

Kemper County IGCC

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ABSTRACT

The Kemper County IGCC plant is a lignite-fueled 2-on-1 Integrated Gasification Combined-Cycle (IGCC) facility incorporating the air-blown Transport Integrated Gasification (TRIG™) technology jointly developed by Southern Company; KBR; and the United States Department of Energy (DOE) at the Power Systems Development Facility (PSDF) in Wilsonville, Alabama. The plant is owned by Mississippi Power Company (MPC) and has a calculated nameplate capacity of 830 MW with a peak net output of 582 MW. As a result of advanced emissions-control equipment, the facility is designed to produce marketable products of ammonia (NH₃), sulfuric acid (H₂SO₄), and carbon dioxide (CO₂). The plant is designed to capture 65 percent of the carbon entering to sell for enhanced oil recovery (EOR), which makes the Kemper County plant's carbon emissions comparable to those of a natural-gas-fired combined cycle power plant. This report describes the basic design and function of the plant as determined at the end of the Detailed Design phase of the project.

The technical sections of the report were completed in October 2013, and the cost information was incorporated into Section 6.0 in March 2018.

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EXECUTIVE SUMMARY

Southern Company Services, Inc. entered into a Cooperative Agreement with the U.S. Department of Energy (DOE) to demonstrate Transport Integrated Gasification (TRIG™) technology with CO₂ capture and compression at the Kemper County IGCC. This report summarizes the design information for the Kemper County IGCC in accordance with the requirements of the Cooperative Agreement.

The Kemper County IGCC is a 524 MW net plant designed to transform locally mined lignite into a syngas to fuel a combined cycle power plant while simultaneously capturing CO₂ for enhanced oil recovery. Southern Company, KBR, and the United States Department of Energy (DOE) jointly developed the air-blown gasification technology for this project at the Power Systems Development Facility (PSDF) in Wilsonville, Alabama. The PSDF has over 19,500 hours of operating experience with this technology, with more than 3,000 hours of operation on Mississippi lignite.

The Kemper County IGCC is a 2x1 configuration with two gasification trains, two combustion turbines, two heat recovery steam generators (HRSGs), and a common steam turbine. The process begins with the delivery of lignite to each gasification train from the adjacent mine. The lignite is dried, milled, and subsequently fed to the gasifier, producing a syngas. The syngas passes through several cleanup steps to remove particulate matter, ammonia, sulfur species, and CO₂ before fueling the combustion turbine to generate electricity. Steam produced in the process generates electricity in a steam turbine generator.

In addition to electricity, this plant produces several marketable products. The plant is designed to capture 65 percent of the carbon entering to sell for EOR, reducing the carbon emissions to a level comparable to a natural-gas-fired combined cycle power plant. Other marketable products include approximately 21,000 tons per year of commercial grade anhydrous ammonia and 169,000 tons per year of sulfuric acid.

The plant is located on a 2,968 acre greenfield site in Kemper County, Mississippi, adjacent to a 31,000 acre lignite mine. Makeup water to the site is treated effluent from the city of Meridian, MS, and the site is designed for zero liquid discharge.

The average lignite composition, as received is:

Average Coal Composition (As Received)		
HHV	Btu/lb	5,290.00
Moisture	%	45.50
Ash	%	11.95
Sulfur	%	0.99
Nitrogen	%	0.48
Carbon	%	31.53
Hydrogen	%	1.98
Oxygen	%	7.57

Estimated performance with two combustion turbines at full load is:

Average Annual Conditions	Peak Conditions
524 MW	582 MW
12,150 Btu/kWh (HHV)	11,820 Btu/kWh (HHV)

1.0 INTRODUCTION

1.1 Report Purpose

The purpose of this detailed design report is to provide an overview of the design information for the Kemper County IGCC. This report also summarizes technical information and documentation on construction and operation of the Kemper County facility.

1.2 Project Description

The Kemper County IGCC, named David M. Ratcliffe Generating Plant, is a lignite-fueled 2-on-1 IGCC facility incorporating the air-blown TRIG™ technology jointly developed by Southern Company, KBR, and the United States DOE at the PSDF in Wilsonville, Alabama.

Lignite reserves near the plant site, developed and mined by Liberty Fuels, a subsidiary of North American Coal Corporation (NACC), are the feedstock for the IGCC plant. The estimated nameplate capacity of the plant is 830 MW with a peak net output capability of 582 MW. The peak capacity of 582 MW occurs while firing syngas in the combustion turbine coupled with natural gas firing in the duct burners. During syngas-only operations, the plant is designed to achieve a net generating capacity of 524 MW and a heat rate of 12,150 Btu/kWh. As a result of advanced emissions control equipment, the facility is capable of producing marketable products of NH₃, H₂SO₄, and CO₂. The plant is designed to capture 65 percent of the carbon entering and sell for EOR, making the Kemper County facility's carbon emissions comparable to those of a natural-gas-fired combined cycle power plant.

1.3 Project Participants

The major organizations involved in the project are:

- Mississippi Power Company

MPC, headquartered in Gulfport, Mississippi, is an investor-owned utility and an affiliate of Southern Company. MPC's total generating capacity is 3,099 MW; 51 percent coal fueled, 49 percent natural gas fueled. The MPC Generation organization has experience in burning a variety of fossil fuels, including bituminous coal, PRB coal, petroleum coke, and natural gas. The operating performance of MPC and other Southern Company generating units consistently results in forced outage rates that are among the best in the industry.

MPC's responsibilities include:

- Overall project management during all phases of the project.
- Control of budgets and schedule.
- All regulatory approvals, environmental permitting, and compliance activities necessary to construct and operate the plant.

- South Mississippi Electric Power Association (SMEPA)

South Mississippi Electric Power Association is a not-for-profit cooperative that generates, transmits, and sells wholesale electrical energy to 11 member distribution cooperatives. The 11 member systems own and maintain approximately 56,300 miles of distribution lines that provide service to approximately 410,000 homes and businesses in 56 of the 82 Mississippi counties, across 52 percent of the state's land mass. SMEPA's primary purpose is to provide affordable and reliable electric energy to its members.

- Southern Company Services, Inc.

Southern Company Services (SCS), Inc., is a Southern Company subsidiary that provides engineering and support services to affiliate operating companies.

SCS's responsibilities include:

- Management of the engineering, procurement, and construction (EPC) phases of the project.
- Design of select portions of the gasifier island, lignite receiving, storage, and handling systems
- Design of the combined cycle power block.
- Procurement of equipment for the plant.
- Assisting MPC in the environmental permitting process.

The SCS technical staff has considerable practical experience and fundamental understanding of a wide range of coal-based technologies and associated ancillary equipment. This work experience—much of it from SCS operation of the PSDF—includes many items necessary for managing the project EPC, including extensive project management, equipment design, plant construction, start-up and commissioning, controls and instrumentation, plant operation and troubleshooting, test planning, data evaluation, reporting, and technical and economic studies.

- Liberty Fuels

Liberty Fuels, a subsidiary of North American Coal Company (NACC), is responsible for performing all lignite mining activities. This includes all necessary permits to perform a surface mine operation in Kemper County, Mississippi. NACC has extensive experience in mining lignite and currently is America's largest miner of lignite, operating eight surface mines, including one in Mississippi.

- KBR

KBR is an international technology-based engineering and construction contractor that has successfully completed more than 5,000 projects in more than 80 countries for more than 1,200 private enterprises and governmental entities. KBR provided engineering design and procurement assistance for portions of the gasifier island equipment.

KBR has extensive experience with synthesis gas production and, along with SCS, designed the Transport Gasifier test facility at the PSDF. KBR and Southern Company jointly own the Transport Gasifier Technology and have worked together at the PSDF to advance its development, providing process analysis and equipment design services.

- U.S. Department of Energy

The U.S. Department of Energy (DOE) is providing cost-shared financial assistance under the congressionally mandated Clean Coal Power Initiative (CCPI) program to the Kemper County IGCC Project. The U.S. Congress established the CCPI program to accelerate commercial deployment of advanced technologies for generating clean, reliable, and affordable electricity in the United States using abundant domestic reserves of coal.

2.0 DESIGN BASIS DESCRIPTION

2.1 Performance Design Basis

2.1.1 Capacity

The calculated nameplate capacity of the plant is 830 MW with a peak net output of 582 MW. The peak capacity of 582 MW occurs while firing syngas in the combustion turbine coupled with firing natural gas in the duct burners. The plant is designed for a net generating capacity of 524 MW on syngas alone with a heat rate of 12,150 Btu/kWh.

2.1.2 On Stream Time

The plant is designed for an average annual on stream time of 7,780 hours per year. The time is based on a projected availability following the demonstration phase.

2.1.3 Fuels

2.1.3.1 Coal

Mississippi lignite with an average heating value of 5,290 BTU/lb and 1.0 percent average sulfur on as-received basis.

The coal is mined from a lignite reserve, identified as the Damascus Prospect by NACC. The mine borders the plant site. The area of interest for the mine covers approximately 31,000 acres with less than 13,000 acres mined for this plant.

2.1.3.1 Coal Composition

Kemper County IGCC Fuel Composition							
						Design Basis	
Lignite Composition			Average Coal Composition	Worst Case {Minimum}	Best Case {Maximum}	Minimum Coal Constituents	Maximum Coal Constituents
As- Received	HHV	Btu/lb	5,290.0	4,827.0	5,962.0	4,765.0	5,872.0
	Moisture	%	45.5	45.56	42.64	42.20	50.00
	Ash	%	11.95	15.02	10.02	8.61	17.00
	Sulfur	%	0.99	1.00	0.99	0.35	1.70
	Nitrogen	%	0.48	0.47	0.55	0.33	0.61
	Carbon	%	31.53	28.87	35.68	28.10	35.68
	Hydrogen	%	1.98	1.91	2.02	1.73	2.40
	Oxygen	%	7.57	7.19	8.11	4.17	10.47
	Chlorine	ppm	116.0	101.5	85.0	45.0	295.0
	Mercury	ppm	0.077	0.054	0.084	0.027	0.187
	Fluorine	ppm	28.7	70.5	29.0	8.6	79.6

Grindability	105
Top Size (inches)	2.0

Ash Fusibility (Reducing)	
I.T.	2,195 °F
S.T.	2,226 °F
H.T.	2,239 °F
F.T.	2,281 °F

2.1.3.2 Natural Gas

Pipeline grade natural gas at 1,000 psia.

2.1.4 **Products**

The Kemper IGCC facility is designed to produce saleable products from the gasification and gas clean-up process. The products include CO₂, anhydrous ammonia, and H₂SO₄. The NH₃ and H₂SO₄ onsite storage is included and trucked offsite for sale. CO₂ is conveyed offsite through a pipeline.

2.1.4.1 Carbon Dioxide

EOR quality CO₂ at pipeline pressure.

2.1.4.2 Ammonia

Commercial-grade anhydrous ammonia at 99.5 to 99.8 percent ammonia with a maximum oil content of 50 ppm.

2.1.4.3 Sulfuric Acid

Commercial grade sulfuric acid concentrated at 93.2 percent.

2.2 **Site Conditions**

2.2.1 **Geological Conditions**

2.2.1.1 Elevation

- Low point of ground level (LGL): Design mean sea level +473 ft @ grid reference line N. 1147615' 2 5/8" and at grid reference line N. 1146087' 2 5/8".
- High point of ground level (HGL): Design mean sea level +481 ft. (Between grid reference line N. 1146915' 2 5/8" and N. 1146831' 10 5/8".)
- Site is to be provided with a -1 percent slope from grid reference line N. 1146915' 2 5/8" to reference line N. 1147615' 2 5/8" and a -1.5 percent slope from reference line N. 1146831' 10 5/8" to reference line N. 1146087' 2 5/8".
- Actual Grade : +481 ft

2.2.1.2 Earthquake

- Section zone X
- Applicable Code ASCE 7-05
- Soil Profile (Seismic Type) Site Class C
- Occupancy Importance Factor $I = 1.25$
- Occupancy Category III
- Site Coefficient, F_a 1.20
- Site Coefficient, F_v 1.70
- Seismic Design Category "B"
- (Per Tables 11.6-1 and 11.6-2; AISC and 7-05)

- One Second (1.0 sec) Design Spectral Acceleration $S_{D1} = 0.099 \text{ g}$

- Short Period (0.2 sec) Design Spectral Acceleration $S_{DS} = 0.163 \text{ g}$

- Maximum considered earthquake return is 2,500 years.
- $S_s=.204$; $F_a=1.2$; $S_{ms}=.244$
- $S_1=.087$; $F_1=1.7$; $S_{m1}=.148$

2.2.1.3 Frost Depth

- Design depth of frost 6 in.

2.2.2 Climate Conditions

2.2.2.1 Air Temperature

	Min. (°F)	Max. (°F)
Dry bulb temperature for the design of mechanical equipment	10	110
Dry bulb temperature for the design of electrical/instrument equipment and materials	10	130
Indoor temperature		130
Earth Temperature		130
Dry bulb temperature for the design basis of heating and steam/electrical tracing	10	
Dry bulb temperature for the design basis of hot insulation		140
Dry bulb temperature for the design basis of cold insulation	10	
Dry bulb temperature for design basis of winterizing	10	

2.2.2.2 Humidity

Design basis for all equipment:

	Relative humidity	Wet bulb temperature
Summer peak	45% at 95 °F	77.0 °F
Annual average	75% at 65 °F	59.9 °F

2.2.2.3 Rainfall and Snowfall

- Design one-day maximum rainfall 9.6 in.
- Design hourly rainfall 8.6 in./hour for 24 hours (25 year point)
3.1 in./hour (10 year point)
- Snow loading code ASCE 7-05
- Design snow load $P_g = 5$ psf
- Terrain category C
- Design depth of snowfall 5.7 in.
- Thermal category $C_t = 1.2$ (unheated structures)
(see ASCE 7-05 Table 7-3)
- Importance factor $I = 1.1$

2.2.2.4 Wind Condition

- Wind direction (prevailing) N/NE (fall and winter)
S (spring and summer)
- Applicable code ASCE 7-05
 - Basic wind speed 100 mph
 - Exposure category C
 - Occupancy category III
 - Importance factor $I = 1.15$

2.2.2.5 Barometric Pressure

- Design barometric pressure 29.404 in Hg or 14.44 psia

2.3 Utilities

2.3.1 Water Supply

Treated effluent piped from the city of Meridian, MS, is stored in a 100 acre reservoir onsite.

2.3.2 Electrical Interface

The transmission interface is designed for 230 kV electric power in accordance with the Southern Company Reactive Production Policy. The requirements for the policy are the following:

The generator must be able to provide a minimum of 0.33-MVar/MW (0.95 pf) into a system with a 230 kV-bus voltage of 101 percent of 230 kV at continuous rated output for peak conditions.

The generator must be able to absorb a minimum of 0.33-MVar/MW (0.95 pf) from a system with a 230 kV-bus voltage of 104 percent of 230 kV at continuous rated output for peak conditions.

