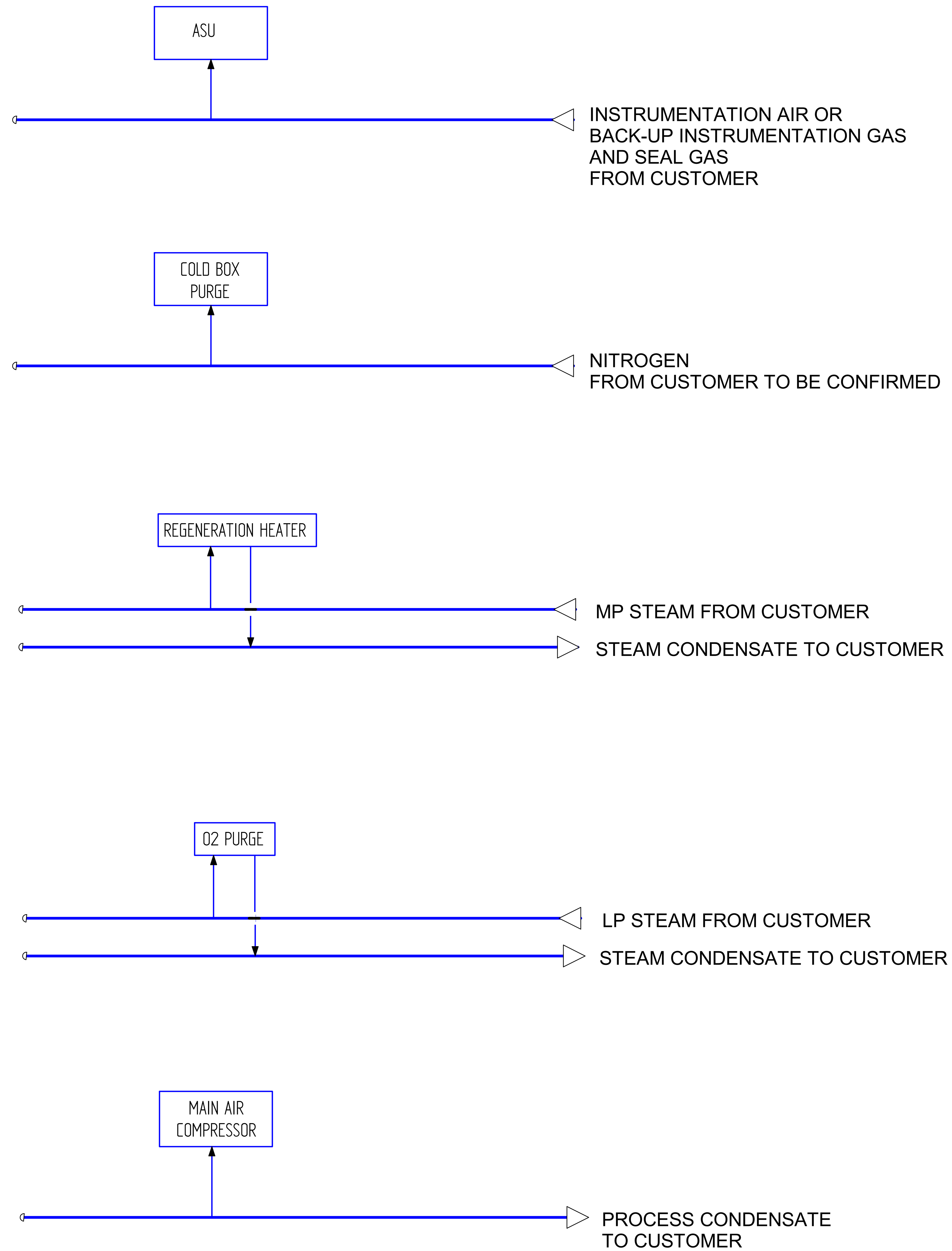
FUTUREGEN 2.0
OVERALL PROCESS FLOW DIAGRAM
PRELIMINARY





FUTURE GEN 2.0 — MEREDOSIA POWER STATION — OXYCOMBUSTION
REVISIONS
REV
DESCRIPTION
DATE
APPROVAL
TRONA FILTER RECEIVER
TRONA FILTER RECEIVER ROTARY FEEDERS
TRONA WETTING BOX
SERVICE WATER
TRONA LIQUOR FEED PUMPS (2 X 100%)
TRONA LIQUOR STORAGE TANK (1.5 TRUCKLOADS)
COOLING TOWER BLOWDOWN TO RECLAIM WATER TANK
COOLING TOWER RECIRCULATION PUMPS (2 X 100%) (BY OTHERS)
SERVICE WATER (BY OTHERS)
COOLING TOWER (BY OTHERS)
CO2 FROM AL
PULSE GAS RECEIVER (1 X 100%)
TO OTHER CO2 USERS
PULSE AIR DRYERS (2 X 100%)
PULSE AIR COMPRESSOR (1 X 100%)
PULSE AIR RECEIVER (1 X 100%)
TO PJFF PULSE CLEANING SYSTEM
SERVICE WATER PUMPS (2 X 100%)
TO SERVICE WATER DISTRIBUTION
FROM ASU COOLING TOWER (BY OTHERS)
FROM MAKE-UP WATER PUMPS (BY OTHERS)
SERVICE WATER STORAGE TANK (1 X 4 HRS PLUS 30 MIN OF QUENCH)
MIST ELIMINATOR WASH WATER PUMPS (2 X 100%)
TO WFGD ABSORBER EMERGENCY QUENCH
EMERGENCY QUENCH WATER SUPPLY PUMPS (2 X 100%)
DCCPS AREA SUMP
DCCPS
DCCPS BLOWDOWN PUMPS (2 X 100%)
PRIMARY GAS REHEATER
AIR INTAKE
TSO
C
PRIMARY FANS (2 X 50%)
FLUE GAS TO RECYCLE HEATER
FLUE GAS TO CPU
FLUE GAS TO STACK (BY OTHERS)
STEAM COIL AIR HEATER
SECONDARY GAS REHEATER
SECONDARY FANS (2 X 50%)
O2 FROM ASU
SERVICE WATER
SEPARATOR
VACUUM DRUM FILTER VACUUM RECEIVER
VACUUM DRUM FILTER VACUUM PUMP
RECEIVER FILTRATE PUMP
VACUUM DRUM FILTER
VACUUM DRUM FILTER GYPSUM CONVEYOR (1 X 100%)
TRONA FROM TRONA STORAGE SILO
OXIDATION AIR BLOWERS (2 X 100%)
OXIDATION AIR VENT (7 TOTAL)
FLUE GAS FROM RECYCLE HEATER
PULSE JET FABRIC FILTER
ID FANS (2 X 50%)
TO WASTE ASH STORAGE SILO
SERVICE WATER TO EMERGENCY QUENCH
WFGD ABSORBER
WFGD ABSORBER BLEED PUMPS (2 X 100%)
PRIMARY HYDROCLONE (1 X 100% W/20% SPARE CYCLONES)
STANDPIPE
SECONDARY HYDROCLONE (1 X 100% W/20% SPARE CYCLONES)
SEC. HYDROCLONE FEED PUMPS (2 X 100%)
CHLORIDE BLOWDOWN TANK (3 DAYS)
CHLORIDE BLOWDOWN PUMPS (2 X 100%)
CHLORIDE BLOWDOWN TO WASTE ASH PUG MILLS
RECLAIM WATER PUMPS (2 X 100%)
LIMESTONE PREP AREA SUMP
POWDERED LIMESTONE TO SYSTEM
DUST FILTER
POWDERED LIMESTONE (PL) STORAGE SILO (2 DAYS)
PL STORAGE SILO ROTARY FEEDER
PL SLUICE BOWL
WFGD ABSORBER RECIRCULATION PUMPS (3 X 50%)
EMERGENCY STORAGE TANK (ABSORBER TANK VOLUME)
EMERGENCY STORAGE TANK TRANSFER PUMP (1 X 100%)
VACUUM FILTER FEED PUMPS (2 X 100%)
VACUUM FILTER FEED TANKS (2 X 4 HRS)
COOLING TOWER BLOWDOWN
DEWATERING AREA SUMP
RECLAIM WATER TANKS (2 X 4 HRS OF FILTRATE)
SERVICE WATER
RECLAIM WATER
ATM
PL STORAGE SILO FLUIDIZING AIR BLOWERS (3 X 50%)
LIMESTONE SLURRY FEED PUMPS (2 X 100%)
LIMESTONE SLURRY STORAGE TANKS (2 X 8 HRS)
ABSORBER AREA SUMP
VACUUM DRUM FILTER
TO GYPSUM PILE & DISPOSAL (BY OTHERS)
RECLAIM WATER TO POWDERED LIMESTONE WETTING SYSTEM
PRELIMINARY & CONCEPTUAL 05/24/11
FLY ASH FROM PJFF HOPPERS
PJFF ASH TRANSPORT VACUUM BLOWERS (2 X 100%)
DUST COLLECTOR
WASTE ASH STORAGE SILO (3 DAYS)
WASTE ASH PUG MILLS (2 X 100%)
TO DISPOSAL (BY OTHERS)
CHLORIDE BLOWDOWN
WASTE ASH STORAGE SILO FLUIDIZING AIR BLOWERS (2 X 100%)
WASTE ASH STORAGE SILO AREA SUMP
TO TBD
COMPRESSED CO2 FROM PULSE GAS RECEIVER
TRONA INJECTION BLOWER (1 X 100%)
AIR DEHUMIDIFIER SKID
TRONA PD TRUCK
TRONA STORAGE SILO DUST COLLECTOR
TRONA STORAGE SILO (3 DAYS)
TRONA STORAGE SILO ROTARY FEEDER
TRONA FEEDER HOPPER WITH SCREW FEEDER
TRONA VENT HOPPER
TRONA ROTARY AIRLOCK
TRONA TO FLUE GAS
FUTURE GEN 2.0
MEREDOSIA POWER STATION
MEREDOSIA, ILLINOIS
Babcock & Wilcox Power Generation Group, Inc.
DWN CM COLE
DATE MM/DD/11
SCALE NONE
GQCS EQUIPMENT SCHEMATIC & EQUIPMENT LIST
User Defined Field GQCS
PROJECT NO. 0635-239U
COA G00000
DWG. NO. B0186750
REV. E00

WASTE NITROGEN
WASTE NITROGEN
C05-1
C05-2
AIR PURIFICATION
AIR BOOSTER
AIR BOOSTER 2
R01
R02
Nitrogen vent
Nitrogen vent
Nitrogen vent
COOLING WATER
COOLING WATER
COLD BOX
GOX to primary and secondary
GOX to burners
LOX
LOX STORAGE
V40
LOX VAPORIZER
P41
MAIN AIR COMPRESSOR
F01
C01
BFW
OPTION
E07
X60
PRECOOLING
P60
E60
P61
PRELIMINARY
AIR LIQUIDE KEEP THE RIGHT TO MODIFY THIS DRAWING DURING THE PROJECT EXECUTION
a
11/10/10
JB
Preliminary
HM
HM
REV REV
DATE DATE
DESSINE PAR DRAWN BY
MODIFICATIONS REVISIONS
VERIFIE PAR CHECKED BY
APPROUVE PAR APPROVED BY
AFFAIRE / JOB
FUTUREGEN 2.0
ENSEMBLE / PART
BLOCK DIAGRAM
TITRE / TITLE
ASU BLOCK DIAGRAM
AIR LIQUIDE
N° D'AFFAIRE JOB N°
7978
DOCUMENT N° N° DOCUMENT
7978-020-ASU BFD-001-UL
a
A0 - DS.122.07.03



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REV REV	DATE DATE	DESSINE PAR DRAWN BY	MODIFICATIONS REVISIONS	VERIFIE PAR CHECKED BY	APPROUVE PAR APPROVED BY
a	12/06/10	JB	Preliminary	HM	HM

AFFAIRE / JOB
FUTUREGEN 2.0

ENSEMBLE / PART
BLOCK DIAGRAM

TITRE / TITLE
ASU UTILITIES BLOCK DIAGRAM

AIR LIQUIDE

N° D'AFFAIRE JOB N°: 7978

DOCUMENT N° N° DOCUMENT: 7978-020-ASU BFD-002-UL

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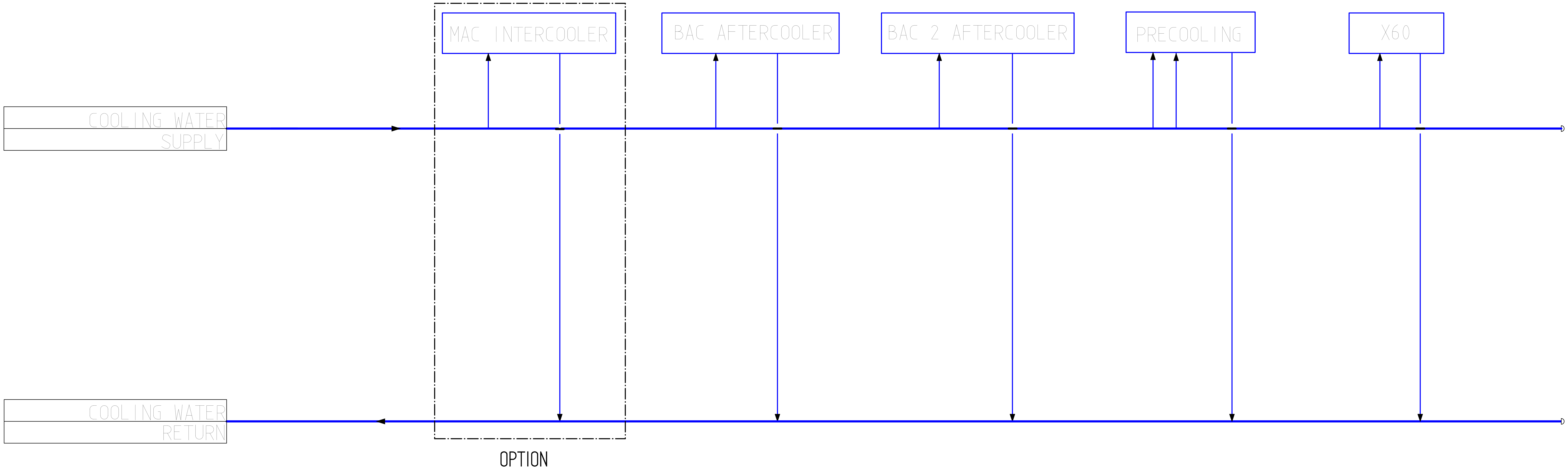
A0 - DS.122.07.03



PRELIMINARY
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REV	DATE	DESSINE PAR / DRAWN BY	MODIFICATIONS / REVISIONS	VERIFIE PAR / CHECKED BY	APPROUVE PAR / APPROVED BY
a	11/10/10	JB	Preliminary	HM	HM

AFFAIRE / JOB: FUTUREGEN 2.0

ENSEMBLE / PART: BLOCK DIAGRAM

TITRE / TITLE: ASU COOLING WATER BLOCK DIAGRAM

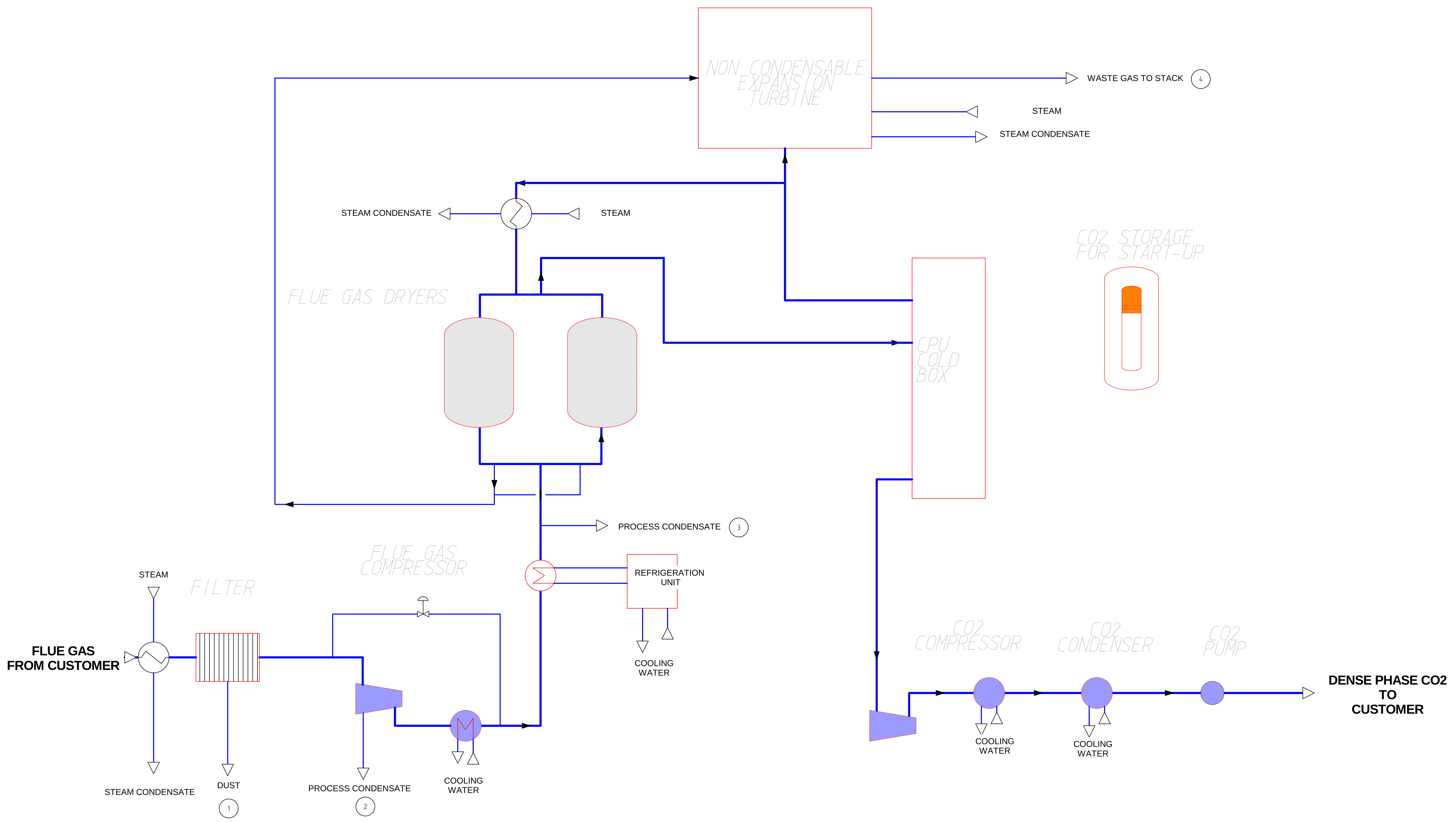
AIR LIQUIDE™

N° D'AFFAIRE / JOB N°: 7978

DOCUMENT N° / N° DOCUMENT: 7978-020-ASU BFD-003-UL

a

A0 - DS.122.07.03



PRELIMINARY
AIR LIQUIDE KEEP THE RIGHT TO MODIFY THIS DRAWING DURING THE PROJECT EXECUTION

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SZAMLEWSKI	LOCKWOOD	.	.	SZAMLEWSKI	PRELIMINARY	2011-08-31	D
VALLIER	LOCKWOOD	.	.	SZAMLEWSKI	PRELIMINARY	2010-12-14	C
DENISART	LOCKWOOD		.	SZAMLEWSKI	PRELIMINARY	2010-12-03	B
DENISART	LOCKWOOD	.	.	SZAMLEWSKI	PRELIMINARY	2010-11-18	A

PROJECT NAME
FUTURE GEN 2.0

PART
OXYCOMBUSTION LARGE SCALE TEST

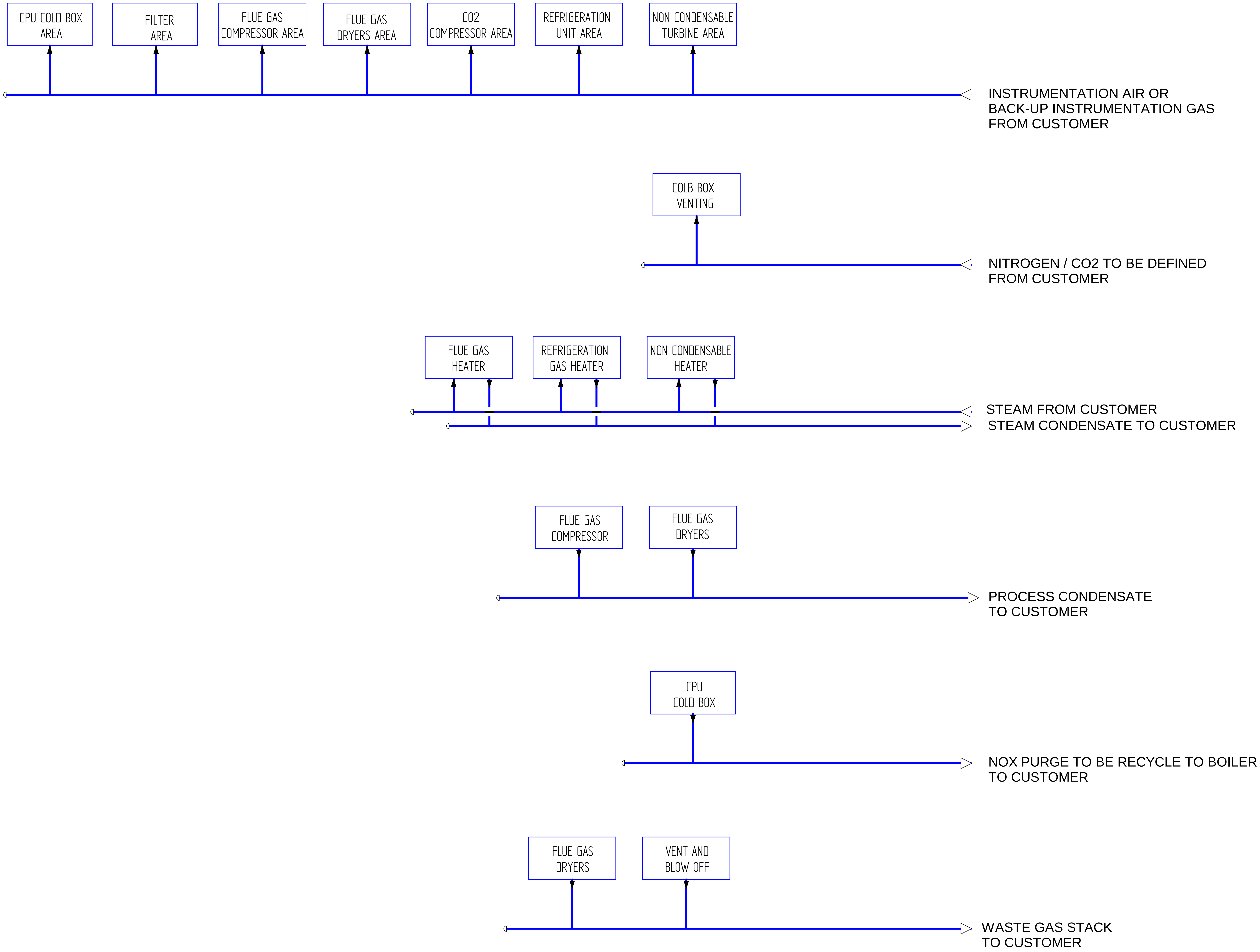
TITLE
OVERALL
BLOCK FLOW DIAGRAM

AIR LIQUIDE

ALE DOCUMENT NUMBER	CONF.
50-3495-CPU-000-013-001	UL

SIZE	SCALE	PROJECT N°	ALPC DOCUMENT NUMBER	SHEET/OF
			7978-020-CPU-BFD-001-UL	

A0 - DS.122.07.03



PRELIMINARY
AIR LIQUIDE KEEP THE RIGHT TO MODIFY THIS DRAWING DURING THE PROJECT EXECUTION

DRAWN BY	PROCESS CHECKED	PROCESS CONT. CHECKED	SYSTEMS CHECKED	APPROVED BY	REVISIONS	DATE YYYY-MM-DD	REV.
VALLIER	LOCKWOOD	.		SZAMLEWSKI	PRELIMINARY	2010-12-14	C
DENISART	LOCKWOOD	.	.	SZAMLEWSKI	PRELIMINARY	2010-12-03	B
DENISART	LOCKWOOD	.	.	SZAMLEWSKI	PRELIMINARY	2010-11-08	A

PROJECT NAME: FUTURE GEN 2.0

PART: OXYCOMBUSTION LARGE SCALE TEST

TITLE: UTILITIES BLOCK FLOW DIAGRAM

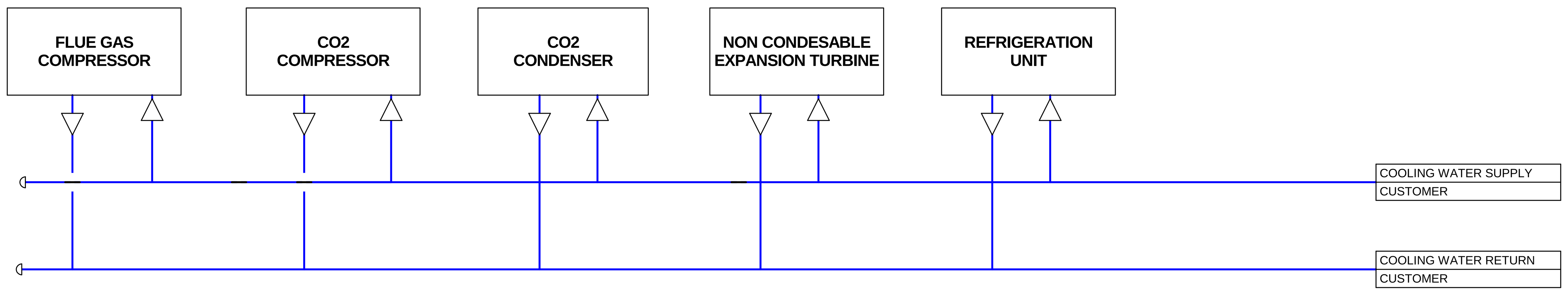
AIR LIQUIDE

ALE DOCUMENT NUMBER: 50-3495-CPU-000-013-002 | CONF.: UL

SIZE | SCALE | PROJECT N°

ALPC DOCUMENT NUMBER: 7978-020-CPU-BFD-002-UL | SHEET/OF

A0 - DS.122.07.03



PRELIMINARY
AIR LIQUIDE KEEP THE RIGHT TO MODIFY THIS DRAWING DURING THE PROJECT EXECUTION

W-CTP-13-1-14-b

DRAWN BY	PROCESS CHECKED	PROCESS CONT. CHECKED	SYSTEMS CHECKED	APPROVED BY	REVISIONS	DATE YYYY-MM-DD	REV.
VALLIER	LOCKWOOD	.	.	SZAMLEWSKI	PRELIMINARY	2010-12-14	C
DENISART	LOCKWOOD		.	SZAMLEWSKI	PRELIMINARY	2010-12-03	B
DENISART	LOCKWOOD	.	.	SZAMLEWSKI	PRELIMINARY	2010-11-18	A

PROJECT NAME: FUTURE GEN 2.0

PART: OXYCOMBUSTION LARGE SCALE TEST

TITLE: WATER BLOCK FLOW DIAGRAM

AIR LIQUIDE

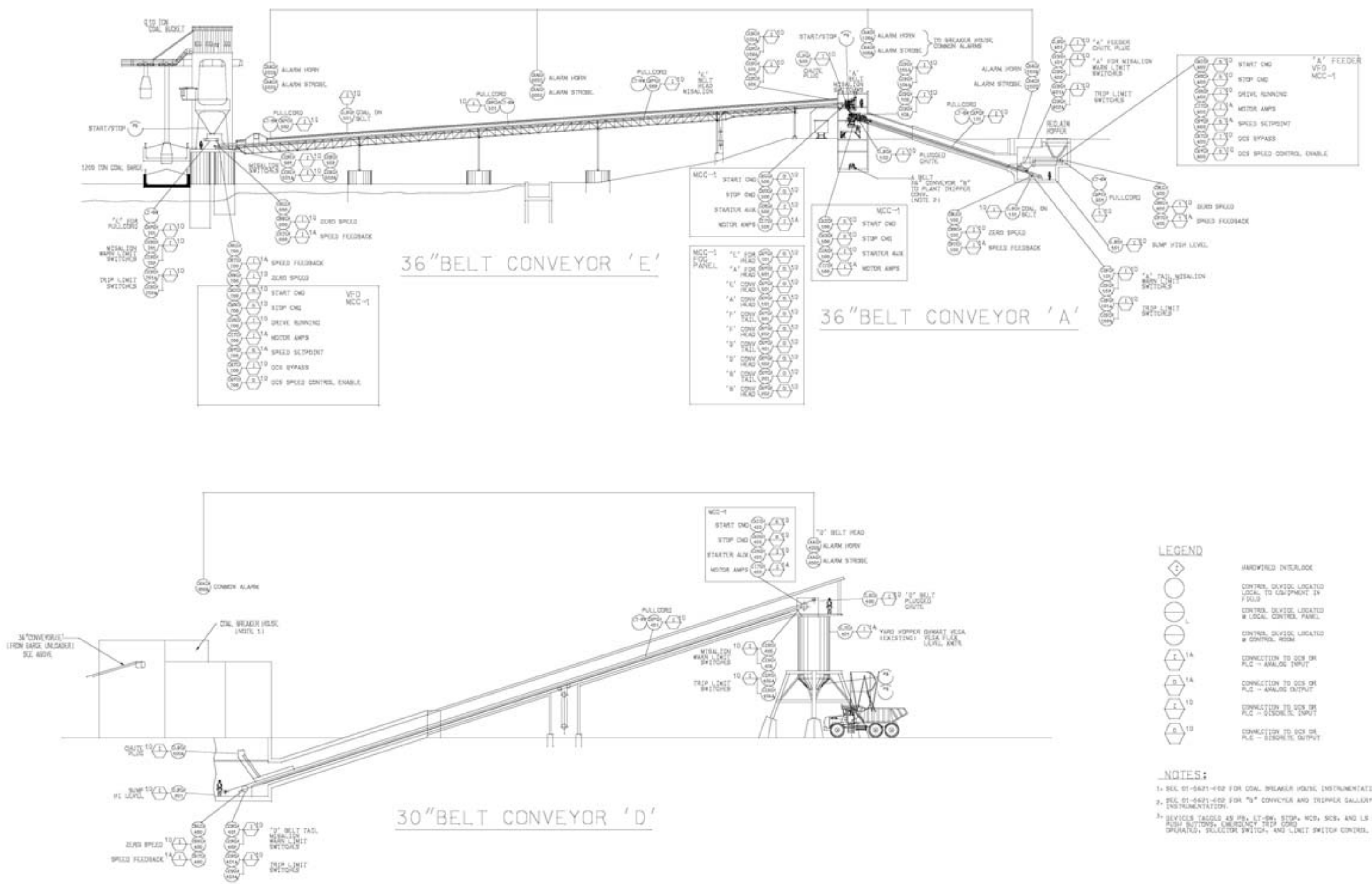
ALE DOCUMENT NUMBER: 50-3495-CPU-000-013-003

CONF.: UL

SIZE | SCALE | PROJECT N° | SHEET/OF

ALPC DOCUMENT NUMBER: 7978-020-CPU-BFD-003-UL

A0 - DS.122.07.03



LEGEND

I	HARDWIRED INTERLOCK
	CONTROL DEVICE LOCATED LOCAL TO EQUIPMENT IN FIELD
L	CONTROL DEVICE LOCATED @ LOCAL CONTROL PANEL
	CONTROL DEVICE LOCATED @ CONTROL ROOM
I 1A	CONNECTION TO DCS OR PLC - ANALOG INPUT
O 1A	CONNECTION TO DCS OR PLC - ANALOG OUTPUT
I 1D	CONNECTION TO DCS OR PLC - DISCRETE INPUT
O 1D	CONNECTION TO DCS OR PLC - DISCRETE OUTPUT

NOTES:

1. SEE 01-6621-602 FOR COAL BREAKER HOUSE INSTRUMENTATION.
2. SEE 01-6621-602 FOR "B" CONVEYOR AND TRIPPER GALLERY INSTRUMENTATION.
3. DEVICES TAGGED AS PB, LT-SW, STOP, MCS, SCS, AND LS ARE EXISTING HARDWI[illegible] PUSH BUTTONS, EMERGENCY TRIP CORD OPERATED, SELECTOR SWITCH, AND LIMIT SWITCH CONTROL DEVICES.

DRAWING RECORD

REVIEWED	APPROVED	DESCRIPTION	REV.	DATE	PREPARED	REVIEWED	APPROVED	DESCRIPTION
AEW	AEW	ISSUED FOR RECORD						

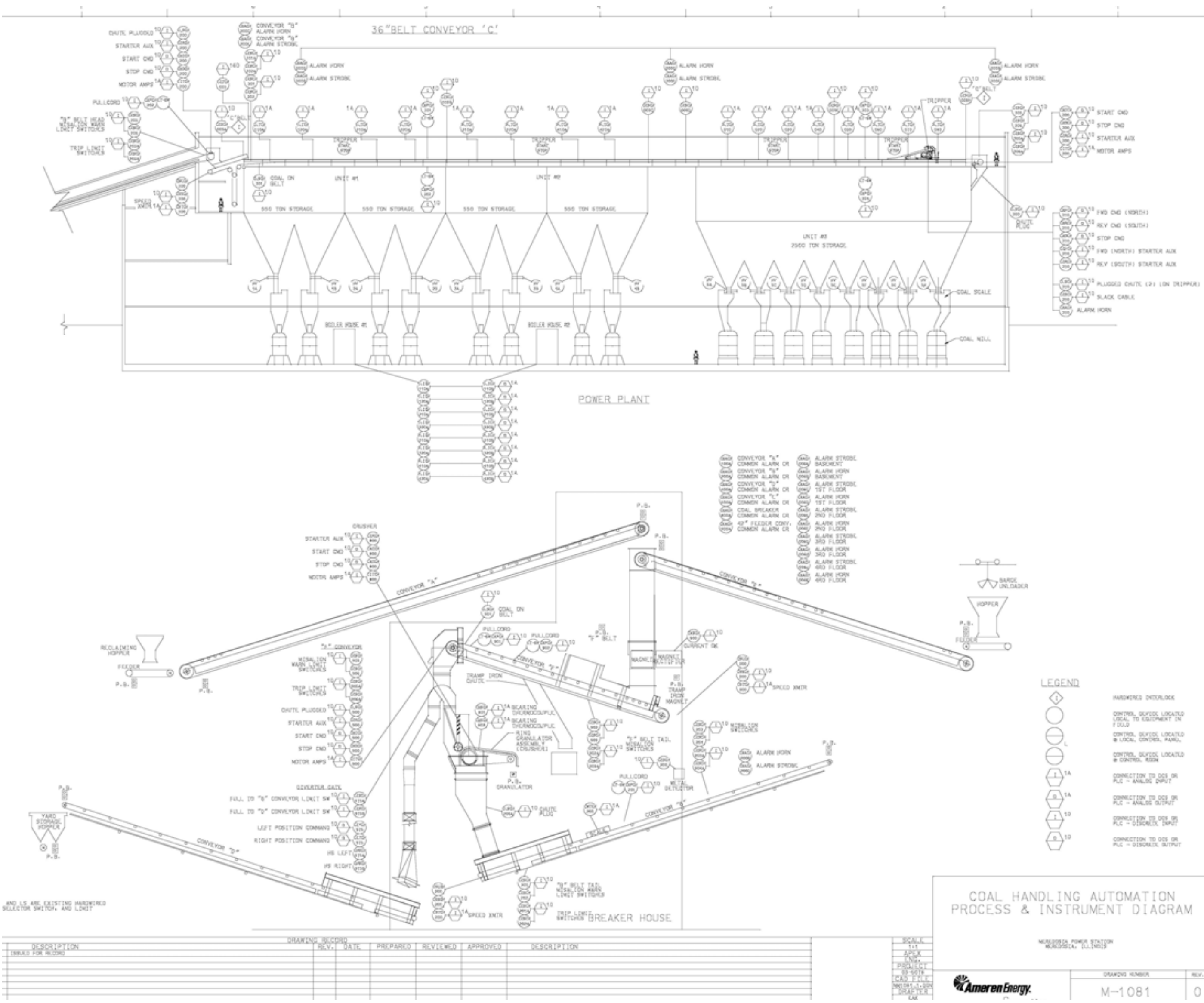
SCALE 1:1
APEX ENG.
PROJECT 03-6579
CAD FILE M1081.1.DGN
DRAFTER KAK
DATE 8-18-03

COAL HANDLING AUTOMATION
PROCESS & INSTRUMENT DIAGRAM

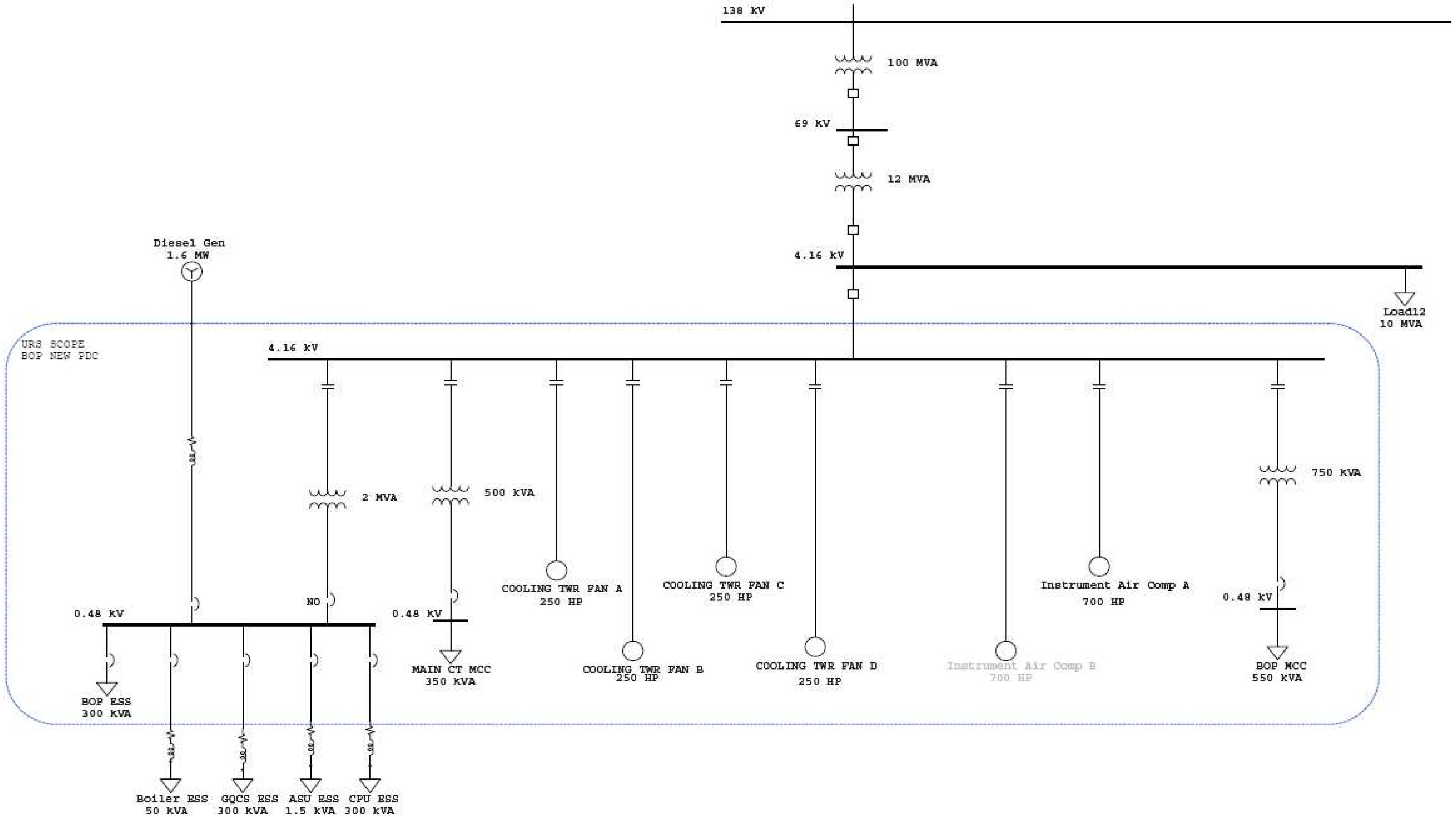
MEREDOSIA POWER STATION
MEREDOSIA, ILLINOIS

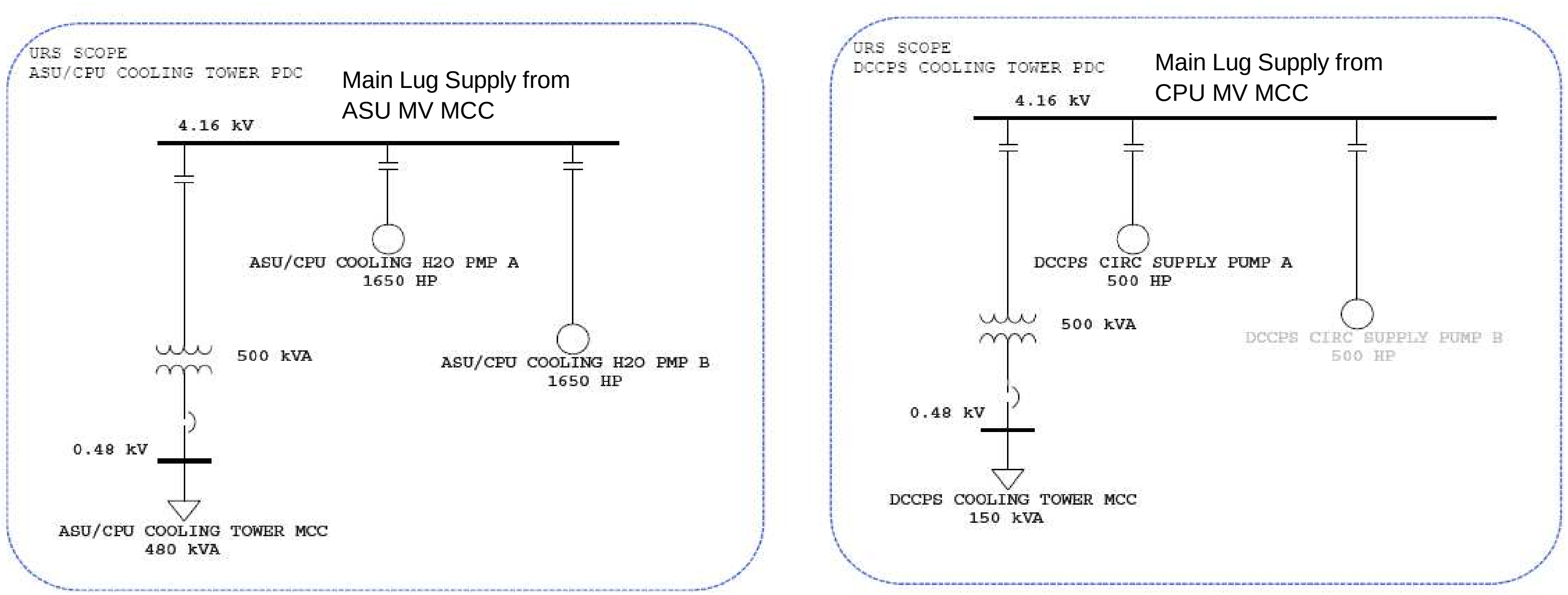
Ameren Energy Generating

DRAWING NUMBER M-1081
REV. 0
PAGE NO. 1


36"BELT CONVEYOR 'C'
UNIT #1
UNIT #2
UNIT #3
550 TON STORAGE
2500 TON STORAGE
BOILER HOUSE #1
BOILER HOUSE #2
COAL SCALE
COAL MILL
TRIPPER
ALARM HORN
ALARM STROBE
START CMD
STOP CMD
STARTER AUX
MOTOR AMPS
PULLCORD
CHUTE PLUGGED
POWER PLANT
CRUSHER
CONVEYOR "A"
CONVEYOR "B"
CONVEYOR "D"
CONVEYOR "E"
RECLAIMING HOPPER
FEEDER
HOPPER
BARGE UNLOADER
YARD STORAGE HOPPER
GRANULATOR
BREAKER HOUSE
DIVERTER GATE
LEGEND
HARDWIRED INTERLOCK
COAL HANDLING AUTOMATION
PROCESS & INSTRUMENT DIAGRAM
Ameren Energy
DRAWING NUMBER
M-1081
REV.
0

D APPENDIX – ELECTRICAL ONE-LINES





PRELIMINARY

REV. NO.	DATE	REVISION	BY	CHK.	ENG.	APPR.	OTHER
P1	13-May-11	Preliminary Issue - Phase 1	RCA				---

New BOP Electrical Single Line Diagram

MEREDOSIA UNIT 4 REPOWERING USING OXY-PC WITH CO_2 CAPTURE

B&W power generation group

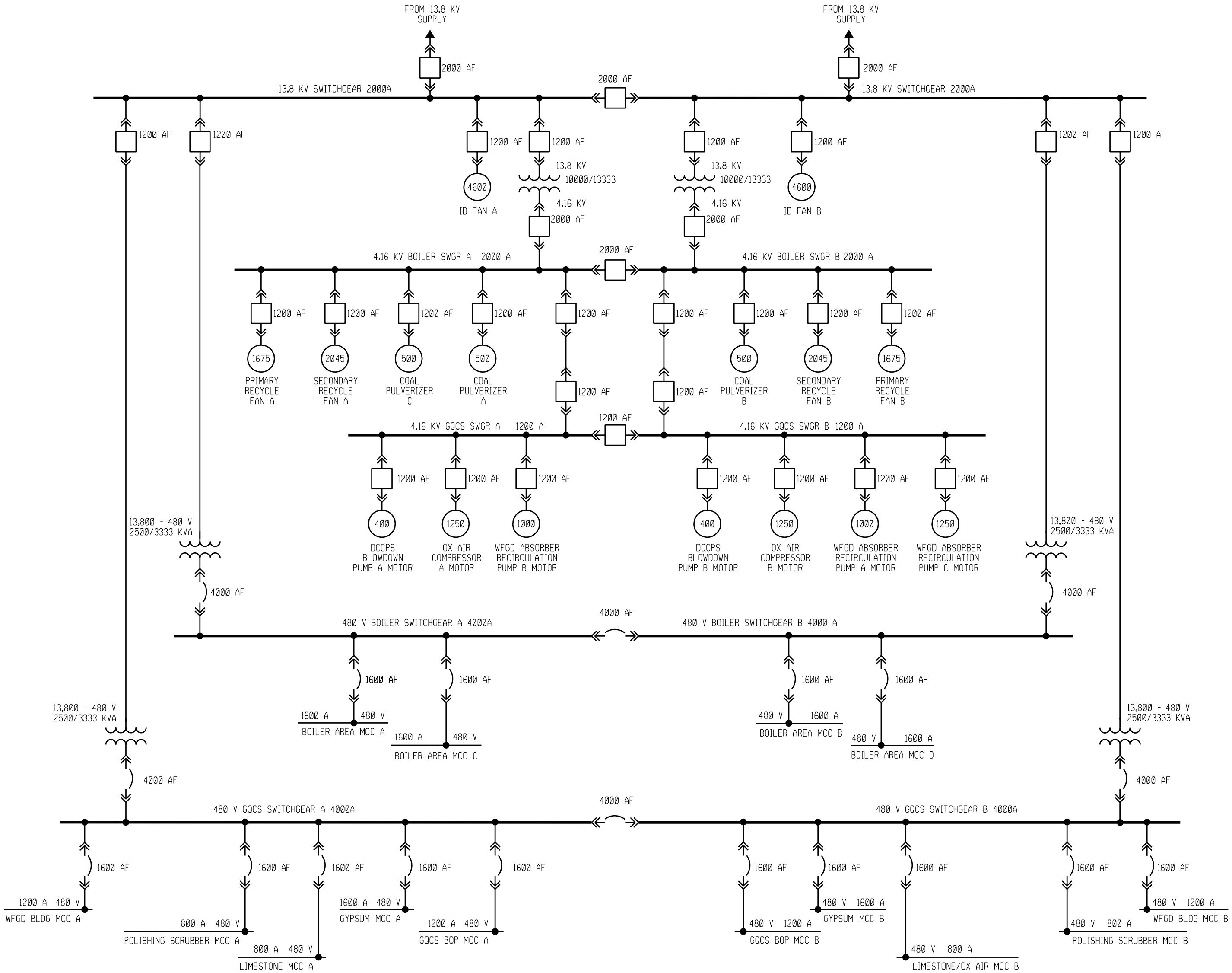
AIR LIQUIDE

URS

Document Number	Revision
17-11-050-001	P1

MEREDOSIA POWER STATION
AUXILIARY POWER KEY DIAGRAM

PRELIMINARY



PRELIMINARY

REV	DATE	DESCRIPTION	DRAWN	CHECKED	LEAD DESIGNER	ENGINEER/TECH.SPEC	LEAD DISC ENGINEER	PROJ ENGR MANAGER	PROJECT MANAGER
A	03/31/11	ISSUED FOR REVIEW	SMF		TPJ		SRB		PWS

PRELIMINARY STATUS — DATE — REPRESENTS GENERAL DESIGN CONCEPTS BASED ON ASSUMPTIONS. REVIEWED NOT CHECKED.

LDE S.R. BARKER 03/31/11

APPROVED STATUS — DATE — REPRESENTS REVIEWED AND APPROVED DESIGN. ANY PORTION MARKED "HOLD" RETAINS PRELIMINARY STATUS.

LDE

ORIGINATING PERSONNEL

DRAWN BY: SMF

CHECKED BY

LEAD DESIGNER: T.P. JONES

ENGINEER/TECH SPECIALIST

PROJECT ENGINEERING MANAGER

PROJECT MANAGER: P.W. SHEWCHUCK

OneWay to zero harm

PROFESSIONAL ENGINEER'S SEAL

ORIGINALLY PREPARED UNDER THE RESPONSIBLE SUPERVISION OF
PE: ______ STATE: ______
LIC. NO.: ______ DATE: ______

WorleyParsons
resources & energy

CLIENT/PROJECT TITLE

ELECTRICAL ONE - LINE
KEY ONE LINE DIAGRAM

SCALE: N/A
DRAWING SIZE: ANSI D (34" x 22")

WORLEYPARSONS DWG. NO.: BWFG-1-DW-601-206-002
REV: A

...\BWFG-1-DW-601-206-002.dgn
3/31/2011 4:01:13 PM

E APPENDIX – EQUIPMENT LISTS

FUTUREGEN 2.0 PLANT EQUIPMENT LIST

MEREDOSIA UNIT 4 REPOWERING USING OXY-PC WITH CO_2 CAPTURE

REV. NO.	DATE	REVISION	BY	CHK.	ENG.	APPR.	OTHER
C	26-May-11	Preliminary Issue End of Phase I	LK	MDP			
P1	11-Mar-11	Preliminary Issue	MDP				---

Equipment List - Oxy-PC Plant

MEREDOSIA UNIT 4 REPOWERING USING OXY-PC WITH CO_2 CAPTURE

Document Number	Revision
30384-15-05-100-001	C

BOILER EQUIPMENT LIST

PRELIMINARY

Rev	Tag Number	B&W Tag Number	Equipment Name	Qty	Operating Mode (Operating/ Intermittent/ Standby)	Design Pressure (psig)	Operating Pressure (psig)	Design Temperature (oF)	Operating Temperature (oF)	% Cap @	Capacity each	Nameplate Loads KW each	H.P. each	Speed (RPM)	Voltage	Remarks
			BOILER								---					
	Boiler 7		Furnace w/ steam cooled convection pass enclosures w/ Buckstays & supports	1	OPERATING		2550	1009	1000	100	1.5 MLB/HR STEAM @					
	Boiler No. 7 Stea	7-BC-701-DRM	STEAM DRUM	1	OPERATING	2875	2695			100						
		7-AX-941-DRM	LOWER DRUM	1	CONTINUOUS					100						
	7-FC-14-C-1/2	7-AG-842A/B-BLO	FLAME SCANNER COOLING AIR BLOWER 7A & 7B	2	OPERATING/STBY					100		18.6	25		460	
	7-FC-15-F-1/2	7-AG-843A/B-FLT	FLAME SCANNER COOLING AIR BLOWER FILTER 7A & 7B	2	OPERATING/STBY					100						
	7-AS-11-K-1 TO	7-SB-718-ST TO 7-SB-751-ST	SOOTBLOWER, IK	22	INTERMITTENT					100		1.5	2		460	
	7-MOV-SB-510	7-MOV-SB-510	SOOTBLOWER STEAM SUPPLY ISOLATION VALVE	1	INTERMITTENT					100		2.6	3.5		460	
	7-MOV-SB-511	7-MOV-SB-511	SOOTBLOWER STEAM SUPPLY MOV	2	INTERMITTENT					100		2.6	3.5		460	
	7-MOV-SB-512	7-MOV-SB-512	SOOTBLOWER AUXILIARY STEAM SUPPLY VALVE	1	INTERMITTENT					100		2.6	3.5		460	
	7-SB-718-CAB-L	7-SB-718-CAB-L	SB SENTRY SERIES CONTROL CABINET	1	INTERMITTENT					100		4.8			120	
	7-AS-	7-SB-755-MU TO 7-SB-782-ST	WALL BLOWER SOOTBLOWERS	14	INTERMITTENT					100		1.5	2		460	
			BLOWOFF VALVE FROM DOWNCOMER MANIFOLD	1	INTERMITTENT					100					460	
	7-FW-001	7-MOV-FW-500	BOILER FEEDWATER STOP VALVE	1	INTERMITTENT					100		4.1	5.5		460	
			Vertical Steam Separators	2	OPERATING					100			---			
	Economizer 7	7-AX-942-ECO	ECONOMIZER	1	OPERATING		2800		478	100	1.42 MLB/HR		---			
	SH 7-1		Superheater	1	OPERATING		2550	1009	1000	100	1.42 MLB/HR		---			
	SH Attemperator	7-MS-711-DSH, 7-MS-712-DSH	Superheater Attemperators	2	OPERATING								---			
	RH 7		Reheater	1	OPERATING		569	1005	1000	100	1.2384 MLB/HR		---			
	RH Attemperator	7-RH-713-DSH	Reheater attemperating system	1	OPERATING					100			---			
	7-MS-001	7-MS-1097	EMERGENCY RELIEF VALVE & SILENCER	1	INTERMITTENT					100					460	
	7-RH-1112, 7-RH-1113, 7-RH-1114	7-RH-1112, 7-RH-1113, 7-RH-1114	Safety Valves w/ vent stacks & silencers		INTERMITTENT					100			---			
			BOILER BUILDING ELEVATOR	1	INTERMITTENT					100					460	
	7-WW-18-P		BOILER BUILDING ELEVATOR SUMP PUMP	1	INTERMITTENT					100					460	
			Trim Valves & piping	bulk												
	7-WW-28-T	7-ST-879-TNK	BOILER BLOWDOWN TANK	1	OPERATING											
	7-CD-05-T	7-AX-928-TNK	CONDENSATE COLLECTION /FLUSH TANK	1	OPERATING											
	7-BA-01-E-1/2	7-AG-882A-CMR, 7-AG-882B-CMR	FURNACE TV CAMERA A/B	2	CONTINUOUS					100						
		7-AG-888A/B-CLR	FURNACE TV CAMERA A/B AIR COOLERS	1	CONTINUOUS					100						
		7-AG-883A-CPL	FURNACE CAMERA CONTROL CABINET	1	CONTINUOUS					100						
		7-AG-887A-CLR	FURNACE CAMERA CONTROL CABINET AIR CLR	1	CONTINUOUS					100						
			ASH HANDLING													
	7-BC-01-S	7-AH-854-SCC	SUBMERGED ASH FLIGHT CONVEYOR	1	INTERMITTENT					100		14.9	20		460	
	7-BC-02-S	7-AH-852-HYD	SUBMERGED ASH FLIGHT CONVEYOR HYDRAULIC DRIVE UNIT	1	INTERMITTENT					100		0.7	1		460	
	7-BC-04-S	7-AH-853-HYD	BA SCC CHAIN TENSION HYDRAULIC SYSTEM	1	INTERMITTENT							0.7	1		460	
	7-FA-19-S	7-AH-867-CNV	ECONOMIZER FLYASH COLLECTION CONVEYOR	1	INTERMITTENT					100		0.7	1		460	
	7-FA-20-S	7-AH-868-CNV	ECONOMIZER FLYASH TRANSFER CONVEYOR	1	INTERMITTENT					100		0.7	1		460	
	7-FC-13-P-1/2	7-AH-869A/B-PMP	PULVERIZER PYRITES HP WATER PUMP 7A & 7B	2	INTERMITTENT					100		37.3	50		460	
		7-AH-869A/B-PMP-L	PYRITE HP WATER PUMP 7A, 7B MOTOR HEATER	2	INTERMITTENT					100		0.375			120	
	7-FC-16-P-1/2	7-AH-870A/B-PMP	PYRITE HP WATER PUMP 7A, 7B	2	INTERMITTENT					100		37.3	50		460	
		7-AH-870A/B-PMP-L	PYRITE HP WATER PUMP 7A, 7B MOTOR HEATER	2	INTERMITTENT					100		0.375			120	
		7-AH-865A/B-RTR	ECONOMIZER HOPPER 2/3 DISCH ROTARY VALVE	2	OPERATE/STBY					100		1.5	2		460	
	7-FC-17-T		ASH WATER OVERFLOW TANK	1	CONTINUOUS											
	7-FC-18-P-1/2	7-AW-859A/B-PMP	ASH WATER RECIRCULATING PUMPS 7A, 7B	2	OPERATE/STBY					100		3.7	5			
	7-FC-19-P-1/2	7-AW-856A/B-PMP	ASH SLUDGE PUMPS 7A, 7B	2	OPERATE/STBY					100		1.5	2			
	7-FC-20-A-1/2	7-AW-855A/B-HTR	ASH WATER HEAT EXCHANGER 7A, 7B	2	OPERATE/STBY											
			COMBUSTION EQUIPMENT													
			Burner Sleeve Dampers 7A1-A3, 7B1-B3, 7C1-C3, 7D1-D3	12	OPERATING/STBY					100						
	Coal Burner 7-1,	7-FC-844A1-A6/B1-B6/C1-C6/-BNR	COAL BURNERS	12	OPERATING/STBY											
	Pilot Burner 7-1, 7-2 to 7-12		PILOT BURNERS	12	OPERATING/STBY											
		7-FC-844A1-A6/B1-B6/C1-C6/-JB-L	BNR (ALL) IGN FLAME DET JB	12	OPERATING/STBY					100		0.03			120	
		7-FO-371A1-3/B1-3/C1-3/D1-3/E1-3/F1-3	BNR A/B/C/D/E/F 1/2/3 IGN HEI JB	18	OPERATING/STBY					100		0.25			120	
		7-FC-844-CAB-L	BNR MAIN FLAME SCANNER CABINET	1	OPERATING					100		4.20			120	
		7-MCD-AG-370A1-6/B1-6/C1-6	COAL BURNER SLEEVE DAMPER DRIVES	18	OPERATING/STBY					100		0.4	0.5		120	
	Mill 7-1, 7-2, 7-3	7-CH-813A/B/C-PLV	B&W PULVERIZER 7A, 7B, 7C	3	2 OPERATE/1 STBY					33		372.9	500		4160	
		7-CH-813A/B/C-HTR-L	PULVERIZER A/B/C MOTOR SPACE HEATER	3	2 OPERATE/1 STBY					100		0.375			120	
		7-CH-834A/B/C-PNL-L	PULV A/B/C I&C LCP	3	2 OPERATE/1 STBY					100		0.240			120	
	7-FC-21-S-1/2/3	7-CH-832A/B/C-GBX	PULVERIZER GEAR BOX	3	2 OPERATE/1 STBY											
	7-FC-10-P-1/2/3	7-LO-839A/B/C-PMP	B&W Pulverizer Lube Oil Pump 7A, 7B, 7C	3	2 OPERATE/1 STBY					100		7.5	10		460	
	7-FC-11-A-1/2/3	7-LO-838A/B/C-HT	PULVERIZER LUBE OIL HEATER 7A, 7B, 7C	3	2 OPERATE/1 STBY					100		20.0			460	
	7-FC-22-F-1/2	7-LO-835/836A-FLT	PULVERIZER A LUBE OIL FILTER	2	1 OPERATE/I STBY											
	7-FC-23-F-1/2	7-LO-835/836B-FLT	PULVERIZER B LUBE OIL FILTER	2	0 OPERATE/I STBY											

BOILER EQUIPMENT LIST

PRELIMINARY

Rev	Tag Number	B&W Tag Number	Equipment Name	Qty	Operating Mode (Operating/ Intermittent/ Standby)	Design Pressure (psig)	Operating Pressure (psig)	Design Temperature (oF)	Operating Temperature (oF)	% Cap @	Capacity each	Nameplate Loads KW each	H.P. each	Speed (RPM)	Voltage	Remarks
	7-FC-24-F-1/2	7-LO-835/836C-FLT	PULVERIZER C LUBE OIL FILTER	2	1 OPERATE/I STBY											
	7-FC-25-A-1/2/3	7-LO-837A/B/C-CLR	PULVERIZER LUBE OIL COOLER 7A, 7B, 7C	3	2 OPERATE/1 STBY											
			ROLL WHEEL SEAL AIR FILTER	1	CONTINUOUS					100						
	7-FC-26-A-1/2	7-CW-909, 910, 911-HTR	PULVERIZER LUBE UNIT HEAT EXCHANGERS	3	OPERATING											
	7-AS-09-S		Pulverizer steam inerting system 7A, 7B, 7C	3	INTERMITTENT					100						
	Seal Air Fans 7-	7-AG-825A/B-FAN	Pulverizer seal air fan 7A & 7B	2	OPERATE/STBY					100		111.9	150		460	
		7-AG-820A/B-SIL	SEAL AIR SILENCER	2	OPERATE/STBY					100						
		7-AG-825A/B-FAN-L	PULVERIZER SEAL AIR FAN A/B MOTOR SPACE HTR	2	OPERATING					100		0.375			120	
	7-FC-12-G-1/2/3	7-CH-829A/B/C-FDR	Coal Feeders 7A, 7B, 7C	3	2 OPERATE/1 STBY					100		1.1	1.5		460	
		7-CH-829A/B/C-CAB-L	COAL FEEDER A/B/C MPC CONTROL CABINET	3	2 OPERATE/1 STBY					100					460	
			Coal piping and valves	bulk	OPERATING					100						
		7-CH-829A/B/C-CNV	Coal Feeder Cleanout Conveyor 7A, 7B, 7C	3	INTERMITTENT					100		0.4	0.5		460	
		7-CH-327A/B/C-CAB	CO MONITORING MILL A/B/C CABINET	3	2 OPERATE/1 STBY					100		0.3			120	
		1-MOV-FP-574A/B/C	FIRE PROT WATER TO PULV A/B/C MOV	3	INTERMITTENT					100		2.6	3.5		460	
			TRIPPER DECK													
	7-FC-02-G	7-CH-827-CNV	TRIPPER CONVEYOR H	1	INTERMITTENT	---	---									
		7-CH-891A-CNV-L	COAL TRIPPER CONVEYOR MOTOR 1 SPACE HEATER	1	INTERMITTENT					100		0.375			120	
		7-CH-891A-CNV	COAL TRIPPER CONVEYOR MOTOR 1	1	INTERMITTENT					100		74.6	100		460	
		7-CH-891B-CNV	COAL TRIPPER CONVEYOR MOTOR 2	1	INTERMITTENT					100		2.2	3		460	
		7-CH-891C-CNV	COAL TRIPPER CONVEYOR MOTOR 3	1	INTERMITTENT					100		2.2	3		460	
		7-CH-891D-CNV	COAL TRIPPER CONVEYOR MOTOR 4	1	INTERMITTENT					100		1.5	2		460	
		7-CH-891-CAB-L	TRIPPER CONVEYOR CONTROL CABINET	1	OPERATING					100		2.5			120	
	7-FC-04-G		TRIPPER POSITIONER 7A, 7B	2	INTERMITTENT							2.2	3		460	
	7-FC-05-G		TRIPPER GATE	1	INTERMITTENT							1.5	2		460	
		7-CH-470-C	COAL CONVEYOR 2 DUST COLLECTOR	1	INTERMITTENT					100		1.5	2		460	
		7-CH-471-C	COAL CONVEYOR 3 DUST COLLECTOR	1	INTERMITTENT					100		1.5	2		460	
	7-FC-06-C		DUST COLLECTOR EXHAUST FAN	1	CONTINUOUS							55.9	75		460	
	7-FC-07-C		DUST COLLECTOR BLOWER	1	CONTINUOUS							3.7	5		460	
	7-FC-08-G		DUST COLLECTOR ROTARY FEEDER	1	INTERMITTENT							0.7	1		460	
	7-FC-09-G		THREE WAY DIVERTING VALVE	1	INTERMITTENT							1.5	2		460	
			FUEL OIL SYSTEM													
	7-FO-01-T	7-FO-848-ACC	FUEL OIL ACCUMULATOR	1	OPERATING											
	7-FO-02-T	7-FO-847-ACC	FUEL OIL ACCUMULATOR	1	OPERATING											
		7-CH-829A/B/C-FDR														
		7-CH-467A/B/C-C	COAL SILO A/B/C SILO DUST COLLECTOR	3	3 OPERATING/1 STBY					100		1.5	2.0		460	
			AIR/RECYCLE HEATER													
	Preheater 7	7-FG-795-AHT	GAS PREHEATER	1	OPERATING					100		22.4	30		460	
	7-BY-03-P-1/~~2~~	7-LO-806-PMP	GAS HEATER GUIDE BEARING OIL PUMP 7A ~~& 7B~~	1	OPERATING					100		0.4	0.5		120	
	7-BY-08-F	7-LO-802-FLT	GAS HEATER GUIDE BEARING LUBE OIL FILTER	1	OPERATING											
	7-BY-09-A	7-LO-803-HTR	GAS HEATER GUIDE BEARING LUBE OIL HEATER	1	OPERATING					100		0.375			120	
	7-BY-10-S	7-AG-794-DRV	GAS HEATER ROTOR DRIVE UNIT	1	OPERATING					100		22.4	30		460	
		7-AG-795-CPL-L	AIR HEATER MAIN CONTROL PANEL	1	OPERATING					100		1.2			120	
		7-AG-795-JB-L	AIR HEATER LIGHT FIXTURE JB	1	OPERATING					100		0.3			120	
	7-BY-11-P	7-LO-805-PMP	GAS HEATER SUPPORT BEARING OIL PUMP	1	OPERATING					100		0.4	0.5		120	
	7-BY-12-F	7-LO-804-FLT	GAS HEATER SUPPORT BEARING OIL FILTER	1	OPERATING											
	7-AS-10-S-1/2	7-SB-807-SBL, 7-SB-808-SBL	GAS PREHEATER SOOTBLOWER 7A & 7B	2	INTERMITTENT					100		1.5	2		120	
		7-AX-933-HTR	AIR HEATER	1	CONTINUOUS					100						
		7-AG-880A/B/C/D-CPL-L	AIR HEATER LCS MTR 1-4 STARTER PANEL	4	OPERATING					100		0.24			120	
		7-AG-880A/B/C/D-DR	AIR HEATER LCS DRIVE MOTOR 1-4	4	OPERATING					100		0.4	0.5		120	
		7-AG-996-HST-M	AIR HEATER HOIST	1	INTERMITTENT					100		0.7	1		460	
			AIR/GAS FANS													
	FD Fans 7-1	7-AX-932-FAN	Forced Draft Fan w/ VFD motors & silencer	1	OPERATING					50		1081.3	1450		4 kV	
	7-BY-05-Y-1/2		FORCED DRAFT FAN INLET VANE 7A & 7B	2	OPERATING					50		0.4	0.5		460	
	7-BA-02-C-1/2	7-AG-826A/B-FAN	PRIMARY RECYCLE FAN A/B	2	OPERATING					100		1249.0	1675		4160	
		7-AG-826A/B-HTR-L	PRIMARY RECYCLE FAN A/B MOTOR SPACE HTR	2	OPERATING					100		0.375			120	
		7-AG-826A/B-LV	PRIMARY RECYLE FAN A/B INLET VANE DRIVE	2	OPERATING					100		0.4	0.5		460	
		7-AG-892A/B-HTR-L	PRIMARY RECYCLE FAN A/B OUTBOARD BEARING SUMP HEATER	2	OPERATING					100		0.425			120	
		7-AG-893A/B-HTR-L	PRIMARY RECYCLE FAN A/B INBOARD BEARING SUMP HEATER	2	OPERATING					100		0.425			120	
		7-LO-904A/B-PMP	PRIMARY RECYCLE FAN A/B LOW PRESSURE OIL PUMP A MOTOR	2	OPERATING					100		1.5	2		460	
		7-LO-905A/B-PMP	PRIMARY RECYCLE FAN A/B LOW PRESSURE OIL PUMP B MOTOR	2	OPERATING					100		1.5	2		460	
		7-LO-906A/B-FAN	PRIMARY RECYCLE FAN A/B LUBE OIL COOLING FAN MOTOR	2	OPERATING					100		0.4	0.5		460	
		7-LO-907A/B-HTR-L	PRIMARY RECYCLE FAN A/B LUBE OIL HTR	2	OPERATING					100		6.0			460	
	7-BA-03-C-1/2	7-AG-793A/B-FAN	SECONDARY RECYCLE FAN A/B	2	OPERATING					100		1525.0	2045		4160	
		7-AG-793A/B-HTR-L	SECONDARY RECYCLE FAN A/B MOTOR SPACE HTR	2	OPERATING					100		0.375			120	
		7-AG-793A/B-LV	SECONDARY RECYLE FAN A/B INLET VANE DRIVE	2	OPERATING					100		0.373	0.5		460	
		7-AG-890A/B-HTR-L	SECONDARY RECYLE FAN A/B OUTBOARD BEARING SUMP HEATER	2	OPERATING					100		0.425			120	