3.0 PLANT DESCRIPTION

3.1 Site Description

The 2,968-acre plant site is located near the unincorporated community of Liberty in Kemper County, Mississippi, on or about latitude 32° 38' N and longitude 88° 46' W. The site is located 20 miles north of Interstate 20/59 and adjacent to State Route 493 as shown in Figure 3.1-1 - Location of Kemper County IGCC Site. It is also 22 miles north of Meridian Regional Airport. The land where the plant is located is relatively flat with slight rolling terrain. The surrounding area is agriculture and primarily timberland. The plant footprint occupies 80 acres, including the gasifier and combined-cycle power block and the lignite-handling facilities. The 31,000-acre coal mine is adjacent to the plant site.

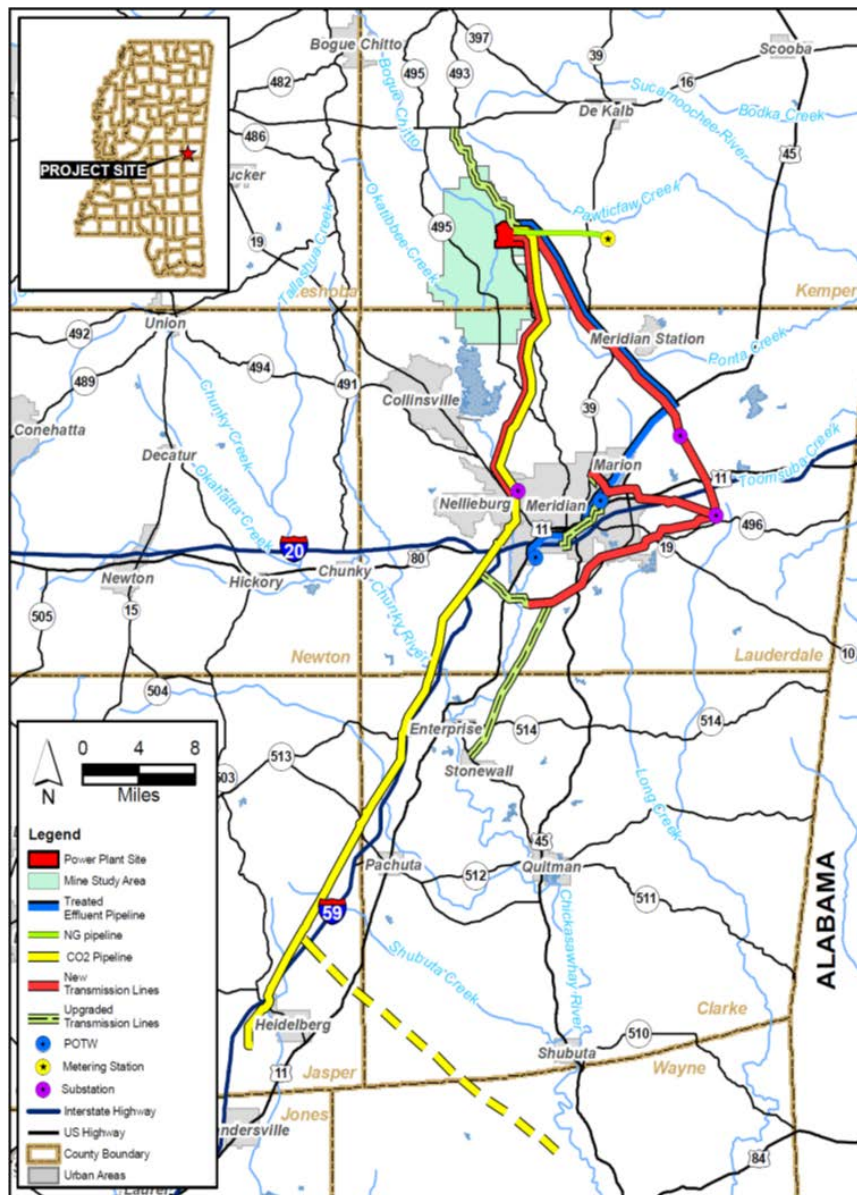


Figure 3.1-1 - Location of Kemper County IGCC Site

3.2 Layout

Site layout drawings, 3D renderings, and pictures are included in the following appendixes:

- Appendix D Site Layout Drawings
- Appendix E Site Renderings
- Appendix F Site Pictures

3.3 Process Overview

The site for the IGCC power generation facility is in Kemper County, Mississippi. A net 582 MW (524 MW on syngas alone) combined-cycle power island is being built, fueled with syngas produced from air-blown, lignite-fueled transport gasifiers. Figure A.1 (see appendix A) shows a block flow diagram of the overall process. From figure A.1, some of the overall layout characteristics of the facility can be seen:

- There are two separate gasification trains; each gasification train supplies syngas to a single combustion turbine and HRSG.
- The two gasification/combustion turbine trains supply steam to a single, common steam turbine.
- Each gasification train has three parallel coal drying and milling (coal preparation) trains and each of these trains feed two HP coal feed systems. Therefore, there are six coal feeders per gasifier.
- There are two process air compressors per gasification train.
- Exiting each gasifier, the syngas splits into two parallel streams through the high-temperature syngas coolers and the particulate control devices (PCDs). These streams recombine after the PCDs and flow as a single stream through the gas cleanup systems to a combustion turbine.
- Several systems shown are common to both gasification trains – the steam turbine, the sour water system, NH_3 recovery, and the wet sulfuric acid (WSA) process.
- There are a number of balance of plant (BOP) systems not shown that are also common to both gasification trains – water treatment, cooling tower/closed loop cooling water, instrument air, natural gas, diesel, etc. There are two separate cooling towers – one for the gasification island heat load and one for the combined cycle.

3.3.1 Gasification Island

Each of the two gasifiers is fueled with lignite for a total raw feed rate of 600 tons/hour and a total air-feed rate of 840 tons/hour, based on the expected average lignite composition. Carbon conversion is projected to be more than 97 percent. Sulfur and other contaminants in the lignite are removed from the syngas upstream of the combustion turbine.

The particulate-laden syngas leaves the gasifier at approximately 620 psia and is indirectly cooled from 1,740 to 600 °F, producing HP superheated steam. Subsequent dry gas filtration in the PCD removes essentially all the particulate matter present in the cooled syngas stream. A proprietary continuous fine ash depressurization (CFAD) unit removes the ash from the filter vessel, while cooling and depressurizing it. CFAD has no moving parts and has exhibited high reliability in more than 16,000 hours of operation at the PSDF.

Following filtration, the syngas enters a syngas scrubber column where water-soluble compounds such as chlorides and fluorides are removed, and the syngas is nearly saturated with water prior to entering the water gas shift (WGS) reactors. In the WGS reactors, CO reacts with water to produce CO_2 and H_2 . This step facilitates the removal of CO_2 in the acid gas removal (AGR) unit.

Exiting the WGS reactors, the syngas is cooled using high-temperature recuperators before entering the carbonyl sulfide (COS) hydrolysis reactor, which converts most of the COS (a trace sulfur compound) to H₂S to facilitate removal in the AGR. Low-temperature recuperators and water-cooled heat exchangers further cool the syngas, while condensing moisture from it. The resulting process condensate is recycled back to the syngas scrubber. After the process condensate is removed, the syngas is cooled further before passing through a final water-spray column, the ammonia scrubber, to remove the remaining soluble species present. The resulting sour water is combined with sour water from the syngas scrubber and sent to the plant sour water system. The sour water system prepares the water for reuse while producing anhydrous ammonia for sale as a product.

The scrubbed syngas enters absorbers that remove more than 99 percent of the H₂S using a SELEXOL™ solvent. The captured H₂S is stripped from the solvent, then recycled back to the absorbers, and the concentrated H₂S stream is routed to a sulfuric acid plant where the sulfur is converted into commercial grade H₂SO₄. Following sulfur removal, a portion of the CO₂ in the syngas is removed using an additional set of absorbers. The removed CO₂ stream is dehydrated and compressed and sold as a product for EOR, resulting in its geologic storage.

After the CO₂ removal system, the syngas passes through a fixed-bed adsorption vessel that removes nearly all of the mercury remaining in the gas. A portion of the "sweet" syngas is separated and passed to the syngas recycle system where it is used to back-pulse clean the filter elements in the dust filtration system, for aeration in the gasifiers, and for concentrating the acid gas stream in AGR area. The remainder of the sweet syngas stream is heated by passing it back through the low- and high-temperature recuperators before flowing to the combustion turbines. Approximately 440 tons/hour of syngas is sent to each combustion turbine with a lower heating value of approximately 120 Btu/scf. The combustion turbine compressors provide the combustion air for the syngas and about 60 percent of the air required by the gasification island at full load. The remaining air required is supplied by motor-driven process air compressors.

Ash removed from the gasifier and the dry gas filtration system is sent to storage silos. Each silo, complete with dust-suppression equipment, is discharged into trucks that transport the ash to an appropriate ash disposal site.

The plant is comprised primarily of commercially available equipment with the exceptions being the transport gasifiers, fine- and coarse-ash cooling and depressurization systems, and coal feed devices. These proprietary systems are based on established design principles, incorporate commercially available equipment items, and have been successfully demonstrated at the PSDF.

3.3.2 Combined Cycle

The two combustion turbines for Kemper County are modified to operate on syngas. Flame-diffusion combustors, rather than low-NO_x designs, prevent flashback caused by the hydrogen content of the syngas. Ports added to the compressor casing allow air to be extracted and supplied to the gasification island.

When firing syngas, each combustion turbine generates approximately 232 MW_{gross}. This power output is maintained across the expected ambient temperature range by adjusting the air extraction rate so that the mass of gas passing through the turbine is constant. For example, at low ambient temperatures, more air is induced into the compressor section because of the increased air density, and this allows more to be extracted. The total air entering the gasifier is relatively constant for a given load, so the mass flow rate of air from the process air compressor is reduced because of the availability of the increased extraction air, which decreases the power consumption of the process air compressor. To maximize the air induced into the compressor and maintain combustion turbine output during periods of high-ambient temperature, an

inlet air evaporative cooling system is placed in service whenever the ambient temperature is at or above 65 °F.

Although the plant is designed and intended to operate on syngas, the capability exists to fire the combustion turbines on natural gas. During natural gas operations, steam must be injected into the combustion cans to limit thermal NO_x formation to 25 ppmv. The reduction in fuel mass flow rate during natural gas firing decreases power output as low as 200 MW at high ambient temperatures.

Each combustion turbine exhausts into a conventionally designed, triple-pressure level HRSG. When operating on syngas, the normal HRSG stack temperature is 274 °F. This is above the acid dewpoint temperature so there are no problems with wet corrosion. Any ammonium bisulfate that may deposit on the economizer tubes downstream of the SCR unit will be removed by off-line washing.

High pressure (HP) superheated steam from both HRSGs is combined with superheated steam from the gasifier islands and passed to the steam turbine. Under normal conditions, the HP superheated steam enters the steam turbine at approximately 1,830 psia and 1,000 °F. Steam exhausted from the HP turbine is reheated in the HRSGs to 1,000 °F at 327 psia, combined with superheated intermediate-pressure (IP) steam generated in the HRSGs, and expanded through the IP turbine. Exhaust from the IP turbine is combined with superheated low-pressure steam generated in the HRSGs and passed to the low-pressure turbine before being condensed at 1.8 in. of mercury. Varying amounts of each steam level are extracted from the HRSGs and steam turbine for use in the gasifier island processes. At normal operating conditions, the steam turbine generates 310 MW_{gross}. For peaking duty, steam turbine output can be increased to around 365 MW_{gross} by firing natural gas in the HRSGs.

Condensate from the steam turbine condenser is used for cooling in the gasification process before returning to the HRSG for further heating and deaeration. HP feedwater flows from the HRSG to the gasifier island where it is used in the syngas cooler to generate the superheated HP steam.

Within the HRSG, an SCR is installed for NO_x reduction during natural gas operation at a location where the flue gas temperature is in the optimal temperature range of 600 to 700 °F. Liquid anhydrous ammonia produced by the gasification island is used for the SCR reagent.

3.3.3 Summary of Projected Thermal and Environmental Performance

3.3.4 Heat and Material Balance

Figure A.2 shows an overall mass balance for the process based on the average lignite coal composition at average annual ambient conditions with two combustion turbines at 100 percent load and 67 percent CO₂ removal. The flows shown represent the total flows for two trains.

3.3.4.1 Heat Rate

The higher heating value of the “average” as-received lignite is 5,290 Btu/lb. When operating with this coal, the projected heat rate is 12,150 Btu/kWh (HHV basis).

3.3.4.2 Emissions

3.3.4.2.1 Sulfur Dioxide

Sulfur removal is projected to be more than 99 percent and the SO₂ content of the flue gas discharged from each combustion turbine is permitted at around 13.1 lb/hour based on a 24-hour rolling average.

3.3.4.2.2 NO_x Emissions

Each combustion turbine is permitted to emit 210 lb/hour of NO_x on a 24-hour rolling average basis while burning syngas. To reduce high-NO_x emissions that occur during natural gas operations, the HRSG unit is equipped with an SCR. The SCR unit is expected to reduce NO_x emissions to levels of approximately 0.015 lb/MMBtu and no more than 39 lb/hour per combustion turbine. For syngas operations, an SCR demonstration test is scheduled to be conducted after the COD.

3.3.4.3 PM Emissions

The gasification island filter system removes high levels of the particulate from the syngas, and loadings to the combustion turbine are expected to be below 0.01 lb/MMBtu. Particulate emissions are permitted at 24 pph, or 0.01 lb/MMBtu, per stack when firing syngas.

3.3.4.4 Mercury Emissions

Packed beds of adsorbent are designed to remove more than 90 percent of the mercury in the product syngas and CO₂ streams. The sorbent selected for the CO₂ stream is sulfur-impregnated carbon. A sulfur-impregnated alumina sorbent is selected for the syngas application to prevent release of the sulfur in the hydrogen-rich syngas atmosphere.

3.3.5 Water Balance

The Kemper site is designed for zero liquid discharge, meaning that all of the inlet water is utilized and then recycled to minimize the makeup requirement and optimize reuse of all internal water streams.

Any water not reused is sent to the wastewater treatment system where the solids and salts are removed. The pure water recovered is then sent back to the plant for reuse. The waste solids and salts are landfilled. The flow diagram with the volumetric flow can be seen in Appendix C.

3.3.6 Technology Development

The largest transport gasifier built to-date, with a maximum coal-feed rate of 5,500 lb/hr, commenced operation in 1996 at the PSDF near Wilsonville, Alabama. This unit has proven easy to operate and control, achieving 5,000 hours as a combustor and more than 19,500 hours as a gasifier. Both air and oxygen have been used successfully as the gasification oxidant.

SCS has acquired invaluable experience with the transport gasification technology from its 20-year involvement in the design, construction, operation, and management of the PSDF. The equipment at the PSDF was sized to provide reliable data for confident scale-up to commercial scale.

The Gasification Technology staff in Research and Environmental Affairs has been involved in extensive process design, data evaluation, and cost estimation studies for the TRIG™ technology for more than 10 years. The focus of this work has been to identify how to lower capital costs and increase cycle efficiency to provide a cost competitive, environmentally superior, commercial coal-based power generation technology.

The transport gasifier is a fuel-flexible design with a higher efficiency and lower capital and operating costs than the currently available oxygen-blown entrained flow gasifiers. The TRIG system at Kemper County is designed to achieve high environmental standards for sulfur dioxide (SO₂), nitrous oxide (N₂O), dust emissions, mercury, and CO₂. Means of reducing water consumption are incorporated into the design and potential gasifier ash utilization applications have been identified.