BOILER EQUIPMENT LIST

PRELIMINARY

Rev	Tag Number	B&W Tag Number	Equipment Name	Qty	Operating Mode (Operating/ Intermittent/ Standby)	Process (Design/Performance) Data: Design Pressure (psig)	Operating Pressure (psig)	Design Temperature (oF)	Operating Temperature (oF)	% Cap @	Capacity each	Nameplate Loads: KW each	H.P. each	Speed (RPM)	Voltage	Remarks
		7-AG-891A/B-HTR-L	SECONDARY RECYCLE FAN A/B INBOARD BEARING SUMP HEATER	2	OPERATING					100		0.425			120	
		7-LO-900A/B-PMP	SECONDARY RECYCLE FAN A/B LOW PRESSURE OIL PUMP A MOTOR	2	OPERATING					100		1.5	2		460	
		7-LO-901A/B-PMP	SECONDARY RECYCLE FAN A/B LOW PRESSURE OIL PUMP B MOTOR	2	OPERATING					100		1.5	2		460	
		7-LO-902A/B-FAN	SECONDARY RECYCLE FAN A/B LUBE OIL COOLING FAN MOTOR	2	OPERATING					100		0.4	0.5		460	
		7-LO-903A/B-HTR-L	SECONDARY RECYCLE FAN A/B LUBE OIL HTR	2	OPERATING					100		6.0			460	
	ID Fans 7-1, 7-2	7-FG-039-C-A/B	Induced Draft Fans w/ VFD motors	2	OPERATING					50		3430.2	4600		13.2KV	
	7-BY-13-T-1/2	7-LO-053-T-A/B	ID FAN MAIN BEARING OIL TANK 7A &7B	2	OPERATING											
	7-BY-14-E-1/2	7-LO-054-E-A/B	MAIN OIL BEARING HEATER 7A & 7B	2	OPERATING								6		480	
	7-BY-15-P-1/2	7-LO-057-C-A/B	ID FAN 7A MAIN BEARING OIL PUMP 7A& 7B	2	OPERATING/STBY							2.0			480	
	7-BY-16-P-1/2	7-LO-058-C-A/B	ID FAN 7B MAIN BEARING OIL PUMP 7A& 7B	2	OPERATING/STBY							2.0			480	
	7-BY-17-F-1/2	7-LO-059-F-A/B	ID FAN 7A OIL FILTERS 7A & 7B	2	OPERATING/STBY											
	7-BY-18-F-1/2	7-LO-060-F-A/B	ID FAN 7B OIL FILTERS 7A & 7B	2	OPERATING/STBY											
	7-BY-19-A-1/2	7-LO-061-C-A/B	MAIN BEARING OIL COOLER 7A & 7B	2	OPERATING								0.5		480	
	7-BY-06-Y-1/2		INDUCED DRAFT FAN INLET VANE 7A & 7B	2	OPERATING					50		0.4	0.5		460	
		7-FG-MOV-132A/B	ID FAN A/B DISCHARGE DAMPER	2	OPERATING/STBY					100			0.5		460	
		7-FG-MOV-133A/B	ID FAN INLET A INLET DAMPER A/B1	2	OPERATING/STBY					100			0.5		460	
		7-FG-MOV-134A/B	ID FAN B INLET DAMPER A/B2	2	OPERATING/STBY					100			0.5		460	
		7-FG-MOV-039-C-A/B-L	ID FAN A/B MOTOR SPACE HEATER	2	OPERATING/STBY					100	S		0.375		120	
		7-LO-062-E-A/B-L	ID FAN A/B DE BRG HEATER	2	OPERATING/STBY					100		1.2			120	
		7-LO-063-E-A/B-L	ID FAND A/B NDE BEARING HEATER	2	OPERATING/STBY					100		1.2			120	
		7-MTR-700B	IDFAN B LUBE OIL COOLIG FAN MOTOR	1	OPERATING					100			0.5		480	
	7-BA-04-C	7-FG-785-BLO-L	PENTHOUSE SEAL AIR BLOWER MOTOR SPACE HTR	1	OPERATING					100		0.375			120	
		7-FG-785-BLO	PENTHOUSE SEAL AIR BLOWER	1	OPERATING					100		29.8	40		460	
	7-BA-05-A	7-CW-913-HTR	PA FAN HEAT EXCHANGER	1	OPERATING					100			6		480	
	7-BA-06-A	7-CW-912-HTR	FD FAN HEAT EXCHANGER	1	OPERATING					100			6		480	
			FLUE GAS COOLERS/HEATERS													
	7-CD-01-A		Gas Cooler/Condensate Heater	1	OPERATING											
	7-AS-01-A	7-CW-914-HTR	QUADSECTOR RECYCLE HEATER LUBE UPPER BEARING HEAT EXCHANGER	1	OPERATING		243.3	X			7.6MBTU/HR					
	7-AS-02-A	7-AG-790A-HTR	Steam Coil Air Heaters	1	INTERMITTENT		150		366	25	57MBTU/HR					
		7-AG-792-SIL	RECYCLE GAS SILENCER	1	CONTINUOUS					100						
	7-BA-07-A	7-AG-818-HTR	PRIMARY GAS HEATER	1	OPERATING											
	7-BA-08-A	7-AG-791-HTR	Secondary Gas Reheater	1	OPERATING											
	7-OX-37-A	7-OX-788-HTR	Secondary GOX Heater	1	OPERATING											
	7-OX-38-A	7-OX-811-HTR	Secondary GOX Heater	1	OPERATING											
	7-OX-39-A	7-OX-812-HTR	Secondary GOX Heater	1	OPERATING											
	7-BA-09-T	7-AX-920-TNK	Air Preheat Drain Tank	1												
	7-BA-10-P	7-AX-890-PMP	SCAH DRAIN Pump	1	INTERMITTENT					100		14.9	20		460	
			CONTROLS													
			Burner Management System implemented in DCS	1	OPERATING											
			FLUES AND DUCTS													
			Flues	bulk												
			Dampers	bulk												
			Expansion Joints	bulk												
	7-OX-01-G-2		Secondary Floxinators for oxygen mixing	1	OPERATING											
	7-OX-01-G-1		Primary Floxinators for oxygen mixing	1	OPERATING											
			FIRE PROTECTION													
		7-MOV-FP-624	FIRE PROTECTION WATER TO RECYCLE AIR HEATER	1						100		2.6	3.5		460	
			INSTRUMENTATION	bulk												
			MONORAILS AND HOISTS													
			AUX BOILER													
		7-MOV-AX-660	AUX BOILER LOW PRESS STEAM ISO MOV	1						100		2.6	3.5		460	
		7-AX-997-CAB-L	AUX BOILER CONTROL CABINET	1						100		5.0			120	
		7-AX-999-FAN	AUX BOILER FD FAN MOTOR	1						100		55.9	75		4160	
		7-AX-999-HTR-L	AUX BOILER FD FAN MOTOR SPACE HEATER	1						100		0.375			120	
		7-PMP-1501-944-M	AUX BOILER FEEDWATER PUMP	1						100		22.4	30			
			POWER SUPPLY													
			4160 V Switchgear													
			DC Power supply and Battery System													
			480 V MCCs													
			HVAC EQUIPMENT													
			Boiler Building Unit Heater 01	1	INTERMITTENT					100		15			480	
			Boiler Building Unit Heater 04	1	INTERMITTENT					100		15			480	
			Boiler Building Unit Heater 07	1	INTERMITTENT					100		15			480	
			Boiler Building Unit Heater 10	1	INTERMITTENT					100		15			480	
			Boiler Building Unit Heater 13	1	INTERMITTENT					100		15			480	
			Boiler Building Unit Heater 16	1	INTERMITTENT					100		15			480	
			Boiler Building Unit Heater 19	1	INTERMITTENT					100		15			480	
			Boiler Building Unit Heater 22	1	INTERMITTENT					100		15			480	
			Boiler Building Unit Heater 25	1	INTERMITTENT					100		15			480	

BOILER EQUIPMENT LIST

PRELIMINARY

					Operating Mode	Process (Design/Performance) Data						Nameplate Loads				
Rev	Tag Number	B&W Tag Number	Equipment Name	Qty	(Operating/ Intermittent/ Standby)	Design Pressure (psig)	Operating Pressure (psig)	Design Temperature (oF)	Operating Temperature (oF)	% Cap @	Capacity each	KW each	H.P. each	Speed (RPM)	Voltage	Remarks
			Boiler Building Unit Heater 28	1	INTERMITTENT					100		15			480	
			Boiler Building Unit Heater 31	1	INTERMITTENT					100		15			480	
			Boiler Building Unit Heater 34	1	INTERMITTENT					100		15			480	
			Boiler Building Unit Heater 37	1	INTERMITTENT					100		15			480	
			Boiler Building Unit Heater 40	1	INTERMITTENT					100		15			480	
			Boiler Building Unit Heater 42	1	INTERMITTENT					100		15			480	
			Battery Room Air Conditioner 2	1	INTERMITTENT					100		9.6096			480	
			Boiler Building Unit Heater 02	1	INTERMITTENT					100		15			480	
			Boiler Building Unit Heater 05	1	INTERMITTENT					100		15			480	
			Boiler Building Unit Heater 08	1	INTERMITTENT					100		15			480	
			Boiler Building Unit Heater 11	1	INTERMITTENT					100		15			480	
			Boiler Building Unit Heater 14	1	INTERMITTENT					100		15			480	
			Boiler Building Unit Heater 17	1	INTERMITTENT					100		15			480	
			Boiler Building Unit Heater 20	1	INTERMITTENT					100		15			480	
			Boiler Building Unit Heater 23	1	INTERMITTENT					100		15			480	
			Boiler Building Unit Heater 26	1	INTERMITTENT					100		15			480	
			Boiler Building Unit Heater 29	1	INTERMITTENT					100		15			480	
			Boiler Building Unit Heater 32	1	INTERMITTENT					100		15			480	
			Boiler Building Unit Heater 35	1	INTERMITTENT					100		15			480	
			Boiler Building Unit Heater 38	1	INTERMITTENT					100		15			480	
			Boiler Building Unit Heater 41	1	INTERMITTENT					100		15			480	
			Boiler Building Unit Heater 43	1	INTERMITTENT					100		15			480	
			Boiler Building Unit Heater 03	1	INTERMITTENT					100		15			480	
			Boiler Building Unit Heater 06	1	INTERMITTENT					100		15			480	
			Boiler Building Unit Heater 09	1	INTERMITTENT					100		15			480	
			Boiler Building Unit Heater 12	1	INTERMITTENT					100		15			480	
			Boiler Building Unit Heater 15	1	INTERMITTENT					100		15			480	
			Boiler Building Unit Heater 18	1	INTERMITTENT					100		15			480	
			Boiler Building Unit Heater 21	1	INTERMITTENT					100		15			480	
			Boiler Building Unit Heater 24	1	INTERMITTENT					100		15			480	
			Boiler Building Unit Heater 27	1	INTERMITTENT					100		15			480	
			Boiler Building Unit Heater 30	1	INTERMITTENT					100		15			480	
			Boiler Building Unit Heater 33	1	INTERMITTENT					100		15			480	
			Boiler Building Unit Heater 36	1	INTERMITTENT					100		15			480	
			Boiler Building Unit Heater 39	1	INTERMITTENT					100		15			480	
			Boiler Building Unit Heater 44	1	INTERMITTENT					100		15			480	
			Boiler Area 120/208V Lighting Panelboard A		INTERMITTENT					100		40.95			480	
			Boiler Area 120/208V Lighting Panelboard B		INTERMITTENT					100		40.95			480	
			Boiler Area 120/208V Lighting Panelboard D		INTERMITTENT					100		40.95			480	
			Boiler Area 120/208V Lighting Panelboard C		INTERMITTENT					100		40.95			480	
			Boiler Building Roof Ventilator 1		INTERMITTENT					100		7.46			480	
			Boiler Building Roof Ventilator 13		INTERMITTENT					100		7.46			480	
			Boiler Building Roof Ventilator 17		INTERMITTENT					100		7.46			480	
			Boiler Building Roof Ventilator 21		INTERMITTENT					100		7.46			480	
			Boiler Building Roof Ventilator 23		INTERMITTENT					100		7.46			480	
			Boiler Building Roof Ventilator 5		INTERMITTENT					100		7.46			480	
			Boiler Building Roof Ventilator 9		INTERMITTENT					100		7.46			480	
			Boiler Area Electrical Room Chiller Unit 1		INTERMITTENT					100		27.9552			480	
			Boiler Building Roof Ventilator 10		INTERMITTENT					100		7.46			480	
			Boiler Building Roof Ventilator 14		INTERMITTENT					100		7.46			480	
			Boiler Building Roof Ventilator 18		INTERMITTENT					100		7.46			480	
			Boiler Building Roof Ventilator 2		INTERMITTENT					100		7.46			480	
			Boiler Building Roof Ventilator 20		INTERMITTENT					100		7.46			480	
			Boiler Building Roof Ventilator 6		INTERMITTENT					100		7.46			480	
			Boiler Building Roof Ventilator 11		INTERMITTENT					100		7.46			480	
			Boiler Building Roof Ventilator 15		INTERMITTENT					100		7.46			480	
			Boiler Building Roof Ventilator 19		INTERMITTENT					100		7.46			480	
			Boiler Building Roof Ventilator 22		INTERMITTENT					100		7.46			480	
			Boiler Building Roof Ventilator 3		INTERMITTENT					100		7.46			480	
			Boiler Building Roof Ventilator 7		INTERMITTENT					100		7.46			480	
			Boiler Area Electrical Room Chiller Unit 2		INTERMITTENT					100		27.9552			480	
			Boiler Building Roof Ventilator 12		INTERMITTENT					100		7.46			480	
			Boiler Building Roof Ventilator 16		INTERMITTENT					100		7.46			480	
			Boiler Building Roof Ventilator 24		INTERMITTENT					100		7.46			480	
			Boiler Building Roof Ventilator 25		INTERMITTENT					100		7.46			480	
			Boiler Building Roof Ventilator 4		INTERMITTENT					100		7.46			480	
			Boiler Building Roof Ventilator 8		INTERMITTENT					100		7.46			480	
			EYEWASH STATIONS													

GQCS EQUIPMENT LIST

PRELIMINARY

						Process (Design/Performance) Data						Nameplate Loads				
Rev	Tag Number	B&W Tag Number	Equipment Name	Qty	Operating Mode (Operating/ Intermittent/ Standby)	Design Pressure (psig)	Operating Pressure (psig)	Design Temperature (oF)	Operating Temperature (oF)	% Cap @	Capacity @	KW @	H.P. @	Speed (RPM)	Voltage	Remarks
	7-DC-01-D	7-PS-203-D	**DIRECT CONTACT COOLER POLISHING SCRUBBER (DCCPS)**													
	7-DC-07-T	7-PS-202-T	DCCPS REACTION TANK	1	OPERATING					100	20.75 ft diameter	---	---		---	
	7-DC-08-T	7-PS-359-T	DCCPS AREA SUMP	1	OPERATING					100	10 ' x 10 ' x 10 '	---	---		---	
	7-DC-02-S	7-PS-360-D	DCCPS AREA SUMP AGITATOR	1	OPERATING					100	---	3.7	5.0		480	
	7-DC-03-P-1/2	7-PS-361-A/B	DCCPS AREA SUMP PUMP 7A & 7B	2	INTERMITTENT					100	500 gpm	18.6	25.0		480	
	7-DC-04-P-1/2	7-PS-221-C-A/B	DCCPS BLOWDOWN PUMP 7A & 7B	2	INTERMITTENT					100	15420 gpm	335.6	450.0		4160	
		7-PS-221-K-A/B-L	DCCPS BLOWDOWN PUMP A/B MOTOR SPACE HEATER	2	INTERMITTENT					100	---	0.375	---		120	
	7-DC-09-T	7-PS-201-T	DCCPS OVERFLOW SEAL TANK	1	OPERATING					100	---	---	---		---	
	7-DC-10-D	7-PS-209-D	pH SINK	1	OPERATING					100	---	---	---		---	
			LIMESTONE PREPARATION & FEED SYSTEM													
	7-CF-50-C-1/2	7-PL-118-C-A/B	POWDERED LIMESTONE STORAGE SILO DUST FILTER FAN 7A & 7B	2	OPERATING					100	TBD	3.7	5.0		460	
	7-CF-104-F-1/2	7-PL-116-F-A/B	POWDERED LIMESTONE DUST FILTER 7A & 7B	2	OPERATING/STBY					100	---	---	---		---	
	7-CF-51-T-1/2	7-PL-115-T-A/B	LIMESTONE STORAGE SILO 7A & 7B	2	OPERATING					100	2 days	---	---		---	
	7-CF-52-C-1/2/3	7-PL-110-C-A/B/C	POWDERED LIMESTONE-STORAGE SILO FLUIDIZING AIR BLOWER 7A, 7B, 7C	3	OPERATING/STBY					50	TBD	18.6	25.0		460	
	7-CF-105-A-1/2	7-PL-112-E-A/B	POWDERED LIMESTONE STORAGE SILO FLUIDIZING AIR HEATER 7A & 7B	2	OPERATING/STBY					100	---	20.0	---		460	
	7-CF-54-S-1/2	7-PL-113-G-A/B	POWDERED LIMESTONE STORAGE SILO ROTARY AIRLOCK FEEDER 7A & 7B	2	OPERATING/STBY					100	TBD	1.5	2.0		460	
	7-CF-55-T-1/2	7-LS-124-T-A/B	LIMESTONE SLURRY STORAGE TANK 7A & 7B	2	OPERATING					100	8 hrs	---	---		---	
	7-CF-56-P-1/2	7-LS-128-C-A/B	LIMESTONE SLURRY FEED PUMP 7A & 7B	2	OPERATING/STBY					100	245 gpm	18.6	25.0		460	
	7-CF-57-S-1/2	7-LS-125-D-A/B	LIMESTONE SLURRY STORAGE TANK AGITATOR 7A & 7B	2	OPERATING					100	---	29.8	40.0		460	
		7-LS-125-D-A/B-L	LIMESTONE SLURRY FEED TANK A/B AGITATOR SPACE HEATER	2	OPERATING					100	---	0.375	---		120	
	7-CF-106-S-1/2	7-PL-117-F-A/B	POWDERED LIMESTONE SILO TARGET BOX 7A & 7B	2	OPERATING/STBY					100	---	---	---		---	
	7-CF-107-T	7-MP-342-T	LIMESTONE PREPARATION SUMP	1	OPERATING					100	10 ' x 10 ' x 10 '	---	---		---	
	7-CF-108-P-1/2	7-MP-344-C-A/B	LIMESTONE PREPARATION SUMP PUMP 7A & 7B	2	OPERATING/STBY					100	500 gpm	18.6	25.0		460	
	7-CF-109-S	7-MP-343-D	LIMESTONE PREPARATION AREA SUMP AGITATION	1	OPERATING					100	---	3.7	5.0		460	
		7-PL-366-E	POWDERED LIMESTONE STORAGE SILO HOIST	1	INTERMITTENT					100	1/2 TON (MINIMUM)	1.1	1.5		460	
			OXIDATION AIR SYSTEM													
	7-OX-26-C-1/2	7-OA-275-C-A/B	OXIDATION AIR BLOWER 7A, 7B	2	OPERATING					100	42000 lb/hr (wet)	596.6	800.0		4160	
		7-OA-275-C-A/B-L	OXIDATION AIR BLOWER MOTOR SPACE HEATER 7A/7B	2	OPERATING					100	---	0.375	---		120	
	7-OX-27-P-1/2	7-LO-286-C-A/B	OXIDATION AIR MAIN LUBE OIL PUMP 7A1, 7A2	2	OPERATING					100	TBD	7.5	10.0		460	
	7-OX-28-P-1/2	7-LO-285-C-A/B	OXIDATION AIR AUXILIARY LUBE OIL PUMP 7B1, 7B2	2	STANDBY					100	TBD	7.5	10.0		460	
	7-MOV-0A557A/B	7-MOV-OA-557A/B	OXIDATION AIR BLOWER BLOWOFF VALVE 7A, 7B	2	INTERMITTENT					100	---	0.1	0.2		460	
		7-MOV-OA-558A/B	OXIDATION AIR BLOWER A/B DISCHARGE CONTROL VALVE	2	INTERMITTENT					100	---	0.1	0.2		460	
	7-OX-29-Y-1/2	7-OA-275-C-A/B	OXIDATION AIR BLOWER VARIABLE DIFFUSER VANE 7A, 7B	2	OPERATING					100	---	0.3	0.4		460	
	7-OX-30-T-1/2	7-LO-284-T-A/B	OXIDATION AIR BLOWER LUBE OIL TANK 7A & 7B	2	OPERATING/STBY					100	TBD	---	---		---	
	7-OX-31-Y-1/2	7-OA-272-Y-A/B	OXIDATION AIR BLOWER INLET LOUVER	2	OPERATING/STBY					100	---	---	---		---	
	7-OX-32-F-1/2	7-DA-273-F-A/B	OXIDATION AIR BLOWER TW0-STAGE FILTER.SILENCER 7A & 7B	2	OPERATING/STBY					100	---	---	---		---	
	7-OX-33-M-1/2	7-OA-278-M-A/B	OXIDATION AIR BLOWER SILENCER A/B	2	OPERATING/STBY					100	---	---	---		---	
	7-OX-34-F-1/2	7-LO-289-F-A, 7-LO-290-F-A	OXIDATION AIR BLOWER 7A DUPLEX OIL FILTER	2	OPERATING/STBY					100	---	---	---		---	
	7-OX-35-F-1/2	7-LO-289-F-B, 1-LO-290-F-B	OXIDATION AIR BLOWER 7B DUPLEX OIL FILTER	2	OPERATING/STBY					100	---	---	---		---	
	7-OX-36-A-1/2	7-LO-291-C-A/B	OXIDATION AIR BLOWER LUBE OIL COOLER 7A & 7B	2	OPERATING/STBY					100	---	---	---		---	
			PULSE JET FABRIC FILTER (PJFF)													
	7-FA-01-F		PJFF	1	OPERATING					100	---	---	---		---	
	7-FA-02-A-1/2/3/4/5/6	7-FG-034-E-A/B/C/D/E/F-L	PJFF 1 COMPARTMENT HOPPER HEATER 7A, 7B, 7C, 7D, 7E & 7F	6	INTERMITTENT					100	---	11.3	---		460	
	7-FA-03-S		PJFF 1 JIB CRANE 1	1	STANDBY					100	1/2 TON (MINIMUM)	1.1	1.5		460	
	7-FA-04-S	7-FG-365-E	PJFF 1 PENTHOUSE HOIST 1	1	STANDBY					100	1/2 TON (MINIMUM)	0.7	1.0		460	
	7-FA-05-C-1/~~2~~	7-IA-297-C	PULSE AIR COMPRESSOR 7A	1	OPERATING/~~STBY~~					100	540 SCFM	55.9	75.0		460	
		7-IA-297-C-L	PULSE AIR COMPRESSOR MOTOR SPACE HEATER	1	OPERATING					100	---	0.375	---		120	
	7-FA-06-P-1/~~2~~		PULSE AIR COMPRESSOR LUBRICATION OIL PUMP 7A & 7B	2	OPERATING/STBY					100	TBD	1.5	2.0		460	
	7-FA-19-D-1/2	7-IA-300-D-A/B-L	PULSE AIR DRYER 7A & 7B HEATER	2	OPERATING/STBY					100	---	40.0	---		460	
		7-IA-300-D-A/B	PULSE AIR DRYER BLOWER 7A & 7B	2	OPERATING/STBY					100	TBD	14.9	20.0		460	
	7-FA-20-X	7-IA-301-X	PULSE GAS RECEIVER	1	OPERATING					100	TBD gallons	---	---		---	
	7-FA-09-T	7-IA-298-X	PULSE AIR RECEIVER	1	OPERATING/STBY					100	TBD gallons	---	---		---	
	7-FA-10-C-1/2	7-FA-333-C-A/B	PJFF ASH TRANSPORT VACUUM BLOWER 7A, 7B	2	OPERATING/STBY					100	TBD	55.9	75.0		460	
		7-FA-333-C-A/B-L	PJFF ASH TRANSPORT VACUUM BLOWER 7A, 7B MOTOR SPACE HEATER	2	OPERATING/STBY					100	---	0.375	---		460	
	7-FA-13-T	7-FA-318-T	**WASTE ASH STORAGE SILO**	1	OPERATING					100	3 days	---	---		---	
	7-FA-14-S		WASTE ASH STORAGE SILO JIB CRANE	1	STANDBY					100	1/2 TON (MINIMUM)	1.1	1.5		460	
	7-FA-15-C-1/2	7-FA-328-C-A/B	WASTE ASH STORAGE SILO FLUIDIZING AIR BLOWER 7A & 7B	2	OPERATING/STBY					100	96 ICFM	7.5	10.0		460	
		7-FA-328-C-A/B-L	WASTE ASH STORAGE SILO FLUIDIZING AIR BLOWER 7A & 7B MOTOR SPACE HTR	2	OPERATING/STBY					100	---	0.375	---		120	
	7-FA-16-A	7-FA-331-E	WASTE ASH STORAGE SILO FLUIDIZING AIR HEATER	1	5123					100	---	8.0	---		460	
	7-FA-17-S	7-FA-363-E-M	WASTE ASH STORAGE SILO UNLOADER FLOOR HOIST	1	STANDBY					100	1 TON (MINIMUM)	1.5	2.0		460	
	7-FA-21-C	7-FA-317-C	FLY ASH SILO VENT FAN	1	OPERATING					100	TBD	0.4	0.5		460	
	7-FA-18-F	7-FA-319-F	WASTE ASH STORAGE SILO BIN VENT FILTER	1	OPERATING					100	---	---	---		---	
	7-FA-12-S	7-FA-315-G	WASTE ASH STORAGE SILO PUG MILL/UNLOADER	1	INTERMITTENT					100		29.8	40.0		460	
		7-FA-315-G-L	WASTE ASH STORAGE SILO PUG MILL/UNLOADER MOTOR SPACE HEATER	1	INTERMITTENT					100	---	0.375	---		120	
			WASTE ASH STORAGE SILO AREA SUMP	1	OPERATING					100	10 ' x 10 ' x 10 '	---	---		---	
			WASTE ASH STORAGE SILO AREA SUMP AGITATOR	1	OPERATING					100	---	3.7	5.0		460	
			WASTE ASH STORAGE SILO AREA SUMP PUMP 7A & 7B	2	INTERMITTENT					100	500 gpm	29.8	40.0		460	
	7-FA-22-S	7-FA-316-C	DRY DUST UNLOADING CHUTE VENT FAN	1	INTERMITTENT					100	TBD	3.7	5.0		460	
			DEWATERING AREA													

GQCS EQUIPMENT LIST

PRELIMINARY

						Process (Design/Performance) Data						Nameplate Loads				
Rev	Tag Number	B&W Tag Number	Equipment Name	Qty	Operating Mode (Operating/ Intermittent/ Standby)	Design Pressure (psig)	Operating Pressure (psig)	Design Temperature (oF)	Operating Temperature (oF)	% Cap @	Capacity @	KW @	H.P. @	Speed (RPM)	Voltage	Remarks
	7-CF-110-T	7-FF-346-T	DEWATERING AREA SUMP	1	OPERATING					100	10 ' x 10 ' x 10 '	---	---		---	
	7-CF-58-S	7-FF-347-D	DEWATERING AREA SUMP AGITATOR	1	OPERATING					100	---	3.7	5.0		460	
	7-CF-59-P-1/2	7-FF-348-C-A/B	DEWATERING AREA SUMP PUMP 7A, 7B	2	OPERATING/STBY					100	550 gpm	18.6	25.0		460	
	7-CF-111-D	7-FF-137-D	PRIMARY HYDROCLONE	1	OPERATING					100	425 gpm feed	---	---		---	
	7-CF-112-D	7-AP-149-D	SECONDARY HYDROCLONE	1	OPERATING					100	38 gpnm feed	---	---		---	
	7-CF-60-P-1/2	7-RW-139-C-A/B	SECONDARY HYDROCLONE FEED PUMP 7A, 7B	2	OPERATING/STBY					100	38 gpm feed	3.7	5.0		460	
	7-CF-113-T	7-AP-147-T	CHLORIDE BLOWDOWN TANK	1	OPERATING					100	3.8 days	c	---		---	
	7-CF-61-S	7-AP-148-D	CHLORIDE BLOWDOWN TANK AGITATOR	1	OPERATING					100	---	18.6	25.0		460	
	7-CF-62-P-1/2	7-AP-151-C-A/B	CHLORIDE BLOWDOWN TANK PUMP 7A, 7B	2	OPERATING/STBY					100	130 gpm	29.8	40.0		460	
	7-CF-114-T-1/2	7-FF-158-T-A/B	VACUUM FILTER FEED TANK 7A & 7B	2	OPERATING/STBY					100	4 hrs	---	---		---	
	7-CF-63-S-1/2	7-FF-159-D-A/B	VACUUM FILTER FEED TANK AGITATOR 7A & 7B	2	OPERATING/STBY					100	---	22.4	30.0		460	
	7-CF-64-P-1/2	7-FF-162-C-A/B	VACUUM FILTER FEED TANK PUMP 7A, 7B	2	OPERATING/STBY					100	170 gpm	11.2	15.0		460	
	7-CF-115-F-1/2	7-VF-170-T-A/B	VACUUM DRUM FILTER 7A & 7B	2	OPERATING/STBY					100	23.6 TPH cake (dry)	1.5	2.0		460	
	7-CF-68-S-1/2	7-VF-171-D-A/B	VACUUM DRUM FILTER AGITATOR 7A & 7B	2	OPERATING/STBY					100	---	0.7	1.0		460	
	7-CF-65-P-1/2	7-VF-179-C-A/B	DRUM VACUUM FILTER VACUUM PUMP 7A, 7B	2	OPERATING/STBY					100	1081 ACFM @20" Hg	55.9	75.0		460	
			VACUUM DRUM FILTER DISCHARGE BLOWERS 7A, 7B	2	OPERATING/STBY					100	TBD	2.2	3.0		460	
	7-CF-66-F-1~~/2~~	7-GH-183-G	VACUUM DRUM FILTER GYPSUM CONVEYOR #1- 7A	1	OPERATING					100	23.6 TPH cake (dry)	2.2	3.0		460	
	7-CF-66-F-1	7-GH-184-G	VACUUM DRUM FILTER GYPSUM CONVEYOR #2 - 7B	1	OPERATING					100	23.6 TPH cake (dry)	2.2	3.0		460	
	7-CF-67-P-1/2	7-VF-176-CA/B	RECEIVER FILTRATE PUMP 7A, 7B	2	OPERATING/STBY					100	52 gpm	5.6	7.5		460	
	7-CF-116-T-1/2	7-RW-190-T-A/B	RECLAIM WATER TANK 7A & 7B	2	OPERATING/STBY					100	4 hrs	---	---		---	
	7-CF-70-S	7-RW-191-D-A/B	RECLAIM WATER TANK AGITATOR 7A & 7B	1	OPERATING					100	---	14.9	20.0		460	
	7-CF-71-P-1/2	7-RW-194-C-A/B	RECLAIM WATER PUMP 7A, 7B	2	OPERATING/STBY					100	725 gpm	37.3	50.0		460	
		7-RW-194-C-A/B-L	RECLAIM WATER PUMP A/B MOTOR SPACE HEATER	2	OPERATING/STBY					100	---	0.375	---		120	
	7-CF-117-X-1/2	7-VF-175-X-A/B	VACUUM DRUM FILTER VACCUM RECEIVER 7A & 7B	2	OPERATING/STBY					100	TBD	---	---		---	
	7-CF-118-X-1/2	7-VF-181-X-A/B	SEPARATOR	2	OPERATING/STBY					100	---	---	---		---	
		7-VF-368-E	VACUUM DRUM FILTER HOIST	1	INTERMITTENT					100	1/2 TON (MINIMUM)	1.1	1.5		460	
			ABSORBER AREA													
	7-CF-119-T	7-AB-355-T	ABSORBER AREA SUMP	1	OPERATING					100	10 ' x 10 ' x 10 '	---	---		---	
	7-CF-78-S	7-AB-356-D	ABSORBER AREA SUMP AGITATOR	1	OPERATING					100	---	3.7	5.0		460	
	7-CF-79-P-1/2	7-AB-357-C-A/B	ABSORBER AREA SUMP PUMP 7A & 7B	2	OPERATING/STBY					100	500 gpm	22.4	30.0		460	
	1-CF-120-T	7-AB-069-T	WFGD ABSORBER REACTION TANK	1	OPERATING					100	32.0 ft diameter	---	---		---	
	7-CF-80-S-1/2/3/4	7-AB-076-D-A/B/C/D	ABSORBER REACTION TANK AGITATOR 7A, 7B, 7C, 7D	4	OPERATING					100	---	29.8	40.0		460	
	7-CF-81-P	7-AR-103-K-A/B	ABSORBER RECIRCULATION PUMP 7A, 7B	2	OPERATING					100	33500 gpm	745.7	1000.0		4160	
	7-CF-82-P-1/2	7-AR-103-K-C	ABSORBER RECIRCULATION PUMP 7C	1	OPERATING					100	33500 gpm	932.1	1250.0		4160	
	7-CF-83-P-1/2	7-AR-087-C-A/B	WFGD ABSORBER BLEED PUMP 7A, 7B	2	OPERATING/STBY					100	425 gpm	18.6	25.0		460	
		7-AR-103-K-A/B/C-L	WFGD ABSORBER RECIRCULATION PUMP A/B/C MOTOR SPACE HTR	3	OPERATING					100	---	0.375	---		120	
	7-WS-04-P-1/2	7-SW-258-C-A/B	SERVICE WATER PUMP 7A, 7B	2	OPERATING/STBY					100	1800 gpm	149.1	200.0		460	
		7-SW-258-C-A/B-L	SERVICE WATER PUMP MOTOR SPACE HEATERS 7A & 7B	2	OPERATING/STBY					100	---	0.375	---		120	
	7-CF-84-P-1/2	7-ME-260-C-A/B	MIST ELIMINATOR WASH WATER PUMP 7A, 7B	2	OPERATING/STBY					100	500 gpm	44.7	60.0		460	
		7-ME-260-C-A/B-L	MIST ELIMINATOR WATER WASH PUMP A/B MOTOR SPACE HEATER	2	OPERATING/STBY					100	---	0.375	---		120	
	7-CF-121-1/2	7-EQ-255-C-A/B	EMERGENCY QUENCH PUMPS 7A & 7B	2	OPERATING/STBY					100	1230	74.6	100.0		460	
		7-EQ-255-C-A/B-L	EMERGENCY QUENCH PUMPS A/B MOTOR SPACE HEATERS	2	OPERATING/STBY					100	---	0.375	---		120	
	7-CF-85-S	7-AB-308-D	EMERGENCY STORAGE TANK AGITATOR	1	OPERATING					100	---	55.9	75.0		460	
		7-AB-308-D-L	EMERGEMCY STORAGE TANK AGITATOR MOTOR SPACE HEATER	1	OPERATING					100	---	0.375	---		120	
	7-CF-86-P-1~~/2~~	7-AB-309-C	EMERGENCY STORAGE TANK PUMPS 7A~~, 7B~~	1	OPERATING~~/STBY~~					100	540 gpm	14.9	20.0		460	
	7-CF-87-S	7-AR-362-E-M	ABSORBER HOIST	1	STANDBY					100	1 TON (MINIMUM)	1.5	2.0		460	
	7-CF-88-S		ABSORBER HOIST TROLLY	1	STANDBY					100	1 TON (MINIMUM)	0.4	0.5		460	
	7-CF-89-S	7-AB-070-D	ABSORBER	1	OPERATING					100	32.0 ft diameter	---	---		---	
	7-WS-05-T	7-SW-253-T	SERVICE WATER TANK	1	OPERATING					100	4 hrs + 30 min quench	---	---		---	
	7-CF-122-T	7-ABB-307-T	EMERGENCY STORAGE TANK	1	OPERATING					100	1 WFGD Tower liquid volume	---	---		---	
	7-CF-123-T	7-AB-068-T	WFGD ABSORBER OVERFLOW SEAL TANK	1						100	TBD	---	---		---	
	TBD	TBD	pH SINK	1	OPERATING					100	---	---	---		---	
			SO3 INJECTION SYSTEM													
	7-CF-90-T		SO3 INJECTION SYSTEM	1	OPERATING					100	3 days	---	---		---	
	7-CF-124-T	7-TH-024-F	SO3 STORAGE TANK	1	OPERATING					100	3 days	---	---		---	
	7-CF-92-C		SILO SKIRT EXHAUST FAN	1	OPERATING					100	TBD	0.2	0.3		208	
	7-CF-93-A	7-TH-027-E-L	SILO SKIRT HEATER	1	INTERMITTENT					100	---	10.0	13.4		120	
	7-CF-95-S-1	7-TH-017-G	TRONA STORAGE SILO DISCHARGE ROTARY VALVE, 7	1	INTERMITTENT					100	---	0.7	1.0		460	
	7-CF-96-S-1	7-TH-013-G	WEIGH HOPPER ROTARY FEEDER 7A	1	OPERATING					100	TBD	0.7	1.0		460	
	7-CF-97-S-1	7-TH-010-G	VENT HOPPER ROTARY AIRLOCK 7A	1	OPERATING					100	TBD	0.4	0.5		460	
	7-CF-125-T	7-TH-011-T	SO3 VENT HOPPER	1	OPERATING/STBY					100	---	---	---		---	
	7-CF-126-F	7-TH-025-F	SILO VENT FILTER	1	OPERATING/STBY					100	---	---	---		---	
	7-CF-98-C-1	7-TH-026-C	BIN VENT HOPPER FILTER BLOWER	1	OPERATING					100	TBD	2.2	3.0		460	
	7-CF-99-S-1/2	7-TH-023-G	SILO BIN VIBRATOR 7A	1	OPERATING					100	---	1.1	1.5		460	
	7-CF-100-S		SILO FLUIDIZATION SYSTEM CHILLER/DEHUMIDIFICATION SKID	1	OPERATING					100	TBD	30.6	41.0		460	
	7-CF-127-P-1/2	7-TH-018-A/B	CHILLED WATER PUMPS 7A & 7B	2	OPERATING/STBY					100	TBD	---	---		---	
	7-CF-128-F	7-TH-022-F	SO3 FLUIDIZING AIR FILTER	1	OPERATING					100	---	---	---		---	
	7-CF-129-A	7-TH-021-C	FLUIDIZING AIR PRECOOLER	1	OPERATING					100	TBD	---	---		---	
	7-CF-130-F	7-TH-019-C	FLUIDIZING AIR AFTERCOOLER	1	OPERATING					100	TBD	---	---		---	
	7-CF-101-A		COOLER SKID	1	OPERATING~~/STBY~~					100	TBD	5.2	7.0		460	
	7-CF-131-D	7-TH-001-D	DEMISTER	1	OPERATING					100	---	---	---		---	
		7-TH-029-E-L	TRONA STORAGE DEHUMIDIFIER PANEL	1	OPERATING					100	---	30.6	---		460	
	7-CF-132-F	7-TH-002-F	FILTER	1	OPERATING					100	---	---	---		---	
	7-CF-133-C	7-TH-003-C	CONVEY AIR BLOWER SOUND ENCLOSURE EXHAUST FAN	1	OPERATING					100	TBD	0.2	0.3		120	
	7-CF-103-S-1	7-TH-004-M	INLET SILENCER	1	OPERATING					100	---	---	---		---	
	7-CF-103-S-2	7-TH-008-M	OUTLET SILENCER	1	OPERATING					100	---	---	---		---	
	7-CF-134-C	7-TH-009-C	AIR COOLER	1	OPERATING					100	TBD	1.5	2.0		480	
	7-CF-135-X	7-TH-015-X	AIR RECEIVER	1	OPERATING					100	TBD	---	---		---	
	7-CF-102-C-1	7-TH-006-C	CONVEYOR BLOWER 7A	1	OPERATING					100	600 scfm	29.8	40.0		460	
		7-TH-006-C-L	CONVEYOR AIR BLOWER MOTOR SPACE HEATER	1	OPERATING					100	---	0.375	---		120	
	7-CF-136-T	7-TH-016-T	WEIGH HOPPER	1	OPERATING					100	---	---	---		---	
			TRONA SYSTEM													
	7-CF-137-X-1/2	7-TH-234-X-A	TRONA FILTER RECEIVER 7A & 7B	2	OPERATING/STBY					100	---	---	---		---	
	7-CF-138-S-1/2	7-TH-233-G-A/B	TRONA ROTARY AIR LOCK FEEDER 7A & 7B	2	OPERATING/STBY					100	---	1.1	1.5		460	
	7-CF-139-T	7-TL-240-T	TRONA LIQUOR STORAGE TANK	1	OPERATING					100	1.5 STD Truckloads	---	---		---	
	7-CF-140-S	7-TL-241-D	TRONA LIQUOR STORAGE TANK AGITATOR	1	OPERATING					100	---	11.2	15.0		460	
	7-CF-141-E-1/2	7-TL-242-E-A/B	TRONA LIQUOR STORAGE TANK HEATERS 7A & 7B	2	OPERATING					100	---	50.0	67.1		460	