The key to success of the Kemper County IGCC is the testing of the Mississippi lignite. High-moisture lignite from the Red Hills Mine was successfully gasified in five separate test campaigns for more than 3,000 hours of operation, which provided key design parameters for the gasifier as well as downstream systems.

On lignite, the transport gasifier operated smoothly over a range of conditions, confirming the gasifier design for Kemper County. The gasifier was operated at a range of temperatures between 1,700 to 1,820 °F, coal feed rates of between 2,000 to 5,100 lb/hr, and riser velocities from 18 to 28 ft/s. Recycle gas aeration requirements were minimal because of high flowability of the lignite ash. The gasifier carbon conversion was excellent, at more than 97 percent for all conditions tested.

A fluid bed dryer, similar to the design chosen for Kemper County, was installed at the PSDF to evaluate the reliability and performance of the unit and to verify that low-grade heat could be successfully utilized for drying the coal. The fluid bed dryer at Kemper County has a variable bed height, which is more energy efficient. Prior to the installation of the fluid bed dryer at the PSDF, the existing coal milling and feeding systems could only process coals with a maximum moisture content of 38 weight percent, while the Mississippi lignite can have a moisture content of greater than 50 weight percent. The fluid bed dryer at the PSDF processed more than 9,000 tons of as-received lignite from an average moisture content of around 42 weight percent to less than 20 weight percent, a value low enough for reliable milling and feeding as was demonstrated during the test campaigns at the PSDF.

The pressure-decoupled advanced coal (PDAC) feeder, continuous coarse ash depressurization (CCAD), and continuous fine ash depressurization (CFAD) systems operated reliably through the test campaigns. The particulate collection device (PCD) also operated smoothly, and the particulate collection efficiency was more than 99.99 percent, and the baseline pressure drop was stable over the range of conditions tested. With proven operational success, communication between engineering and manufacturer in early stages of the project is critical to ensure the equipment is designed according specifications and to minimize cost.

Overall, the testing at the PSDF indicated no design or operational challenges that were unique to the Mississippi lignite when using the transport gasifier. The lignite could be dried reliably in the fluid bed dryer and fed to the gasifier; and the gasifier, PCD, and ash removal systems would operate reliably as well.

4.0 SYSTEM DESCRIPTIONS

4.1 Gasification Island

4.1.1 Coal Preparation (Figures B.1.1, B.1.2A, and B.1.2B)

The primary feedstock for the plant is Mississippi lignite with an average heating value of 5,290 Btu/lb and 1.0 percent average sulfur on an as-received basis. NACC is responsible for management of the coal mine. Lignite is delivered from the mine to a covered truck dump hopper located near the power plant by off-road mining trucks.

The lignite delivery facility (LDF) managed by NACC provides the interface between the mine and the plant with the purpose of processing run-of-mine coal to 2 inch minus product. The LDF design is capable of delivering lignite that minimizes handling problems in the crushing, handling, and drying processes of the plant.

From the point the material enters the hopper, a feeder directs the lignite into the primary crusher. The primary crusher is capable of processing run-of-mine material to 2 inch minus. After the product has been processed, a single conveyor transfers the material to one of three possible points:

1. Product can be fed directly to the IGCC plant.
2. Product can be directed to a storage dome equipped with a circular stacker/reclaimer.
3. Product can be directed to an outdoor stockpile.

The lignite that has been stored in either the storage dome or outdoor storage pile can be reclaimed at the barn transfer station.

From the common transfer point, lignite can be delivered onto either of two parallel independent conveyor/tripper systems to the day silos. Each of the parallel conveyors is sized to be capable of delivering 1,200 tons/hour which is approximately twice the demand of the IGCC plant at full production. Both lines can deliver simultaneously, allowing for rapid recovery when needed.

There are six lignite preparation systems (three per gasifier) with sufficient design capacity such that if one system trips off-line, the others increase to meet the design preparation rate. The six preparation and feed systems operate identically, so the operation of only one of the feed systems is described. Coal is supplied to the crushed coal silo (SI1102) as described above. The gas displaced by the coal feed being fed into the silo is vented through the coal silo dust collection system (FL0002) before being vented to atmosphere.

The 2-in. coal falls by gravity to the crushed coal feeder (FD1102) and is fed into the roll crusher (ML1107) where it is crushed to < 0.5 in. before being fed into the fluid bed dryer (PG1102).

The lignite fed into the fluid bed dryer has a moisture content of up to 50 percent. In the fluid bed dryer, the lignite is dried to approximately 22 percent moisture using a mixture of air and nitrogen containing less than 10 vol percent oxygen for the drying gas. For lignite, National Fire Protection Association Code 69 defines gas with such low oxygen concentrations as being inert and unable to sustain a fire. The oxygen content of the drying gas is monitored and nitrogen added as necessary. The fluid bed dryer uses tempered water as the primary heat source and heats the coal directly with in-bed heating coils, as well as indirectly, by heating the drying gas. Low-pressure (LP) steam is used for additional heating, if required. The tempered water system is a hot water loop that transfers heat from one area of the gasification process to another. Using this "low level" heat for drying is preferable because it avoids the operating cost associated with fuel-fired burners, minimizes the amount of moisture present in the drying gas (reducing the gas circulation rate) and improves the overall process efficiency.

After leaving the fluid bed dryer, the drying gas passes through a multi-clone unit (FL1103), in which most of the fine lignite particles entrained in the drying gas are removed. The drying gas then passes through a venturi scrubber (CL1101) nozzle where the final particulate is removed. The upper part of the venturi scrubber acts as a direct contact condenser where the water evaporated from the coal is condensed by coming in contact with circulating water cooled by the cooling tower in the venturi scrubber pump around the cooler (HX1104). As the water condenses, the level rises in the venturi scrubber, and the water is withdrawn into the recovered water drum (DR0004), where it is used in various places throughout the process. The excess water is discharged with other clean wastewater from the gasification process to the cooling tower. The cooled gas is recirculated by the coal dryer gas feed fan (FN1102) back to the fluid bed dryer.

After processing through the fluid bed dryer, the lignite is combined with the fines from the multi-clone then pulverized in a nitrogen swept coal mill (ML1108) to a top size of 500 μm . The gas-solids mixture enters the PC cyclonic baghouse (FL1104) where the lignite is separated and gravity fed into the gasifier coal feed storage bins (SI1110A/B), which are part of the coal feed system. The gas from the baghouse is recycled back to the coal mill using the coal mill feed fan (FN1106).

The coal fines collected by the venturi scrubber are continuously purged to the Filtrate drum (DR0002) where they are combined with the purge streams from the other venturi scrubbers. The fines are filtered by one of the filter presses (FL0005A/B/C), and the water is recycled through the process. The coal fines are backfilled in the coal mine.

4.1.2 Coal Feed, Transport Gasifier, and Solids Management (Figures B.1.13A and B.1.13B)

The lignite entering each PC cyclonic baghouse (FL1104) falls by gravity through a rotary feeder to one of two gasifier coal feed storage bins (SI1110A/B). Each of the storage bins supplies coal to a HP coal feed system. As previously mentioned, there are two gasification trains and a total of six parallel coal preparation systems (three per gasification train). Each coal preparation system supplies lignite to 2 HP coal feed systems, so there are a total of 12 HP coal feed systems (6 per gasification train.) These HP coal feed systems are sized so that if two of the six tripped offline, the gasifier can continue to run at full capacity.

The storage bins operate at atmospheric pressure, and because the gasifier operates at high pressure, the coal feed system must pressurize the lignite before feeding it into the gasifier. This is done by means of a "batch" lock vessel, and then a continuous pressurized dispense vessel and feeder. The gasifier coal feed dispense vessel (FD1115A/B) continuously operates at slightly above the gasifier pressure. It supplies coal to a proprietary Southern Company designed feeder (FD1116A/B), which varies the coal feed into the gasifier based on the syngas demands of the combustion turbine. As the coal is fed into the gasifier, the level drops in the dispense vessel. The dispense vessel is refilled from the lock vessel (FD1110A/B). Coal is fed by gravity from the atmospheric storage bin to the lock vessel. After the lock vessel is full, it is isolated from the storage bin and pressurized with HP nitrogen. After the pressure setpoint is achieved, the isolation valve between the lock vessel and dispense vessel can be opened to transfer the load of coal. After the lock vessel is empty, the isolation valve closes and the lock vessel is depressurized. The gas is vented to the PC cyclonic baghouse. After it is depressurized, the lock vessel can be filled with another cycle.

The design of the pressurized transport gasifier (RX1002) is based on KBR's fluidized catalytic cracking technology and operating experience at the PSDF. Each gasifier has a total height of approximately 185 ft and consists of several refractory-lined pipe sections. The design operating temperature range is 1,500 to 1,800 °F and thermal expansion is accommodated without the expansion joints which have been found to be problematic in high-temperature, refractory-lined systems. Thus, the gasifier assembly utilized advanced tools, such as laser positioning technology, to ensure proper joint connection and to achieve recommended tolerances.

Lignite and air are fed into the mixing zone at the bottom of the gasifier and mixed with gasifier ash, which is recirculated through the J-leg from the standpipe. Lignite is fed near the top of the mixing zone and air is fed at the bottom. Oxygen in the air is consumed by carbon present in the recirculating ash, forming primarily CO, and releases the heat required to maintain gasifier temperature. The lignite is heated up very rapidly by the hot recirculating ash.

Gasifier ash and syngas pass vertically upward from the mixing zone to the riser at a velocity of 18 to 20 ft/s. The high temperature and residence time in the riser crack any tar that is formed. Syngas and gasifier ash pass to a presalter cyclone where larger, denser particles are removed by gravity and fall into a seal leg. The syngas then passes to the standpipe cyclone where most of the remaining gasifier ash is removed and falls by gravity into the standpipe. The syngas leaving the cyclone flows through refractory-lined pipe to the syngas coolers which generate HP steam before flowing through refractory-lined pipe to a filter system for final particulate removal. Gasifier ash flowing through the presalter cyclone seal leg is combined in the standpipe with gasifier ash from the standpipe cyclone. The combined ash stream passes down the standpipe and through the J-leg back into the mixing zone. The J-leg and seal leg are non-mechanical

valves that allow the gasifier ash to flow against a reverse pressure gradient. To achieve reliable flow in these valves, the solids are well fluidized. Recycled syngas, rather than nitrogen, from the recycled gas compressor is used for fluidization to avoid diluting the product syngas and to reduce operating costs.

During the unit's startup, the gasifier must be preheated to approximately 1,700 °F before feeding lignite. This is accomplished by the use of two diesel-fired burners. The primary gasifier startup burners (AH1102 and AH1202), combust diesel to heat the gasifier vessel and the circulating solids. After the temperature in the gasifier is hot enough to support the combustion of diesel fuel, additional diesel is directly added through the gasifier second startup burners (AH1103, AH1203, and AH1303) to continue heating the gasifier to the required temperature for coal feed.

The circulation rate of the gasifier is determined by the level of solids in the gasifier standpipe. A high standpipe level increases the circulation rate, and a low level decreases the circulation rate. To operate the gasifier at a steady circulation rate, solids can be added or removed from the gasifier during operation. Normally, coal ash is accumulating in the gasifier, causing the level of ash to increase. Gasifier ash can be removed continuously from the presalter cyclone seal leg to control standpipe level. The hot solids are first cooled in the primary CCAD coarse ash cooler (HX1030), generating low-pressure steam and then further cooled in the secondary CCAD coarse ash cooler (HX1034), using condensate as the cooling medium. The cooled pressurized solids flow into the proprietary Southern Company designed CCAD (FD1130) system where the pressure of the solids is reduced to near-atmospheric pressure. The cooled, depressurized solids are then conveyed to the coarse ash silo (SI0007) for reuse as bed material in the gasifier, or if the silo is full, conveyed to ash storage silo (SI0008) for removal.

If there is a low level of solids in the gasifier or during startup, solids can be added from the coarse ash silo using the coarse ash feeder (FD0007). The coarse ash feeder is a batch feeder that takes the solids at atmospheric pressure from the coarse ash silo and pressurizes them to the gasifier pressure before pneumatically conveying the solids to the gasifier. During the initial startup, sand is purchased, dried, and prepared to a top size of 500 µm. Up to 130 tons are required for plant startup, although in practice most of the start-up material will be recovered bed material.

During shutdown, cooled, depressurized solids can be removed from the gasifier using the gasifier bottoms drain pot feeder (FD1011). This is also a batch feeder for conveying the solids from the gasifier into the coarse ash silo during shutdown.

4.1.3 Syngas Cooling and Particulate Removal (Figure B.1.4)

Hot syngas from the gasifier flows into the primary syngas coolers for steam generation. Because of the large volume of syngas flow and manufacturing/shipping constraints, there are two syngas cooler units per gasifier. The approximately 1,740 °F syngas first enters the primary syngas cooler steam generator (HX1110) where the heat is used to raise HP steam. The steam generator is a natural circulation boiler, taking saturated boiler feedwater through the downcomer from the HP steam drum (DR1008) and returning a two-phase mixture through the riser between the steam generator and the steam drum.

The steam drum separates the 1,800 psia steam generated by the steam generator and supplies it to the primary syngas cooler superheater (HX1112) where the steam is heated to slightly over 1,000 °F using the hot syngas leaving the steam generator. This superheated steam is combined with the HP superheated steam from the combustion turbine HRSG and fed into the steam turbine for power generation. The steam can be attemperated with boiler feedwater as required to control temperature.

HP boiler feedwater at 1,900 psia and 260 °F is supplied to the primary syngas cooler economizers (HX1114 and HX1116) from the HRSG boiler feedwater pumps and is heated to nearly saturation

temperature using the syngas leaving the superheater. The boiler feedwater enters HX1116 first then flows into HX1114 before entering the steam drum. The syngas exiting HX1116 is cooled to around 600 °F before entering the PCD (FL1106).

A similar process is used during startup to preheat the PCD to enhance controls and minimize potential vibration. Water is pumped into the economizers and mixed with steam to heat the water just below the boiling point. The heated water flows through the economizers to the PCDs.

As with the primary syngas coolers, there are two PCDs per gasifier train. This is primarily for manufacturing/transportation reasons, but having a filter system at the exit of each syngas cooler also balances the syngas flow between the two coolers. Each PCD consists of a number of metal filter elements, approximately 6.6 ft long and about 2.4 in. in diameter. Based on the operating experience at the PSDF, a minimum operating life of 8,000 hours is expected on these filter elements. The particulate is separated from the syngas and accumulates on the outer surface of the filter elements. Periodically (based on a timer sequence) a small percentage of the filter elements are pulse cleaned using clean syngas from the recycle gas compressor (CO1008). By pulse cleaning a small percentage of the elements on a regular time interval, the pressure drop across the filter system remains essentially constant during operation. The particulate loading of the syngas exiting the PCD is projected to be less than 0.1 ppmw, which has been routinely demonstrated at the PSDF and is well below the limits set for the combustion turbine. A failsafe device is installed into each filter element to protect the turbine and downstream equipment from particulate-related damage in the event of a filter element failure or leak. The particulate-free syngas from the two PCDs is combined and flows into the syngas scrubber (CL1007).