GQCS EQUIPMENT LIST

PRELIMINARY

Rev	Tag Number	B&W Tag Number	Equipment Name	Qty	Operating Mode (Operating/ Intermittent/ Standby)	Process (Design/Performance) Data: Design Pressure (psig)	Operating Pressure (psig)	Design Temperature (oF)	Operating Temperature (oF)	% Cap @	Capacity @	Nameplate Loads: KW @	H.P. @	Speed (RPM)	Voltage	Remarks
	7-CF-142-P-1/2	7-TL-245-C-A/B	TRONA LIQUOR FEED PUMP 7A & 7B	2	OPERATING/STBY					100	70 gpm	7.5	10.0		460	
	7-CF-143-T	7-TL-246-T	TRONA LIQUOR STORAGE TANK D&V SCRUBBER	1	OPERATING					100	TBD	---	---		---	
	7-CF-144-C	7-TL-247-C	TRONA LIQUOR STORAGE TANK D&V SCRUBBER EXHAUST FAN	1	OPERATING					100	TBD	0.2	0.3		120	
	7-CF-145-F-1/2	7-TL-243-F-A/B	TRONA LIQUOR STORAGE TANK WETTING BOX 7A & 7B	2	OPERATING/STBY					100	---	---	---		---	
		7-TH-367-E	TRONA STORAGE SILO HOIST	1	INTERMITTENT					100	1 TON (MINIMUM)	1.5	2.0		460	
			HVAC EQUIPMENT													
	TBD	TBD	GQCS BUILDING UNIT HEATER	17	INTERMITTENT					100	---	7.5	---		460	
	TBD	TBD	GQCS BUILDING WALL FANS	15	INTERMITTENT					100	---	0.4	---		460	
	TBD	TBD	GQCS BUILDING ROOF VENTILATORS	4	INTERMITTENT					100	---	1.1	---		460	
	TBD	TBD	GQCS BUILDING ELECTRICAL ROOM HVAC UNIT	2	INTERMITTENT					100	---	28.0	---		460	
	TBD	TBD	PJFF COMPRESSOR ENCLOSURE ROOF MOUNTED EXHAUST FAN	4	INTERMITTENT					100	---	2.2	---		460	
	TBD	TBD	PJFF ENCLOSURE WALL EXHAUST FAN	6	INTERMITTENT					100	---	0.4	---		460	
	TBD	TBD	GQCS DEWATERING BUILDING UNIT HEATER	8	INTERMITTENT					100	---	12.5	---		460	
	TBD	TBD	GQCS DEWATERING BUILDING WALL HVAC UNIT	2	INTERMITTENT					100	---	13.7	---		460	
	TBD	TBD	GQCS DEWATERING BUILDING ROOF VENTILATOR	4	INTERMITTENT					100	---	1.1	---		460	
	TBD	TBD	GQCS DEWATERING BUILDING WALL FAN	2	INTERMITTENT					100	---	0.4	---		460	
	TBD	TBD	PJFF COMPRESSOR ENCLOSURE UNIT HEATER	4	INTERMITTENT					100	---	10.0	---		460	
	TBD	TBD	PJFF ENCLOSURE UNIT HEATER	8	INTERMITTENT					100	---	9.0	---		460	
			SAFETY EQUIPMENT													
	TBD	TBD	EYEWASH STATION - PRIMARY / SECONDARY HYDROCLONE AREA	1	INTERMITTENT					100	---	---	---		---	
	TBD	TBD	EYEWASH STATION - PRIMARY / GYPSUM CONVEYOR AREA	1	INTERMITTENT					100	---	---	---		---	
	TBD	TBD	SAFETY SHOWER/ EYEWASH STATION - DCCPS TRONA UNLOADING AREA	1	INTERMITTENT					100	---	---	---		---	
	TBD	TBD	SAFETY SHOWER/ EYEWASH STATION - POWDERED LIMESTONE UNLOAD AREA	1	INTERMITTENT					100	---	---	---		---	
	TBD	TBD	SAFETY SHOWER/ EYEWASH STATION - PL STORAGE SILO DISCHARGE AREA	1	INTERMITTENT					100	---	---	---		---	
	TBD	TBD	SAFETY SHOWER/ EYEWASH STATION - PL STORAGE SILO SLUICE BOWL AREA	1	INTERMITTENT					100	---	---	---		---	
	TBD	TBD	SAFETY SHOWER/ EYEWASH STATION - WASTE ASH SILO PUGMILL AREA	1	INTERMITTENT					100	---	---	---		---	
	TBD	TBD	SAFETY SHOWER/ EYEWASH STATION - WASTE ASH SILO TRUCK UNLOAD AREA	1	INTERMITTENT					100	---	---	---		---	
	TBD	TBD	SAFETY SHOWER/ EYEWASH STATION - TRONA STORAGE SILO UNLOADING AREA	1	INTERMITTENT					100	---	---	---		---	
	TBD	TBD	SAFETY SHOWER/ EYEWASH STATION - PJFF HOPPER AREA	1	INTERMITTENT					100	---	---	---		---	

BOP EQUIPMENT LIST

PRELIMINARY

Rev	Tag Number	Equipment Name	Qty	Existing or New	Operating Mode (Operating/ Intermittent/ Standby)	Design Pressure (psig)	Operating Pressure (psig)	Design Temperature (^oF)	Operating Temperature (^oF)	% Cap @	Capacity @	KW @	H.P. @	Speed (RPM)	Voltage	Remarks
						Process (Design/Performance) Data						Nameplate Loads				
P1		**BOILER NO. 4**														
P1	~~GLYCOL HEAT EXCHANGER 4-1, 4-2~~	~~GLYCOL HEAT EXCHANGERS~~	~~2~~	E	~~INTERMITTENT~~		~~60 psia~~		~~130/200°F~~	~~100~~	~~650 klb/hr~~					NOT REUSED
P1	~~GLYCOL STORAGE TANK~~	~~GLYCOL STORAGE TANK~~	~~1~~	E	~~OPERATING~~					~~100~~	~~10,000 GAL~~					NOT REUSED
P1	~~GLYCOL AIR HEATING COIL~~	~~STEAM COIL AIR HEATER~~	4	E	~~INTERMITTENT~~		~~60 psia~~		~~200/130°F~~	~~100~~	~~650 klb/hr~~					NOT REUSED
P1	~~GLYCOL PUMP 4-1, 4-2~~	~~GLYCOL PUMPS~~	~~2~~	E	~~INTERMITTENT~~		~~100 ft TH~~			~~100~~	~~650 klb/hr~~	~~37.3~~	~~50~~	~~1800~~	~~460~~	NOT REUSED
P1	~~GAS INJECTION FAN~~	~~GAS INJECTION FAN~~	~~1~~	E	~~OPERATING~~					~~100~~	~~300 KLB/HR (151.7 kcfm @ 28.8 in H_2O~~	~~1491.4~~	~~2000~~	~~890~~	~~4000~~	NOT REUSED
P1	~~PENTHOUSE FAN~~	~~PENTHOUSE FAN~~	~~1~~	E	~~OPERATING~~					~~100~~		~~93.2~~	~~125~~	~~3555~~	~~460~~	NOT REUSED
P1	~~SEAL AIR FAN 4-1, 4-2~~	~~SEAL AIR FAN~~	~~2~~	E	~~OPERATING/STBY~~					~~100~~		~~0.7~~				NOT REUSED
P1	~~FD FAN 4-1, 4-2~~	~~FD FAN~~	~~2~~	E	~~OPERATING~~					~~50~~	~~232,000 CFM @ 59.2 IN H_2O~~	~~2237.1~~	~~3000~~	~~1181~~	~~4000~~	NOT REUSED 373 AMPS EACH
P1		**STEAM TURBINE PACKAGE**			---	---	---	---	---	---	---	---	---	---	---	
P1	TURBINE NO. 4	STEAM TURBINE	1	E	OPERATING	2400	2286	1009 / 1009	1000 / 1000	100	194,175 KW GROSS @ 1 in. Hg ABS	---	---	3600	---	THROTTLE @ 2286 psig, 1000°F
P1	GENERATOR NO. 4	STEAM TURBINE GENERATOR	1	E	OPERATING	60	---	---	---	100	233 MVA @ 0.9 PF	209,700	---	3600	20 kV	BRUSHLESS EXCITER
P1	EXCITER NO. 4	EXCITER	1	E	OPERATING					100		1,050		3600	375	
P1	GLAND STEAM CONDENSER	GLAND STEAM CONDENSER	1	E	OPERATING	625	---	125	105	100	---	---	---	---	---	
P1	GLAND STEAM EXHAUSTER 4-1/2	GLAND STEAM CONDENSER EXHAUSTERS	2	E	OPERATING/STBY	---	---	---	---	100	---	3.7	5	3500	220/460	ODP FRAME 182T
P1	UNIT 4 TURBINE OIL TRANSFER PUMP 4-1	STEAM TURBINE LUBE OIL SKID	1	E	OPERATING	---	---	---	---	100	RESERVOIR-3500 gal	---	---	---	---	SYSTEM CAPACITY 5,075 GAL
P1		MAIN LUBE OIL PUMP	1	E	OPERATING	---	---	---	---	100	---	0.0	0	3600		SHAFT-DRIVEN
P1		AUXILIARY OIL PUMP (TURNING GEAR OIL PUMP)	1	E	STANDBY		40 psia			100	375 gpm	14.9	20	1750		
P1		EMERGENCY LUBE OIL PUMP	1	E	STANDBY	---	40 psia	---	---	100	375 gpm	14.9	20	1750	240 V DC	
P1		TURNING GEAR	1	E	STANDBY					100		11.2	15	3	460	
P1	TURBINE OIL COOLERS	TURBINE LUBE OIL COOLERS	2	E	OPERATING/STBY	125	---		52.6/120 IN/OUT	100	684 gpm	---	---	---	---	
P1	OIL RESERVOIR	OIL RESERVOIR	1	E	OPERATING					100	3500 GAL					
P1	TURBINE OIL TRANSFER PUMP	TURBINE OIL TRANSFER PUMP	1	E	INTERMITTENT		160 ft TH			100	150 gpm	11.2	15	3600	460	
P1	TURBINE OIL PURIFIER	LUBE OIL PURIFIER	1	E	OPERATING	---	---	---	---	100	35O gph	48	---	---	---	
P1		OIL VAPOR EXTRACTOR	1	E	OPERATING							1.5	2	3500		
P1		TURBINE HYDRAULIC OIL SKID	1	E	OPERATING	---	---	---	---	100	---	---	---	---	---	
P1		TURBINE HYDRAULIC OIL PUMPS	2	E	OPERATING/STBY	---	---	---	---	100	---	22.4	30	1750	460	
P1	TURBINE OIL COOLERS	TURBINE HYDRAULIC OIL COOLERS	2	E	OPERATING/STBY	---	---	---	---	100	---	---	---	---	---	
B	AIR/HYDROGEN SIDE H2 SEAL OIL COOLER	GENERATOR SEAL OIL SKID AIR/HYDROGEN	2	E	OPERATING	---	---	---	---	100	---	18.6	25	1200	460	
P1		SEAL OIL BACKUP PUMP AIR SIDE	1	E	STANDBY					100		2.2	3	1750	120 VDC	
P1		GENERATOR GAS COOLERS	2	E	OPERATING/STBY	60	51	---	---	100	---	---	---	---	---	
P1		**CONDENSATE SYSTEM**			---	---	---	---	---	---	---	---	---	---	---	
P1	CONDENSER	CONDENSER	1	E	OPERATING	FULL VACUUM	3.5 Hg abs			100	924.41 MBtu/hr; 85,500 gpm	---	---	---	---	1.0 Hg abs RATED PRESSURE
P1	CONDENSATE PUMP 4-1, 4-2	CONDENSATE PUMPS	2	E	OPERATING		930 ft TDH			50	1275 gpm EACH	298.3	400	1770	4000	ODP
A		MISC CONDENSATE RETURN/BOOSTER PUMPS	2	NEW	OPERATING	300	392.7 ft TDH			50		18.6	25		460	
P1	L.P. HEATER 4-1	LOW PRESSURE FEEDWATER HEATER NO. 1	1	E	OPERATING	FULL VAC/50	9.6 psia	300	111.9/186.4°F	100					---	
P1	L.P. HEATER 4-2	LOW PRESSURE FEEDWATER HEATER NO. 2	1	E	OPERATING	FULL VAC/75	28.2 psia	410/320	186.4/241.8°F	100					---	
P1	L.P. HEATER 4-3	LOW PRESSURE FEEDWATER HEATER NO. 3	1	E	OPERATING	FULL VAC / 100	62.54 psia	560/350	241.8/290.4°F	100					---	
B	D. C. HEATER 4-4	DEAERATOR (HEATER NO. 4)	1	E	OPERATING	VAC/175 psig	136	650		100	1.42 mlb/hr @0.005 mL/L O2				---	MOVED TO BOILER 7
B	STORAGE TANK	DEAERATOR STORAGE TANK	1	E	OPERATING	VAC/175 psig	136	650		100	16 kgal				---	MOVED TO BOILER 7
P1	7-CD-01-P-1/2	CPU CONDENSATE RETURN PUMPS	2	NEW	OPERATING/STBY	300	231 ft TDH			100		3.7	5	1780	480	
P1	7-CD-02-P-1/2	ASU CONDENSATE RETURN PUMPS	2	NEW	STANDBY	300	392.7 ft TDH			100		18.6	25	1780	480	
P1		**CONDENSER AIR EVACUATION SYSTEM**			---	---	---								---	
P1	MAIN CONDENSER VACUUM PUMP 4-1, 4-2	VACUUM PUMPS	2	E	OPERATING/STBY	1 in Hg abs	---			100	89.5 LB/HR @ 1 IN HG ABS	37.3	50	720	480	
P1	VACUUM PUMP HEAT EXCHANGER 4-1, 4-2	VACUUM SYSTEM SEAL WATER COOLERS	2	E	OPERATING/STBY	---	---			100					---	
P1		**CONDENSATE POLISHING SYSTEM**			---	---	---								---	
C	7-CP-01-T-1/2	CONDENSATE POLISHERS	2	NEW	OPERATING/STBY					100					---	
C	7-CP-02-T	FRESH RESIN STORAGE VESSEL	1	NEW	OPERATING					100						
C	7-CP-03-T	EXHAUSTED RESIN STORAGE VESSEL	1	NEW	OPERATING					100						
C	7-CP-04-P-1/2	RECYCLE PUMPS	2	NEW	OPERATING/STBY					100		74.6	100		460	
P1		**FEEDWATER SYSTEM**			---	---	---								---	
P1	MD BFP 4-1, 4-2	BOILER FEED PUMPS	2	E	OPERATING		7200 ft TDH			50	750 klb/hr each	2610.0	3500	3573	4000	427 amps each
P1	HYDRAULIC COUPLING PUMP 4-1, 4-2	BOILER FEED PUMP LUBE OIL SYSTEMS	2	E	OPERATING	---	---			100					480	
P1	HP HEATER 4-5	HIGH PRESSURE FEEDWATER HEATER NO. 5	1	E	OPERATING	400/3150	320.9 psia	450	351.7/418.6°F	100						
P1	HP HEATER 4-6	HIGH PRESSURE FEEDWATER HEATER NO. 6	1	E	OPERATING	700/3150	539.2 psia	500	418.6/474.9°F	100						
P1		**CONDENSATE TRANSFER SYSTEM**			---	---	---								---	
C	7-CD-6-T	CONDENSATE STORAGE TANK	1	NEW	OPERATING	Atm	Atm			100	100 KGAL				---	WELDED, FIELD ERECT, LINED
P1		**STEAM CYCLE CHEMICAL FEED SYSTEM**			---	---	---								---	
P1	7-CF-37-S	OXYGEN SCAVENGER FEED SKID	1	NEW	OPERATING	---	---			100		3.7	5		460	
P1	7-CF-38-S	AMMONIA FEED SKID	1	NEW	OPERATING	---	---			100		3.7	5		460	
P1	7-CF-39-P-1/2	AMMONIA METERING PUMPS	2	NEW	OPERATING/STBY	---	---			100		2.2	3		460	
P1	STEAM & WATER ANALYSIS SYSTEM UNITS 3 & 4	STEAM & WATER ANALYSIS SYSTEM UNITS 3 & 4	2	NEW	OPERATING/STBY		75 ft TH			100	64 gpm	1.5	2		208-230/460	ADDITIONS ONLY TO EXISTING PANEL
P1	SAMPLE PANEL 7	SAMPLE PANEL	1	E	OPERATING	---	---			100		5			120	

BOP EQUIPMENT LIST

PRELIMINARY

Rev	Tag Number	Equipment Name	Qty	Existing or New	Operating Mode (Operating/ Intermittent/ Standby)	Design Pressure (psig)	Operating Pressure (psig)	Process (Design/Performance) Data Design Temperature (°F)	Operating Temperature (°F)	% Cap @	Capacity @	Nameplate Loads KW @	H.P. @	Speed (RPM)	Voltage	Remarks
P1		**CIRCULATING WATER SYSTEM**			---	---	---								---	
B	COOLING TOWER 4	COOLING TOWER	1	NEW	OPERATING	47ft pump head	---	14/92 @ 76 WB		100	85,500 gpm				---	REBUILD TOWER ON EXISTING BASIN
B	7-CW-01-C-1/2/3/4	COOLING TOWER FANS	4	NEW	OPERATING	---	---			25	1665,663 cfm each	149.1	200	1775	460	
B	CIRCULATING WATER PUMP 4-1, 4-2	CIRCULATING WATER PUMPS	2	E	OPERATING	100	78 ft TDH			50	42,750 gpm each	745.7	1000	590	4000	135 amps each
B	7-CW-06-A	ASU/CPU COOLING TOWER	1	NEW	OPERATING					100	22,400 gpm					
B	7-CW-07-C-1/2	ASU/CPU COOLING WATER FANS	2	NEW	OPERATING					50	1,393,000 cfm per fan	184.9	248		4160	
C	7-CW-08-P-1/2	ASU/CPU COOLING WATER PUMPS	2	NEW	OPERATING	150	135.1 ft TDH			50	11,200 gpm each	348.4	467.2		4160	
P1		**DCCPS COOLING SYSTEM**														
P1	7-CW-02-A	DCCPS COOLING TOWER	2	New	OPERATING	40 ft pump head	---			100					---	
B	7-CW-03-C-1/2	DCCPS COOLING TOWER FANS	2	New	OPERATING	---	---			50	1,170,000 cfm each	185.5	248.7	1800	4160	
C	7-CW-04-P-1/2	DCCPS CIRC WATER SUPPLY PUMPS	2	New	OPERATING/STBY	150	121 ft TDH			50	28,000 gpm each	857.6	1150		4160	
P1	7-CF-40-S	DCCPS COOLING TOWER CHEM FEED SYSTEM	1	New	OPERATING	---	---			100		3.7	5		460	
P1		**COOLING TOWER CHEMICAL FEED SYSTEM**			---	---	---									
P1	7-CF-41-S	ASU/CPU COOLING TOWER NON-OX BIOCIDE FEED SI	1	New	OPERATING	---	---			100		0.7	1		460	
P1	7-CF-42-S	ASU/CPU COOLING TOWER ACID FEED SKID	1	New	OPERATING	---	---			100		0.7	1		460	
P1	7-CF-43-S	ASU/CPU COOLING TOWER BLEACH FEED SKID	1	New	OPERATING	---	---			100		0.7	1		460	
P1	7-CF-43-S	ASU/CPU COOLING TOWER CORROSION INHIBITOR FEED SKID	1	New	OPERATING	---	---			100		0.7	1		460	
P1		**CLOSED COOLING WATER SYSTEM**			---	---	---								---	
P1	CLOSED COOLING WATER HEAT EXCHANGER	CLOSED COOLING WATER HEAT EXCHANGERS	1	E	OPERATING				125/105°F	100	250 gpm/500 gpm				---	
P1	CLOSED COOLING WATER COLLECTING TANK	CLOSED COOLING WATER STORAGE TANK	1	E	OPERATING					100	1500 GAL					
P1	CLOSED COOLING WATER PUMP 4-1, 4-2	CLOSED COOLING WATER PUMP	2	E	OPERATING/STBY		175 ft TH			100	250 gpm	14.9	20	3600	460	
P1	7-WC-01-A-1/2	CLOSED COOLING WATER HEAT EXCHANGER	2	New	OPERATING/STBY					100						
P1	7-WC-02-P-1/2	CLOSED COOLING WATER PUMPS	2	New	OPERATING/STBY	200	160 ft TDH			100		111.9	150	1800	460	
P1	7-WC-03-S	CLOSED COOLING WATER EXPANSION TANK	1	New	OPERATING	50	Atm			100					---	
P1		**COMPRESSED AIR SYSTEM**		New	---	---	---								---	
B	INSTRUMENT AIR COMPRESSOR 4-1, 4-2	INSTRUMENT AIR COMPRESSORS	2	E	OPERATING/STBY	150	100			100	140 ICFM	37.3	50	1760	480	RECIPROCATING
B	CONTROL AIR COMPRESSOR 4-1, 4-2	CONTROL AIR COMPRESSORS	2	E	OPERATING/STBY		100			100	150 ICFM	93.2	125	1760	460	
A	CONTROL AIR WATER JACKET COOLER 4-1, 4-2	CONTROL AIR COMPRESSOR WATER JACKET COOLER	2	E	OPERATING/STBY					100						
A	CONTROL AIR AFTERCOOLER 4-1, 4-2	CONTROL AIR AFTERCOOLER	2	E	OPERATING/STBY											
P1	AIR DRYER	AIR DRYER	1	E	OPERATING	150				100	140 ICFM @ -40°F					
P1	SAC 4-2	STATION AIR COMPRESSOR 4-2	1	E	OPERATING		110			100	3000 ICFM	522.0	700	3570	4000	93 AMP
P1	SAC 4-1	STATION AIR COMPRESSOR 4-1	1	E	OPERATING		100			100	750 ICFM	111.9	150	1785	460	174 AMP
C	SAC AFTERCOOLER 4-1, 4-2	SAC AFTERCOOLER	2	E	OPERATING					100						
C	SAC INTER & WATER JACKET COOLER 4-1, 4-2	SAC INTER & WATER JACKET COOLER	2	E	OPERATING					100						
P1	UNIT 3 STATION AIR COMPRESSOR	UNIT 3 STATION AIR COMPRESSOR	1	E	OPERATING					100		111.9	150	1785		
P1	UNIT 1 & 2 STATION AIR COMPRESSOR	UNIT 1 & 2 STATION AIR COMPRESSOR	1	E	OPERATING					100		111.9	150	1785		
P1	STATION AIR COMPRESSOR	STATION AIR COMPRESSOR	1	E	OPERATING/STBY	150	100			100	545 SCFM	93.2	125	1780	480	2 STAGE RECIPROCATING
P1	INSTRUMENT AIR RECEIVER	INSTRUMENT AIR RECEIVERS	1	New	OPERATING	125				100	4' DIA X 12' HT					
P1	AIR RECEIVER	SERVICE AIR RECEIVER	1	New	OPERATING	125				100	3.5' DIA X 10' L					
B	7-IA-01-C-1/2/3	INSTRUMENT AIR COMPRESSORS	3	New	OPERATING/STBY	150	125			100	3625 ICFM EACH	671.1	900	3600	4000	
P1	7-IA-01-C-1/2	INSTRUMENT AIR RECEIVERS	2	New	OPERATING	150	125			100	500 CU. FT EACH				---	
P1	7-SA-01-T	SERVICE AIR RECEIVER	1	New	OPERATING	150	125			100	500 CU. FT				---	
B	7-IA-03-F-1/2	INSTRUMENT AIR DRYERS	2	New	OPERATING/STBY	150	125			100	4500 SCFM EACH	15			480	

BOP EQUIPMENT LIST

PRELIMINARY

Rev	Tag Number	Equipment Name	Qty	Existing or New	Operating Mode (Operating/ Intermittent/ Standby)	Design Pressure (psig)	Operating Pressure (psig)	Design Temperature (°F)	Operating Temperature (°F)	% Cap @	Capacity @	KW @	H.P. @	Speed (RPM)	Voltage	Remarks
								Process (Design/Performance) Data				Nameplate Loads				
P1		**COAL HANDLING SYSTEM**			---	---	---								---	
P1	BARGE UNLOADER	BARGE UNLOADER	1	E	INTERMITTENT	---	---			100	500 TPH	447.4	600	1185	2300	
P1	BARGE UNLOADER HOPPER	BARGE UNLOADER HOPPER	1	E	INTERMITTENT					100						
C	7-FC-29-G	BELT FEEDER BENEATH BARGE UNLOADER	1	NEW	INTERMITTENT					100	125-500 TPH	44.7	60		460	VFD DRIVE
C	DUST SUPPRESSION SPRAY SYSTEM	DUST SUPPRESSION SPRAY SYSTEM	1	E	OPERATING	---	---			100						OPERATING 20 HOURS PER DAY
P1	CONVEYOR E	CONVEYOR E	1	E	INTERMITTENT	---	---			100	500 TPH	44.7	60	1800	440	
P1	TRANSFER TOWER	TRANSFER TOWER	1	E	INTERMITTENT	---	---			100						
C	TRAMP IRON MAGNETIC SEPARATOR	TRAMP IRON MAGNETIC SEPARATOR	1	E	INTERMITTENT	---	---			100						
P1	CONVEYOR F	CONVEYOR F	1	E	INTERMITTENT	---	---			100	500 TPH	55.9	75	1800	440	
C	TRAMP IRON CHUTE	TRAMP IRON CHUTE	2	E	INTERMITTENT	---	---			100						
C	BREAKER	CRUSHER	1	E	OPERATING	---	---			100	500 TPH	37.3	50	705	440	OPERATING 20 HOURS PER DAY
P1	CONVEYOR B	CONVEYOR B	1	E	INTERMITTENT	---	---			100	500 TPH	55.9	75	1800	440	
~~P1~~	~~SCALE~~	~~SCALE~~	~~1~~	~~E~~	~~INTERMITTENT~~	~~---~~	~~---~~			100						
C	7-FC-30-G	BELT SCALE	1	New	INTERMITTENT					100						INSTALL ON "E" CONVEYOR
C	7-FC-33-G	DOUBLE OUTLET TRANSFER CHUTE & DIVERTER GATE	1	New	INTERMITTENT					100						CONTROLS "B" & "C" BELT FLOW
P1	TRIPPER CONVEYOR C	TRIPPER CONVEYOR C	1	E	INTERMITTENT	---	---			100	500 TPH	37.3	50	1800	440	
P1	CONVEYOR D	CONVEYOR D	1	E	INTERMITTENT	---	---			100	250 TPH	37.3	50	1800	440	
C	YARD STORAGE HOPPER	YARD STORAGE HOPPER	1	E	INTERMITTENT	---	---			100						
C	RECLAIM HOPPER	RECLAIM HOPPER	1	E	INTERMITTENT	---	---			100						OPERATING 20 HOURS PER DAY
C	~~RECLAIM FEEDER~~	~~RECLAIM FEEDER~~	~~1~~	~~E~~	~~INTERMITTENT~~	---	---			100						
C	7-FC-31-G	RECLAIM FEEDER	1	New	INTERMITTENT					100	125-500 TPH					VFD DRIVE
C	CONVEYOR A	CONVEYOR A	1	E	OPERATING	---	---			100	500 TPH	44.7	60	1800	440	OPERATING 20 HOURS PER DAY
C	7-FC-32-G	BELT SCALE "A" CONVEYOR	1	New	INTERMITTENT					100						
C	CRUSHER FEEDERS	CRUSHER FEEDERS	2	E	OPERATING	---	---			100						OPERATING 20 HOURS PER DAY
C	7-FC-28-G	BELT TRANSFER FEEDER (B TO G)	1	E	INTERMITTENT					100		44.7	50			OPERATING 10 HOURS PER DAY
C	7-FC-01-G	CONVEYOR G	1	New	INTERMITTENT	---	---			100	500 TPH 36 IN WIDE 450 FPM	149.1	200		460	
C	7-FC-34-G	TRANFER TOWER FOR "G" TO "H"	1	New	INTERMITTENT					100						
C	7-FC-35-G	CONVEROR H	1	New	INTERMITTENT					100	500 TPH 36 IN WIDE 450 FPM					33.75 FT LONG @ 16° SLOPE
C	7-FC-36-G	CONVEYOR K	1	New	INTERMITTENT					100	500 TPH 36 IN WIDE 450 FPM					67.25 FT LONG @ 9° SLOPE
C	7-FC-37-G	CONVEYOR L	1	New	INTERMITTENT					100	500 TPH 36 IN WIDE 450 FPM					35.5 FT LONG @ 0° SLOPE
C	7-FC-03-S	NEW CONVEYOR DUST COLLECTION SYSTEM	1	New	INTERMITTENT	---	---			100						
C	7-FC-38-F	DUST COLLECTOR FOR 7-FC-34-G	1	New	INTERMITTENT					100		11.2	15	1800	460	INCLUDES EXHAUST FAN & PULSEJET CLEANING
C	7-FC-39-F	DUST COLLECTOR FOR SILO "A"	1	New	INTERMITTENT					100		11.2	15	1800	460	INCLUDES EXHAUST FAN & PULSEJET CLEANING
C	7-FC-40-F	DUST COLLECTOR FOR SILO "B"	1	New	INTERMITTENT					100		11.2	15	1800	460	INCLUDES EXHAUST FAN & PULSEJET CLEANING
C	7-FC-41-F	DUST COLLECTOR FOR SILO "C"	1	New	INTERMITTENT					100		11.2	15	1800	460	INCLUDES EXHAUST FAN & PULSEJET CLEANING
P1		**RAW/SERVICE WATER SYSTEM**			---	---	---								---	
P1	FILTERED WATER STORAGE TANK	FILTERED/SERVICE WATER STORAGE TANK	1	E	OPERATING	Atm	Atm			100	60 KGAL				---	
P1	DEEP WELL PUMP NO. 5	DEEP WELL PUMP	1	E	INTERMITTENT		160 ft TH			100						
P1	LP SERVICE WATER PUMP 4-1, 4-2	LOW PRESSURE SERVICE WATER PUMP	2	E	OPERATING		115 ft TH			50	5000 gpm EACH	111.9	150	1185	460	179 AMP @ 85.2 pf
P1	7-WC-04-P-1/2	AUX COOLING WATER PUMPS	2	New	OPERATING					50		111.9	150	1800	460	
P1		**DEMIN WATER TREATMENT SYSTEM**		New	---	---	---								---	
C		~~WATER TREAMENT/HANDLING EQUIPMENT~~	~~1~~	~~New~~								~~186.4~~	~~250~~		~~460~~	
P1	PRIMARY CATION EXCHANGER	PRIMARY CATION EXCHANGER	1	E	OPERATING	125				100	190 gpm & 216 kgal					
P1	PRIMARY ANION EXCHANGER	PRIMARY ANION EXCHANGER	1	E	OPERATING	125				100	190 gpm & 216 kgal					
P1	SECONDARY CATION EXCHANGER	SECONDARY CATION EXCHANGER	1	E	OPERATING	125				100	190 gpm & 216 kgal					
P1	SECONDARY ANION EXCHANGER	SECONDARY ANION EXCHANGER	1	E	OPERATING	125				100	190 gpm & 216 kgal					
P1	DECARBONATOR	DECARBONATOR	1	E	OPERATING					100						
P1	DECARBONATOR BOOSTER PUMP 4-1, 4-2	DECARBONATOR BOOSTER PUMP	2	E	OPERATING/STBY		231 ft TH			100	225 gpm	18.6	25	3600	460	
P1	DECARBONATOR BLOWER 4-1, 4-2	DECARBONATOR BLOWER	2	E	OPERATING/STBY		3 in SP			100	620 cfm	1.1	1.5	3600	460	
P1	ACID TANK	ACID TANK	1	E	OPERATING					100	10 KGAL					
P1	SULFURIC ACID REGENERANT PUMP 4-1, 4-2	SULFURIC ACID REGENERANT PUMP	2	E	OPERATING/STBY		242			100	240 gph	0.6	0.75	1800	460	
P1	CAUSTIC TANK	CAUSTIC TANK	1	E	OPERATING					100	10 KGAL					
P1	CAUSTIC REGENERANT PUMP 4-1, 4-2	CAUSTIC REGENERANT PUMP	2	E	OPERATING/STBY		92			100	322 gph	0.7	1	1800	460	
P1	FILTERED WATER BOOSTER PUMP 4-1, 4-2	FILTERED WATER BOOSTER PUMP	2	E	OPERATING/STBY					100						
P1	FILTERED WATER BACKWASH PUMP 4-1, 4-2	FILTERED WATER BACKWASH PUMP	2	E	OPERATING/STBY		185 ft TH			100	600 gpm	29.8	40	3600	460	
P1	DEMINERALIZER SUPPLY PUMP 4-1, 4-2	DEMINERALIZER SUPPLY PUMP	2	E	OPERATING/STBY		280 ft TH			100	350 gpm	29.8	40	3600	460	
P1	DEMINERALIZER REGENERATION PUMP 4-1, 4-2	DEMINERALIZER REGENERATION PUMP	2	E	OPERATING/STBY		100 ft TH			100	40	2.2	3	3600	460	
P1	VESSEL 4-1, 4-2	CONDENSATE POLISHER VESSEL	2	E	OPERATING/STBY	650				100	3000 gal & 1275 gpm					
P1	PRECOAT TANK	RESIN SLURRY TANK	1	E	OPERATING	Atm				100	~150 gal					
P1	HOLDING PUMP 4-1, 4-2	HOLDING PUMP	2	E	OPERATING/STBY		50 ft TH			100	50 gpm	3.7	5	1800	460	
P1	PRECOAT PUMP	PRECOAT PUMP	2	E	OPERATING/STBY		50 ft TH			100	422 gpm	11.2	15	1800	460	
P1	CHLORINATION DILUTION PUMP	CHLORINATION DILUTION PUMP	1	E	OPERATING		150 ft TH			100	300 gpm	14.9	20	3600	460	
P1	HYDRAZINE SOLUTION FEED PUMP 4-1, 4-2	HYDRAZINE SOLUTION PUMP	2	E	OPERATING/STBY		610			100	3.7 gph	1.5	2	1150	460	
P1	HYDRAZINE SOLUTION MIXING TANK	HYDRAZINE SOLUTION TANK	1	E	OPERATING					100	150 gal					
P1	AMMONIA SOLUTION FEED PUMP 4-1, 4-2	AMMONIA PUMP	2	E	OPERATING/STBY		610			100	8.5 gpm	0.2	0.33	1150	120/230	
P1	AMMONIA SOLUTION MIXING TANK	AMMONIA TANK	1	E	OPERATING					100	300 gal					
C	7-WW-50-P-1/2	DUST SUPPRESSION BOOSTER PUMP	1	New	OPERATING/STBY					100		35.8	48	1800	460	
C	7-CF-146-P-1/2	SODIUM HYPOCHLORITE PUMP	1	New	OPERATING/STBY					100		3.6	4.8	1800	460	
C	7-CF-147-T	SODIUM HYPOCHLORITE TANK	1	New	OPERATING					100						

BOP EQUIPMENT LIST

PRELIMINARY

Rev	Tag Number	Equipment Name	Qty	Existing or New	Operating Mode (Operating/ Intermittent/ Standby)	Design Pressure (psig)	Operating Pressure (psig)	Process (Design/Performance) Data: Design Temperature (^oF)	Operating Temperature (^oF)	% Cap @	Capacity @	Nameplate Loads: KW @	H.P. @	Speed (RPM)	Voltage	Remarks
P1																
P1		**WASTE WATER SYSTEM**			---	---	---								---	
P1	7-WW-24-P-1/2	WASTEWATER AREA SUMP PUMPS	2	New	INTERMITTENT	---	---			50	500 GPM EACH	17.1	22.9	1200	460	
P1	7-WW-25-S	WASTEWATER SUMP	1	New	OPERATING	---	---			100						
P1	7-WW-26-P-1/2	WASTEWATER FORWARDING PUMPS	2	New	INTERMITTENT					50	500 GPM EACH	17.1	22.9	1200	460	
P1		**WASTEWATER TREATMENT SYSTEM**			---	---	---									
P1	UNIT 4 OIL/WATER SEPARATOR	OIL WATER SEPARATOR	1	E	OPERATING	---	---			100					---	
B	NO.2 OIL/WATER SEPARATOR	OIL/WATER SEPARATOR	1	E	OPERATING					100						
P1	BOTTOM ASH POND OIL/WATER SEPARATOR	BOTTOM ASH POND OIL/WATER SEPARATOR	1	E	OPERATING					100						
P1	UNIT 4 BILGE SUMP	UNIT 4 BILGE SUMP	1	E	OPERATING					100						
P1	EXTERNAL BILGE PUMPS	EXTERNAL BILGE PUMPS		E	INTERMITTENT					100						
P1	DEMINERALIZER BUILDING SUMP	DEMINERALIZER SUMPS	1	E	OPERATING					100						
P1	DEMINERALIZER SUMP (MAIN BUILDING)	DEMINERALIZER SUMP (MAIN BUILDING)	1	E	OPERATING					100						
C	~~7-WW-27-S~~	**WASTEWATER TREATMENT/HANDLING SYSTEM**		~~New~~									~~200~~		~~460~~	"Small" chemical feed package
C	7-WW-29-P-1/2	FLOCCULANT (POLYMER) FEED PUMPS	2	New	OPERATING/STBY					100		0.4	0.5		460	
C	7-WW-30-D	SOLIDS CONTACT CLARIFIER	1	New	OPERATING					100			n/a			Solids contact, circular 300 gpm, 1 gpm/sq ft, 20" dia X25 ft H, 3 hours residence time, Field fabricate , FRP or Lined CS
C	7-WW-31-F	CLARIFIER RAKE DRIVE	1	New	OPERATING					100		0.4	0.5		460	Supplied with clarifier
C	7-WW-32-F	CLARIFIER "TURBINE"	1	New	OPERATING					100		1.1	1.5		460	Supplied with clarifier Uses variable frequency drive
C	7-WW-33-T	CLARIFIER SLUDGE HOLDING TANK	1	New	OPERATING					100			n/a			
C	7-WW-34-S	CLARIFIER SLUDGE HOLDING TANK AGITATOR	1	New	OPERATING					100		1.5	2		460	
C	7-WW-35-P-1/2	FILTER PRESS FEED PUMPS	2	New	OPERATING/STBY					100		7.5	10			
C	7-WW-36-F-1/2	FILTER PRESS	2	New	OPERATING/STBY					100						"Small" filter press - xxx lbs/day
C	7-WW-37-T	CLARIFIED WATER TANK	1	New	OPERATING					100	72,000 gallons		n/a			4 hours @ 300 gpm, 25 ft dia X 25 ft H, Field
C	7-WW-38-F-1/2	SAND FILTERS	2	New	OPERATING/STBY					100	300 GPM		N/A			
C		**PROCESS WATER TREATMENT SYSTEM**		New												"Small" chemical feed package
C	7-TW-01-P-1/2	FLOCCULANT (POLYMER) FEED PUMPS	1	New	OPERATING/STBY					100		0.4	0.5			Solids contact, circular 515 gpm, 1 gpm/sq ft, 3 hours residence time, Field fabricate
C	7-TW-02-D	SOLIDS CONTACT CLARIFIER (MAY CONSIDER MORE COMPACT INCLINED PLATE CLARIFIER)	1	New	OPERATING					100			n/a			Supplied with clarifier
C	7-TW-03-F	CLARIFIER RAKE DRIVE	1	New	OPERATING					100		0.4	0.5			Supplied with clarifier Uses variable frequency drive
C	7-TW-04-F	CLARIFIER "TURBINE"	1	New	OPERATING					100		1.5	2			
C	7-TW-05-T	CLARIFIER SLUDGE HOLDING TANK	1	New	N/A					100			n/a			
C	7-TW-05-S	CLARIFIER SLUDGE HOLDING TANK AGITATOR	1	New	OPERATING					100		3.7	5			
C	7-TW-06-P-1/2	FILTER PRESS FEED PUMPS	2	New	INTERM/INTERM					100		7.5	10			"Small" filter press - xxx lbs/day
C	7-TW-07-F-1/2	FILTER PRESS	2	New	INTERM/INTERM					100						8 hours @ 525 gpm Field fabricate
C	7-TW-08-T	CLARIFIED WATER TANK	1	New	N/A					100			n/a			
C	7-TW-09-P-1/2	ASU/CPU COOLING TOWER MAKEUP PUMPS	2	New	OPERATING/STBY					100	400 gpm avg, 50' TDH, 0.6 efficiency	7.5	10			
C	7-TW-10-P-1/2	ULTRAFILTRATION FEED PUMPS	2	New	OPERATING/STBY					100	100 gpm @ 100 psig pump discharge, 0.6 efficiency	7.5	10			
C	7-TW-11-T-1/2	ULTRAFILTRATION MODULES	2	New	OPERATING/STBY					100			n/a			
C	7-TW-12-P-1/2	REVERSE OSMOSIS FEED PUMPS	2	New	OPERATING/STBY					100	120 gpm @ 100 psig pump discharge, 0.6 efficiency	7.5	10			
C	7-TW-13-T-1/2	REVERSE OSMOSIS MODULES	2	New	OPERATING/STBY					100			n/a			8 hours @ 90 gpm Shop fab with shipping permits
C	7-TW-14-T	CPU PROCESS WATER STORAGE TANK	1	New	OPERATING					100			n/a			
C	7-TW-15-P-1/2	SOFTENER FEED PUMPS	2	New	OPERATING/STBY					100	50 gpm @ 50 ft TDH	0.7	0.9			
C	7-TW-16-D	SOFTENER	1	New	OPERATING					100	50 gpm INFLOW		N/A			
C		**CPU PROCESS WASTEWATER TREATMENT SYSTEM**		New												15 GPM mercury polishing to 15 nanog/l (ppt) total mercury
C	7-WW-39-S	MERCURY REMOVAL SYSTEM	2	New	OPERATING/STBY					100						
C	7-WW-40-F-1/2	CARTRIDGE FILTERS ON SKID FOR MERCURY	2	New	OPERATING/STBY					100						
C	7-WW-41-F-1/2	ION EXCHANGE VESSELS ON SKID FOR MERCURY	2	New	OPERATING/STBY					100						
C	7-WW-42-S	ARSENIC REMOVAL SYSTEM	2	New	OPERATING/STBY					100						
C	7-WW-43-F-1/2	CARTRIDGE FILTERS ON SKID FOR ARSENIC	2	New	OPERATING/STBY					100						
C	7-WW-44-F-1/2	ION EXCHANGE VESSELS ON SKID FOR ARSENIC	2	New	OPERATING/STBY					100						
C	7-WW-45-T	CAUSTIC STORAGE TANK WITH MIXER	1	New	OPERATING					100						
C	7-WW-46-S	CAUSTIC FEED SYSTEM	1	New	OPERATING					100						RAISE pH 1 TO 7
C	7-WW-47-P-1/2	PROCESS WATER FORWARDING PUMPS	2	New	OPERATING/STBY					100		0.4	0.5		460	
C	7-WW-48-F-1/2	CHEMICAL FEED SKIDS FOR TOTES	3	New	INTERMITTENT					100		0.2	0.3		120	
C	7-WW-49-T	PRODUCT WATER STORAGE TANK	1	New	OPERATING					100						

BOP EQUIPMENT LIST

PRELIMINARY

Rev	Tag Number	Equipment Name	Qty	Existing or New	Operating Mode (Operating/ Intermittent/ Standby)	Design Pressure (psig)	Operating Pressure (psig)	Design Temperature (°F)	Operating Temperature (°F)	% Cap @	Capacity @	Nameplate Loads KW @	H.P. @	Speed (RPM)	Voltage	Remarks
		SAFETY SHOWER & EYEWASH STATIONS		New												
C		SAFETY SHOWER/EYEWASH STATIONS	3	New	STANDBY					100	30 gpm ea					TEMPERED WATER
P1		**FUEL OIL SYSTEM**		New												
C	~~FUEL OIL TANK 4-1, 4-2~~	~~FUEL OIL TANKS~~	~~2~~	~~E~~	~~OPERATING~~						~~2.35 MGAL~~		-		-	NOT REUSED
C	~~FUEL OIL TRANSFER PUMP 4-1, 4-2~~	~~FUEL OIL TRANSFER PUMPS~~	~~2~~	~~E~~	~~INTERMITTENT~~		~~80 psi TH~~			~~50~~	~~200 gpm~~		~~50~~	~~1770~~	~~460~~	NOT REUSED
C	~~MAIN HEAVY FUEL OIL SUPPLY PUMP 4-3, 4-4~~	~~MAIN HEAVY FUEL OIL SUPPLY PUMPS~~	~~2~~	~~E~~	~~OPERATING~~		~~600 psi TH~~			~~50~~	~~300 gpm~~		~~200~~	~~890~~	~~460~~	NOT REUSED
C	MAIN LIGHT FUEL OIL SUPPLY PUMP 4-1, 4-2	MAIN LIGHT FUEL OIL SUPPLY PUMPS	2	E	INTERMITTENT		520 psi TH			100	260 gpm		200	3565	460	
C	IGNITION & LIGHT FUEL OIL TANK	IGNITION & LIGHT FUEL OIL TANK	7	E	OPERATING/STBY					14.2	13 KGAL EA					
P1	IGNITION & LIGHT FUEL OIL PUMP 4-1, 4-2	IGNITION & LIGHT FUEL OIL PUMPS	2	E	INTERMITTENT		1415 ft TH			50	75 gpm	55.9	75	3545	230	
P1		**FIRE PROTECTION SYSTEM**			---	---	---								---	
B		ELECTRIC MOTOR DRIVEN JOCKEY PUMP	1	E	INTERMITTENT		125 psi			100	15 gpm	2.2	3	3450	460	
B		ELECTRIC MOTOR DRIVEN FIRE PUMP	1	E	INTERMITTENT		125 psi			100	2000 gpm	149.1	200	1780	460	
B		DIESEL ENGINE DRIVEN FIRE PUMP	1	E	INTERMITTENT		125 psi			100	2000 gpm			2100		
C	~~7-FP-01-P~~	~~ELECTRIC MOTOR DRIVEN JOCKEY PUMP~~	~~1~~	~~New~~	~~INTERMITTENT~~	~~250~~	~~150~~					~~37.3~~	~~50~~	~~1780~~	~~480~~	
P1		**MISC PLANT EQUIPMENT**		New	---	---	---								---	
P1		CEMS	1	New	OPERATING	---	---			100					480	
C	7-CD-06-P	WELL PUMP	1	New	OPERATING					100	500 GPM @ 150 ft TDH	20.1	27		460	WELL 100 FEET DEEP
P1		NO. 6 SU PUMP	1	E	OPERATING					100		37.3	50	1770	460	
P1	7-BY-07-S	STACK	1	New	OPERATING	Atm	10 in. w.g.			100	CONCRETE 458 FEET HIGH				---	10 ft ID

FUTUREGEN 2.0 PLANT BOP ELECTRICAL EQUIPMENT LIST

MEREDOSIA UNIT 7 REPOWERING USING OXY-PC WITH CO_2 CAPTURE

REV. NO.	DATE	REVISION	BY	CHK.	ENG.	APPR.	OTHER
P1	13-May-11	Preliminary Issue - Phase 1	RCA				---

BOP Electrical Equipment List - Oxy-PC Plant

MEREDOSIA UNIT 7 REPOWERING USING OXY-PC WITH CO_2 CAPTURE

Document Number	Revision
17-07-100-001	P1

Equipment Number (Tag)	Equipment Description	Location (Zone/Area/Bldg.)	Data Sheet Number	Equipment Rating (voltage, current, frequency, etc.)	MR/PO Number	Work Package Number	Shipping Weight (lbs)	Dimensions (in) (W x H x D)	Remarks	Rev. No.
	Unit #4 Main Generator Step-Up Transformer			138/19.3 KV, 210/235 MVA, FOA, 55°C rise, 3Ph, 60Hz, Grounded WYE-Delta, 120kV primary lighting arrestors	Existing				General Electric 1975	P1
	Unit #4 Main Auxiliary Transformer			12/16/20 MVA, OA/FA/FA, 69-4.16kV, delta-wye (resistance grounded), 3Ph, 60Hz	Existing				Manufactured 1974	P1
	Unit #3 Reserve Transformer			12500 kVA, 69-4.16kV, 3Ph, 60Hz.	Existing				Westinghouse 1959	P1
Turbine-MCC-4-1	Turbine MCC 4-1			480VAC, 800A main bus, 300A vertical bus	Existing				Cuttler Hammer with Westinghouse 600A frame, FB, HFB, and KA molded case circuit breakers, Cutler Hammer type C10 600A contactors	P1
Turbine-MCC-4-2	Turbine MCC 4-2			480VAC, 800A main bus, 300A vertical bus	Existing				Cuttler Hammer with Westinghouse 600A frame, FB, HFB, and KA molded case circuit breakers, Cutler Hammer type C10 600A contactors	P1
Turbine-MCC-4-3	Turbine MCC 4-3			480VAC, 800A main bus, 300A vertical bus	Existing				Cuttler Hammer with Westinghouse 600A frame, FB, HFB, and KA molded case circuit breakers, Cutler Hammer type C10 600A contactors	P1
	Diesel Generator			480VAC, 1600kW, 60hz, 1800rpm	Existing				Caterpillar 3516	P1
4160V-AUX-BUS-4	Unit #4 MV Aux Switchgear			4160VAC, Indoor, Metal-Clad, 3000A Main & Reserve breakers model 5HK350, 80 KAIC, 1200A feeder breakers model 5HK250, 60kAIC, 250VDC control	Modify Existing				ITE Circuit Breaker Co 1975 (replace switchgear or retrofit with vacuum breakers and microprocessor relays)	P1
480V-AUX-BUS-4-1	Unit #4 LV Aux Switchgear 1			480VAC, Indoor, metal-clad, 1600A frame main breakers, 50kAIC, 600A frame load breakers, 30kAIC, 250VDC control	Modify Existing				General Electric AK draw out type, (re-condition, replace breaker trip units)	P1
480V-AUX-BUS-4-2	Unit #4 LV Aux Switchgear 2			480VAC, Indoor, metal-clad, 1600A frame main breakers, 50kAIC, 600A frame load breakers, 30kAIC, 250VDC control	Modify Existing				General Electric AK draw out type, (re-condition, replace breaker trip units)	P1
480V-AUX-BUS-4-3	Unit #4 LV Aux Switchgear 3			480VAC, Indoor, metal-clad, 1600A frame main breakers, 50kAIC, 600A frame load breakers, 30kAIC, 250VDC control	Modify Existing				General Electric AK draw out type, (re-condition, replace breaker trip units)	P1
480V-AUX-BUS-4-5	Unit #4 LV Aux Switchgear 4			480VAC, Outdoor, 1600A frame main breakers, 50kAIC, 600A frame load breakers, 30kAIC, 250VDC control	Demolish				General Electric AK draw out type, (replaced by new cooling tower electrical equipment)	P1

Equipment Number (Tag)	Equipment Description	Location (Zone/Area/Bldg.)	Data Sheet Number	Equipment Rating (voltage, current, frequency, etc.)	MR/PO Number	Work Package Number	Shipping Weight (lbs)	Dimensions (in) (W x H x D)	Remarks	Rev. No.
	Unit #4 CT Pad Mounted Switchgear			4160VAC, Outdoor	Demolish				(replace to permit isolation without fuse removal)	P1
	Unit #4 Station Service Transformer			138kV Delta/ 13.8kV Wye Resistance Grounded, 100MVA, ONAN, 65degC rise, z=9%, HV BIL= 650kV, LV BIL=110kV						P1
	Unit #4 Station Service Switchgear			13.8kV, 4000A, 63kA, NEMA 3R, Outdoor Switchgear, Non-Walk In				185" L X 105" W X 107" H		P1
	Unit #4 Station Service Bus Duct			15kV, 4000A, 63kA Bus Duct						P1
	Unit #4 Essential Service Transformer			4.16kV Delta/ 480V Wye Resistance Grounded, 2MVA, ONAN, 65degC rise, z=6%						P1
	Unit #4 Main Cooling Tower Transformer			4.16kV Delta/ 480V Wye Resistance Grounded, 500kVA, ONAN, 65degC rise, z=6%						P1
	Unit #4 BOP Service Transformer			4.16kV Delta/ 480V Wye Resistance Grounded, 750kVA, ONAN, 65degC rise, z=6%						P1
	Unit #4 DCCPS Cooling Tower Transformer			4.16kV Delta/ 480V Wye Resistance Grounded, 500kVA, ONAN, 65degC rise, z=6%						P1
	Unit #4 ASU/CPU Cooling Tower Transformer			4.16kV Delta/ 480V Wye Resistance Grounded, 500kVA, ONAN, 65degC rise, z=6%						P1
	Unit #4 BOP MV Switchgear			4.16kV, 1200A Switchgear, (2) 1200A Main Breakers				3 vertical sections		P1
	Unit #4 BOP MV Motor Control Center			4.16kV, 1200A MCC, (10) 400A Contactors				5 vertical sections		P1
	Unit #4 Essential Service LV Motor Control Center			480V, 2000A MCC				3 vertical sections		P1

PRELIMINARY

Equipment Number (Tag)	Equipment Description	Location (Zone/Area/Bldg.)	Data Sheet Number	Equipment Rating (voltage, current, frequency, etc.)	MR/PO Number	Work Package Number	Shipping Weight (lbs)	Dimensions (in) (W x H x D)	Remarks	Rev. No.
	Unit #4 Main Cooling Tower LV Motor Control Center			480V, 800A MCC				4 vertical sections		P1
	Unit #4 BOP LV Motor Control Center			480V, 800A MCC				9 vertical sections		P1
	Unit #4 BOP Electrical Building			Power Control Room				12' W x 41' L		P1
	Unit #4 DCCPS Cooling Tower MV Motor Control Center			4.16kV, 1200A MCC, (3) 400A Contactors				3 vertical sections		P1
	Unit #4 DCCPS Cooling Tower LV Motor Control Center			480V, 800A MCC				3 vertical sections		P1
	Unit #4 DCCPS Cooling Tower Electrical Building			Power Control Room				9' W x 16' L		P1
	Unit #4 ASU/CPU Cooling Tower MV Motor Control Center			4.16kV, 1200A MCC, (3) 400A Contactors				3 vertical sections		P1
	Unit #4 ASU/CPU Cooling Tower LV Motor Control Center			480V, 800A MCC				3 vertical sections		P1
	Unit #4 ASU/CPU Cooling Tower Electrical Building			Power Control Room				9' W x 16' L		P1

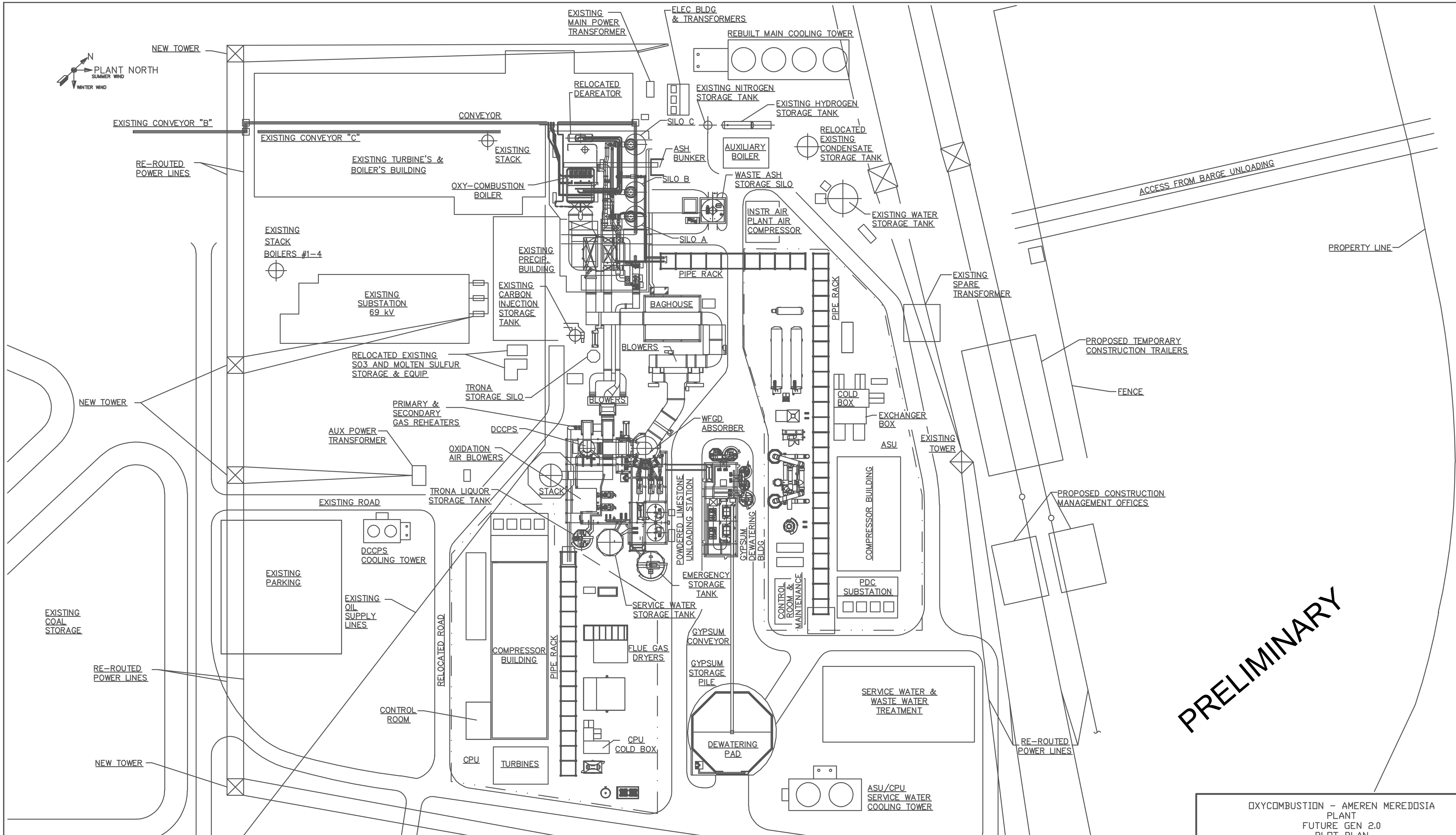
Equipment Number (Tag)	Equipment Description	Location (Zone/Area/Bldg.)	Data Sheet Number	Equipment Rating (voltage, current, frequency, etc.)	MR/PO Number	Work Package Number	Shipping Weight (lbs)	Dimensions (in) (W x H x D)	Remarks	Rev. No.
	Boiler Building 4160kV Unit Substation Transformer A	Boiler Building	BWFG-4-DS-UB00-0001	13800V-4160V, 10.0/13.3MVA						A
	Boiler Building 480V Unit Substation Transformer A	Boiler Building	BWFG-4-DS-UB00-0002	13800V-480V, 2500/3333kVA						A
	GQCS Building 480V Unit Substation Transformer A	Boiler Building	BWFG-4-DS-UB00-0002	13800V-480V, 2500/3333kVA						A
	Boiler Building 4160kV Unit Substation Transformer B	Boiler Building	BWFG-4-DS-UB00-0001	13800V-4160V, 10.0/13.3MVA						A
	Boiler Building 480V Unit Substation Transformer B	Boiler Building	BWFG-4-DS-UB00-0002	13800V-480V, 2500/3333kVA						A
	GQCS Building 480V Unit Substation Transformer B	Boiler Building	BWFG-4-DS-UB00-0002	13800V-480V, 2500/3333kVA						A
	13.8kV SWGR A	Boiler Building	BWFG-4-DS-UAA1-0001	13800V, 2000A						A
	13.8kV SWGR B	Boiler Building	BWFG-4-DS-UAA1-0001	13800V, 2000A						A
	4.16kV BOILER SWGR A	Boiler Building	BWFG-4-DS-UAA1-0003	4000V, 2000A						A
	4.16kV BOILER SWGR B	Boiler Building	BWFG-4-DS-UAA1-0003	4000V, 2000A						A
	4.16kV GQCS SWGR A	GQCS Building	BWFG-4-DS-UAA1-0002	4000V, 1200A						A
	4.16kV GQCS SWGR B	GQCS Building	BWFG-4-DS-UAA1-0002	4000V, 1200A						A
	Boiler Area Dist. Board 01	Boiler Building		480V, 400A						A
	Boiler Area Dist. Board 02	Boiler Building		480V, 400A						A
	Boiler Area Dist. Board 03	Boiler Building		480V, 400A						A
	Boiler Area Dist. Board 04	Boiler Building		480V, 200A						A
	Boiler Area Dist. Board 05	Boiler Building		480V, 200A						A
	Boiler Area Dist. Board 06	Boiler Building		480V, 200A						A
	Boiler Area Dist. Board 07	Boiler Building		480V, 200A						A
	Boiler Area Dist. Board 08	Boiler Building		480V, 400A						A
	Boiler Area Dist. Board 09	Boiler Building		480V, 400A						A
	Boiler Area Dist. Board 10	Boiler Building		480V, 400A						A
	Boiler Area Dist. Board 11	Boiler Building		480V, 400A						A
	Boiler Area MCC A	Boiler Building	BWFG-4-DS-UCD0-0001	480V, 1600A						A
	Boiler Area MCC B	Boiler Building	BWFG-4-DS-UCD0-0001	480V, 1600A						A
	Boiler Area MCC C	Boiler Building	BWFG-4-DS-UCD0-0001	480V, 1600A						A
	Boiler Area MCC D	Boiler Building	BWFG-4-DS-UCD0-0001	480V, 1600A						A
	GQCS BOP Dist. Board A	GQCS Building		480V, 400A						A
	GQCS BOP Dist. Board B	GQCS Building		480V, 400A						A
	GQCS BOP Dist. Board C	GQCS Building		480V, 400A						A
	GQCS BOP MCC A	GQCS Building	BWFG-4-DS-UCD0-0001	480V, 1600A						A
	GQCS BOP MCC B	GQCS Building	BWFG-4-DS-UCD0-0001	480V, 1600A						A
	GYPSUM Dist. Board	Gypsum Building		480V, 400A						A
	GYPSUM MCC A	Gypsum Building	BWFG-4-DS-UCD0-0001	480V, 1600A						A
	GYPSUM MCC B	Gypsum Building	BWFG-4-DS-UCD0-0001	480V, 1600A						A
	LIMESTONE\OX AIR MCC A		BWFG-4-DS-UCD0-0001	480V, 800A						A
	LIMESTONE\OX AIR MCC B		BWFG-4-DS-UCD0-0001	480V, 800A						A
	PJFF Dist. Board			480V, 200A						A
	POLISHING SCRUB MCC A		BWFG-4-DS-UCD0-0001	480V, 800A						A
	POLISHING SCRUB MCC B		BWFG-4-DS-UCD0-0001	480V, 800A						A
	WFGD BLDG MCC A	WFGD Building	BWFG-4-DS-UCD0-0001	480V, 1200A						A
	WFGD BLDG MCC B	WFGD Building	BWFG-4-DS-UCD0-0001	480V, 1200A						A
	UPS Bypass Transformer	Boiler Building	BWFG-4-DS-UEB0-0001	480-120V, single phase, 50kVA						A
	Battery Charger 1	Boiler Building	BWFG-4-DS-UEB0-0001	480VAC input, 125VDC output						A
	Battery Charger 2	Boiler Building	BWFG-4-DS-UEB0-0001	480VAC input, 125VDC output						A
	Battery	Boiler Building	BWFG-4-DS-UEC0-0001	125VDC						A
	Main DC Switchboard	Boiler Building	BWFG-4-DS-UEC0-0001	125VDC, 800A, 42kA						A
	GQCS Area DC Power Panel 1	GQCS Building		125VDC, 100A, 24 ckt						A
	GQCS Area DC Power Panel 2	GQCS Building		125VDC, 100A, 24 ckt						A
	Boiler Area DC Power Panel 1	Boiler Building		125VDC, 100A, 24 ckt						A
	Boiler Area DC Power Panel 2	Boiler Building		125VDC, 100A, 24 ckt						A

PRELIMINARY

Equipment Number (Tag)	Equipment Description	Location (Zone/Area/Bldg.)	Data Sheet Number	Equipment Rating (voltage, current, frequency, etc.)	MR/PO Number	Work Package Number	Shipping Weight (lbs)	Dimensions (in) (W x H x D)	Remarks	Rev. No.
	UPS Rectifier	Boiler Building	BWFG-4-DS-UEB0-0001	125VDC, 400A						A
	UPS Inverter	Boiler Building	BWFG-4-DS-UEB0-0001	125VDC, 40kVA						A
	UPS Main Power Panel	Boiler Building	BWFG-4-DS-UEB0-0001	120VAC, 400A, 1 phase, 12 ckt						A
	Boiler Area UPS Power Panel 1	Boiler Building	BWFG-4-DS-UEB0-0001	120VAC, 100A, 42 ckt						A
	Boiler Area UPS Power Panel 2	Boiler Building	BWFG-4-DS-UEB0-0001	120VAC, 100A, 42 ckt						A
	GQCS Area UPS Power Panel 1	GQCS Building	BWFG-4-DS-UEB0-0001	120VAC, 100A, 42 ckt						A
	GQCS Area UPS Power Panel 2	GQCS Building	BWFG-4-DS-UEB0-0001	120VAC, 100A, 42 ckt						A
	BOILER AREA 480V SWITCHGEAR A	Boiler Building	BWFG-4-DS-UAI0-0001	480A, 4000A						A
	BOILER AREA 480V SWITCHGEAR B	Boiler Building	BWFG-4-DS-UAI0-0001	480A, 4000A						A
	GQCS AREA 480V SWITCHGEAR A	GQCS Building	BWFG-4-DS-UAI0-0002	480A, 4000A						A
	GQCS AREA 480V SWITCHGEAR A	GQCS Building	BWFG-4-DS-UAI0-0002	480A, 4000A						A

PRELIMINARY

F APPENDIX – PLOT PLAN/LAYOUT



OXYCOMBUSTION - AMEREN MEREDOSIA PLANT
FUTURE GEN 2.0
PLOT PLAN

REVISION APPROVAL RECORD					
DISCIPLINE	BY	DATE	DISCIPLINE	BY	DATE
ARCH.			MECHANICAL		
CIVIL			NUCLEAR		
ELECTRICAL			PIPING		
ENVIRON.			PROCESS		
GEN. ARRANG.			QA / QC		
HVAC			STRUCTURAL		
I & C					

REV NO	DATE	REVISIONS	BY	CHKR
P1	05/13/11	ISSUED FOR USE IN PUBLIC MEETINGS	GLH	

DRAWING STATUS				
ISSUED	REV	DATE	SDE	PEM
PRELIMINARY	P1			
APPROVED FOR CONSTRUCTION				

NOT APPROVED FOR CONSTRUCTION UNLESS SIGNED AND DATED. DESTROY ALL PRINTS BEARING EARLIER DATE AND/OR REV.NO.

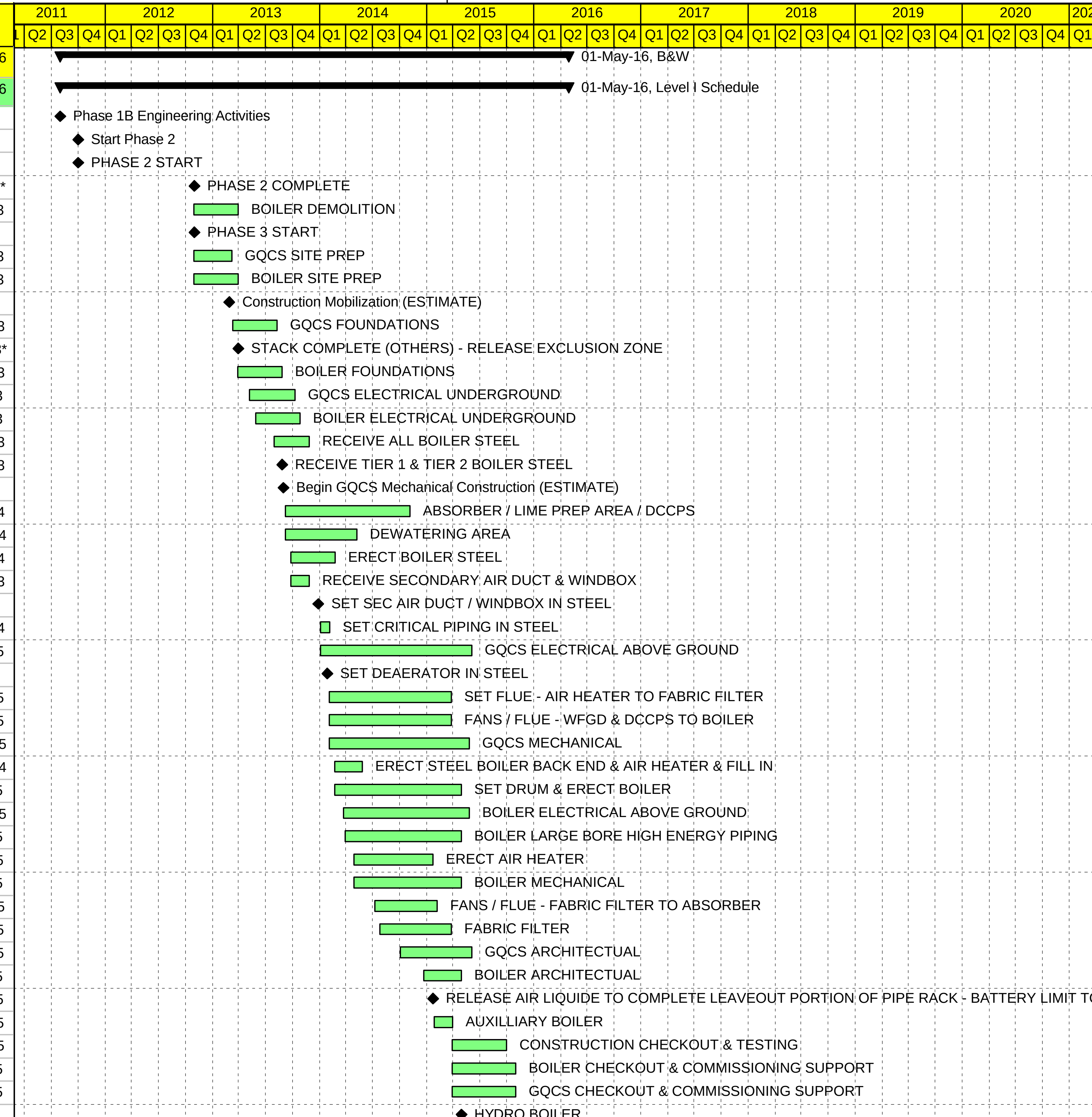
PROJECT NO.: 30384
DRAWN: GLH
DATE: 05/13/11
CHECKED:
DATE:
SCALE: 1"=120'

URS
7800 E. Union Ave.
Denver, CO 80237
303.843.2000
URS ENERGY & CONSTRUCTION, Inc.