The solids leaving the PCDs are cooled in the PCD fines receiver (HX1118) before flowing into the continuous fine ash removal system (CFAD) (FD1120A/B). Like the CCAD system discussed in 4.1.2, Coal Feed, Transport Gasifier, and Solids Management, this is a proprietary Southern Company design that takes the cooled, pressurized solids from the PCD fines receiver and depressurizes them to nearly atmospheric pressure. The gas that is vented off the CCAD and CFAD units is collected into the pressure letdown device (PLD) vent drum (DR1043) and is used to pneumatically convey the solids leaving these devices to the silos. The remaining vented syngas flows to the WSA combustor (AH0070) where it is oxidized.

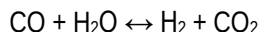
The cool, depressurized gasifier ash is then pneumatically conveyed to the ash storage silo (SI0008) for removal. Because of the small particle size of these solids, they are not reused in the gasifier for bed material. The gasifier ash is mixed with water in the ash conditioner (MX0002) before being hauled away from the facility by truck and landfilled or returned to the mine for site reclamation.

Because solids are conveyed by syngas to the coarse ash silo and the ash storage silo, the syngas must be separated from the solids and safely burned before being vented to the atmosphere. There is a baghouse on top of each silo, and the syngas exiting the baghouse is first cooled by the LP vent gas compressor precooler (HX0040) before entering the LP vent gas compressor (CO0041). The vent gas compressor raises the pressure of the near-atmospheric syngas, leaving the silo baghouses to the pressure required to enter the WSA combustor (AH0070) where the syngas is combusted.

4.1.4 Syngas Cooling and Water Gas Shift (Figures B.1.5.A and B.1.5B)

Almost all of the equipment in figures B.1.5A and B.1.5B is used to minimize the gaseous emissions from the gasification unit. Most of this equipment has specific temperature requirements, and the heat exchangers in figure B.1.5A are there primarily to meet these requirements or to heat the product syngas before it enters the combustion turbine.

The facility is designed to capture 65 percent of the carbon in the lignite as CO₂, and sell the CO₂ as a product. However, to remove this large amount of CO₂, the syngas composition leaving the gasifier must be modified. This is accomplished by using two stages of WGS reactors in series (RX1108/1208 and RX1109/1209). The WGS reactors' catalyst was redesigned and the recommended catalyst reduces the steam/CO ratio. The catalyst changes the syngas composition by the following reaction:



This conversion decreases the carbon monoxide (CO) and water composition in the syngas while increasing the amount of hydrogen and CO₂ in the syngas. Because the gasifier is dry fed instead of slurry fed, and the particulate is removed with a dry filter system instead of a quench system, the syngas leaving the PCD has a relatively low water content. To "shift" the significant amount of CO to CO₂ required, the syngas must first be saturated in the syngas scrubber (CL1007).

The syngas entering the syngas scrubber is contacted with water counter-currently over multiple packed beds. The syngas leaving the syngas scrubber has adequate moisture for the downstream WGS reactions. The syngas scrubber also provides additional cleaning for the syngas. The water removes essentially all soluble compounds such as chloride and fluoride and thus protects the downstream catalyst beds from contamination. A portion of the circulating water from the syngas scrubber is purged to the sour water area for cleanup. Because this is the first process step in which syngas is directly contacted with water, the syngas scrubber has the ability to remove any light organic compounds that may collect in the sump of the column.

A significant amount of makeup water must be added to the column to replace the water that is vaporized into the syngas. As the syngas is cooled, any excess water condenses and is removed from the syngas in the intermediate temperature syngas cooler (HX1021) and the process condensate knockout drum (DR1010). This water is pumped back to the column using the process condensate pump (PU1010) and heated with LP steam in the process condensate trim heater (HX1027). The remaining makeup water is a portion of the water condensed from the lignite drying described in 4.1.1, Coal Preparation. Some of the condensate leaving the recovered water drum (DR0004) is pumped to the sour water system through the HP makeup water pump (PU0008) where it picks up heat in the wastewater cooler (HX0056) and is further heated with LP steam in the makeup water trim heater (HX0059) before entering the syngas scrubber. These heat exchangers can be found on Figure B.1.15.

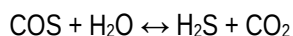
The pump-around water exiting the syngas scrubber is heated using a combination of process heat and IP steam. The circulating water first enters the scrubber pump around heater (HX1007) where it is heated by the syngas leaving the second WGS reactor. The circulating water is further heated to near saturation temperature by IP steam in the scrubber pump around IP steam heater (HX1008).

The syngas leaves the syngas scrubber saturated with water and flows to the first stage WGS reactors (RX1108/1208). The WGS reaction is catalyzed with cobalt and molybdenum active metals over a high surface area support. The energy released by the exothermic reaction is used to heat the syngas entering RX1108/1208 via the shift feed recuperator 1 (HX1009).

A greater percentage of the CO is converted to CO₂ in the first stage WGS reactor. Because of the exothermic reaction and the large quantity of CO converted, the temperature of the syngas leaving HX1009 is still fairly high, so some of this heat is transferred to the "sweet" product syngas in the high-temperature syngas recuperator (HX1020). (Heating of the product syngas is described later in this section.)

The “sour” syngas exits HX1020 and enters the shift feed recuperator II (HX1011) where it is reheated before entering the second stage WGS reactors (RX1109/1209). The second stage WGS reactors convert additional CO to CO₂ so it can be removed in the AGR unit.

The next process for minimizing emissions is the COS hydrolysis reactors (RX1104/1204). A small percentage of the sulfur in the syngas is present as COS. If not converted to H₂S and removed, the COS entering the Selexol unit would exit with the CO₂, and would be of sufficient quantity to exceed the total sulfur concentration in the product CO₂ specification. Therefore, the COS is converted to additional H₂S through the following reaction:



More than 95 percent of the COS will be converted to H₂S over the cobalt-molybdenum WGS catalyst, but additional conversions are necessary with a dedicated COS hydrolysis catalyst. The COS hydrolysis reactor requires an inlet gas temperature of approximately 400 °F, so the syngas exiting the second WGS reactor is first cooled in HX1011, then in HX1007 as previously described. Even though the reaction is exothermic, there is so little COS in the syngas that there is no appreciable rise in temperature across the COS hydrolysis reactor.

After the gas leaves the COS hydrolysis reactor, the next clean-up step is the removal of ammonia from the syngas in the ammonia scrubber (CL1006). Any ammonia entering the combustion turbine in the syngas should be converted to NO_x. Therefore, to minimize NO_x emissions, ammonia is scrubbed from the syngas. As in the syngas scrubber (CL1007), the syngas entering CL1006 will be contacted with water flowing counter-currently over packed beds. However, to efficiently remove the ammonia from the syngas, this must occur at near ambient temperatures. In the first cooling step, the 400 °F syngas leaving the COS hydrolysis reactor is cooled in the low temperature syngas recuperator (HX1022).

The syngas then enters the intermediate temperature syngas cooler (HX1021) where heat is transferred to the tempered water system and used for coal drying. The water that condenses during cooling is separated from the syngas in the process condensate knockout drum (DR1010), where it is returned to the syngas scrubber for makeup as previously described. The intermediate temperature syngas cooler also provides the majority of the heat for the tempered water system.

The syngas is further cooled, first with tempered water in the low temperature syngas cooler (HX1024) and then with cooling water in the low temperature syngas trim cooler (HX1025) before entering the ammonia scrubber. The additional water that condenses from the syngas as it is cooled is separated in the sump of the ammonia scrubber. Water is circulated through the column using the sour water pumparound pumps (PU1006). Since water from the syngas is condensing in the ammonia scrubber, the excess water is purged to the sour water system described in 4.1.11, Sour Water System. The syngas leaving the ammonia scrubber is about 10 to 20 °F above ambient temperature.

The AGR system (described in 4.1.6, Acid Gas Removal System) operates at below ambient temperatures. The product syngas leaving the AGR system is cross-exchanged with the sour syngas in the AGR feed product exchanger (HX1060) to minimize the temperature of the sour syngas entering the AGR system and reduce the refrigeration duty.

4.1.5 Air Supply System (Figure B.1.7)

The TRIG gasifier at Kemper is an air-blown (vs. oxygen-blown) gasifier. This results in the need for a sizeable air supply system. During normal operations the air is provided from two sources: combustion

turbine extraction (via a single extraction air compressor) and from ambient atmospheric air (via two process air compressors).

The process air compressors (CO1102, CO1202) consist of a seven-stage, synchronous motor driven, integral gear machine. Atmospheric air is filtered (FL1109, FL1209) and compressed from ambient conditions to 735 psia and 285 °F. The gas is intercooled, with demineralized water as the cooling source, to minimize the cost, prior to stages two through six. This improves application efficiency and allows for more cost effective materials of construction. However, it is desirable for the gas temperature to the gasifier to be elevated. For this reason, there is no intercooler prior to the seventh stage. The compressor is controlled by a set of adjustable guide vanes on the suction of stages 1, 3, and 4. In addition, the machine is protected from surge by use of a single stage blow-off valve (with silencer) to the atmosphere.

The extraction air compressor (CO1004) is a four-stage, synchronous motor driven, integral gear machine. The compressor raises the gas pressure from about 135 psia to a final pressure of 745 psia. Air extracted from the discharge of the combustion turbine compressor is recuperated in the extraction air recuperator (HX1028) with the process air (for additional heating of the process air to the gasifier) and then cooled in a series of heat exchangers. The extraction air cooler (HX1029) provides heating to the tempered water while the extraction air trim cooler (HX1019) reduces the air to a design operating temperature of 110 °F. The cooled extraction air then passes through a knockout drum (DR1003) prior to entering the extraction air compressor. Consistent with the design of the process air compressors, the extraction air compressor does not have interstage cooling between the final two stages. This again improves plant performance by providing air to the gasifier at higher temperatures. Air leaving the extraction air compressor combines with the discharge of the two process air compressors in the process air header. The compressor is controlled via a single set of adjustable guide vanes on the suction of the first stage. For surge protection, air is diverted back to the suction of the compressor through an anti-surge loop.

A performance controller maintains overall control of the process air system. The controller handles the load-sharing between the two process air compressors. It further balances the process air compressors with the available air from the extraction air compressor. It is desirable to maximize the extraction air supply while maintaining the total air requirement to the gasifier. A small slip stream of air is removed from the process air header for further compression. This air is used as a transport air for conveying coal into the gasifier. Usable heat within the gas is first transferred into the tempered water system via the transport air compressor precooler (HX1005). The stream is further cooled in the transport air compressor trim cooler (HX1026) and any free moisture is removed in the transport air compressor knockout drum (DR1005) just prior to entering the transport air compressor (CO1005).

The transport air compressor is a single-stage, vertically split barrel-type, motor-driven compressor. The air is compressed from 630 psia to about 720 psia. Surge control is via kickback and process control is via a set of guide vanes on the suction of the compressor.

Air discharged from the transport air compressor is cooled in the transport air cooler (HX1006). Any free moisture is removed in the transport air cooler knockout drum (DR1012). Prior to the air contacting the coal feedstock, the air must be very dry. This prevents the feed lines from becoming clogged. The stream is dehydrated to a dew point of -40 °F in the transport air dryer (PG1007). The transport air dryer is a solid desiccant dehydration vessel. This is the final processing step of the transport air stream. The air requirements during startup of the gasifier vary significantly from normal operations. A large volume of air is required at pressures substantially lower than the process air system can reasonably provide. For this reason, air is supplied to the process air header from the ASU/startup air compressor (CO0106). This application is maintained and operated by an onsite, third-party vendor.

4.1.6 Acid Gas Removal System (Figures B.1.5B, B.1.8, and B.1.9)

The AGR system is a multi-column Selexol unit which removes essentially all of the H_2S and a majority of the CO_2 from the syngas stream. The syngas exiting the AGR feed product exchanger (HX1060) first enters the AGR H_2S absorber (CL1060) where the H_2S is removed using the Selexol solvent. The syngas then enters the AGR CO_2 absorbers (CL1161/CL1261/CL1361) where the CO_2 is also removed from the syngas using the Selexol solvent. Because of the large amount of CO_2 removed from the syngas, there are three of these columns per train. The sweet gas exits the AGR CO_2 absorber at a low temperature and is reheated before being burned in the combustion turbine (described in section 4.2.1).

The Selexol solvent circulates through the system in two separate loops: one loop — the lean solvent loop — provides solvent for H_2S removal, and the other loop — the semi-lean solvent loop — provides solvent for the bulk of the CO_2 removal. Both streams flow through the AGR CO_2 .

Lean solvent enters the top of the AGR CO_2 absorber where it is used to “polish” CO_2 from the syngas. (The bulk of the CO_2 , however, is removed in the semi-lean solvent loop discussed later in this section). It is desired to “preload” the solvent with CO_2 before it enters the AGR H_2S absorber so that the solvent selectively removes the H_2S from the syngas in CL1060. The combined solvent stream exits the bottom of the AGR CO_2 absorbers, where it splits into two streams. The stream for the H_2S removal is pumped with the AGR loaded solvent pumps (PU1166) through the AGR loaded solvent chiller (HX1169) where it is cooled with refrigerant before entering CL1060 to remove the H_2S from the syngas. The solvent passes through the H_2S absorber, removing H_2S from the syngas and is now referred to as “rich” solvent, since it is now rich in H_2S . The pressure of the rich solvent exiting CL1060 is increased using the AGR-rich solvent pumps (PU1060) to a pressure above the operating pressure of CL1060 and is heated in the AGR-lean/rich solvent exchanger (HX1061) before entering the AGR concentrator (CL1064). The rich solvent entering the column is stripped using recycled syngas from the recycle gas compressor (CO1008), described in 4.1.7, Wet Sulfuric Acid Process (Sulfuric Acid Production). The purpose of this column is to remove as much of the CO_2 and other light gases from the solvent as possible to make a concentrated H_2S stream that will be supplied to the WSA unit (described in 4.1.7). This concentrated stream improves the operability of the WSA unit. Since the operating pressure of CL1064 is greater than CL1060, the stripped gas will flow back to CL1060 without compression, but is first cooled in the AGR-stripped gas cooler (HX1062).

The pressure of the rich solvent exiting the bottom of CL1064 is decreased across a control valve, and the decrease in pressure causes absorbed gases to flash out of the solvent. These gases are separated from the solvent in the AGR-rich solvent flash drum (DR1063), and then cooled and compressed by the AGR flash gas compressor (CO1065). This gas combines with the gas from the AGR concentrator and returns to CL1060. A small flash gas stream from the sour water system (described in 4.1.11, Sour Water System) also enters DR1063 where it combines with the gases that flash from the rich solvent and are recycled back to CL1060.

From the AGR rich solvent flash drum, the rich solvent flows to the AGR regenerator (CL1063). In this column, the H_2S and remaining CO_2 are steam stripped from the solvent. The resulting acid gas stream flows to the WSA unit to be converted into sulfuric acid (described in 4.1.7). The hot, “lean” solvent leaves the bottom of CL1063 and is pumped through HX1061 where it is cooled by heating the rich solvent leaving CL1060. It is further cooled with refrigerant in the AGR lean solvent chiller (HX1067) before it returns to the AGR CO_2 absorber to complete the loop.