DWG. NO. 30384-SK-001S
REV P1

G APPENDIX – LEVEL I PROGRAM SCHEDULE

Activity ID	Activity Name	Original Duration	Start	Finish
B&W		1235d	01-Aug-11	01-May-16
Level I Schedule		1235d	01-Aug-11	01-May-16
BWMS01	Phase 1B Engineering Activities	0d	01-Aug-11	
BWP2	Start Phase 2	0d	03-Oct-11*	
WP2000	PHASE 2 START	0d	03-Oct-11	
WP2010	PHASE 2 COMPLETE	0d		31-Oct-12*
BC1000	BOILER DEMOLITION	134d	01-Nov-12	29-Mar-13
BC0100	PHASE 3 START	0d	01-Nov-12	
BC1105	GQCS SITE PREP	115d	01-Nov-12	08-Mar-13
BC1005	BOILER SITE PREP	134d	01-Nov-12	29-Mar-13
BWConstMOB	Construction Mobilization (ESTIMATE)	0d	28-Feb-13*	
BC1100	GQCS FOUNDATIONS	135d	11-Mar-13*	07-Aug-13
BC1230	STACK COMPLETE (OTHERS) - RELEASE EXCLUSION ZONE	0d		29-Mar-13*
BC1010	BOILER FOUNDATIONS	134d	01-Apr-13	27-Aug-13
BC1270	GQCS ELECTRICAL UNDERGROUND	135d	10-May-13	08-Oct-13
BC1260	BOILER ELECTRICAL UNDERGROUND	134d	31-May-13	28-Oct-13
BC1015	RECEIVE ALL BOILER STEEL	109d	29-Jul-13	26-Nov-13
BC1020	RECEIVE TIER 1 & TIER 2 BOILER STEEL	0d		27-Aug-13
BWConstGQCS	Begin GQCS Mechanical Construction (ESTIMATE)	0d	02-Sep-13*	
BC1110	ABSORBER / LIME PREP AREA / DCCPS	379d	09-Sep-13	05-Nov-14
BC1130	DEWATERING AREA	218d	09-Sep-13	08-May-14
BC1030	ERECT BOILER STEEL	134d	27-Sep-13	24-Feb-14
BC1035	RECEIVE SECONDARY AIR DUCT & WINDBOX	54d	27-Sep-13	26-Nov-13
BC1040	SET SEC AIR DUCT / WINDBOX IN STEEL	0d	27-Dec-13	
BC1250	SET CRITICAL PIPING IN STEEL	28d	06-Jan-14*	04-Feb-14
BC1220	GQCS ELECTRICAL ABOVE GROUND	460d	07-Jan-14	04-Jun-15
BC1050	SET DEAERATOR IN STEEL	0d	28-Jan-14	
BC1090	SET FLUE - AIR HEATER TO FABRIC FILTER	370d	06-Feb-14	26-Mar-15
BC1140	FANS / FLUE - WFGD & DCCPS TO BOILER	370d	06-Feb-14	26-Mar-15
BC1125	GQCS MECHANICAL	424d	06-Feb-14	26-May-15
BC1060	ERECT STEEL BOILER BACK END & AIR HEATER & FILL IN	83d	25-Feb-14	27-May-14
BC1080	SET DRUM & ERECT BOILER	384d	25-Feb-14	29-Apr-15
BC1160	BOILER ELECTRICAL ABOVE GROUND	380d	27-Mar-14	26-May-15
BC1180	BOILER LARGE BORE HIGH ENERGY PIPING	355d	28-Mar-14	29-Apr-15
BC1070	ERECT AIR HEATER	244d	28-Apr-14	23-Jan-15
BC1170	BOILER MECHANICAL	325d	01-May-14	29-Apr-15
BC1150	FANS / FLUE - FABRIC FILTER TO ABSORBER	190d	08-Jul-14	04-Feb-15
BC1120	FABRIC FILTER	218d	25-Jul-14	25-Mar-15
BC1135	GQCS ARCHITECTUAL	218d	06-Oct-14	04-Jun-15
BC1190	BOILER ARCHITECTUAL	113d	25-Dec-14	29-Apr-15
BC1240	RELEASE AIR LIQUIDE TO COMPLETE LEAVEOUT PORTION OF PIPE ...	0d		23-Jan-15
BC1200	AUXILLIARY BOILER	55d	28-Jan-15	30-Mar-15
BC1045	CONSTRUCTION CHECKOUT & TESTING	165d	31-Mar-15	30-Sep-15
BC1210	BOILER CHECKOUT & COMMISSIONING SUPPORT	190d	01-Apr-15	29-Oct-15
BC1145	GQCS CHECKOUT & COMMISSIONING SUPPORT	190d	01-Apr-15	29-Oct-15
BC0200	HYDRO BOILER	0d	30-Apr-15*	



Actual Work — Milestone
Remaining Work — Summary

FutureGen Level I
Program Schedule

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Activity ID	Activity Name	Original Duration	Start	Finish
BWGQCS CO	GQCS Commissioning Mobilize	0d	01-May-15*	
BC1055	CONSTRUCTION SUBSTANTIAL COMPLETE	0d		01-Oct-15*
BC0300	FIRST FIRE OIL	0d	30-Oct-15*	
BC0400	FIRST FIRE COAL	0d	15-Dec-15*	
WP3010	PHASE 3 COMPLETE	0d		29-Apr-16*
BWP4	Start Phase 4	0d	01-May-16*	
URS		2414d	03-Oct-11	31-Dec-20
Level I Schedule		2414d	03-Oct-11	31-Dec-20
M-30010	Notice to Proceed (Phase 2)	0d	03-Oct-11*	
M-30020	Begin Detailed Design	0d	03-Oct-11	
FGA20000	FGA Begin Phase 2 - NEPA, Permitting & Preliminary Design	0d	03-Oct-11*	
AER2000	Ameren Start Phase 2 Feed, NEPA and Permitting (10/01/11)	0d	03-Oct-11*	
AER2020	Ameren BOP Feed	228d	03-Oct-11	15-Aug-12
AER2210	Ameren Assess Legislative Needs (PPA) to Suppport IPA Procurement Plan	87d	03-Oct-11*	31-Jan-12
AER2220	Ameren Identify Power Purchase Agreement (PPA) Potential Alternate Financ...	0d		21-Oct-11*
AER2225	Ameren Phase 2 Project Management Plan	0d		30-Nov-11*
M-30030	Initial GA Design Review Complete with URS, B & W, Air Liquide & Ameren	0d		02-Dec-11
AER2222	Ameren Power Purchase Agreement (PPA) Alternate Financing Options Settl...	0d		30-Dec-11
M-30040	P & ID Interfaces Required from B & W	0d		27-Jan-12
AER2224	Ameren Resolving Power Purchase Agreement (PPA) Alternate Financing	0d		30-Jan-12
AER2550	Ameren Submit Final EIV Data to DOE for EIS (TBD)	0d		27-Feb-12*
DOE2025	DOE Receipt of Final EIV Data from FGA/Ameren	0d		28-Feb-12*
FGA21020	FGA Submit Final EIV Data to DOE for EIS Review	0d		28-Feb-12*
AER2226	IPA Issues Power Purchase Agreement (PPA) RFP	0d		14-Mar-12
M-30050	P & ID Interfaces Required from Air Liquide	0d		23-Mar-12
FGA20060	FGA Signed CO2 Off-Take Agreement	0d		31-May-1...
AER2450	Ameren/FGA CO2 Off-take Agreement (Final)	0d		31-May-12
AER2228	Ameren Respond to IPA Power Purchase Agreement (PPA) RFP	0d		15-Jun-12
AER2230	Ameren Budget (including contingency analysis) Ready for ICC review for PPA	0d		15-Jun-12
AER2232	Ameren Diversity Plan Ready for ICC review for PPA	0d		15-Jun-12
AER2234	Ameren Finance Plan Ready for ICC review for PPA	0d		15-Jun-12
AER2236	Ameren Fuel Assumptions Plan Ready for ICC review for PPA	0d		15-Jun-12
AER2238	Ameren Environmental Performance Plan Ready for ICC review for PPA	0d		15-Jun-12
AER2240	Ameren Labor Agreement Plan Ready for ICC Review for PPA	0d		15-Jun-12
DOE2100	DOE Issue Draft EIS for Public Comments	0d		27-Jun-12
AER2242	Ameren Provide Feed Information to ICC for Power Purchase Agreement (PP...	0d		28-Jun-12
AER2280	Ameren PDRI Feed Phase 2	0d		18-Jul-12
FGA20070	PPA Final Agreement Established	0d		10-Aug-12*
AER2410	ICC Final Approval of Power Purchase Agreement (PPA)	0d		10-Aug-12*
AER2800	Ameren Phase 2 PRB Presentation	0d		16-Aug-12
AER2840	Ameren Phase 2 CPOC Gate Review	0d		23-Aug-12*
FGA20090	FGA Submit DP-2 Application	0d		30-Aug-12*
AER2600	Ameren Submit DP-2 Application for DOE Review	0d		30-Aug-12*
DOE2400	Final (EIS) Environmental Impact Statement	0d		01-Oct-12
M-30060	Complete Phase 2	0d		31-Oct-12
DOE2990	DOE DP-2 Approval to Proceed to Phase 3	0d		31-Oct-12

Actual Work ◆ Milestone
Remaining Work Summary

FutureGen Level I
Program Schedule

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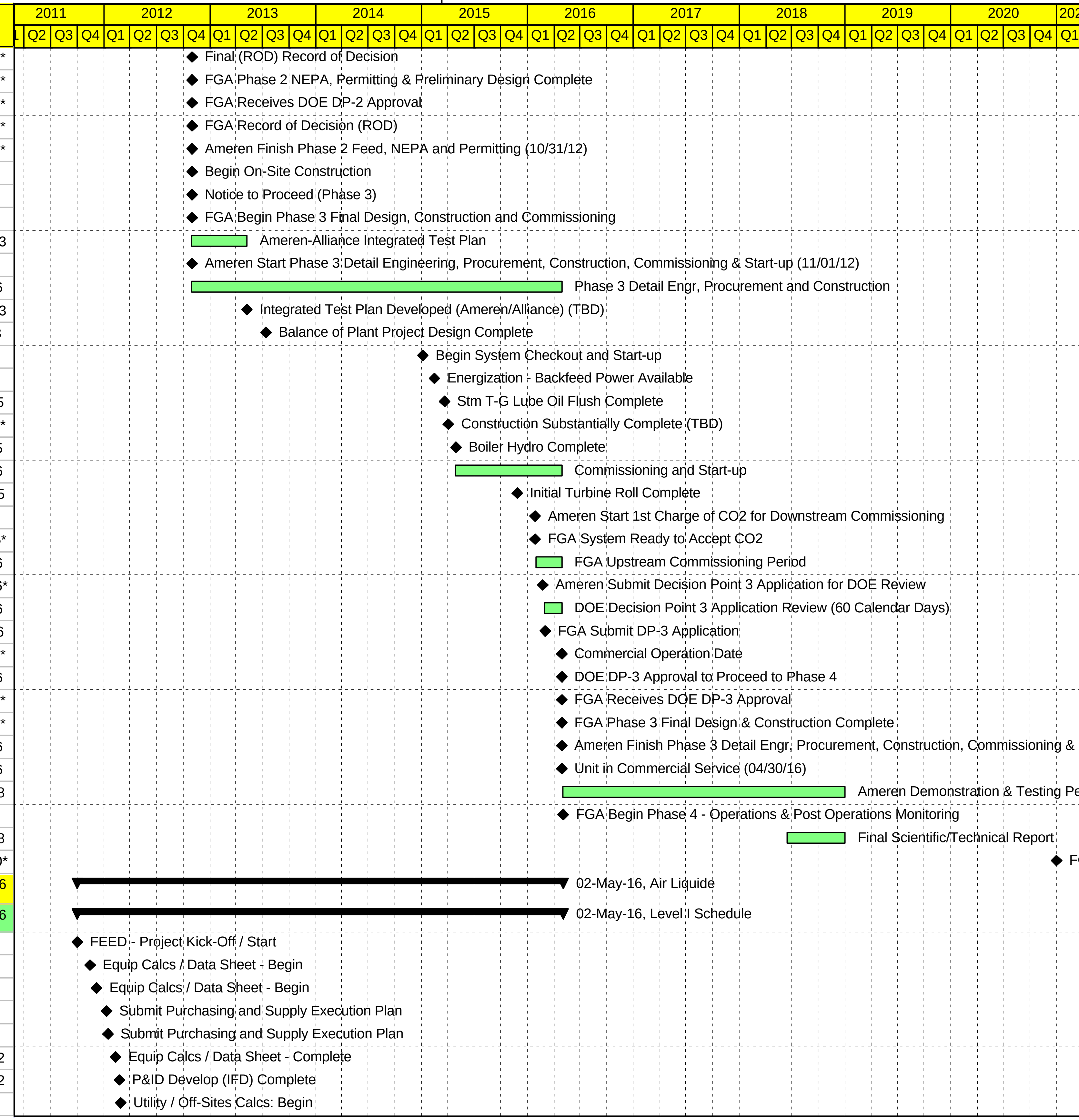
Activity ID	Activity Name	Original Duration	Start	Finish
DOE2600	Final (ROD) Record of Decision	0d		31-Oct-12*
FGA20130	FGA Phase 2 NEPA, Permitting & Preliminary Design Complete	0d		31-Oct-12*
FGA20110	FGA Receives DOE DP-2 Approval	0d		31-Oct-12*
FGA21110	FGA Record of Decision (ROD)	0d		31-Oct-12*
AER2900	Ameren Finish Phase 2 Feed, NEPA and Permitting (10/31/12)	0d		31-Oct-12*
M-30080	Begin On-Site Construction	0d	01-Nov-12	
M-30070	Notice to Proceed (Phase 3)	0d	01-Nov-12*	
FGA30000	FGA Begin Phase 3 Final Design, Construction and Commissioning	0d	01-Nov-12*	
FGA30060	Ameren-Alliance Integrated Test Plan	134d	01-Nov-12	07-May-13
AER3200	Ameren Start Phase 3 Detail Engineering, Procurement, Construction, Commi...	0d	01-Nov-12*	
AER3210	Phase 3 Detail Engr, Procurement and Construction	912d	01-Nov-12*	29-Apr-16
AER3400	Integrated Test Plan Developed (Ameren/Alliance) (TBD)	0d		07-May-13
M-30090	Balance of Plant Project Design Complete	0d		15-Jul-13
M-30100	Begin System Checkout and Start-up	0d	05-Jan-15	
M-30110	Energization - Backfeed Power Available	0d	13-Feb-15	
M-30120	Stm T-G Lube Oil Flush Complete	0d		20-Mar-15
AER3500	Construction Substantially Complete (TBD)	0d		01-Apr-15*
M-30130	Boiler Hydro Complete	0d		29-Apr-15
AER3800	Commissioning and Start-up	262d	30-Apr-15*	29-Apr-16
M-30140	Initial Turbine Roll Complete	0d		26-Nov-15
AER3700	Ameren Start 1st Charge of CO2 for Downstream Commissioning	0d	29-Jan-16	
FGA39020	FGA System Ready to Accept CO2	0d		29-Jan-16*
FGA39030	FGA Upstream Commissioning Period	65d	01-Feb-16*	29-Apr-16
AER3840	Ameren Submit Decision Point 3 Application for DOE Review	0d		22-Feb-16*
DOE3950	DOE Decision Point 3 Application Review (60 Calendar Days)	44d	01-Mar-16*	29-Apr-16
FGA30080	FGA Submit DP-3 Application	0d		01-Mar-16
M-30150	Commercial Operation Date	0d		29-Apr-16*
DOE3990	DOE DP-3 Approval to Proceed to Phase 4	0d		29-Apr-16
FGA30100	FGA Receives DOE DP-3 Approval	0d		29-Apr-16*
FGA30120	FGA Phase 3 Final Design & Construction Complete	0d		29-Apr-16*
AER3900	Ameren Finish Phase 3 Detail Engr, Procurement, Construction, Commissioni...	0d		29-Apr-16
AER3990	Unit in Commercial Service (04/30/16)	0d		29-Apr-16
AER4010	Ameren Demonstration & Testing Period of Clean Coal Facility (05/01/2016 - ...	696d	02-May-16*	31-Dec-18
FGA40000	FGA Begin Phase 4 - Operations & Post Operations Monitoring	0d	02-May-16*	
AER5090	Final Scientific/Technical Report	142d	15-Jun-18	31-Dec-18
FGA40040	FGA Phase 4 - Operations & Post Operations Monitoring Complete (12/31/20...	0d		31-Dec-20*
Air Liquide		1191d	03-Oct-11	02-May-16
Level I Schedule		1191d	03-Oct-11	02-May-16
SM.0001	FEED - Project Kick-Off / Start	0d	03-Oct-11	
ASU.MI.020.25	Equip Calcs / Data Sheet - Begin	0d	14-Nov-11	
CPU.MI.20.25	Equip Calcs / Data Sheet - Begin	0d	05-Dec-11	
ASU.MI.045.4	Submit Purchasing and Supply Execution Plan	0d	09-Jan-12	
CPU.MI.045.4	Submit Purchasing and Supply Execution Plan	0d	16-Jan-12	
ASU.MI.020.25	Equip Calcs / Data Sheet - Complete	0d		10-Feb-12
ASU.MI.057.67	P&ID Develop (IFD) Complete	0d		24-Feb-12
ASU.MI.057.68	Utility / Off-Sites Calcs: Begin	0d	27-Feb-12	



Actual Work
Remaining Work
Milestone
Summary

FutureGen Level I
Program Schedule

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Activity ID	Activity Name	Original Duration	Start	Finish
CPU.MI.20.25	Equip Calcs / Data Sheet - Complete	0d		02-Mar-12
CPU.MI.PU.30	Eval & Clarify Bids - Begin	0d	16-Mar-12	
ASU.MI.051.5	Spec / Req - Begin: Electrical Equipment	0d	19-Mar-12	
CPU.MI.51.53	Spec / Req - Begin: Electrical Equipment	0d	19-Mar-12	
ASU.MI.PU.30	Eval & Clarify Bids - Begin	0d	23-Mar-12	
ASU.MI.050.0	Tech Mgmt - Submit MH's for EPC Estimate	0d		30-Mar-12
ASU.MI.020.2	Equip Calcs - Complete / Submit Equip Sizing Summary Sheet	0d		06-Apr-12
CPU.MI.20.25	Equip Calcs - Complete / Submit Equip Sizing Summary Sheet	0d		27-Apr-12
CPU.MI.51.53	Spec / Req - PDC Complete	0d		27-Apr-12
CPU.MI.PU.30	Eval & Clarify Bids - Complete (Mech)	0d		01-Jun-12
ASU.MI.PU.30	Eval & Clarify Bids - Complete (Mech)	0d		09-Jul-12
ASU.MI.PU.30	Eval & Clarify Bids - Complete (Electrical)	0d		09-Jul-12
ASU.MI.PU.30	Eval & Clarify Bids - Complete (Instruments)	0d		16-Jul-12
CPU.MI.PU.30	Eval & Clarify Bids - Complete (Instruments)	0d		16-Jul-12
CPU.MI.PU.30	Eval & Clarify Bids - Complete (Electrical)	0d		17-Jul-12
ASU.MI.SG.010	Gate Review B - EPC Proposal Estimate Review (internal prep)	0d		25-Jul-12
ASU.MI.SG.100	Gate Review B - EPC Proposal Estimate Review	0d		01-Aug-12
FM.9999	FEED - Complete	0d		31-Oct-12*
PM.0130	Complete Short-Term Deliverables	0d		01-Nov-12
SG.010.1000	IPDS Gate A - Select a Technical Solution	0d		01-Nov-12
SG.020.1000	IPDS Gate Ba - Approve the Offer	0d		01-Nov-12
SG.020.2000	IPDS Gate Bc - Update and Request Capital (If necessary)	0d		01-Nov-12
SG.030.1000	IPDS Gate C - Authorize Placement of POs	0d		01-Nov-12
AM.0100	FGA Begin Phase 3 Final Design, Construction and Commissioning	0d	01-Nov-12	
PM.0110	Project Kickoff	0d	01-Nov-12	
PM.0120	Limited Notice To Proceed	0d	01-Nov-12	
PM.0100	ALPC Project Kickoff Meeting	0d	01-Nov-12	
PM.0140	Complete Major Equipment Specifications	0d		07-Nov-12
PM.0190	Complete P&ID's (IFD)	0d		15-Nov-12
PM.0200	Complete Main Equipment Purchase Orders	0d		24-Jan-13
PM.0180	Complete P&ID's (IFD) Cold Box	0d		14-Mar-13
PM.0160	Begin UG Piping / Misc Site Prep	0d	29-Mar-13	
PM.0150	Complete Laydown Area (by AHMSA)	0d		07-May-13
PM.0210	Award Foundation Contract	0d		03-Jun-13
SG.040.1000	IPDS Gate D - Site Work Authorized to Break Ground	0d		03-Jun-13
PM.0230	Begin Concrete	0d	17-Jun-13	
PM.0170	Complete Equipment Inventory / Relocation	0d		19-Jun-13
PM.0250	Award Steel / Mechanical Contract	0d		09-Oct-13
PM.0270	Begin Field Erected Tanks	0d	17-Oct-13	
SG.050.1000	IPDS Gate E - Mechanical Construction Authorized to begin	0d		17-Oct-13
PM.0280	Complete Concrete Foundations	0d		31-Oct-13
PM.0260	Begin Mechanical Installation	0d	13-Nov-13	
PM.0300	Begin Structural Steel (Pipe Racks)	0d	02-Jan-14	
PM.0220	Complete Mechanical Package (IFC)	0d		04-Apr-14
PM.0240	Complete E&I Package (IFC)	0d		30-May-14
PM.0310	Begin Piping	0d	06-Aug-14	
PM.0290	Award E&I Contract	0d		15-Aug-14

Actual Work ◆ ◆ Milestone
Remaining Work Summary

FutureGen Level I
Program Schedule

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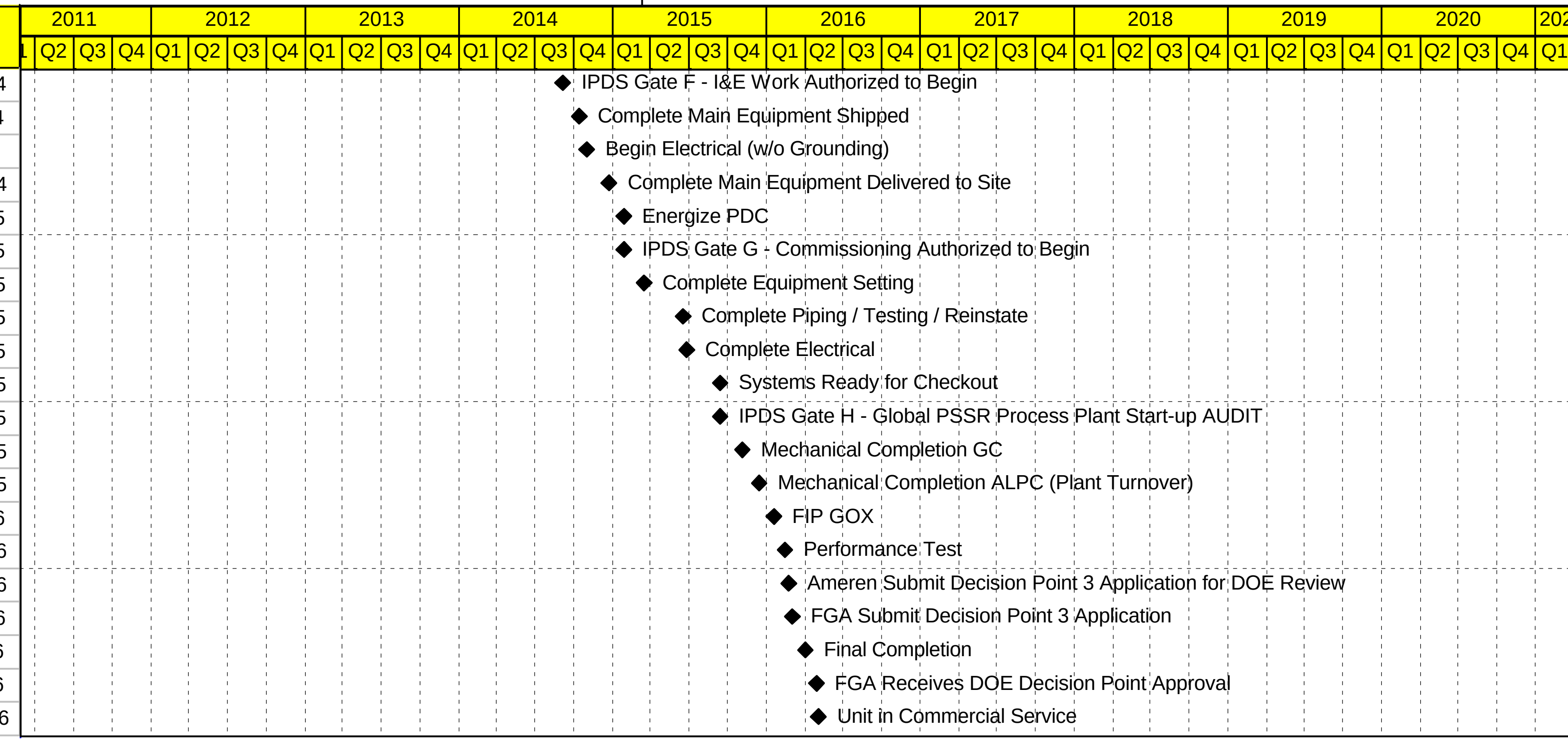
Activity ID	Activity Name	Original Duration	Start	Finish
SG.060.1000	IPDS Gate F - I&E Work Authorized to Begin	0d		05-Sep-14
PM.0320	Complete Main Equipment Shipped	0d		16-Oct-14
PM.0330	Begin Electrical (w/o Grounding)	0d	31-Oct-14	
PM.0350	Complete Main Equipment Delivered to Site	0d		25-Dec-14
PM.0340	Energize PDC	0d		29-Jan-15
SG.070.1000	IPDS Gate G - Commissioning Authorized to Begin	0d		29-Jan-15
PM.0360	Complete Equipment Setting	0d		18-Mar-15
PM.0370	Complete Piping / Testing / Reinstate	0d		17-Jun-15
PM.0380	Complete Electrical	0d		25-Jun-15
PM.6000	Systems Ready for Checkout	0d		11-Sep-15
SG.080.1000	IPDS Gate H - Global PSSR Process Plant Start-up AUDIT	0d		11-Sep-15
PM.5000	Mechanical Completion GC	0d		04-Nov-15
PM.5010	Mechanical Completion ALPC (Plant Turnover)	0d		16-Dec-15
PM.7000	FIP GOX	0d		18-Jan-16
PM.8000	Performance Test	0d		15-Feb-16
AM.0110	Ameren Submit Decision Point 3 Application for DOE Review	0d		22-Feb-16
AM.0120	FGA Submit Decision Point 3 Application	0d		01-Mar-16
PM.9000	Final Completion	0d		04-Apr-16
AM.0130	FGA Receives DOE Decision Point Approval	0d		29-Apr-16
AM.0140	Unit in Commercial Service	0d		02-May-16



Actual Work ◆ ◆ Milestone
Remaining Work Summary

FutureGen Level I
Program Schedule

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H APPENDIX – COST ESTIMATE DETAILS

FutureGen 2.0 Total Project Cost Estimate Methodology

The overall cost estimate represents the sum total project capital cost for all phases of the Project, including the cost for the Phase 1.

Each partner (Ameren, URS, B&W, and Air Liquide) built up their own island estimates using their own internal methods, databases and unique tools and then translated the totals to the estimate summary sheets at a high level. This allows use of familiar tools and processes (minimizing the opportunity for error introduction) at the working level while summarizing costs utilizing common terminology at the summary level.

While the individual estimating methods are very similar, some differences are apparent at the detail level. This means that one partner may estimate some costs (bulk materials as an example) at the detailed scope level while another partner includes these costs within another category.

Major cost categories included in the estimate and the participants' approach to developing costs for each category are discussed herein.

Total Labor Manhours

URS, B&W and Air Liquide built up total labor manhours by totaling the estimated subcontract labor and direct hire labor hours. The labor hours originated in the detailed estimates for each individual scope item and were then summed up to generate a total number.

B&W Construction Company (BWCC) worked in conjunction with Worley Parsons to develop subcontract RFQ packages that were issued to a minimum of three qualified vendors. Determinations were made to identify and carry material and labor costs for this subcontracted work.

Labor hours were generated for the various work scope items by using either an in-house database generated from actual labor hours from previous projects or by directly obtaining quotes from subcontractors. In addition, the hours for URS', B&W's and Air Liquide's field staff are included.

Direct Hire Manhours

Direct Hire Manhours are utilized where the BOP contractor or B&W will hire craft directly to do the work (vs. utilizing a Contractor intermediary). Direct Hire Manhours are included in the total labor man hours. Air Liquide intends to execute their project scope using a Contractor or sub-contractors and therefore has no direct labor hours included.

URS and B&W developed the direct hire labor hours at the detailed level based on their in-house databases and actual hours from previous projects. Hours for URS and B&W supervision over the direct hire labor force are included in their respective Construction Management staffing plans.

Direct Costs

Craft Labor

Craft labor rates were obtained directly from the local union halls and are included in the total Project Estimate Section of the Decision Point Application (DPA) for reference. Hourly craft rates were obtained for the following:

Boilermakers	Bricklayers	Carpenters
Cement Masons	Electricians	Insulators
Ironworkers	Laborers	Millwrights
Operating Engineers	Painters	Pipefitters
Sheetmetal Workers	Teamsters	

The cost was built up from the individual scope line items by defining the appropriate labor crew (foreman, journeyman, apprentice, etc.) and the hours estimated for each member to execute the work.

URS, B&W and Air Liquide all used the same craft labor rates when building their estimates allowing the entire project to quickly adjust to craft labor rate escalation and/or revisions. The total labor cost is a summary of the direct hire craft labor force and the subcontracted labor force.

Bulk Permanent Materials

URS and Air Liquide estimate bulk materials within the individual scope items. These materials might include items such as concrete, cable, etc. B&W includes the majority of these costs within engineered equipment and subcontract line items.

Bulk materials are obtained from material take-offs from preliminary engineering work products for the individual scope items.

Engineered Equipment

URS, B&W and Air Liquide developed engineered equipment sizing from the preliminary engineering deliverables generated as part of the Pre-FEED effort. The pre-FEED effort has benefitted from a very detailed equipment list, interface list, heat and material balance, valve list, instrument list, water balance, P&IDs, and other well-developed deliverables.

Over 80% of the BOP engineered equipment pricing was obtained directly from vendor quotes. For the BOP work, equipment was sized during the preliminary engineering phase and quotes were obtained from vendors for items such as coal conveyors, compressed air equipment, pumps, water treatment systems, tanks, transformers and MCCs in addition to other smaller pieces of equipment rolled up into a combined miscellaneous category in the estimate.

B&W, as an OEM, relied heavily on quotes from their normal commercial supply chain for over 75% of the supply. The use of database information was minimized in the development of their estimate. The boiler was sized based on the plant steam cycle and operational requirements such as fuel type allowing for major boiler equipment to be subsequently sized and quoted.

Quoted engineered equipment would include items such as the fans, air heaters, motors, etc. Major fabrication packages were also quoted such as heavy steel plate, steam drum, flue and duct work, piping, etc. Finally, major subcontract packages such as the mechanical, electrical, and civil packages were quoted as well.

A similar process was followed for the GQCS where the size and design of the system was developed during the Pre-FEED phase allowing major equipment to be subsequently sized and quoted.

Air Liquide is also an OEM and utilizes a rigorous process for quoting engineered equipment that involves a combination of in-house database information and vendor quotes. The ASU and CPU islands are part of Air Liquide's normal business line, but both are rather large for this application. However, Air Liquide was able to use a great deal of in-house information built up from recent projects in addition to obtaining vendor quotes for some equipment.

Freight

URS included the freight cost with the material for the BOP, while B&W and Air Liquide split freight out separately. This is primarily due to the fact that B&W and Air Liquide will assemble and provide much of their own manufactured modules and equipment for the project.

B&W and Air Liquide included a premium for using US flagged vessels for international shipping in their estimates. The premium estimating basis is summarized below:

Air Liquide ASU and CPU		$1,669,000
B&W Boiler and GQCS		$688,000
	Total	$2,357,000

The majority of B&W's transportation premium as it relates to US flagged vessels is due to shipping pressure parts and flue and ductwork from international fabricators to the US. Additional shipping costs are realized from the movement of the large pre-assembled modules to the site. The modules will be assembled elsewhere and shipped internationally before being placed on barges that will be off-loaded at the job site. The size and configuration of the modules was determined during the Pre-FEED preliminary engineering phase and are listed below.

Description:	Quantity	Height (Ft.)	Length (Ft.)	Width (Ft.)	Weight (Lbs.)
6 LP Core Boxes	1	22.500	57.000	27.500	397,000
4 LP Core Boxes	2	22.500	57.000	21.00	338,000
4 HP/Subcooler Box	1	20.500	72.00	20.000	509,000
LP-1 Column Box	1	20	120	25	660,000
LP-2 Column Box	1	20	120	25	509,000
HP/SubCooler Column Box	1	20	120	25	643,000
Absorber	2	18	90	18.5	250,000
Steam Drum	1	9	44	9	300,000
WFGD Absorber	1	9	28	9	500,000

The majority of the equipment procured by URS will be procured via US OEM's or distributors where international shipping is required to a lesser extent such that the premium is not a significant cost adder.

Construction Equipment- Rental

Rental costs for construction equipment are determined at the detailed scope level based on in-house databases, equipment supplier quotes and actual costs from previous jobs. Within this cost are items such as crane rental, earth moving equipment, trucks, etc.

Small Tools

URS and B&W use their in-house database and some factoring to determine small tool costs for direct hire work. The cost is typically determined at the detailed scope level and then rolled up to an overall total.

Air Liquide's costs for small tools are included in their bulk material costs since they typically don't split out this cost and will rely on subcontractors to execute the work.

Subcontracts

A breakdown of the major subcontracts expected on the project was developed. The subcontract scope was built up using preliminary engineering work products developed in the Pre-FEED phase and then either quotes were obtained from actual subcontractors to determine the cost of the subcontract package or it was built up using material take offs and in-house databases. A summary of the method used to determine the subcontract cost for the islands is summarized below:

Package	Method
BOP Site-prep	In-house database
BOP Demolition	Vendor quote
BOP H-Piles	In-house database
BOP Gypsum Dome	Vendor quote
BOP Pre-Eng Bldgs	In-house database
BOP Cooling Towers	Vendor quote
BOP Chimney	Vendor quote
BOP Pipe Insulation	In-house database
BOP Pre/PWHT pipe	In-house database
BOP NDE	In-house database
BOP Assessments	In-house database
BOP Ameren (T&D)	Vendor quote
B&W Field Tanks	Vendor quote
B&W Flue Linings	Vendor quote
B&W Masonry	Vendor quote
B&W HVAC	Vendor quote
B&W EPDM Roofing	Vendor quote
B&W Architectural	Vendor quote
B&W Fire Protection	Vendor quote
B&W Electrical	Vendor quote
B&W Foundations	Vendor quote
B&W Insulation Lagging	Vendor quote

Package	Method
Air Liquide Civil Work	Vendor quote
Air Liquide Erection	Vendor quote

Note: Air Liquide will execute their scope under a master erection sub-contract and have developed their cost estimate accordingly.