The bulk of the CO_2 removal from the syngas occurs in the semi-lean solvent loop. The circulation rate of the semi-lean loop is significantly higher than that of the “rich/lean” loop, because of the significant quantity of CO_2 that must be removed from the syngas. The semi-lean solvent also enters the AGR CO_2 absorber, but at an intermediate position in the column instead of at the top and physically absorbs the CO_2 from the

syngas. It combines with the solvent circulating in the rich/lean loop and exits the bottom of the column where the two streams are divided.

The pressure of the loaded solvent is dropped across a valve to an intermediate pressure where “light” gases, such as H_2 and CH_4 , flash from the solvent. These gases are compressed in the AGR CO_2 recycle compressor (CO1066) and returned to the AGR CO_2 absorber. The pressure of the solvent is again decreased to approximately 50 psia where a significant amount of the CO_2 is liberated from the solvent in the AGR medium pressure (MP) CO_2 flash drum (DR1167). The solvent flows across another valve where the pressure is decreased to approximately 5 psia and the remaining CO_2 flashes from the solvent in the AGR LP CO_2 flash drum (DR1168). The two CO_2 product streams flow to the CO_2 compressor (CO1080) shown on figure B1.11. From DR1168, the solvent is pumped back up to operating pressure and chilled with refrigerant in the AGR semi-lean solvent chiller (HX1168) before returning to the midsection of the AGR CO_2 absorber.

4.1.7 Wet Sulfuric Acid Process (Sulfuric Acid Production) (Figure B.1.10)

As mentioned in the previous section, acid gas is separated from the Selexol solvent in the AGR regenerator. It then flows to the sulfuric acid production area. In this area H_2S in the acid gas stream is oxidized, hydrated, and condensed to produce a commercial-grade H_2SO_4 product.

The first step in this process is the combustion of H_2S with air to sulfur dioxide (SO_2) in the combustor (AH0070). This combustor also treats several syngas vent streams from the ash removal equipment (described in 4.1.2, Coal Feed, Transport Gasifier, and Solids Management, and 4.1.3, Syngas Cooling and Particulate Removal). During normal operation, the acid gas stream has a high enough heating value to support combustion without the addition of natural gas as a support fuel. However, if the lignite feed to the gasifier has a low sulfur content, natural gas is supplemented to maintain the desired combustor outlet temperature.

The hot process gas from the combustor is cooled in the waste heat steam generator (HX0070) with boiler feedwater to produce saturated MP steam. The cooled process gas then enters the SCR reactor (RX0070) to control the nitrogen oxides (NO_x) generated in the combustion process. The gas leaving the SCR reactor flows to the SO_2 converter (RX0071). The SO_2 converter consists of multiple catalyst beds with cooling coils after each bed to remove heat released by the strongly exothermic conversion of SO_2 to sulfur trioxide (SO_3). The heat released in the first two catalyst beds is used to superheat the saturated MP steam generated in the waste heat steam generator. This superheated MP steam is a valuable by-product and is exported for use in the gasification process.

The exhaust from the SO_2 converter, which now contains a high concentration of SO_3 , is first cooled in the process gas cooler before flowing to a tube-in-shell, falling film condenser tower (HX0074). In HX0074 the process gas is cooled with ambient air to promote the condensation of H_2SO_4 from SO_3 and water vapor (H_2O). The condensed acid drains down the inner walls of the condenser tubes counter-currently to the hot process gas flowing up the tubes, which concentrates the acid to a nominal 96 wt% acid that is collected in the bottom of the condenser vessel.

The cooled process gas leaving the top of the condenser is routed to the quench column (CL0070) and then the scrubber column (CL0071). This cools the gases and recovers a majority of any remaining SO_2 as sulfuric acid by reacting it with hydrogen peroxide (H_2O_2). Before exiting through the WSA stack, the gases pass through a wet electrostatic precipitator (ESP) (FL0071) to minimize emissions of H_2SO_4 droplets.

The product sulfuric acid collected in the condenser tower flows to an acid recirculation loop where it is mixed with dilution water and the acid recovered from the polishing scrubber system to produce commercial

grade (93.2 percent) H_2SO_4 . The acid product is also cooled by the acid cooler (HX0076) in the recirculation loop. As acid accumulates in this loop, a slipstream diverts the product to the acid storage area where it is eventually distributed by tanker truck. The process generates approximately 785 tons of acid product per day at peak output.

4.1.8 CO_2 Compression (Figure B.1.11)

The purpose of the CO_2 compression system is to prepare the CO_2 for delivery to an off-taker for EOR use. The CO_2 is liberated from the AGR semi-lean solvent loop at two pressure levels – approximately 50 psig and 5 psig. The two streams flow into a multi-stage CO_2 compressor (CO1080) after passing through knockout drums (DR1078 and DR1079) to remove any residual droplets of solvent. The LP CO_2 enters the first stage of the compressor and proceeds through two stages of compression with subsequent intercooling. Prior to the third stage, the LP stream is combined with the MP CO_2 . The gas is then compressed via two additional stages and with associated intercooling.

Following the fourth stage, the entire gas stream exits the compressor and passes through a dehydration unit (PG1080) and the CO_2 mercury adsorber (RX1080). These additional steps are necessary to meet the purity requirements of the off-taker. The CO_2 stream returns to the CO_2 compressor where the gas is compressed into the dense phase to the final off-take pressure 2,150 psig. Following the compressor, the CO_2 is cooled to the off-take temperature 100 °F in the compressor aftercooler (HX1085). Finally the CO_2 streams from each gasifier train are combined and delivered to the pipeline.

The CO_2 compressor is an eight-stage, integral-gear compressor with a synchronous motor drive. The machine is controlled by three sets of adjustable inlet guide vanes. It is further protected from the effects of surge by three separate recirculation loops. A dynamic simulation study was performed on the CO_2 compressor to confirm its operability and safety design and it is recommended for future complex compression systems.

4.1.9 AGR Refrigeration (Figures B.1.20)

The AGR refrigeration package (PG0061) consists of an anhydrous ammonia-based system that chills the Selexol solvent to below ambient temperatures. The system is common to both AGR units. Cooling the Selexol solvent increases the ability to absorb H_2S and CO_2 . This offers significant benefits by reducing the required solvent circulation rates and reducing the size of the AGR equipment.

The refrigeration system operates on a typical vapor-compression cycle. The ammonia is compressed in eight oil-flooded screw compressors (PG0061-CO-A through H). The compressed gas is then fully condensed into liquid within two parallel condensers (PG0061-HX1 and HX2). Each condenser takes half of the gas flow. The condensed liquid ammonia is then charged into a receiver vessel (PG0061-DR1). The receiver is sized to accommodate changes in refrigerant circulation rates as cooling demand varies.

From the receiver, liquid ammonia is charged to an economizer (PG0061-DR2) which flashes a small portion of the refrigerant and returns it to an interstage side port on the compressor. This improves the cycle efficiency of the refrigeration system.

The majority of the liquid ammonia is directed through the refrigerant subcooler tubes (PG0061-HX3) where it is subcooled to 15 °F. Just prior to the subcooler, a small slip stream of ammonia is fed to the shell side where it vaporizes. As it does, the temperature of the shell side decreases such that the vaporizing ammonia provides sufficient subcooling to the bulk liquid ammonia stream on the tube side. The vaporized ammonia is then combined with the return vapor from the 14 solvent refrigeration drums. This occurs in the suction knockout drum (PG0061-DR3) which is physically connected directly above the subcooler via two

standpipes. This combined vapor ammonia is fed the suction of the compressor for recompression. The subcooled liquid ammonia is then charged to the 14 refrigerant drums: Two lean solvent refrigerant drums (DR1054 and 2054), six loaded solvent refrigerant drums (DR1153, DR1253, DR1353, DR2153, DR2253, and DR2353), and six semi-lean solvent refrigerant drums (DR1155, DR1255, DR1355, DR2155, DR2255, and DR2355). A natural circulation loop is developed between each drum and connected Selexol solvent chiller which together functions as an evaporator. The Selexol solvent flows through each chiller and transfers heat into the ammonia causing it to vaporize. The vaporized ammonia is returned to the refrigerant drum where it is vented to a collection header. The ammonia from all solvent drum vents is collected in this common header and returned to the compressor after passing through the suction knockout drum to remove any condensed ammonia, after which the process begins again.

4.1.10 Mercury Removal (Figure B.1.5A and B.1.5B)

The sweet product syngas exits the Selexol system below ambient temperatures, but the design temperature of the syngas entering the turbine is 450 °F. To reheat the syngas efficiently, and minimize steam usage, heat is transferred from the sour syngas through three exchangers as previously described. The first of these heat exchangers is the AGR feed product exchanger (HX1060) where the sweet syngas is heated to approximately 75 °F. The sweet syngas exiting HX1060 then enters the mercury adsorber (RX1106) where the mercury in the syngas is adsorbed on a sulfur-on-alumina sorbent bed. The syngas leaving the Selexol unit has a very low water content and is superheated in HX1060, eliminating the possibility of water condensation in the mercury adsorber. The syngas exiting the mercury adsorber flows through a filter system (FL1010) to protect the combustion turbine from any adsorbent fines that may exit the mercury adsorber. The syngas is further heated in the syngas recuperators (HX1022 and HX1020) with the hot sour syngas as previously described before entering the export syngas trim heater (HX1023) where it is heated with MP steam again before entering the combustion turbine (as shown on figure B.1.5A).

After the syngas passes through the mercury adsorber, but before entering the low-temperature syngas recuperator (HX1022) a portion of the product syngas is diverted to the recycle gas compressor (CO1008). The pressure of the syngas is increased and it is used in several places throughout the gasification process. The primary uses are aeration gas in the transport gasifier, pulse gas in the PCD, and “stripping” gas in the AGR concentrator (CL1064) (described in 4.1.6, Acid Gas Removal System).

As described in 4.1.3, Syngas Cooling and Particulate Removal, the gasifier is initially heated by combusting diesel fuel. This exhaust gas does not go to the combustion turbine, but is vented to atmosphere through the start-up stack. When the gasifier reaches a temperature of around 1,700 °F, coal feed begins. The diesel injection stops, while the air flow to the gasifier is adjusted, and the gasifier transitions from an oxidizing environment to a reducing environment. During this time the syngas is burned in the HP flare (BR1098). When the syngas flow and quality is sufficient to enter the combustion turbine, flaring of the syngas will stop. However, if there is a trip of the gasification system or the combined cycle, the syngas will be combusted in the HP flare on an emergency basis until the unit can be brought back online or safely shut down.

4.1.11 Sour Water System (Figure B.1.14)

Water condensed from the syngas or purged from the syngas and ammonia scrubbers is sent to the sour water treatment area where the streams from both gasification trains are combined into the single wastewater drum (DR0040). As the sour water streams flow into the drum, the pressure is dropped, which flashes out dissolved gases. The ammonia in the water retains most of the dissolved H₂S, so the gas released from the DR0040 is primarily CO₂ and nitrogen. This vent gas stream is recycled to the AGR rich solvent flash drum (DR1063), where it is recycled to the AGR H₂S absorber. DR0040 is a multi-phase separator designed for the removal of any organics that condense with the sour water. These organic

streams are separated from the sour water and recycled back to the gasifier for destruction via the hydrocarbon drain drum (DR0047). In the event the sour water system goes offline, the water is temporarily collected in the wastewater storage tank (TK0042) and processed when the sour water system returns to operation.

The water leaving DR0040 passes through an activated carbon bed filter (PG0040) for the removal of any dissolved organics and heavy metals before being heated in the hydrogen sulfide stripper feed preheater (HX0041), and then entering the hydrogen sulfide stripper (CL0042). In CL0042, the sour water is stripped with heat from steam, causing dissolved H_2S , CO , and CO_2 to be released from the water. These gases also flow to DR1063 and to the AGR H_2S absorber.

Caustic is added to the stripped water leaving the bottom of CL0042 before it is fed to the steam heated wastewater ammonia stripper (CL0044), where dilute ammonia and effectively all of the H_2S components are removed from the water and condensed in the wastewater ammonia stripper reflux drum (DR0045). The stripped water from CL0044 flows through HX0041 to heat the sour water and cool the stripped water. Additional heat from the stripped water stream is recovered in the wastewater cooler (HX0056) where condensate from the lignite drying is heated before being used as makeup in the syngas scrubber. The cooled, stripped water exiting HX0056 flows into the unit's reclaim sump. Water from the reclaim sump is used to offset makeup water required by the cooling towers.

The aqueous ammonia from DR0045 flows to a steam-heated wastewater ammonia purifier column (CL0052) where the ammonia is concentrated and stored in ammonia storage drums (DR0058A/B/C/D) for sale or use in the plant SCR reactors or other SCR reactors within Southern Company. Because of the high purity ammonia product required, the water drawn from the bottom of CL0052 still contains appreciable ammonia and H_2S and is therefore recycled to the gasifier mixing zone for destruction. Also, the ammonia stripper's control logic was refined to robustly maintain the product quality with adjusting overhead temperature, not ammonia concentration.

The activated carbon in PG0040 is removed and replenished as required to minimize hydrocarbon loading in the stripper feed. The spent carbon is removed by trucks and regenerated.

4.2 Power Island

4.2.1 Combustion Turbine (Figure B.2.1)

The combustion turbine converts the chemical energy in the syngas into electricity and hot gases. Two identical combustion turbines are included in the plant, one for each train.

The combustion turbine for the Kemper project is modified from a typical natural-gas-fired engine that uses a dry low NO_x (DLN) system. Equipment changes to the engine proper for IGCC application chiefly focus on the combustion system and fuel delivery systems.

The combustion system uses diffusion flame combustors arranged around the periphery of a combustor shell and introduces fuel into a single stage. Diffusion flame combustion is similar to that of a candle flame in that fuel mixes with air after ignition. This technology is extremely reliable and simple. It was the primary means of combustion turbine combustion before attention to NO_x reduction led to the introduction of premix systems, in which air is mixed with fuel prior to combustion and fuel is introduced in multiple stages.

Combustion system components are designed to operate on syngas and natural gas. The fuel nozzle is designed to accommodate multi-fuel operation, diluents injection, fuel transfers, and co-firing. It can introduce syngas, natural gas, steam, air, and nitrogen into the combustion system. Combustor baskets

attach to a transition piece that fits into the row one vane inlet. Each basket contains a single retractable igniter which is used for igniting gas in the combustor. Cross flame tubes are not used in this design.

Syngas is the primary fuel and is designed to operate the unit between 30 percent load and a maximum rated power of 232 MW. This fuel system is not intended to be operated below 30 percent load. Therefore, the system always is brought into service with natural gas. Because syngas is approximately 30 percent hydrogen, it is highly flammable and lightweight; caution is taken in the design to prevent syngas escape to either the atmosphere or through backflow into the fuel manifolds. The system is designed per Hazardous Class 1 Division 2 Group D requirements.

Fuel is switched on a principle of maintaining constant energy. Energy supplied by the syngas is approximately nine times less than natural gas on a mass basis. By measuring energy input, two fuels may be mixed in various portions to provide a constant energy content in the mixed gas.

The natural gas system is designed as an alternate fuel system capable of continuous full-load operation and must be used for ignition and start-up of the combustion turbine until reaching 30 percent combustion turbine load. Above 30 percent load, natural gas may be co-fired with syngas as long as both fuels are at a ratio to meet a constant energy input. When operating with natural gas solely, or when co-firing, steam injection is required to meet NO_x emission compliance when loads are 60 to 100 percent.

The combustion turbine includes an air extraction system that provides some of the air required by the gasification process. Without this air extraction, the process air compressors would have to be sized to meet the air requirements for the gasifier. This air extraction also allows the combustion turbine to operate at maximum output, irrespective of ambient air temperature, after base load conditions are established. The extraction air system functions closely with the gasification island and with the fuel the gasification island provides to the turbine. With this interdependence of systems, both extraction air and fuel supply controls are closely integrated into operation of the plant.

4.2.2 Heat Recovery Steam Generator (Figures B.2.1 and B.2.2)

The HRSG is located at the exhaust of the combustion turbine. The function of the HRSG is to recover exhaust energy from the combustion turbine and use it to generate steam. Combustion turbine exhaust gas enters the HRSG through an inlet transition duct and expands to the full height of the HRSG. This expansion duct is designed to provide uniform distribution of the exhaust gas both vertically and horizontally across the entrance to the heat transfer surface. This inlet duct contains a stainless steel distribution grid to assist in proper flow division. The hot combustion turbine exhaust gas flows horizontally through the HRSG, across tubes containing water and steam. These tubes are positioned vertically with flow going both up and down in alternating sections. A selective catalytic reduction (SCR) system is located within the tube modules to control NO_x emissions.

The HRSG also contains a duct burner within the tube modules to provide additional heat energy when steam demand is high. An augmenting air system is provided with the duct burner system. Two 100-percent fans provide air to the firing elements to supplement the oxygen in the turbine exhaust gas stream. The use of synthesis gas in the combustion turbine requires additional oxygen to be added to the gas stream.

The heat transfer sections are divided into LP, intermediate pressure (IP), and HP systems.

4.2.2.1 Low Pressure Steam System

Condensate enters the LP evaporator through the deaerator at the cold end of the HRSG. Steam formed in the evaporator section circulates back to the deaerator. This LP steam scrubs the incoming condensate to remove non-condensable gases that vent out of the system. Deaerated condensate is then stored in the LP drum.

4.2.2.2 Intermediate Pressure Steam System

Condensate from the LP drum feeds the IP boiler feed pump (BFP). The IP BFP provides water to the IP economizer. In the economizer, the water is heated close to the saturation temperature of the IP drum's pressure. Water from the economizer enters the IP drum where it flows down into the IP evaporator and back up to the IP drum. Steam is separated from the entrained liquid in the IP drum separators. Condensate re-enters the evaporator while the IP steam flows out of the drum into the IP superheater. Two IP superheater modules superheat the steam above the saturation temperature. Superheated IP steam mixes with cold reheat from the steam turbine. The cold reheat steam is then superheated in two reheater modules before going back to the steam turbine IP section. Reheat steam is attemperated to 1,005 °F by mixing a stream of cooler cold reheat steam with the hot reheat outlet steam.

4.2.2.3 High Pressure Steam System

Condensate from the LP drum feeds the HP BFP. The HP BFP provides water to the HP economizer. In the economizer, the water is heated close to the saturation temperature of the HP drum's pressure. Water from the economizer enters the HP drum where it flows down into the HP evaporator and back up to the HP drum. Steam is separated from the entrained liquid in the HP drum separators. Condensate re-enters the evaporator while the HP steam flows out of the drum into the HP superheater. Two HP superheater modules superheat the steam above the saturation temperature. Superheated HP steam is attemperated to 1,005 °F by spraying BFP water into the header between the two HP superheaters.

4.2.3 **Steam Turbine Generator (Figure B.2.1)**

The single steam turbine converts the energy from the steam generated in the HRSG and syngas cooler to electricity.

The Kemper County IGCC steam turbine is a two casing, tandem compound, double-flow exhaust, condensing steam turbine consisting of a single-flow HP turbine, single-flow IP turbine and a two-flow low-pressure turbine. The HP turbine and the IP turbine are in one casing. The two-flow LP turbine is in another casing and has 40 in. last stage blades.

During normal operating conditions, steam is admitted into the HP turbine at approximately 1,720 psia and 1,000 °F. It flows through the HP turbine and provides some power to turn the generator. Steam exhausted from the HP turbine is reheated in the HRSG and returned to the steam turbine at to 1,000 °F. This hot reheat steam expands through the IP and LP sections of the steam turbine, providing the remainder of the power to turn the generator. Steam is exhausted from the LP turbine to the condenser.

At normal operating conditions, the steam turbine generates approximately 310 MW_{gross}. For peaking duty, steam turbine output can be increased to approximately 365 MW_{gross} by firing natural gas in the HRSG duct burner.

Varying amounts of each steam level are extracted from the HRSG and steam turbine for processes in the gasification island. Process steam is provided to the gasification island via steam turbine extractions as follows:

- HP turbine extraction
- IP turbine extraction
- IP/LP crossover extraction

4.3 Balance of Plant

4.3.1 Lignite Mining, Receiving, and Storage

The primary feedstock for the plant is Mississippi lignite with an average heating value of 5,290 Btu/lb and 1.0 percent average sulfur on an as-received basis. The lignite strip mine is adjacent to the power plant and has more than 40 years of reserves.

The strip mine and the LDF are managed by a contract mining operator who provides the interface between the mine and the plant, with the purpose of processing run-of-mine coal to 2 in. minus product. The LDF design is capable of delivering lignite to minimize problems in the crushing, handling, and drying processes of the plant.

Off-road mining trucks deliver lignite from the mine to a covered truck dump hopper located near the power plant. A run of mine stock pile is also located adjacent to the truck dump hopper. This buffer stock pile feeds the plant when mining operations are interrupted. The truck dump hopper is sized to 150-ton capacity off-road trucks, and has a 500-ton capacity. An apron feeder below the hopper feeds a four roll crusher that reduces the lignite to 2 in. minus size. The receiving/stock-out system consists of a series of 60 in. wide conveyors rated at 1,200 to 2,400 tons/hour that transport the lignite to the barn transfer station. The receiving/stock-out conveyor system has magnetic separators, metal detectors, belt scales, and on-line analyzers to monitor the as-received lignite.

From the barn transfer station the lignite can be conveyed to one of three possible points:

- Product can be directed to a storage dome equipped with a circular stacker/reclaimer.
- Product can be directed to an outdoor stockpile.
- Product can be fed directly to the plant.

The 311 ft diameter storage dome can store 80,000 to 100,000 tons of lignite, approximately 5 to 6 days, protected from the rain. The dome is constructed from concrete and contains an automated circular stacker reclaimer. The stackers' boom conveyor builds the kidney shaped pile and the rake reclaimer boom reclaims the lignite to a hopper in the center of the pile that discharges the lignite onto reclaim conveyor 3. A second reclaim feeder is also located in the dome and it discharges to reclaim conveyor 3, which transports the lignite back to the barn transfer station.

The outdoor storage pile is located near the dome and has a capacity of 100,000 to 200,000 tons. The conveyor feeding the outdoor storage pile is a fixed stacker with a telescopic chute. A dozer is used to groom and reclaim the lignite in this pile. The outdoor pile has an above grade reclaim feeder that discharges to conveyor 7, which transports the lignite back to the barn transfer station.

From the barn transfer station, the lignite can be delivered onto either of two parallel independent reclaim conveyor/tripper systems and transported into the day silos. Each of the parallel, 48-in.-wide conveyors (4A&B, 5A&B, and 6A&B) is sized to be capable of delivering 1,200 tons/hour – approximately twice the

demand of the plant at full production. The reclaim conveyor system has magnetic separators, metal detectors, belt scales, sweep type sampling systems, and on-line analyzers to monitor the as-fired lignite that is delivered to the plant silos. Both lines can deliver lignite simultaneously, allowing for rapid recovery when needed. The traveling belt trippers feed the six plant silos (three silos per gasifier).

Fogging systems control the dust at the conveyor transfer point; suppression systems at the circular stacker and the fixed stacker control the dust. The tripper floor silo inlet slots use a dust collector to control the dust.

4.3.2 Cooling Water System (Figures B.2.10 and B.2.11)

4.3.2.1 Gasification Island Circulating Water System

The gasification island cooling water is designed to meet all of the equipment cooling requirements of the gasification island. This system provides cooling for both gasification island trains. The major components of the system include the following:

- 10 cell mechanical draft cooling tower.
- Circulating water pumps.
- Auxiliary circulating water pumps.
- Closed-loop cooling water pumps.
- Intake system for receiving cooling water makeup.
- Discharge system for discharge of cooling tower blowdown.
- Chemical treatment system for treatment of the cooling tower makeup.
- Heat exchanger interface with the service water cooling system.
- Heat exchangers within the service water cooling system for equipment cooling.

The function of the gasification island cooling system is to remove waste heat from the gasification island heat exchangers. The gasification island cooling system primarily consists of the cooling tower, circulating water pumps, and gasification island heat exchangers. The gasification island system utilizes a closed-loop cooling circuit that circulates cooled water from the 10 cell mechanical draft cooling tower to the gasification island heat exchangers. Heated water is returned to the mechanical draft cooling tower where it is cooled via an evaporative cooling process.

4.3.2.2 Gasification Island Auxiliary Service Water Cooling System

The gasification island uses a closed-loop service water system to cool various plant auxiliaries. The closed-loop system is identified as the primary system. The primary service water system utilizes heat exchangers to transfer the waste heat to a secondary cooling system (the cold leg). The secondary cooling system uses cooling water from the cooling tower basin to reject the waste heat to the atmosphere through the cooling tower.

The primary system uses horizontal closed-loop cooling water pumps to circulate the cooling water. The pumps take suction from a gasification island closed-loop cooling water tank for makeup water. The cooling water flows from the primary pumps (quantity of three) through a distribution header system to the plant gasification island heat exchangers. The primary cooling water (now heated) then flows through six plate-type service water heat exchangers (coolers) where it is cooled prior to recirculation.

The secondary service water cooling system is a separate system from the circulating water system. The auxiliary circulating water pumps take suction from the cooling tower basin in front of the circulating water pumps. There are two 50 percent capacity vertical auxiliary circulating water pumps. The secondary

cooling water then goes to the service water heat exchangers (coolers). The hot secondary cooling water is then returned to a cooling tower hot leg riser. The secondary service water is then cooled by the tower.

4.3.2.3 Combined Cycle Circulating Water System (Figures B.2.10, B.2.12, and B.2.13)

The circulating water system is designed to meet all of the equipment cooling requirements of the combined cycle, including the cooling requirements of the steam condenser. The major components of the system include the following:

- 12-cell mechanical draft cooling tower.
- Circulating water pumps.
- Auxiliary circulating water pumps.
- Intake system for receiving cooling water makeup.
- Discharge system for discharge of cooling tower blowdown.
- Chemical treatment system for treatment of the cooling tower makeup.
- Steam condenser for condensing the exhaust of the steam turbine.
- Heat exchanger interface with the service water cooling system.
- Heat exchangers within the service water cooling system for equipment cooling.

The function of the cooling system on the combined cycle is to remove waste heat from the plant thermal cycle. The efficiency of the thermal cycle to produce power is directly dependent on the effectiveness of the cooling system to remove waste heat from the power cycle. The combined cycle cooling system primarily consists of the condenser, cooling tower, and circulating water pumps. The condenser condenses steam from the turbine exhaust and transfers the heat to the circulating water to the cooling tower. The cooling tower transfers waste heat from the cooling water to the ambient air primarily via evaporation (latent heat) and to a lesser extent sensible heat (heated air).

4.3.2.4 Combined Cycle Auxiliary Service Water Cooling System (Figures B.2.12 and B.2.13)

The combined cycle uses an auxiliary service water system to cool various plant heat exchangers. The closed loop system is identified as the primary system. The primary service water system utilizes heat exchangers to transfer the waste heat to a secondary cooling system (the cold leg). The secondary cooling system uses cooling water from the cooling tower basin to reject the waste heat to the atmosphere through the cooling tower.

The primary system uses horizontal cooling water pumps to circulate the cooling water. The pumps take suction from a service water surge tank for makeup. The cooling water flows from the horizontal cooling water pumps through a distribution header system to the plant equipment heat exchangers. The primary cooling water then flows through three 50-percent capacity plate-type service water heat exchangers (coolers).

The secondary service water cooling system is a separate system from the circulating water system. The auxiliary circulating water pumps take suction from the cooling tower. There are two 100-percent capacity vertical auxiliary circulating water pumps. The secondary cooling water then goes to the service water heat exchangers (coolers). The hot secondary cooling water is then returned to a cooling tower hot leg riser. The combined circulating water and secondary service water is then cooled by the tower.

4.3.3 Tempered Water System (Figure B.1.19)

The tempered water system is designed to use low-grade available heat from various process streams to dry coal prior to being gasified. The tempered water system consists of a network of heat exchangers and

pipings that transfer heat into the tempered water which then transfers heat into the fluid bed dryers. The tempered water system is a closed-loop system that uses demineralized water as the heat transfer media. By using low-grade heat as a heat source for coal drying, the load to the cooling towers, as well as the amount of steam needed for coal drying is reduced.

The tempered water system can be heated with LP steam to start coal drying, or when the heat output from the process exchangers is not sufficient for coal drying. Additionally the tempered water system is designed to adjust to the various process conditions and correct for any imbalances between the demand for heat from the fluid bed dryers and the heat generated from the process. If excess heat is generated from the process exchangers, flow can be diverted to HX0091 which preheats the HRSG condensate, thereby increasing the amount of steam generated by the HRSG. Additionally, if not enough heat is generated by the process exchangers to dry coal, then steam can be added to HX0095 which adds heat to the tempered water loop.

4.3.4 Nitrogen System (Figure B.1.21)

Nitrogen is generated in a cryogenic air separation unit (ASU). High- and low-pressure nitrogen are generated within the nitrogen generation facility and distributed throughout the plant at approximately 900 psia and 115 psia respectively. Additionally HP nitrogen is stepped down to IP nitrogen via a pressure control valve to 725 psia and further distributed throughout the gasification island. Liquid nitrogen is also generated by the ASU and is stored for backup.

HP liquid nitrogen pumps are capable of pressurizing the liquid nitrogen to approximately 900 psia where it can then be vaporized and distributed throughout the plant as backup. HP nitrogen is used mainly for coal conveying into the gasifier; whereas, IP nitrogen is used mostly for fluidization. Low-pressure nitrogen is mainly used for inerting the coal drying loop and various vessels throughout the plant. The nitrogen plant essentially has two main air compressors. Therefore, additional redundancy is provided in case one of the main air compressor trips or is unoperational. However, during startup both main air compressors must be operational because one provides air to the startup burners and the other provides air to the ASU.

4.3.5 Auxiliary Boiler (Figure B.2.5)

The auxiliary boiler provides steam early in the plant startup sequence before steam is generated in the syngas coolers or HRSGs. It generates a maximum of 186,000 lb/hour of superheated steam at 325 psig and 590 °F.

The auxiliary boiler provides steam to the unit when sufficient steam for equipment operation is not available.