Casual Overtime

URS' and B&W's estimates include a factor of 5.5% for casual overtime. This cost is typically incurred if a direct hire crew is held over to finish their work (example: large pipe post weld heat treatment) before going home for the day. The percentage is based on actuals from past projects and in-house databases.

Since Air Liquide will rely on subcontracts to execute their work this cost is not delineated separately.

Sales Tax

URS and B&W include an allotment for sales tax whereas Air Liquide carries this cost in their engineered materials.

Subcontract Bond

Subcontracts typically require bonding and this cost would be passed on and is therefore included at an industry typical value of 1.25% of the direct costs. The BOP EPC subcontract bond cost was obtained by totaling the Direct and Indirect Cost subcontracts and then multiplying by the 1.25% factor.

Indirect Costs

The project's comprehensive Division of Responsibility (DOR) document clearly delineates which partner is responsible for what scope. As the document was developed, the team determined that it would be most fitting for URS, as the BOP EPC contractor, to be responsible for carrying the majority of the project's indirect costs. In addition, URS is including some construction management assistance to Ameren that would be provided by a typical EPC contractor.

It should be noted that the indirect costs in the BOP estimate are being carried for the entire project and therefore appear to be disproportionate to the total BOP Direct Cost.

Construction Management

Using the DOR as a guide, B&W, URS and Air Liquide all developed a very detailed time phased resource loaded schedule for their construction management staffs. This cost represents all field staff from the partners. The project schedule and staffing plans were reviewed as a team to minimize any duplication between roles.

General Conditions

Indirect costs in this category include miscellaneous items such as travel and living expenses for field personnel, office supplies for the construction trailers, telephone and radio communications, IT support, software, first aid supplies, drinking water and ice machine, fire extinguishers, etc. The cost is built up by line item and is based on using in-house data base information from previous projects.

General Auto/Rental

Items in this cost category include trucks, desks and chairs for site personnel. The line items in this cost were built up following the creation of the site staffing plan since the amount of equipment in this category is dependant on those numbers.

General Plant

Items in this cost category include temporary warehouse, general craft shop (for the direct hire workforce) and a security badging station for the main gate. The individual line items in this cost category are built up using in-house data base information from previous projects.

Subcontracts

This cost category includes site support subcontracts for janitor service, outside nursing services, watchman and guards, site surveying, snow removal and trash removal. The costs are built up using the project schedule to find the duration that the service will be required and in-house database information.

Other Costs

This category includes a roll-up of multiple smaller miscellaneous cost categories.

Sales Tax

URS calculated sales tax at 6.25% on General Conditions, General Auto Rental and General Plant costs.

Design Engineering Home Office

URS, B&W and Air Liquide underwent a rather involved process to build up their home office engineering budgets. The project DOR was used to delineate scope between the islands and this in turn defined the engineering deliverables that each should have to produce. URS, B&W and Air Liquide met and worked in an iterative manner to determine required interface points between the individual engineering teams and this was accounted for in the schedules and staffing plans.

The project Integrated Master Schedule (IMS) has been resource-loaded with the home office detailed engineering effort for Phase 2.

Startup

The project DOR delegates plant startup responsibly to B&W and they proceeded to estimate their startup staffing requirements based on their knowledge of the oxy-combustion technology in addition to actual experiences from previous projects.

The startup labor costs for Ameren, URS and Air Liquide are included in their home office, CM and labor cost categories.

BOP G&A and Fee

URS estimated the BOP EPC scope as if it were a standard industry contract and arrangement. G&A is calculated by multiplying the difference of the Subtotal EPC cost and Design Engineering by 5%. Fee is calculated by multiplying the difference of the Subtotal EPC cost and Design Engineering plus G&A by 8%. The Design Engineering cost already contains a G&A and fee component and is therefore excluded from the Subtotal EPC cost when considering the G&A and fee costs.

B&W and Air Liquide would not earn fee on the project.

Ameren (Home Office, CM, Labor)

This cost category is included for the BOP island and includes all of Ameren's costs for the project. Ameren developed a detailed time phased staffing plan for the project that was used in part to create these costs.

Ameren Escalation

Ameren's costs are escalated at 3% per year starting with Phase 3 in November of 2012. These costs are accounted for separately in the estimate so they can easily be differentiated from the BOP escalation costs.

Escalation

Each partner was responsible to determine their own escalation using their internal systems and experience with visibility to the rest of the group. A project level escalation system was not used since it would have potentially been difficult for URS', B&W's and Air Liquide's companies to agree on rates generated outside of their internal procedures and experience.

In calculating escalation, URS used 2.0% for engineered equipment, 3.0% for construction management staff and home office engineering salaries and 2.5% for construction labor, bulk materials, construction equipment, and supplies.

B&W used information from Global Insights to escalate to time of performance based on the project schedule. B&W Construction Company (BWCC) used 4% for labor and 7% for materials. BWCC applied the same escalation to subcontracts. B&W also included 3% for all home office engineering and project and construction management budgets.

Air Liquide used 3% for equipment and materials as a common industry mark in addition to the April 2011 International Monetary Fund report on global inflation expectations for 2011 and 2012, which call for a worldwide average of 4.5% and a 2.2% for the USA. 3% appeared to be reasonable merging of the two numbers. Home office engineering and management was escalated at 5% to the rates based on internal company projections. Construction labor was also escalated at 5% to the rates based on past project experience.

The numbers represented in the estimate are the built up escalations for each island excluding Ameren's escalation number.

Construction and Startup Power

The electricity used to construct the plant and start it up is a real project cost and is therefore included in the estimate. These numbers are extremely difficult to predict, especially given the experimental nature of the project.

Each partner built up their estimated construction and startup power consumption by factoring it based on previous projects or attempting a buildup based on historical in-house information:

BOP:	5,110 MWh
Boiler:	10,582 MWh
GQCS:	6,215 MWh
ASU:	11,410 MWh
CPU:	8,628 MWh
Total:	41,950 MWh

The project used a cost of $58.7 per MWh based information provided by Ameren.

Management Reserve

Management reserve is considered a project cost and accounts for the "known unknowns" that occur on a project. As such, it is included in the estimate. URS, B&W and Air Liquide each have their own internal systems for determining the appropriate amount of management reserve to assign to a project.

URS, B&W and Air Liquide all used proven statistical methods to buildup the management reserve for their respective islands. The process involved combining the individual project cost line items into various categories and then assigning a low and high rate to each category with a cost percentile around the range. The simulation then returned a probability of project cost with a recommended management reserve level at a certain confidence interval.

The project cost estimate incorporates a management reserve calculated at the 80% confidence interval (80% probability that the project could be completed on-budget utilizing the corresponding reserve percentage) for each of the process islands as follows:

Island	Management Reserve at 80% Confidence
URS BOP	8.38%
B&W Boiler	7.38%
B&W GQCS	7.00%
AL ASU	12.2%
AL CPU	16.4%

URS and B&W used the same Monte Carlo analysis system to calculate the recommended management reserve for each of their islands. Air Liquide used a similar but slightly different process proven through their past projects. All partners used systems they were familiar with and normally use in the course of their respective businesses to generate the recommended management reserve level for their projects.

I APPENDIX – PERMIT MATRIX

Recently updated items are shown in italic red or *italic white.*

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No.	Description of Required Permit or Activity	Agency	Responsible Persons	Applicable Projects	When Permit Required	Required Deliverables and Scheduled Date	Submittal Date	Agency Review Time	Approval Date	Comments and Issues	Associated Permits	Status
Air Permits												
1.0	Air Pollution Control Construction Permit (for FutureGen 2.0 ASU Boiler/GQCS CPU BOP)	IEPA/DAPC	Mike Hutcheson	FutureGen 2.0 ASU Boiler/GQCS CPU BOP	Prior to Boiler 7 construction/ Turbine 4 modification October 2012 based upon current construction schedule.	Permit Application	Sch: 7/15/11 Act:		Sch: Act:	Must determine scope of project so that "Net Emission Increase" is finalized and the type and content of application can be determined.		In Process
1..1	Air Quality Modeling	IEPA/DAPC	Mike Hutcheson	FutureGen 2.0 ASU Boiler/GQCS CPU BOP	October 2012 based upon current construction schedule.	Detailed Modeling Report for inclusion in permit application.	Sch: 7/15/11 Act:	9 to 12 months				
1.1.1	Pre-construction monitoring (or pre-application monitoring)	IEPA/DAPC	Mike Hutcheson	FutureGen 2.0 ASU Boiler/GQCS CPU BOP	IEPA can allow pre-construction monitoring rather than pre-application monitoring N/A	URS requested clarification from Ameren-Environmental on the need to collect this data. 5/18/2011 Ameren-Environmental provided decision not to conduct pre-construction monitoring. 5/25/2011	Sch: N/A	N/A	Sch: N/A	Preconstruction monitoring should not be required for this project. Recent USEPA EAP decision cast some doubt on IEPAs decisions in this matter.		
1.1.2	Air quality modeling protocol	IEPA/DAPC	Mike Hutcheson Ken Anderson	FutureGen 2.0 ASU Boiler/GQCS CPU BOP	October 2012 based upon current construction schedule.	AER Environmental to provide URS with draft protocol. 1/14/2011 URS provided AER with comments. 1/18/2011 AER Environmental provided protocol to IEPA. 2/4/2011	Sch: 1/24/11	TBD	Sch:	This protocol is intended for IEPA to obtain agreement on limited items to include hourly meteorological data.		Complete
1.1.2.1	Air quality modeling inputs	IEPA/DAPC	Mike Hutcheson	FutureGen 2.0 ASU Boiler/GQCS CPU BOP	October 2012 based upon current construction schedule.	AER provided URS with the fenceline and building heights that were provided to IEPA for 1-hour SO2 modeling. 1/14/2011 B&W provided limited building heights for new structures. 1/17/2011 B&W provided revised remaining heights. 1/20/2011 URS provided stack parameters on B&W and AL provided emission rates. 5/31/2011 Ameren- Environmental to provide modeling scenarios. TBD	Sch:	NA				
1.1.2.2	Air quality modeling met processing	IEPA/DAPC	Gregg Hagerty	FutureGen 2.0	October 2012 based upon current construction schedule.	AER discussed modeling years and Stage 3 inputs with IEPA. 1/24/11 Project will use 03-07 met data from Newton project, based upon 1/24/11 Matt Will email. 2/4/11	Sch:	NA		Obtain land use determination for surface met station from IEPA, then process met data for use in AERMOD.		
1.1.2.3	Air quality modeling elevation data processing	IEPA/DAPC	Gregg Hagerty	FutureGen 2.0	October 2012 based upon current construction schedule.	URS obtained National Elevation Data (NED) from USGS. 2/4/11	Sch: 4/1/2011	NA		Once coordinates for buildings, and stacks are provided, elevations will be assigned using AERMAP.		Complete
1.1.2.4	Air quality modeling building locations	IEPA/DAPC	Gregg Hagerty	FutureGen 2.0	October 2012 based upon current construction schedule.	URS reconciled building dimension information. 3/3/2011 URS to send building dimension to AER for approval. 3/15/2011 URS finalized initial plot plan information. 3/8/2011						

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1.1.2.4	Air quality modeling building locations (continued)	IEPA/DAPC	Gregg Hagerty	FutureGen 2.0		URS input building dimension information into AERMOD. 3/11/11						
1.1.3	Green House Gas (GHG) information for air permit application.	IEPA/DAPC	Mike Hutcheson	FutureGen 2.0 ASU Boiler/GQCS CPU BOP	October 2012 based upon current construction schedule.		Sch: Act:			Place holder for GHGs.		
1.1.4	Air quality modeling results	IEPA/DAPC	Gregg Hagerty	FutureGen 2.0 ASU Boiler/GQCS CPU BOP	October 2012 based upon current construction schedule.		Sch:	NA		Air quality modeling representative of boiler retirements and installation of oxy-combustion boiler will be needed for NEPA documentation.		
1.1.4.1	BPIP results	IEPA/DAPC	Gregg Hagerty	FutureGen 2.0 Boiler/GQCS	October 2012 based upon current construction schedule.	Ameren-Environmental approved building input data. 3/24/2011 URS ran BPIP and provided Ameren-Environmental with results. 4/12/2011 B&W building height information changed. 4/14/2011 URS reran BPIP and provided revised report to Ameren-Environmental. 5/11/2011	Sch:	NA		Once model parameters (buildings, met data, elevation data) are set, GEP height for various locations within the facility can be determined.		
1.1.4.2	NAAQS Results	IEPA/DAPC	Gregg Hagerty	FutureGen 2.0 ASU Boiler/GQCS CPU BOP	October 2012 based upon current construction schedule.	URS to provide AER with current Unit 3, Boiler 5 stack parameters. 5/10/2011 AER to confirm/provide Unit 3, Boiler 5 stack parameters and emission rates. 5/13/2011 Ameren-Environmental to provide modeling protocol sent to IEPA. 5/13/2011 Ameren-Environmental to provide URS with NAAQS emission inventory provided by IEPA. *TBD*				NAAQS modeling will be provided to IEPA (per Ameren-Environmental) under state permitting to show compliance with NAAQS. PHE will require HAP modeling results to include in their human health risk assessment.		
1.1.4.3	Increment Consumption Results	IEPA/DAPC	Gregg Hagerty	FutureGen 2.0 ASU Boiler/GQCS CPU BOP	October 2012 based upon current construction schedule.	Ameren-Environmental to provide URS with increment consuming inventory provided by IEPA. *TBD*				This is only a requirement if project is significant for SO_2, PM, or NO_2.		
1.2	Net Emission Analysis	IEPA/DAPC	Mike Hutcheson	FutureGen 2.0 ASU Boiler/GQCS CPU BOP		AER-Environmental to finalize draft netting tables. TBD URS sent sources of fugitive PM for review. 5/10/2011 URS sent fugitive PM emission spreadsheet to Ameren-Environmental for review. 6/1/2011 Ameren-Environmental provided initial comments. 6/2/2011 URS responded to comments and requested additional guidance. 6/6/2011 *Ameren-Environmental provided guidance and requested more information. 6/17/2011*				Netting is dependent on project assumptions and AER decisions with regard to boiler retirements.		

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1.2.1	Boiler/GCQS Emission Rates	IEPA/DAPC	Jim MacInnis	FutureGen 2.0 Boiler/GQCS		B&W provided characterization of direct emissions from WFGD system. B&W completed Air Emission Worksheet for pollutants and operating conditions (except transition emissions through DCCPS). B&W provided transition emission rates through DCCPS. Ameren/URS asked for air emissions at 100% firing on oxygenate as they would go to the stack bypass. B&W asked for clarification, Ameren confirmed need for information. Ameren/URS asked B&W to verify CO emission rates and fine PM methodology. B&W verified CO emission rates and provided additional fine PM methodology.	4/12/11 4/26/11 5/11/2011 4/29/2011 5/11/2011 5/20/2011 5/20/2011 5/26/11				B&W has not provided emission rates as of 4/25/2011.		
1.2.2	ASU/CPU Emission Rates	IEPA/DAPC	Mark Estopinal	FutureGen 2.0 ASU CPU		AL completed Air Emission Worksheet for CPU long term normal operating conditions. Conference Call at 8AM CST to discuss CPU malfunction scenarios and emission impacts. AL provided emission estimate for CPU short term conditions associated with pipeline not available. Ameren/URS informed AL that general information on ASU will be included in permit application. *AL provided additional information on BMCR and no pipeline emissions.* AL to provide emission estimate for CPU short term conditions representative of start-up conditions. AL to provide information on variations associated with non-condensible stream during normal operations.	5/13/2011 5/11/2011 6/1/2011 5/13/2011 *6/15/2011* 6/10/2011 6/30/2011				AL is first completing long term average emission rates for netting analysis, then will work on short term emission rates for modeling.		

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1.2.3	Existing Boiler Emission Reductions	IEPA/DAPC	Mike Hutcheson	FutureGen 2.0		Ameren to provide URS with emission reduction information. TBD URS to send data package to Ameren, AL, and B&W for approval. URS to provide data package to PHE.				PHE is requesting this information for NEPA documentation.		
1.2.4	Existing Boiler Retirement	Internal	Dave Burbridge	FutureGen 2.0		AER-Environmental provide information to management to decide which boilers will be retired. *6/10/2011* AER Management decide which Boilers will be retired. *6/17/2011*						
1.3	BACT analysis	IEPA/DAPC	Mike Hutcheson	FutureGen 2.0			Sch: 7/15/11 Act:			PSD Pollutants		
1.3.1	NOx BACT	IEPA/DAPC	Mike Hutcheson	FutureGen 2.0 ASU Boiler/GQCS CPU BOP	If project requires PSD permit for NO_x. 07/12/11	URS provided AER with NOx technology list. 2/18/2011 URS provided AER with NOx RBLC results. 3/2/2011 URS to provide AER with NOx RBLC permits. 3/4/2011 URS to FOIA stack test results associated with RBLC permits. 3/4/2011				This is only required if project requires PSD permit for NO_x.		
1.3.2	SOx BACT	IEPA/DAPC	Mike Hutcheson	FutureGen 2.0 ASU Boiler/GQCS CPU BOP	If project requires PSD permit for SO_x. 07/12/11	URS provided AER with SOx technology list. URS to provide AER with SOx RBLC results.				This is only required if project requires PSD permit for SO_x.		
1.3.3	PM BACT	IEPA/DAPC	Mike Hutcheson	FutureGen 2.0 ASU Boiler/GQCS CPU BOP	If project requires PSD permit for PM. 07/12/11					This is only required if project requires PSD permit for PM.		
1.3.4	CO BACT	IEPA/DAPC	Mike Hutcheson	FutureGen 2.0 ASU Boiler/GQCS CPU BOP	If project requires PSD permit for CO. 07/12/11					This is only required if project requires PSD permit for CO.		
1.3.5	CO2 BACT	IEPA/DAPC	Mike Hutcheson	FutureGen 2.0 ASU Boiler/GQCS CPU BOP	If project requires PSD permit for CO_2. 07/12/11	URS provided AER with CO2 technology list. URS to provide AER with CO2 RBLC results.				This is only required if project requires PSD permit for CO_2.		
1.3.6	VOM BACT	IEPA/DAPC	Mike Hutcheson	FutureGen 2.0 ASU Boiler/GQCS CPU BOP	If project requires PSD permit for VOM. 07/12/11					This is only required if project requires PSD permit for VOM.		
1.4	Case by Case MACT Determination	IEPA/USEPA	Ken Anderson	FutureGen 2.0	October 2012 based upon current construction schedule.							
1.4.1	Oxy-Combustions Boiler case by case MACT	IEPA/USEPA	Ken Anderson	Oxy-Combustion Boiler	October 2012 based upon current construction schedule.					EGU MACT currently proposed, currently scheduled to be finalized in November 2011.		

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1.4.1.1	Oxy-Combustions Boiler case by case MACT	IEPA/USEPA	Ken Anderson	Oxy-Combustion Boiler	October 2012 based upon current construction schedule.	AER-Environmental to evaluate emission rates provided by B&W and AL against proposed EGU MACT requirements. 5/20/11						
1.4.2	Auxiliary Boiler MACT	IEPA/USEPA	Ken Anderson	Auxiliary Boiler	October 2012 based upon current construction schedule.					Final "Boiler" MACT rules promulgated, 3/21/2011. Unit will be operated less than 10% of the time. Implementation of "Boiler" MACT rules delayed, 5/18/2011.		
1.5	Ecological Assessment	IEPA/DAPC	Kevin Pulley	FutureGen 2.0 PSD Pollutants	If PSD permit is required. 07/12/11	PSD Pollutants only				Required by PSD permit application. Need to ensure it is appropriately classified.		
1.5.1	Deposition Results (Ecological)	IEPA/DAPC	Gregg Hagerty	FutureGen 2.0 PSD Pollutants	If PSD permit is required. 07/12/11	PSD Pollutants only				Deposition rates and air concentrations needed for input into risk model.		
1.5.1.1	Additional Meteorological Data	IEPA/DAPC	Gregg Hagerty	FutureGen 2.0 PSD Pollutants	If PSD permit is required. 07/12/11	PSD Pollutants only				Depending upon the pollutants requiring ecological assessment, additional met data is needed for wet deposition or evaluation of H2SO4 mist impacts.		
1.5.2	Determine Federally Listed Species in Area.	IEPA/DAPC	Kevin Pulley	FutureGen 2.0 PSD Pollutants	If PSD permit is required. 07/12/11	PSD Pollutants only						
1.5.3	Complete Exposure Pathways	IEPA/DAPC	Jen Schwent	FutureGen 2.0 PSD Pollutants	If PSD permit is required. 07/12/11	PSD Pollutants only						
1.5.4	Determine Environmental Setting	IEPA/DAPC	Jen Schwent	FutureGen 2.0 PSD Pollutants	If PSD permit is required. 07/12/11	PSD Pollutants only						
1.5.5	Conduct Media Specific Concentrations using IRAP-H model.	IEPA/DAPC	Kevin Pulley	FutureGen 2.0 PSD Pollutants	If PSD permit is required. 07/12/11	PSD Pollutants only						
1.5.6	Determine applicable media specific TACO background values.	IEPA/DAPC	Kevin Pulley	FutureGen 2.0 PSD Pollutants	If PSD permit is required. 07/12/11	PSD Pollutants only						
1.5.7	Determine media specific ecological screening threshold values.	IEPA/DAPC	Jen Schwent	FutureGen 2.0 PSD Pollutants	If PSD permit is required. 07/12/11	PSD Pollutants only						
1.5.8	Write Ecological Risk Assessment Report	IEPA/DAPC	Kevin Pulley	FutureGen 2.0 PSD Pollutants	If PSD permit is required. 07/12/11	PSD Pollutants only						
1.5.8.1	Evaluate media specific concentrations to screening threshold values.	IEPA/DAPC	Kevin Pulley	FutureGen 2.0 PSD Pollutants	If PSD permit is required. 07/12/11	PSD Pollutants only						
1.5.8.2	Determine project uncertainties.	IEPA/DAPC	Kevin Pulley	FutureGen 2.0 PSD Pollutants	If PSD permit is required. 07/12/11	PSD Pollutants only						
1.6	Air Pollution Control Permit for constructing Fiberglass Reinforced Plastic (FRP) stack liner.	IEPA/DAPC	B&W and Subcontractor	On-Site Construction of FRP Flue Liners			Sch: Act:	3 months	Sch: Act:	Permit will only be required if FRP liners are to be installed.		
1.8	Fuel Additives (calcium bromide injection) Air Construction Permit Conditions	IEPA/DAPC	Ken Anderson	Pilot Evaluation of Fuel Additives for Mercury Control (calcium bromide injection)	Prior to conducting calcium bromide injection pilot testing.					Current mercury control plans do not include fuel additives.		
1.9	Impingement Study of Proposed Stacks	NA	TBD	New Stacks - if applicable		AER-Environmental and project team to determine necessity. 5/1/11						
2.0	Air Pollution Control Construction Permit (for an Emergency Diesel Generator for FGD Plant)	IEPA/DAPC	Mike Hutcheson	FutureGen 2.0	Prior to installation of an Emergency Diesel Generator for the FGD Plant	Specification of generator size, expected hrs of operation & other supporting info.	Sch: Act:	3 months	Sch: Act:			
2.1	Air Pollution Control Construction Permit (Boiler Chemical Cleaning)	IEPA/DAPC	Mike Hutcheson	Outage support			Sch: Act:	6 months	Sch: Act:	For use if Ameren decides to incinerate the boiler chemical cleaning chemicals.		
3.0	CAAPP (Title V) Permit (for wet FGD and related projects)	IEPA/DAPC	Mike Hutcheson	FutureGen 2.0 ASU Boiler/GQCS CPU BOP		Application forms (see Note 2)	Sch: 7/7/05 Act:	See Note 3	Sch: Note 3 Act:	Need to update Title V permit within year of new equipment installation. Current CAAPP permit staged.		
4.0	Acid Rain (Title IV) Permit	IEPA/DAPC	Mike Hutcheson	FutureGen 2.0 ASU Boiler/GQCS CPU BOP			Sch: Act:		Sch: Act:			

Sch: scheduled date
Act: actual date

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5.0	Open Burning Permit	IEPA/DAPC	Mike Hutcheson	FutureGen 2.0 ASU Boiler/GQCS CPU BOP	Prior to open burning	Completed APC 325 - Application for Open Burning Permit	Sch: Act:	3 months	Sch: Act:			
6.0	CEMS Certification	IEPA and USEPA	Mike Hutcheson	Installation of new CEMS in new stack	When the new stack monitor is placed in-service (see Note 4) See below	See below	Sch: See below	N/A	Sch:	Certification typically provided by vendor		
6.0.1	CEMS Pre-test Notification	IEPA and USEPA	Mike Hutcheson	New CEMS system	Submittal required 45 days prior to first scheduled day of testing	Submittal of monitoring plan, test notice and test protocol	Sch:	N/A	Sch:			
6.0.2	CEMS Pre-operation Notice	IEPA and USEPA	Mike Hutcheson	New CEMS system	Written notice required 45 days prior to initial operation.		Sch:	N/A	Sch:			
6.0.3	CEMS Post-operation Notice	IEPA and USEPA	Mike Hutcheson	New CEMS system	Required within 7 days after initial operation.	Written notice of the actual date of initial operation.	Sch:	N/A	Sch:			
6.0.4	CEMS Certification Application	IEPA and USEPA	Mike Hutcheson	New CEMS system	No later than 45 days after completion of certification tests		Sch:	4 months (see note 5)	Sch:			
7.0	Mercury CEMS Certification	IEPA and USEPA	Mike Hutcheson	Installation of Hg CEMS in new chimney	Required by regulation by ??/??/??, which is after the new stack is placed in-service See below	See below	Sch: See below	N/A	Sch: See below	Certification typically provided by vendor		
7.0.1	Mercury CEMS Pre-test Notification	IEPA and USEPA	Mike Hutcheson	New Hg CEMS system	Submittal required at least 45 days prior to first scheduled day of initial certification testing	Submittal of monitoring plan, certification test notice and test protocol is required.	Sch:	N/A	Sch: N/A			
7.0.2	Mercury CEMS Pre-operation Notice	IEPA and USEPA	Mike Hutcheson	New Hg CEMS system	Written notice required at least 45 days prior to anticipated date of initial operation.		Sch:	N/A	Sch: N/A			
7.0.3	Mercury CEMS Post-operation Notice	IEPA and USEPA	Mike Hutcheson	New Hg CEMS system	Required within 7 days after initial operation.	Written notice of the actual date of initial operation.	Sch:	N/A	Sch: N/A			
7.0.4	Mercury CEMS Certification Application	IEPA and USEPA	Mike Hutcheson	New Hg CEMS system	No later than 45 days after completion of certification tests		Sch:	4 months (see note 5)	Sch:			
8.0	Continuous Opacity Monitors (COMs)	IEPA and USEPA	Mike Hutcheson	Relocated COMS in new Flue.			Sch: See below	N/A	Sch: See below			
8.0.1	Determination of number of COMs, their pathways, and compliance methodology.	IEPA and USEPA	Mike Hutcheson	Relocated COMS in new Flue.								
8.0.2	COMS Pre-test Notification	IEPA and USEPA	Mike Hutcheson	New COMS system	Submittal required at least 45 days prior to first scheduled day of initial certification testing	Submittal of monitoring plan, certification test notice and test protocol is required.	Sch:	N/A	Sch: N/A			
8.0.3	COMS Pre-operation Notice	IEPA and USEPA	Mike Hutcheson	New COMS system	Written notice required at least 45 days prior to anticipated date of initial operation.		Sch:	N/A	Sch: N/A			
8.0.4	COMS Post-operation Notice	IEPA and USEPA	Mike Hutcheson	New COMS system	Required within 7 days after initial operation.	Written notice of the actual date of initial operation.	Sch:	N/A	Sch: N/A			
8.0.5	COMS Certification Application	IEPA and USEPA	Mike Hutcheson	New COMS system	No later than 45 days after completion of certification tests		Sch:	4 months (see note 5)	Sch:			
9.0	Demolition (Notification of Demolition & Renovation)	IEPA/ Asbestos Unit	TBD	FutureGen 2.0 Boiler No. 6	Notice must be submitted 10 working-days prior to demolition	Notice forms for IEPA. AER (Warren Mueller) shall pre-approve the disposal facility.	Sch: 5/16/11 Act:	10 days	Sch: Act:			
9.1	Asbestos Inspection		TBD	FutureGen 2.0 Boiler No. 6			Sch: Act:			Inspection should be within 60 days of demolition.		
9.2	Lead Inspection		TBD	FutureGen 2.0 Boiler No. 6			Sch: Act:			Inspection should be within 60 days of demolition.		

Note 1 A complete CAAPP application must be submitted within 12 months after commencing operation.
Note 2 IEPA rules allow filing for an Administrative Permit Amendment to incorporate conditions of a CAAPP compliant construction permit.
Note 3 The agency review time and CAAPP permit issuance date is uncertain; an "application shield" will be in effect.
Note 4 For an existing unit that completes construction, completion of all certification tests is required within 90 unit operating days or 180 calendar days (whichever occurs first) after the date that emissions first exit to the atmosphere through the new stack, flue, or flue gas desulfurization system. However, all of the emissions through the new system must be determined by missing data substitution methods until certification tests have been completed.
Note 5 Regulations provide for a certification by default after 120 days; rarely does Agency issue an actual certification
Note 6 FGD draft permit comments from IEPA 1) limit 500,000 TPY limestone, 2) FGD must have "high efficiency" mist eliminators no numeric definition supplied. 3) Particulate testing using methods 5 & 202 within 180 days of startup, SO2 data with SO2% removal also required at that time.
Note 7 Demolition Permits may apply to remodeling - Lead paint triggers OSHA requirements, possibly disposal requirements.

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Landfill Permits												
10.0	Approval by Local Unit of Government (Section 39.2 of IEPA Act; see also 35 IL Adm. Code 812.105)	IEPA/DLPC	Paul Pike	Landfill	Local siting approval completed before submitting an application for Solid Waste Development Permit (No. 11)		Sch: Act:		Sch: Act:			
10.1	Evaluation of Solid Waste Management Facility Options.	Internal	Paul Pike	FutureGen 2.0		B&W provided draft solid waste production rates. 1/21/2011 Air Liquide to provide list of solid waste streams and production rates. 4/29/2011	Sch: Act:		Sch: Act:	Evaluation should include comparison to TCLP limits for individual metals.		
10.1.1	Evaluation of Landfill Capacity at Duck Creek	Internal	Paul Pike	FutureGen 2.0			Sch: Act:		Sch: Act:			
10.1.2	Evaluation of Commercial Landfill Capacity to receive solid waste from Meredosia.	Internal	Paul Pike	FutureGen 2.0			Sch: Act:		Sch: Act:			
10.1.3	Evaluation of Offsite Property to build additional landfill capacity.	Internal	Paul Pike	FutureGen 2.0		Ameren-Environmental to provide list of criteria to be considered for siting the landfill to URS. 5/10/2011 URS to send landfill criteria to AER, B&W, and AL for approval. 5/11/2011 URS to send landfill criteria to PHE for inclusion in the draft EIS. 5/16/2011	Sch: Act:		Sch: Act:	Working with Barbara Skitt on locating site.		
10.2	Evaluate CCR material to validate design basis water content to pass paint filter test to send material to landfills.	Internal	Paul Pike & Gregg Hagerty	FutureGen 2.0	NA	URS obtained gypsum data used in Newton analysis. 4/27/2011 Ameren-Environmental to obtain data for CCR material. TBD						
10.3	Obtain Solid Waste characteristics and estimated quantities	Internal	Paul Pike & Gregg Hagerty	FutureGen 2.0								
10.3.1	ASU solid waste	Internal	Paul Pike & Gregg Hagerty	ASU Compressor Filters		AL to provide information on solid waste from ASU. 6/30/11						
10.3.2	Boiler Island solid waste	Internal	Paul Pike & Gregg Hagerty	Boiler Island Bottom Ash Fly Ash Gypsum		Information regarding bottom ash, fly ash, and gypsum available in design basis revision *D*. 5/5/11						
10.3.3	CPU solid waste	Internal	Paul Pike & Gregg Hagerty	CPU Compressor Filters Dust Collection Solids		AL to provide information on solid waste from CPU. 6/30/11						
10.3.4	BOP solid waste	Internal	Paul Pike & Gregg Hagerty	BOP Oil Separation Unit Oils WWTP Solids		Ameren-Environmental to provide URS with guidance regarding WWTP options. TBD URS to provide information on solid waste from oil water separators. 6/30/11 URS to provide information on solid waste from WWTP. 6/30/11						
11.0	Solid Waste Development Permit (35 IL Adm. Code 807.201)	IEPA/DLPC	Paul Pike	Landfill	Development permits are required to construct new landfills or new units at existing landfills		Sch: Act:		Sch: Act:			
12.0	Solid Waste Operating Permits (35 IL Adm. Code 807.202)	IEPA/DLPC	Paul Pike	Existing Landfill	Operating permits are required before receiving waste at a new landfill or new unit		Sch: Act:		Sch: Act:			
13.0	Initial Facility Report (35 Ill. Adm. Code 815 Subpart B)	IEPA/DLPC	Paul Pike	Landfill		None	Sch: Act:		Sch: Act:			

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14.0	Initial Facility Report (35 Ill. Adm. Code 815 Subpart B)	IEPA/DLPC	Paul Pike	Gypsum Management Facility	The initial facility report must be filed before any waste is accepted at an exempt (un-permitted) landfill	To be determined	Sch: Act:		Sch: Act:			
Notes												
Wastewater Permits												
20.0	NPDES Permit (Subpart A, see Note 1)	IEPA/DWPC	Mike Smallwood	FutureGen 2.0 ASU Boiler/GQCS CPU BOP	Required prior to discharge of wastewater	Conference call with Ameren-Environmental and URS to discuss stormwater, 404/401, and NPDES permitting issues. 5/4/11	Sch: NA Act:	NA	Sch: NA Act:			
20.1	Water Balance Evaluation	Internal	Gregg Hagerty	FutureGen 2.0		URS provided draft water balance information to AER-Environmental based upon available information. 1/25/2011 Air Liquid provided input into the water balance. 5/2/2011 URS provided updated water balance to Ameren-Environmental. 4/27/2011 Conference call with Ameren and URS to discuss water balance and U3 flows to be treated. 5/12/2011 URS provided Final Phase I water balance. 5/20/2011				Collect and collate water balance from Air Liquide, B&W, and URS. Includes process flow diagrams, water flows, water characteristics, and material balances.		
20.2	Evaluation of Antidegradation needs	Internal	Mike Smallwood / David Jessup	FutureGen 2.0		AER requested URS quantify U1 and U2 historical discharges based on 2002 and 2010 permit applications. 5/12/2011 URS provided draft results/data gaps to AER for discussion. 5/25/2011				Determination if there is an increase in pollutant or thermal load, which will trigger antidegradation requirements. Pollutants of particular interest are mercury and selenium.		
20.3	NPDES Operating Permit	IEPA/DWPC	Mike Smallwood	ASU/CPU Cooling Tower	Required prior to discharge of wastewater	URS to provide draft conceptual design. 6/6/11	Sch: Act:		Sch: Act:			
20.4	NPDES Operating Permit	IEPA/DWPC	Mike Smallwood	DCCPS Cooling Tower	Required prior to discharge of wastewater	URS to provide draft conceptual design. 6/6/11	Sch: Act:		Sch: Act:			
20.5	NPDES Operating Permit	IEPA/DWPC	Mike Smallwood	Main Cooling Tower	Required prior to discharge of wastewater	URS to provide draft conceptual design. 6/6/11	Sch: Act:		Sch: Act:			
20.6	NPDES Operating Permit	IEPA/DWPC	Mike Smallwood	Wastewater Treatment Plant	Required prior to discharge of wastewater	URS to provide draft conceptual design. 6/6/2011 URS provided information on key conceptual design issues to discuss with Ameren. 5/25/2011	Sch: Act:		Sch: Act:			
20.7	NPDES Operating Permit	IEPA/DWPC	Mike Smallwood	Boiler Island Oil/Water Separator	Required prior to discharge of wastewater	URS to provide draft conceptual design (vendor packages). 6/6/11	Sch: Act:		Sch: Act:			
20.8	NPDES Operating Permit	IEPA/DWPC	Mike Smallwood	CPU Oil/Water Separator	Required prior to discharge of wastewater	URS to provide draft conceptual design (vendor packages). 6/6/11	Sch: Act:		Sch: Act:			
20.9	NPDES Operating Permit	IEPA/DWPC	Mike Smallwood	ASU Oil/Water Separator	Required prior to discharge of wastewater	URS to provide draft conceptual design (vendor packages). 6/6/11	Sch: Act:		Sch: Act:			
20.10	NPDES Operating Permit	IEPA/DWPC	Mike Smallwood	Unit 4 Oil/Water Separator	Required prior to discharge of wastewater	URS to provide draft conceptual design (vendor packages). 6/6/11	Sch: Act:		Sch: Act:			

Sch: scheduled date
Act: actual date

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21.0	Water Pollution Control Construction Permit (Subpart B, see Note 2)	IEPA/DWPC	Mike Smallwood	FutureGen 2.0 ASU Boiler/GQCS CPU BOP	Required prior to construction or installation of wastewater treatment equipment	Conference call with Ameren-Environmental and URS to discuss stormwater, 404/401, and NPDES permitting issues. 5/4/11	Sch: NA Act:	NA	Sch: NA Act:			
21.1	NPDES Construction Permit	IEPA/DWPC	Mike Smallwood	ASU/CPU Cooling Tower	Required prior to installation of wastewater treatment equipment.	URS to provide draft final design (Phase 2). TBD	Sch: Act:		Sch: Act:			
21.2	NPDES Construction Permit	IEPA/DWPC	Mike Smallwood	DCCPS Cooling Tower	Required prior to installation of wastewater treatment equipment.	URS to provide draft final design (Phase 2). TBD	Sch: Act:		Sch: Act:			
21.3	NPDES Construction Permit	IEPA/DWPC	Mike Smallwood	Main Cooling Tower	Required prior to installation of wastewater treatment equipment.	URS to provide draft final design (Phase 2). TBD	Sch: Act:		Sch: Act:			
21.4	NPDES Construction Permit	IEPA/DWPC	Mike Smallwood	Wastewater Treatment Plant	Required prior to installation of wastewater treatment equipment.	URS to provide draft final design (Phase 2). TBD	Sch: Act:		Sch: Act:			
21.5	NPDES Construction Permit	IEPA/DWPC	Mike Smallwood	Boiler Island Oil/Water Separator	Required prior to installation of wastewater treatment equipment.	URS to provide draft final design (Phase 2). TBD	Sch: Act:		Sch: Act:			
21.6	NPDES Construction Permit	IEPA/DWPC	Mike Smallwood	CPU Oil/Water Separator	Required prior to installation of wastewater treatment equipment.	URS to provide draft final design (Phase 2). TBD	Sch: Act:		Sch: Act:			
21.7	NPDES Construction Permit	IEPA/DWPC	Mike Smallwood	ASU Oil/Water Separator	Required prior to installation of wastewater treatment equipment.	URS to provide draft final design (Phase 2). TBD	Sch: Act:		Sch: Act:			
21.8	NPDES Construction Permit	IEPA/DWPC	Mike Smallwood	Unit 4 Oil/Water Separator	Required prior to installation of wastewater treatment equipment.	URS to provide draft final design (Phase 2). TBD	Sch: Act:		Sch: Act:			
22.0	Sanitary holding system/septic tank permit	DPH	Mike Smallwood	Construction/ demolition contractor trailer sanitary systems	Prior to installation of holding tanks		Sch: Act:		Sch: Act:	URS is currently planning on a mix of porta-potties and trailer holding tanks discharging to plant sanitary system for Phase 2 estimate.		
23.0	Cooling Water Intake Structure	IEPA/DWPC	Mike Smallwood	FutureGen 2.0			Sch: Act:		Sch: Act:	Evaluate the need to replace existing wells with new wells based upon the GA, once it is set.		
23.1	Evaluation of Phase I, Track I requirements versus proposed Phase II requirements.	IEPA/DWPC	Mike Smallwood / David Jessup	FutureGen 2.0			Sch: Act:		Sch: Act:	Phase I, Track I option would be Johnson Screens. There are a number of Phase II options available.		
23.2	Evaluation of current river study availability/ sufficiency for Phase II requirement	IEPA/DWPC	Mike Smallwood / David Jessup	FutureGen 2.0		AER Environmental provided URS with 2002 and 2010 NPDES permit application. 1/19/2011 1/18/2011	Sch: Act:		Sch: Act:	Only needed if Phase II water intake structure requirements are followed.		
23.3	Post implementation river study for Phase II water intake structure	IEPA/DWPC	Mike Smallwood / David Jessup	FutureGen 2.0			Sch: Act:		Sch: Act:	Only needed if Phase II water intake structure requirements are followed.		