4.3.6 Flare System (Figure B.1.22)

Three separate flare systems exist at the facility – the HP flares (BR1098/BR2098), the ammonia flare (BR0099), and the LP/acid gas flare (BR0097). The HP flares are used to safely combust syngas during startup, an upset condition, and shutdown. The ammonia flare and the LP/acid gas flares are sized to combust gases that would be released from safety valves on these systems in the event of an emergency. These systems are separate from one another primarily because of differing materials of construction requirements and possible chemical interaction of these two systems.

Each flare system contains a knockout drum for removing entrained liquids, as well as a pump for transferring the liquid collected in the knockout drums to the sour water system. The HP flare systems have

liquid seal drums to prevent a vacuum from forming in it. Natural gas for enrichment is supplied to all flare systems for use as needed.

4.3.7 Chemical Storage (Figure B.1.18)

The Kemper IGCC facility stores chemicals produced and delivered on the site. Anhydrous ammonia and H_2SO_4 are produced on site while Selexol, sodium hydroxide, and hydrogen peroxide are delivered to the site.

The anhydrous ammonia is stored in ammonia storage drums (DR0058A/B/C/D) whereas the H_2SO_4 is kept in large tanks in the acid storage area. The new ammonia tank design enhances operational flexibility because it provides a 5 to 7 day storage and temporary storage for off-spec production. The two large storage tanks alternate between product accumulation and distribution. There are also two smaller tanks that serve as a rundown tank and additional product storage.

In addition to these storage tanks, tanks are onsite to provide storage for the bulk chemicals used by the plant. The AGR Selexol storage tank (TK0060) provides storage for the Selexol solvent, especially during plant outages. Sodium hydroxide provides caustic for the sour water system and is stored in TK0095. Hydrogen peroxide is used in the sulfuric acid production area as a reagent for the sulfur dioxide polishing scrubber system. The tank (TK0070) stores approximately 11 days of hydrogen peroxide at peak consumption.

4.4 Electrical

4.4.1 Electrical System

The plant is designed to provide electric power into the MPC transmission system at 230 kV via a MPC transmission switchyard located adjacent to the unit. Each of the generators has a dedicated GSU transformer to transform the nominal generator voltage up to the transmission voltage level. Each GSU transformer is sized for its turbine generator output rating.

The high voltage (HV) side of each GSU transformer is connected to a transmission collector bus with a HV circuit breaker. This HV circuit breaker is used for synchronizing the generator to the transmission grid. The collector bus also supplies two station auxiliary transformers (SATs). The three collector buses connect to an MPC transmission switchyard in separate bays of a breaker and half bus substation arrangement. Multiple transmission connections are used because of the number of SATs and GSU transformers required. The generator and SATs are separated per gasifier and common BOP on the collector buses to balance power flows on the three transmission connections. The majority of the major loads are centrally located in the compressor alley and therefore one plant switchyard was designed. For clear separation of generation owner and transmission owner issues, a separate transmission switchyard is provided.

To provide electrical power for station service there are six SATs. The SATs supply plant station service for both unit start-up and normal running conditions. The SATs have two low-side windings, 4,160 V and 13,800 V. This was selected to best serve the specific loads. Station service at rated output is expected to be in the range of 225 to 250 MW. The total nameplate connected load is larger. The approximate station service split is one-third on the 4,160 V system and two-thirds on the 13,800 V system at the SAT level.

Refer to Appendix I for the main single line, which shows the arrangement down to the medium voltage station service buses.

There are two process air compressors per gasifier. For gasifier operation, the preference is to lose both process air compressors on one gasifier rather than one on each gasifier, therefore the power is distributed by gasifier 1, gasifier 2, and BOP common. Each system has two main 13,800 V systems and two main 4,160 V systems. When multiple load equipment (e.g., two 100 percent pumps/trains) is used, the electric supply is from separate buses within that system.

The plant is not designed for operation without connection to the transmission system (i.e., islanding). The plant is not designed with black start capability on syngas or natural gas.

The total loss of off-site AC power is an unlikely event, but it has been evaluated and is considered acceptable for personnel safety and investment protection (based on HAZOP evaluations). No on-site AC source, such as a diesel generator, is provided. Limited use of permanent construction power (Maintenance Power) as back-up power is included for certain key facilities. No cross connections between the major buses are provided because of the equipment redundancy and large loads involved.

The medium voltage electrical equipment (switchgear and 4.16 kV MCCs) are centrally located in the main electrical building and gasifier buildings for ease of operation and maintenance. Typically the 480 V MCCs are located local to load areas in packaged electrical enclosures.

4.4.2 Design Analysis Requirements

The selection of switchgear interrupting ratings; voltage ratios; and impedances of main and auxiliary transformers, cable sizes, and load equipment rating is coordinated to meet all appropriate criteria including, but not limited to, the following:

- The auxiliary switchgear is sized to maintain at least a 10 percent short circuit margin for a worst-case bolted three-phase fault. All fault calculations were performed according to IEEE standards, and include fault contributions from spinning loads. Generator bus faults are determined at 105 percent pre-fault voltage. All other faults are determined at 100 percent pre-fault voltage. For fault calculations, a negative 10 percent impedance tolerance for three-winding SATs were used initially before the transformers were manufactured (7.5 percent for the two winding transformers).
- It is possible to start the largest motor on an otherwise fully loaded system without depressing any bus voltage to a level where running motors stall, motors or driven equipment are at risk of damage, or controllers would dropout.
- Under normal operating conditions the generator voltage is 95 to 105 percent of nominal.
- Under normal operating conditions the medium voltage systems (> 1,000 V) is 92.5 to 105 percent of nominal.
- Under normal operating conditions the low voltage systems (< 1,000 V) is 90 to 105 percent of nominal.

4.4.3 Generators

4.4.3.1 Combustion Turbine Generator

The combustion turbine generators (CTGs) are rated 18.0 kV, 60 Hz, 277 MVA, 0.85 power factor at a 95 °F cooling water temperature. The generators are totally enclosed water-to-air cooled (TEWAC) design. Generator capability (MVA) is a function of cooling water temperature, thereby directly related to ambient

temperature and increases with colder cooling water to coordinate with the increase in combustion turbine power output at lower ambient conditions.

4.4.3.2 Steam Turbine Generator

The steam turbine generator is rated 18 kV, 60 Hz, 410 MVA, 0.9 power factor at 60 psig hydrogen and 95 °F cooling water. Generator capability (MVA) is a function of cooling water temperature, thereby related to ambient temperature, and decreases with cooling water above rated temperature.

4.4.4 Isolated Phase Bus

The isolated phase bus provides the electrical interconnection between the generators' terminals and the GSUs. The isolated phase bus voltage capability is at least 1.05 times the generator voltage rating.

4.4.5 Combustion Turbine Starting System

Each CTG is started using a static starting system consisting of a static frequency converter. The static frequency converter is powered by a dedicated static frequency converter isolation transformer, which is supplied from the plant 4,160 V station service bus. The static start system interfaces with the turbine control system via a communication bus. One static starting system is shared by two CTGs. The static frequency converter and excitation system are supplied by the vendor in a control house. The station service design allows for starting of only one CTG at a time. The plant is not designed to be able to start without power supplied from the transmission system.

4.4.6 AC Auxiliary System

The AC auxiliary system consists of:

- One 13,800 V main bus fed from each SAT.
- 13,800 V switchgear to provide power to various load center transformers (LCTs) and the 13.2 kV motors (synchronous and induction).
- One 4,160 V main bus fed from each SAT.
- 4,160 V switchgear to provide power to the motor control center (MCC) lineups and LCTs rated 4,160 to 480 V for 480 V power distribution.
- 480 V LCTs, bus, switchgear, and MCCs.

4.4.7 Motors

The plant has a wide range of motors from very small to large. The design basis established early in the project included the following, based on horsepower (hp):

$hp \leq 10,000$	Induction motors (across the line start)
$10,000 < hp < 20,000$	Induction or synchronous
$hp \geq 20,000$	Synchronous motors (soft started)

To provide consistency, common motor requirements were adopted including API standards for the large motors and IEEE 841 for the NEMA (small) motors.

All motors comply with the industry standard voltage and frequency requirements including ratings and variations.

AC motors have the following voltage ratings:

<u>Horsepower</u>	<u>System Voltage</u>	<u>Nameplate Voltage</u>
Below ½	120 V, 1 Phase	115 V, 1-Phase
1/2 – 200	480 V, 3 Phase	460 V, 3-Phase
201 – 7,000	4,160 V, 3 Phase	4,000 V, 3-Phase
4,000-Up	13,800 V, 3 Phase	13,200 V, 3-Phase

The 13.2 kV synchronous motors are fed via switchgear breakers from the 13.8 kV bus. These motors are soft started using a variable frequency drive system that provides for synchronous transfer to the 13.8 kV bus. The starter is used only for starting. The motors are shut down by opening the switchgear breaker.

The 13.2 kV induction motors are across-the-line started.

All 4,000 V motors are fed directly from the 4,160 V MCC using 4,160 V contactors. All 4,000 V motors are conventional induction motors designed for across-the-line starting.

4.4.8 DC Systems

The plant has multiple batteries located strategically to support associated equipment. The batteries for the DC systems are flooded cell lead acid design.

Each CTG has a dedicated 125 VDC battery system consisting of multiple cells, battery support racks, and redundant battery chargers. This system is designed to supply emergency DC power to the CTG DC loads in the event of a total power loss. Under normal conditions CTG DC loads are shared by both the battery bank and chargers.

The combined cycle has a dedicated 125 VDC battery system consisting of multiple cells, battery support racks, and redundant battery chargers. This system is designed to supply emergency DC power to the BOP DC loads, including the BOP, steam turbine generator, and uninterruptible power supply in the event of a total power loss. Under normal conditions BOP DC loads are shared by both the battery bank and chargers.

Five battery systems are associated with the gasifiers and BOP system. Three are located in the main electrical building and one is located in each of the gasifier buildings.

The nitrogen system electrical equipment area has a battery as does the LDF.

4.4.9 Grounding

The grounding system provides an adequate path to permit the dissipation of ground fault currents, lightning, and switching surges for protection of plant personnel and electrical equipment.

4.4.10 Raceway

The raceway system provides support and protection for electrical power and control circuits between various pieces of equipment, devices, and cabinets. The raceway system consists of the following major components: Cable tray, conduit, cable trench, wireway, and junction boxes.

4.4.11 Lighting

The control area lighting system provides personnel with illumination for plant operation under normal conditions, means of egress under emergency conditions, emergency lighting to perform manual operations during a power outage of the normal power source, and construction lighting in areas where early installation is feasible.

4.4.12 Lightning Protection

The lightning protection system provides personnel and equipment protection from lightning surges. The system consists of lightning rods and ground cables connecting to the grounding system.

4.5 Instrumentation and Controls

4.5.1 Gasifier Island Instrumentation and Controls Systems

The gasifier island control system is made up of a combination of subsystems. The majority of control for the gasifier island is performed by the plant digital control system (DCS). The DCS monitors the process parameters and provides automatic control of the coal preparation systems, gasifiers, steam generators, ash removal systems, sour water system, waste water systems, cooling water systems, steam and condensate systems, and syngas gas cleanup systems. The operator interface to these systems is through the control room human machine interfaces (HMIs).

There are a number of centrifugal compressors associated with the gasifier island. Each of these compressors is provided with a compressor control system that interfaces with the DCS to control the compressor as needed. Each compressor controller monitors the compressor process conditions, compressor condition, bearing conditions, and performs surge control of the compressor.

There are multiple additional systems that contain a programmable logic controller that monitors the health of the system and provides control through an interface to the plant DCS. The operator is able to view and change the operating parameters for these systems through the control room DCS HMI.

4.5.1.1 Safety Instrumented System

The gasifier island is provided with a safety instrumented system (SIS). This is an independent control system that monitors select process parameters; in the event of an unsafe condition, the appropriate equipment will be isolated or shut down. The SIS acts completely separate from the DCS, with the exception of using the same shared DCS HMI screens for display of status and operating parameters.

4.5.1.2 Continuous Emissions Monitoring System

The WSA system is provided with a continuous emissions monitoring system (CEMS). This CEMS monitors the constituents required by the State air permit.

4.5.1.3 Nitrogen Plant

The gasifier island has a stand-alone nitrogen separation unit that has an independent control system that is not connected to the gasifier island DCS, except through a limited number of hardwired points. The nitrogen plant DCS is designed to control the production and storage of the nitrogen. The gasifier island DCS should provide a demand requirement to the nitrogen plant DCS as nitrogen is needed for the gasification process.

4.5.2 Combined Cycle Instrumentation and Controls Systems

The control system for the facility consists of a digital distributed control and information system that enables the plant operating staff to perform safe and efficient start-up, normal operation, shutdowns, and emergency shutdown of the facility. The Instrumentation and Controls (I&C) systems do not require an operator to be present at the equipment to initiate any operating sequence.

4.5.2.1 Combustion Turbine Control System, Steam Turbine Control System, Digital Control System

The combustion turbine control system is a packaged DCS provided with the combustion turbine package. The steam turbine control system is provided with the steam turbine package. Southern Company designed the HRSG and BOP DCS to interface with the turbine control systems. The DCS is a system that can perform process control functions, plant monitoring, alarming, logging, sequence of events, data trending, data analysis, data storage, data retrieval, report generation, and performance monitoring functions. Typical DCS input/output signals include breaker position, pump and motor vibrations, pressure and level transmitters, metal and fluid temperatures, process analyzers and relay contacts. Approximately 5,300 inputs and outputs are connected to the combined cycle portion of the DCS.

Hard-wired emergency stop pushbuttons are included, which bypass the digital communication functions of the DCSs and provide individual emergency tripping of each major piece of equipment (for example, combustion turbine, steam turbine-generator, and duct burners).

The DCS includes the capability for remote off-site monitoring and dispatching of the electrical power output of the combined cycle unit.

All HRSG and BOP control system functions for the site are controlled through DCS equipment distributed throughout the facility.

Desktop HMIs installed in the administration/control building are used to monitor and operate the DCS. With the operator interface, the operators can adjust unit loads, start and stop motors, and monitor and trend all plant operations. All plant alarming is directed through the DCS and indicated on dedicated screens in the control room.

The HRSG duct burner is controlled through an independent set of redundant control processors that are dedicated to performing burner management system functions in accordance with NFPA 85 requirements.

Primary remote control operation of the combustion turbines and steam turbine are via the plant DCS HMIs. Backup remote control of the combustion turbine and steam turbine can be accomplished from the remote HMI equipment provided with each respective turbine control system. These remote HMIs are located in the administration/control building at the site.

4.5.2.2 CEMS

A CEMS is included for each HRSG stack in accordance with state air permit requirements. The CEMS equipment is based on a typical combined cycle requirement, including dedicated CEMS shelter near the base of each exhaust stack and a probe in the exhaust stack at the CEMS port elevation. A similar CEMS for the auxiliary boiler is also included.

4.5.2.3 Historical Data Storage and Communications

The site has two levels of data historian. First is the historian on the DCS. This historian provides sequence of events, basic data, alarm, and operator event logs; and is considered short-term storage. The second is the plant operating information system (OIS). The OIS system is linked directly to data sources and provides long-term history of operational parameters and data. OIS data is readily available across the company network.