Note 1 35 IL Adm. Code Part 309, Subpart A
Note 2 35 IL Adm. Code Part 309, Subpart B, Section 309.202

Stormwater Permits												
25.0	Industrial Stormwater Discharge (NPDES) Permit	IEPA/DWPC	Mike Smallwood	FutureGen 2.0 ASU Boiler/GQCS CPU BOP		None	Sch: Act:	NA	Sch: Act:			
25.1	Conceptual Stormwater Retention/Detention Basin Design	IEPA/DWPC	Kathy Anderson	FutureGen 2.0 ASU Boiler/GQCS CPU BOP		Conference call with Ameren-Environmental and URS to discuss stormwater, 404/401, and NPDES permitting issues. 5/4/11				Discussion with Kathy Anderson and Mike Smallwood would be beneficial in initiating stormwater basin conceptual design.		

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25.2	Final Stormwater Retention/Detention Basin Design	IEPA/DWPC	Kathy Anderson	FutureGen 2.0 ASU Boiler/GQCS CPU BOP								
26.0	Construction Stormwater Discharge (NPDES) Permit ("Land disturbance permit")	IEPA/DWPC	Mike Smallwood	FutureGen 2.0 ASU Boiler/GQCS CPU BOP			Sch: Act:		Sch: Act:			

Note 1 For any planned changes, it may be required to give notice to the IEPA as soon as possible of any planned physical alterations or additions to the permitted facility, to develop a revised Storm Water Pollution Prevention Plan (SWPPP), or submit a completed Notice of Intent (NOI) prior to operation.
Note 2 Normal construction storm water permit requirements include a Storm Water Pollution Prevention Plan (SWPPP) and a completed Notice of Intent (NOI)

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Resource Studies												
30.1	Wetland Delineation/Jurisdictional Determination	USACE/MVS	Gregg Hagerty	FutureGen 2.0 ASU Boiler/GQCS CPU BOP		URS provided PHE with figure delineating areas that may be impacted for their field study. 5/2/2011 PHE conducted field study. 5/27/2011 *PHE provided draft wetlands report for review. 6/13/2011* *Ameren provide comments on draft report. 6/25/2011* *URS consolidate and provide comments to PHE. 6/27/2011* *7/8/2011* *PHE to finalize wetlands report.*	Sch: NA Act:	NA	Sch: NA Act:	Field studies will be performed by DOE's contractor PHE. Analysis will be reviewed by AER/URS. Initial indications are the RR property to the south are not wetlands.		
30.2	Wetland Delineation/Jurisdictional Determination	USACE/MVS	Gregg Hagerty	Natural Gas Pipeline Extension		AER-Meredosia to find ROW width for NG pipeline. *6/7/2011* URS sent data package to AER, B&W, and AL for approval. *6/20/2011* URS provided PHE with figure with proposed NG pipeline routes. *5/12/2011*	Sch: NA Act:	NA	Sch: NA Act:	This task will only be needed if natural gas is determined to be the fuel source for auxiliary boiler as well as main boiler igniters.		
30.3	Wetland Delineation/Jurisdictional Determination	USACE/MVS	Gregg Hagerty	Solid Waste Landfill						This task will only be needed if solid waste landfill location is determined before the Final EIS is published and ROD complete.		
31.1	Endangered Species Evaluation and/or Consultation (state/federal)	USFWS and IDNR/ORC	Gregg Hagerty	FutureGen 2.0 ASU Boiler/GQCS CPU BOP		PHE conducted field study. 5/27/11	Sch: NA Act:	NA	Sch: NA Act:	Field studies will be performed by DOE's contractor PHE. Analysis will be reviewed by AER/URS.		
31.2	Endangered Species Evaluation and/or Consultation (state/federal)	USFWS and IDNR/ORC	Gregg Hagerty	Natural Gas Pipeline Extension		AER-Meredosia to find ROW width for NG pipeline. *6/7/2011* URS sent data package to AER, B&W, and AL for approval. *6/20/2011* URS provided PHE with figure with proposed NG pipeline routes. *5/12/2011*	Sch: NA Act:	NA	Sch: NA Act:	This task will only be needed if natural gas is determined to be the fuel source for auxiliary boiler as well as main boiler ignitors.		
31.3	Endangered Species Evaluation and/or Consultation (state/federal)	USFWS and IDNR/ORC	Gregg Hagerty	Solid Waste Landfill						This task will only be needed if solid waste landfill location is determined before the Final EIS is published and ROD complete.		

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32.1	Cultural Resources Review (Section 106)	IHPA (SHPO)	Gregg Hagerty	FutureGen 2.0 ASU Boiler/GQCS CPU BOP		PHE to conduct desktop study. TBD	Sch: NA Act:	NA	Sch: NA Act:	Field studies will be performed by DOE's contractor PHE. Analysis will be reviewed by AER/URS.		
32.2	Cultural Resources Review (Section 106)	IHPA (SHPO)	Gregg Hagerty	Natural Gas Pipeline Extension		AER-Meredosia to find ROW width for NG pipeline. *6/7/2011* URS sent data package to AER, B&W, and AL for approval. *6/20/2011* URS provided PHE with figure with proposed NG pipeline routes. *5/12/2011*	Sch: NA Act:	NA	Sch: NA Act:	This task will only be needed if natural gas is determined to be the fuel source for auxiliary boiler as well as main boiler ignitors.		
32.3	Cultural Resources Review (Section 106)	IHPA (SHPO)	Gregg Hagerty	Solid Waste Landfill			Sch: NA Act:	NA	Sch: NA Act:	This task will only be needed if solid waste landfill location is determined before the Final EIS is published and ROD complete.		
Notes												
Water Resource Permits (waterways, floodplains and wetlands)												
33.1	Corps of Engineers Construction Permit (Section 404)	USACE/MVS	Mike Smallwood	FutureGen 2.0 ASU Boiler/GQCS CPU BOP		Conference call with Ameren-Environmental and URS to discuss stormwater, 404/401, and NPDES permitting issues. 5/4/11	Sch: Act:	NA	Sch: Act:			
34.1	Water Quality Certification (Section 401)	IEPA/WMS	Mike Smallwood	FutureGen 2.0 ASU Boiler/GQCS CPU BOP			Sch: NA Act:	NA	Sch: NA Act:	An IEPA water quality certification is only required if an individual Corps of Engineers construction permit is required (see Nos. 30.5 and 33.1, above).		
35.1	IDNR Water Resources Construction Permit (Parts 3700 and/or 3704)	IDNR/OWR	Mike Smallwood	FutureGen 2.0 ASU Boiler/GQCS CPU BOP			Sch: NA Act:	NA	Sch: NA Act:	An IDNR Water Resources Construction Permit is only required for work in a regulated floodway or in public waters of the state (see Note 1)		
36.0	Dam Safety Permit (Part 3702 - Construction and Maintenance of Dams)	IDNR/OWR	Mike Smallwood	FutureGen 2.0 ASU Boiler/GQCS CPU BOP			Sch: Act:	6 months	Sch: Act:		21.5	
37.0	Corps of Engineers Construction Permit (Section 10)	USACE/MVS	Mike Smallwood	FutureGen 2.0 Barge Unloading Facility			Sch: Act:	NA	Sch: Act:	Both B&W and Air Liquide have stated that unloading larger loads at the existing Meredosia Boat Dock will save the project 10's millions of dollars and weeks of time. The design basis assumption now includes the ability to unload at this facility and move loads to Meredosia Plant.		
38.0	Consultation on Section 10 permit and No Rise Certification.	US Coast Guard	Mike Smallwood	FutureGen 2.0 Barge Unloading Facility			Sch: Act:	NA	Sch: Act:	Only need to consult Coast Guard when bridges or dike.		

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No.	Description of Required Permit or Activity	Agency	Responsible Persons	Applicable Projects	When Permit Required	Required Deliverables and Scheduled Date	Submittal Date	Agency Review Time	Approval Date	Comments and Issues	Associated Permits	Status
39.0	No Rise Certification	IDNR	Mike Smallwood	FutureGen 2.0 Barge Unloading Facility		URS provided Ameren-Environmental with email asking determination who can approach USACE to discuss floodway modeling issues. 5/2/2011 Ameren-Environmental decided they will schedule meeting with USACE. 5/10/2011 Ameren-Environmental (John Pozzo) to schedule meeting with USACE. TBD	Sch: Act:	NA	Sch: Act:	Issues to be discussed with USACE may include: 1) Floodplain analysis questions 2) Barge unloading timing 3) OWHM 4) Mussle bed evaluation		
39.1	Determine Floodway on Illinois River at Meredosia	IDNR	Gregg Hagerty	FutureGen 2.0 Barge Unloading Facility		Clarification on lower Illinois River floodway determination from USACE. TBD URS to determine floodway level on Illinois River at Meredosia. TBD				It will take approximately 6 weeks to determine floodway at the Meredosia plant once data is obtained from USACE.		
39.2	Determine Preliminary Rise due to temporary modifications at Meredosia	IDNR	Gregg Hagerty	FutureGen 2.0 Barge Unloading Facility						This task will take approximately 4 weeks to complete once task 39.1 is complete.		

Note 1 USACE Permits expire March 18, 2007 with nationwide permits. A new permit application will be needed UNLESS a contract is in place or construction is underway prior to the NWP expiration.
Note 2 OK to bid work while draft NPDES permit is out for public comment.

Local Permits

No.	Description of Required Permit or Activity	Agency	Responsible Persons	Applicable Projects	When Permit Required	Required Deliverables and Scheduled Date	Submittal Date	Agency Review Time	Approval Date	Comments and Issues	Associated Permits	Status
41.0	Zoning changes or variances	County Planning & Zoning	TBD	FutureGen 2.0		Variance request	Sch: Act:		Sch: Act:	Dusty Douglas, Regional Planning for the County, stated the County does not have any local permitting.		
42.0	Special Use or Conditional Use Permits		Barbara Skitt	FutureGen 2.0 ASU Boiler/GQCS CPU BOP			Sch: Act:		Sch: Act:	Meredosia Plant is in an Enterprise Zone; therefore, AER will have to submit an application to Morgan County.		
43.0	County Building Permit	County Planning & Zoning	TBD	New buildings, rows to be added for specific buildings.			Sch: Act:		Sch: Act:	Dusty Douglas, Regional Planning for the County, stated the County does not have any local permitting.		
44.0	Fire Department Approval Sheet	County Planning & Zoning	TBD	New buildings, rows to be added for specific buildings.			Sch: Act:		Sch: Act:	Dusty Douglas, Regional Planning for the County, stated the County does not have any local permitting.		
45.0	Health Department Permits	County Planning & Zoning	TBD	New buildings, rows to be added for specific buildings.			Sch: Act:		Sch: Act:	Dusty Douglas, Regional Planning for the County, stated the County does not have any local permitting.		
46.0	County Right-Of-Way Permits	County Planning & Zoning	Barbara Skitt	FutureGen 2.0			Sch: Act:		Sch: Act:	Potential for off-road vehicles to cross county road going from Meredosia to the laydown area to the south on RR property.		
47.0	Erosion and Sediment Control Permit Sec 7.5-65	County Planning & Zoning	TBD	Construction projects			Sch: Act:		Sch: Act:	Dusty Douglas, Regional Planning for the County, stated the County does not have any local permitting.		
49.0	Electrical Permit	County Planning & Zoning	TBD	Construction projects			Sch: Act:		Sch: Act:	Dusty Douglas, Regional Planning for the County, stated the County does not have any local permitting.		
50.0	HVAC Permit	County Planning & Zoning	TBD	Construction projects			Sch: Act:		Sch: Act:	Dusty Douglas, Regional Planning for the County, stated the County does not have any local permitting.		
51.0	Plumbing Permit	County Planning & Zoning	TBD	Construction projects			Sch: Act:		Sch: Act:	Dusty Douglas, Regional Planning for the County, stated the County does not have any local permitting.		

Note 1
Note 2

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No.	Description of Required Permit or Activity	Agency	Responsible Persons	Applicable Projects	When Permit Required	Required Deliverables and Scheduled Date	Submittal Date	Agency Review Time	Approval Date	Comments and Issues	Associated Permits	Status
Other Permits												
51.0	Certificate of public convenience and necessity (CPCN)	ICC	Legal	FutureGen 2.0 ASU Boiler/GQCS CPU BOP	Not required	None	Sch: NA Act:	N/A	Sch: NA Act:	Meredosia is a non-rate regulated plant; therefore CPCN in not required		
52.0	FAA Notice of Proposed Construction (FAA Form No. 7460-1) (for new stack)	FAA	Gregg Hagerty	FutureGen 2.0 ASU Boiler/GQCS CPU BOP	Start of stack construction	Notice of Proposed Construction	Sch: Act:	30 to 45 working days	Sch: Act:	Only needed if a new stack will be constructed at the facility.		
52.1	IDOT, Division Of Aeronautics permit (for new stack)	IDOT/ Aeronautics	Gregg Hagerty	FutureGen 2.0 ASU Boiler/GQCS CPU BOP	Start of stack construction	All necessary information is sent to IDOT by FAA.	Sch: Act:	1 month	Sch: Act:	IDOT Aeronautical Department does not have verify stack height restrictions until information provided by FAA.		
52.2	Temporary Construction Equipment FAA Notification	FAA	Gregg Hagerty	FutureGen 2.0 ASU Boiler/GQCS CPU BOP	Concurrent with stack construction	Notice of Proposed Construction and reference to the permanent aeronautical study number.	Sch: Act:	30 to 45 working days	Sch: Act:	FAA allows the use of e-filing for these notifications.		
52.3	FAA Extension Request	FAA	Gregg Hagerty	FutureGen 2.0 ASU Boiler/GQCS CPU BOP	If construction does not begin within 18 months of the initial filing.		Sch: Act:	15 days	Sch: Act:	Only one extension is allowed per filing. If another "extension" is required, a new filing needs to be submitted.		
52.4	FAA Notice of Actual Construction	FAA	Gregg Hagerty	FutureGen 2.0 ASU Boiler/GQCS CPU BOP	48 hours prior to start of stack construction. Within 5 days after stack structure reaches its maximum height.	Notice of Proposed Construction (FAA Form No. 7460-2)	Sch: Act:	5 days	Sch: Act:	FAA may request notice 10 days prior to construction commencement.		
53.0	State Right-Of-Way Permits	IDOT	TBD	Work in ROW of state highways			Sch: NA Act:	N/A	Sch: NA Act:			
54.0	Noise control permits (35 Ill. Adm. Code 900 and 901)	None	Mike Hutcheson	FutureGen 2.0 ASU Boiler/GQCS CPU BOP	Not required	None	Sch: NA Act:	N/A	Sch: NA Act:			
55.0	Spill Prevention, Control and Countermeasure (SPCC) Plan	USEPA	Don Richardson	FutureGen 2.0 ASU Boiler/GQCS CPU BOP	Within 6 months of a change in oil storage capacity or potential for discharge to Waters of the US.		Sch: TBD Act:	N/A	Sch: TBD Act:			
56.0	Risk Management Plan (RMP)	USEPA	Steve Burns	FutureGen 2.0 ASU Boiler/GQCS CPU BOP			Sch: TBD Act:	N/A	Sch: TBD Act:	The plant does not currently have a RMP.		
57.0	Radioactive Material License amendment	IEMA/DNS	TBD	Installation of density gauges			Sch: Act:		Sch: Act:	Non-nuclear of meters are to be used, no permit required.		
58.1.1	Registration of Conveyance	ISFM/ESD	Shawn Wallace/ Subcontractor	Elevators	Required prior to installation of elevators, valid for 12 months.	Application Form with plans and specifications	Sch: Act:	1 month	Sch: Act:	Must be submitted by registered contractor to IFSM.		
58.2.1	Conveyance Installation Permit	ISFM/ESD	Shawn Wallace/ Subcontractor	Elevators	Required prior to installation of elevators	Application Form with plans and specifications	Sch: Act:	1 month	Sch: Act:	Must be submitted by registered contractor to IFSM.		
58.3.1	Final Inspection	ISFM/ESD	Shawn Wallace/ Subcontractor	Elevators		Notify ISFM 7 days prior to registered inspector conducting final inspection .	Sch: Act:	NA	Sch: Act:			
58.4.1	Certification of Operation	ISFM/ESD	Shawn Wallace/ Subcontractor	Elevators	Required prior to operation of elevators	Application Form with plans and specifications	Sch: Act:	1 month	Sch: Act:	Must be submitted by registered contractor to IFSM.		
60.1.1	Illinois OSFM Review Letter	ISFM/PCS	Gregg Hagerty	Emergency Diesel Generator	Prior to installation of an Emergency Diesel Generator for the FGD plant.		Sch: Act:	2 months	Sch: Act:			
60.1.2	Illinois OSFM Inspection	ISFM/PCS	Gregg Hagerty	Emergency Diesel Generator	Prior to filling of Emergency Diesel Generator fuel tanks		Sch: Act:	1 months	Sch: Act:			

Sch: scheduled date
Act: actual date

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60.1.3	Illinois OSFM Review Letter Renewal	ISFM/PCS	Gregg Hagerty	Emergency Diesel Generator	Required prior to expiration of Review Letter		Sch: Act:	1 month	Sch: Act:			
70.0	RR Access Agreement/Easement	AER	Barbara Skitt	FutureGen 2.0 ASU Boiler/GQCS CPU BOP		AER-Real Estate met with BNSF RR representatives to discuss southern laydown area & obtained access agreement application. 5/12/2011 URS to prepare maps and provide limited information for access agreement application. 5/27/2011 AER-Real Estate to finalize and submit access agreement application. 6/6/2011				Limited access agreement to conduct environmental assessment of property to determine potential impacts for inclusion into the draft EIS.		
71.0	Boiler and Pressure Vessel Registration	ISFM/BPVS	Gregg Hagerty	FutureGen 2.0 ASU Boiler/GQCS CPU BOP	Inspection must occur before vessel operation.	List of pressure vessels associated with wet FGD project	Sch: Act:	TBD	Sch: Act:	IL regulations - pressure vessels > 15psi & 15ft3 need inspections.		
Notes	ISFM = Office of the Illinois State Fire Marshal IEMA/DNS = Illinois Emergency Management Agency, Division of Nuclear Safety ISFM/BPVS = Office of the Illinois State Fire Marshal, Division of Boiler and Pressure Vessel Safety ISFM/PCS = Office of the Illinois State Fire Marshal, Division of Petroleum and Chemical Safety											
NEPA Actions												
80.0	Kick-off Meeting with DOE and PHE (subcontractor) for NEPA actions	AER	Mary Hagerty	FutureGen 2.0								
80.1	Kick-off Meeting Outline	AER	Mary Hagerty	FutureGen 2.0		URS provided outline of kickoff meeting to AER Environmental. 1/7/2011 URS Environmental provided list of data needs to URS E&C, B&W, and Air Liquide. 1/16/2011 URS to provide draft presentation to AER Environmental. 1/21/2011						
80.2	Develop list of Technical Memos to be submitted to DOE.	AER	Mary Hagerty	FutureGen 2.0		URS and PHE to review items needed for EIS and assign responsibility for tasks to develop the EIS. TBD						

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81.0	Notice of Intent to Prepare an EIS	DOE	Fred Carey	FutureGen 2.0		PHE provided public notice of the Intent to Prepare an EIS to AER for review. 4/1/11 DOE set dates, times, and locations for public meetings. 5/10/2011 Ameren and URS discussed public meeting preparation. 5/16/2011 Ameren provided handouts, presentation boards, and presentation slides to URS. 5/25/2011 URS sent presentation material to AL, B&W, and Ameren for approval. 5/25/2011 URS sent presentation material to PHE/DOE. 5/26/2011 *Ameren and URS attended 3 Public Scoping Meetings. 6/7/2011 - 6/9/2011*	Sch: Act:	TBD	Sch: Act:			
82.0	Draft EIS	DOE	Fred Carey	FutureGen 2.0			Sch: Act:	TBD	Sch: Act:	Information requests and submittals tracked in separate spreadsheet.		
82.1	*Preliminary Draft* Section 3.1 Project Components	DOE	Mary Hagerty	FutureGen 2.0		URS drafted section. 5/15/2011 URS provided section to Ameren-Environmental for review. 5/16/2011 Ameren-Environmental provided comments. 5/27/2011 URS provided draft section to Ameren, AL, and B&W for review. 5/31/2011 URS provided revised draft section to Ameren, AL, and B&W for approval. 6/2/2011 URS *sent* section to PHE. *6/9/2011*	Sch: Act:		Sch: Act:			
82.2	Data Packages for PHE	DOE	Mary Hagerty	FutureGen 2.0			Sch: Act:		Sch: Act:			
82.2.1	Package 1 - Memo on Application of Noise Regulations	DOE	Mary Hagerty	FutureGen 2.0		URS provided data package to Ameren, AL, and B&W for review/approval. 3/22/2011 URS sent data package to PHE 3/23/2011	Sch: Act:		Sch: Act:			
82.2.2	Package 2 - Impact Areas Drawing	DOE	Mary Hagerty	FutureGen 2.0		URS provided data package to Ameren, AL, and B&W for review/approval. 4/27/2011 URS sent data package to PHE 5/02/2011	Sch: Act:		Sch: Act:			
82.2.3	Package 3 - Potential Natural Gas Pipeline Routing	DOE	Mary Hagerty	FutureGen 2.0		URS provided data package to Ameren, AL, and B&W for review/approval. 5/10/2011 URS sent data package to PHE 5/12/2011	Sch: Act:		Sch: Act:			

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82.2.4	Package 4 - Existing Air Permits	DOE	Mary Hagerty	FutureGen 2.0		URS provided data package to Ameren, AL, and B&W for review/approval. URS sent data package to PHE	5/2011/2011 5/19/2011	Sch: Act:		Sch: Act:			
82.2.5	Package 5 - Power Generation Equipment Plot Plan	DOE	Mary Hagerty	FutureGen 2.0		URS provided data package to Ameren, AL, and B&W for review/approval. URS provided revised data package to Ameren, AL, and B&W for approval. URS sent revised data package to PHE.	5/17/2011 5/19/2011 5/25/2011	Sch: Act:		Sch: Act:			
82.2.6	Package 6 - Additional Existing Air Permits	DOE	Mary Hagerty	FutureGen 2.0		URS provided data package to Ameren, AL, and B&W for review/approval. URS sent data package to PHE	5/2011/2011 5/19/2011	Sch: Act:		Sch: Act:			
82.2.7	Package 7 - Impact Areas PHE; GIS-compatible version	DOE	Mary Hagerty	FutureGen 2.0		URS provided data package to Ameren, AL, and B&W for review/approval. URS sent data package to PHE	5/12/2011 5/23/2011	Sch: Act:		Sch: Act:			
82.2.8	Package 8 - NOI Public Meeting Ameren Handouts	DOE	Mary Hagerty	FutureGen 2.0		URS provided data package to Ameren, AL, and B&W for review/approval. URS sent data package to PHE	5/19/2011 5/25/2011	Sch: Act:		Sch: Act:			
82.2.9	Package 9 - Meredosia Control Point drawing	DOE	Mary Hagerty	FutureGen 2.0		URS provided data package to Ameren, AL, and B&W for review/approval. URS sent data package to PHE	5/19/2011 5/23/2011	Sch: Act:		Sch: Act:			
82.2.10	Package 10 - DOE Public Hearing Posters	DOE	Mary Hagerty	FutureGen 2.0		URS provided data package to Ameren, AL, and B&W for review/approval. URS sent data package to PHE	5/23/2011 5/26/2011						
82.2.11	Package 11 - NEPA Scoping Meeting Storyboards	DOE	Mary Hagerty	FutureGen 2.0		URS provided data package to Ameren, AL, and B&W for review/approval. URS sent data package to PHE	5/25/2011 5/26/2011						
82.2.12	Package 12 - NEPA Scoping Meeting Storyboards	DOE	Mary Hagerty	FutureGen 2.0		URS provided data package to Ameren, AL, and B&W for review/approval. URS sent data package to PHE	5/25/2011 5/26/2011						
82.2.13	Package 13 - NOI Public Meeting	DOE	Mary Hagerty	FutureGen 2.0		URS provided data package to Ameren, AL, and B&W for review/approval. URS sent data package to PHE	5/27/2011 TBD						

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82.2.14	Package 14 Draft EIS - Section 3.1	DOE	Mary Hagerty	FutureGen 2.0		URS provided data package to Ameren, AL, and B&W for review/approval. 5/31/2011 URS provided revised data package to Ameren, AL, and B&W for approval. 6/2/2011 URS sent revised data package to PHE. *6/9/2011*						
82.2.15	Package 15 - TBD	DOE	Mary Hagerty	FutureGen 2.0								
82.3	Information Request of Ameren based upon PHE requests.	DOE	Mary Hagerty	FutureGen 2.0								
82.3.1	Current List of Data Needs from PHE	DOE	Mary Hagerty	FutureGen 2.0		URS to provide DOE/PHE current data gaps in requested information along with expected delivery in terms of Project Phase. 5/23/11						
82.3.2	Existing Air Permits	DOE	Mary Hagerty	FutureGen 2.0		URS requested Ameren provide current air permits. 5/10/2011 Ameren provided partial set of permits. 5/10/2011 Ameren provided partial set of permits. 5/11/2011 URS transmitted two data packages to PHE. 5/19/2011 Ameren to provide rest of air permits. TBD						
82.4	No Action Alternative	DOE	Mary Hagerty	FutureGen 2.0		URS requested Ameren provide information defining No Action Alternative. 5/10/2011 Ameren responded with information. 5/13/2011 URS requested clarification on 2 points: 5/13/2011 1) U1, U2, U3 future same with and without FG2. 2) Clarification on status of U1 & U2. Ameren-Environmental to get clarification on U1/U2 from Legal. TBD						
83.0	Final EIS	DOE	Fred Carey	FutureGen 2.0			Sch: Act:	TBD	Sch: Act:			

J APPENDIX – OTF DISCUSSION

Values of the “Over The Fence” Concept for Supply of Industrial Gases

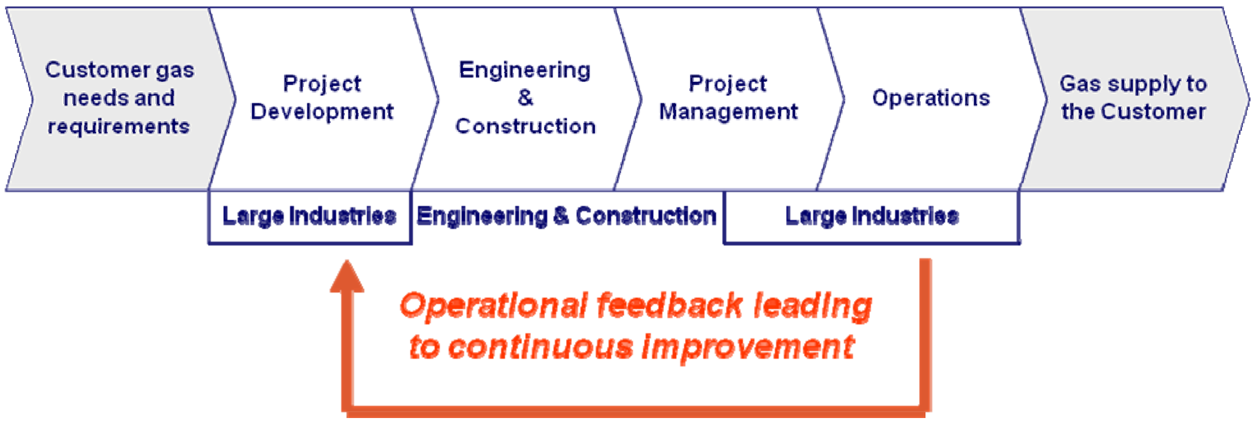
The Air Liquide business model for "Over The Fence" (OTF) supply is to Build, Own and Operate its plants, supplying industrial gases products to its customers.

Air Liquide Large Industries Business Line supplies products to several hundred customers and some of the most demanding clients world-wide in the chemical, refining, steel, metallurgy, glass and electronics industries and maintains the highest reliabilities as required by such industries. The clients are supplied either through dedicated on-site facilities or through Air Liquide pipelines depending on the location. In this “Over The Fence” concept, Air Liquide creates a long-term partnership with its customer featuring a long-term gas supply agreement.

Air Liquide invests in, operates and maintains its production facilities in order to fulfill its commitments with strong support within the company that is oriented towards total service to the customer. Apart from experienced and qualified onsite teams at all Air Liquide sites, some of the key departments supporting these activities are:

- Centers of Excellence for Operation and Maintenance of all production units. These centers monitor and optimize the performance and operation of the units and access a wide experience base within the company for operations and maintenance.
- Technical Center for machines and equipment providing technical and troubleshooting expertise to all the operating units.
- Centers of Excellence for Project Development helping in elaborating appropriate commercial solutions for various situations.
- The Engineering Department (ISO 9001 certified) which provides technical support from project development, studies, design, project execution and troubleshooting for all Air Liquide plants worldwide.
- A pipeline installation and maintenance group with offices at all important locations. This group additionally helps in leak and pressure drop detection, compressor monitoring, analysis and metering, control systems, remote processing of gas consumption and optimization of operations.
- All the production units are linked to the local offices and headquarters to provide a quick response to any problem.
- Research and Development (R&D) Centers assist in technical studies, assessing Client requirements and proposing technical solutions based on their vast experience.

The local production team, the Centers of Excellence, Engineering Department and R&D Centers are linked in a process depicted below which provides access to all production findings and engineering improvements to the benefit of new projects and existing production units from anywhere in the world.



For an Air Separation Unit (ASU) Air Liquide typically has in its scope for OTF the complete separation plant including feed air compression, product pumping or compression; all foundations, piping, and electrical ISBL; connection to an electrical supply system; control room and control system; local building, parking, fencing for site.

Additional scope that can be provided includes water treatment, liquid oxygen / nitrogen production and liquid backup system; additional electrical infrastructure for electricity supply to the ASU.

The main benefits for the customer to go through an Over The Fence supply of its gases requirements are:

- Customized gas supply solution and pricing for each customer, adapted to its gases requirements and consumption profile;
- Commercial risk on volumes are shared between Air Liquide and Customer;
- Transfer to Air Liquide of the risks from operations and maintenance. Gas production operations are provided by specialists, allowing the customer to focus on their core operations;
- Over The Fence pricing "all in" capex + opex, including all feedstock, utility, operation, maintenance, capital costs, taxes, etc.;
- All commitments & responsibility of supply managed through a Gas Supply Agreement to be negotiated between parties and ruling for the term of contract relationships and pricing;
- Long term visibility on gas price evolution (pricing with indexation formula) for the life of the contract.

Overall cost reductions are obtained with:

- A business approach of the industrial area leading to optimized investments for multi-customers portfolio, co-production of several gases and merchant market, i.e. third party synergies, where appropriate;
- Guarantees on performance and efficiency through the price structure for the life of the contract;

- Reduced risk on project implementation when Air Liquide manages the project from the design until the commissioning is responsible for operation and maintenance;
- A spare parts strategy that is centrally managed, reducing the need for large amounts of captive spares for a single project.
- Excellence in quality and reliability of supply provided by long-term operating experience of Air Liquide in its core business activities;
- Reduction of capital employed for the customer allowing customers to dedicate capital and resources to its core business activities;
- OTF *may* increase net exportable power from Oxycombustion power plants and lower LCOE.