Data generated by the site control systems, generation information management system, OIS, and CEMS is available to the company digital information network via an Ethernet LAN connection through a company Information Technology (IT) approved firewall.

4.6 **Safety Features**

4.6.1 **Fire Protection System Overview**

The fire protection system for the Kemper County IGCC is designed to incorporate all fire suppression and fire detection needs for the power plant and its required equipment. It is the intent of the fire protection systems to provide adequate suppression and detection for the plant based on a risk analysis of potential fire scenarios.

4.6.1.1 Pump House/Water Supply

The fire pump house is a skid-mounted, packaged assembly consisting of an electric-driven main fire pump, two diesel-driven fire pumps, and a maintenance jockey pump. The maintenance jockey pump is provided to maintain a constant pressure on the underground fire loop. Fire pump controllers are provided for automatic operation of each pump. Two 550-gallon double-wall diesel fuel tanks are located inside the pump house for fuel supply to the diesel fire pumps. The water supply to the fire pump house is fed from a shared filtered water/fire water concrete storage tank. The total tank capacity is 1.4 million gallons with 360,000 gallons dedicated for fire protection use. Nozzle locations on the tank do not allow any other system to pull water from the 360,000 gallons dedicated for fire protection. Below is the major equipment provided with the fire pump house:

- Electric driven fire pump – 3,000 gpm @ 150 psi
- Two diesel driven fire pumps – 3,000 gpm @ 150 psi (each)
- Maintenance Jockey pump – 100 gpm @ 160 psi
- Two diesel fuel storage tanks – 550 gallons (each)
- Fire pump controllers – 3 total
- Maintenance jockey pump controller
- Fire pump test header
- Fire pump components – piping and valves
- Pump house suppression system
- Fire alarm system integration

4.6.1.2 Underground Fire Protection Loop

The underground fire protection system is a multiple loop, ductile iron piping system consisting of approximately 4 miles of piping. Sectional valves, curb boxes, fire hydrants, and fire hydrants with monitors are placed strategically throughout the system. The main fire loop is 12 in. ductile iron piping with branch lines for hydrants and aboveground system tie-ins. Fire hydrant branch lines are 6 in. ductile iron with a curb box style valve for isolation of each hydrant. Below is a summary of the underground fire protection system equipment:

- Fire hydrants – 68 total
- Fire hydrant with monitor – 9 total
- Post indicator valves (sectional valves) – 63 total
- Curb boxes (hydrant isolation) – 76 total
- Underground piping (ductile iron) – approximately 22,000 feet total (all sizes)

4.6.1.3 Combined Cycle Area

The combined cycle area hazards are protected by automatic fire suppression systems. The aboveground systems are fed from the underground fire loop at various tie-in points. Fire protection valve houses are provided at these tie-in points to protect and house the sprinkler valves. Notification devices (such as tamper switch, flow switch, and low air) are provided with each sprinkler valve and report to the main fire alarm panel located in the control room. This allows the operators to know when a system has actuated or is in trouble. The following are above-ground systems located in or near the combined cycle area:

Above-Ground System	Type
Steam turbine lube oil skid Under the steam turbine pedestal Steam turbine hydrogen seal oil unit Transformer protection (six station service and three GSU) Combustion turbine lube oil skid Combustion turbine control oil and lift oil	Deluge
Steam turbine generator bearings	Closed head pre-action
Anhydrous ammonia tank	Water mist

4.6.1.4 Gasifier Island

The gasifier island and associated areas are protected by manual and automatic fire suppression systems. The gasifier structure is equipped with two hose stations at each level. Two standpipes, gasifier north and gasifier south, are provided to feed hose valves and suppression systems in the structure. The south standpipe feeds suppression systems for the crushed coal silos, PC cyclonic baghouse, and the tripper floor dry-pipe suppression system. The hose valves are located outside of the stairwells at each level on both the north and south ends of the structure. The following are aboveground systems located in the gasifier structure and locations near:

Above-Ground System	Type
Hose valves - two per level (north and south)	Manual system
PC cyclonic baghouse	Manual suppression system
Crushed coal silos	Manual suppression system with F-500 wetting agent
Bunker dust collector	Manual and automatic suppression system
Tripper floor	Dry-pipe suppression system
Process air compressor lube oil skids (four total)	Deluge system
Anhydrous ammonia tank	Water mist

4.6.1.5 Lignite Delivery Facility

The LDF conveyor systems, including transfer locations and dome storage, are protected with deluge and dry-pipe sprinkler systems. Linear heat detection is used as the detection device for the conveyor deluge systems. When heated to a specific temperature, the linear heat sends a signal to release the deluge valve. Fire protection valve houses are provided to protect and house each sprinkler valve. The aboveground suppression systems are fed from an underground fire protection branch line from the main fire loop. Fire hydrants, sectional valves, and curb boxes are provided with the underground fire protection line. Listed below is the major equipment located throughout the LDF:

- Conveyor systems – deluge systems with linear heat detection
- Transfer locations – dry-pipe suppression systems
- Fire hydrants – 12 total
- Post indicator valves (sectional valves) – 13 total
- Curb boxes (hydrant isolation) – 10 total
- Underground piping (ductile iron) – approximately 5,000 feet total (all sizes)

4.6.1.6 Alarm and Detection

Fire alarm and detection systems are located throughout the site for operator notification of an event. The fire alarm system panels are looped together via fiber optic cable. This allows all of the panels throughout the site to report to the main fire alarm panel located in the plant control room. Operators will receive an alarm when a system is actuated or is in trouble. Smoke detection systems are provided for the majority of the buildings on site. This provides the operators with early notification so manual action can be taken.

5.0 ENVIRONMENTAL PERFORMANCE

5.1 Air

5.1.1 Gasifier Startup Stacks 1&2 (limits apply to each emission point)

<u>Contaminants</u>	<u>Emissions Limitations</u>
Opacity	20%
Sulfur	<15 ppm
Other contaminants (SO _x , NO _x , etc.) to be monitored during the first 12 months of startups/shutdowns and subsequently used to establish permit limits during startup/shutdown.	

5.1.2 Gasifier Flare Derrick (limits apply to entire flare derrick)

<u>Contaminants</u>	<u>Emissions Limitations</u>
Carbon monoxide	24.3 lb/hr
	106.5 tons/year
<u>Pollutants</u>	
Nitrogen oxides	30.3 lb/hour as NO ₂
	133 tons/year as NO ₂
Sulfur oxides	45 lb/hour as SO ₂
	197.1 tons/year as SO ₂
Opacity	0% (except for periods not to exceed 5 minutes every 2 consecutive hours)

Pollutants (SO_x, NO_x, etc.) to be monitored during the first 12 months of startups/shutdowns and subsequently used to establish permit limits during startup/shutdown.

These limits do not apply during periods of upset or equipment malfunction.

5.1.3 AGR Process Startup and Shutdown Vents 1&2 (limits apply to each emission point)

Contaminants	Emissions Limitations	Comments
Reduced sulfur compounds	9.9 tons/yr	(RSC) including H ₂ S, COS, and C ₂ S
Opacity	20%	
Other contaminants (SO _x , NO _x , etc.) to be monitored during the first 12 months of startups/shutdowns and subsequently used to establish permit limits during startup/shutdown.		

5.1.4 Auxiliary Boiler Stack (limits apply to each emission point)

Contaminants	Emissions Limitations	Comments
Nitrogen oxides	0.04 lb/MMBTU (natural gas)	Based on a 30-day rolling average.
	0.065 lb/MMBTU (propane)	
	11.4 lb/hour (natural gas)	
	13.8 lb/hour (propane)	
	8.55 tons/year (either fuel)	Based on a 12-month rolling total.
Opacity	20%	
After characterization of normal startup operations, the auxiliary boiler shall be limited to a maximum operating time of 1,500 hours in any consecutive 12-month period.		

5.1.5 Wet Sulfuric Acid Unit

Contaminants	Emissions Limitations	Comments
Sulfur dioxide	45.4 lb/hr	Based on a 24-hour operating rolling average.
	199.0 tons/year	Based on a 12-month rolling total.
Sulfuric acid mist	5.0 lb/hr	Based on a 24-hour operating rolling average.
	22.0 tons/year	Based on a 12-month rolling total.
Opacity	40%	
Total sulfur oxides shall be limited to 500 ppmv or less.		

5.1.6 Combustion Turbines 1&2 (limits apply to each emission point on syngas)

Contaminants	Emissions Limitations	Comments
Sulfur dioxide	13.1 lb/hr	Based on a 24-hour operating rolling average.
	58 tons/year	Based on a 12-month rolling total.
Nitrogen oxides	210 lb/hour as NO ₂	Based on a 24-hour operating rolling average.
	920 tons/year	Based on a 12-month rolling total.
Carbon monoxide (no AGR process vent to IGCC stack)	105 lb/hr	Based on a 24-hour operating rolling average.
	557 tons/year	Based on a 12-month rolling total.
Carbon monoxide (AGR process vent to IGCC stack)	380 lb/hr	Based on a 24-hour operating rolling average.
PM/PM ₁₀ (filterable)	52 lb/hr	Based on a 3-hour block average.
	228 tons/year	
Volatile organic compounds	17.1 lb/hr	Based on a 3-hour block average.
	91 tons/year	
Sulfuric acid mist	1.8 lb/hr	Based on a 3-hour block average.
	8 tons/year	

Reduced sulfur compounds (running on natural gas)	9.9 tons/year	
Opacity	20%	Based on 6-minute average, except for one 6-minute period per hour of not more than 27%.
The limitation of total reduced sulfur compounds (H ₂ S, COS, etc.) includes the AGR process startup and shutdown vents and the combustion turbine stacks.		

5.1.7 Cooling Tower #1 - #2

<u>Contaminants</u>	<u>Emissions Limitations</u>
Opacity	40%

5.1.8 Fire Pumps

<u>Contaminants</u>	<u>Emissions Limitations</u>
Opacity	40%

5.1.9 Crushed Coal Storage Silo

<u>Contaminants</u>	<u>Emissions Limitations</u>	<u>Comments</u>
PM/PM ₁₀ (filterable)	0.005 gr/dscf	Based on a 3-hour block average.
Opacity	10%	

5.1.10 Coal Mining/Drying #1 - #7

<u>Contaminants</u>	<u>Emissions Limitations</u>	<u>Comments</u>
PM/PM ₁₀ (filterable)	0.005 gr/dscf	Based on a 3-hour block average.
Opacity	10%	

5.1.11 Coal Processing, Conveying, and Storage

<u>Contaminants</u>	<u>Emissions Limitations</u>
Opacity	10%

5.2 Wastewater

5.2.1 Wastewater - leaving the gasification island

Stripped water (to SCS water treatment)

- pH value 9.2
- HCl 173 ppm
- HF 694 ppm
- NH₃ 14 ppm
- NaOH 853 ppm

5.3 Waste Disposal

A detailed plan is in development to properly dispose of all waste removed from the site. The plan is scheduled to go into effect during demonstration phase.

5.4 Compliance

A separate mitigation action plan has been prepared in accordance with 10 CFR 1021.331, and describes the monitoring and mitigation actions required from design through the conclusion of demonstration phase for the project. The mitigation action plan specifies the environmental impacts subject to a mitigation, describes mitigating measures, identifies the party accountable for mitigating measure, and identifies those responsible for implementing the mitigating measure.

The plant will comply to all federal, state, and local agencies to satisfy statutes, regulations, and permits.

6.0 PLANT COST DATA

Presented below are the actual costs for the Kemper County IGCC plant through May 2017. The costs represent "inside the fence" EPC and startup costs for the IGCC. Not included are costs for the lignite mine, offsite pipelines, land, transmission facilities, Ad Valorem taxes and AFUDC.

\$ x 1,000,000					
<u>WBS</u>	<u>WBS Description</u>	<u>Labor</u>	<u>Material</u>	<u>Subcontract</u>	<u>Total</u>
0	Indirects	1,411	-	969	2,379
1	Site General	67	73	121	261
2	Steam Generator Area	9	53	30	91
3	Turbine & Generator Area	27	218	23	269
4	Fuel Facilities	-	-	147	147
6	Plant Water Systems	17	73	26	115
7	Electrical Distribution & Switchyard	9	24	6	40
8	Instrumentation & Controls	11	10	-	22
9	Other	1	-	33	33
A	Coal Gasification / Gas Cleanup / Byproduct Production	560	1,192	160	1,913
Total		2,112	1,644	1,515	5,271

APPENDIXES

- A. Heat and Material Balances
- B. Process Flow Diagrams –
 - B.1 Gasifier Island
 - B.2 Power Island
- C. Water Balance
- D. Site Layout Drawing
- E. Site Renderings
- F. Site Pictures
- G. Electrical Single Line Diagram
- H. Equipment List

ACRONYMS AND ABBREVIATIONS

AGR	acid gas removal
ASU	air separation unit
BFP	boiler feed pump
BOP	balance of plant
CCAD	continuous coarse ash depressurization
CEMS	continuous emissions monitoring system
CFAD	continuous fine ash removal system
CO	carbon monoxide
CO ₂	carbon dioxide
COD	commercial operation date
COS	carbonyl sulfide
CTG	combustion turbine generator
DCS	digital control system
DLN	dry low NO _x
DOE	United States Department of Energy
E&CS	Engineering and Construction Services
EOR	enhanced oil recovery
EPC	engineering, procurement, and construction
ESP	electrostatic precipitator
FEED	front-end engineering design
GSU	generator step-up transformer
H ₂ O ₂	hydrogen peroxide
H ₂ S	hydrogen sulfide
H ₂ SO ₄	sulfuric acid
HGL	high point of ground level
HMI	human machine interfaces
HP	high pressure
HRSG	heat recovery steam generator
HV	high voltage
I&C	Instrumentation and Controls
IGCC	integrated gasification combined-cycle
IP	intermediate-pressure
IT	Information Technology
KBR	Kellogg, Brown, and Root
LCT	load center transformers
LDF	lignite delivery facility
LGL	low point of ground level
LP	low-pressure
MCC	motor control center
MP	medium pressure
MPC	Mississippi Power Company
MPSC	Mississippi Public Service Commission

NACC	North American Coal Corporation
N ₂ O	nitrous oxide
NO _x	nitrogen oxides
OIS	operating information system
PCD	particulate control device
PDAC	pressure-decoupled advanced coal feeder
PLD	pressure letdown device
PSDF	Power Systems Development Facility
SAT	station auxiliary transformer
SCR	selective catalytic reduction
SCS	Southern Company Services
SFC	static frequency converter
SIS	safety instrumented system
SO ₂	sulfur dioxide
SO ₃	sulfur trioxide
ST	steam turbine
TEG	turbine exhaust gas
TEWAC	totally enclosed water-to-air cooled
TRIG™	transport integrated gasification
VFD	variable frequency drives
VDC	volts direct current
WBS	work breakdown structure
WGS	water gas shift
WSA	wet sulfuric acid

Appendix A

Heat and Material Balances

- Figure A.1 – Heat and Material Balance Diagram
- Figure A.2 – Material Balance

<u>Total Plant Performance Summary</u>		
Net Output	524 MW	
Net Heat Rate	12,150 Btu/kWh (HHV)	
<u>Ambient Conditions</u>		
<u>Dry Bulb (F)</u>	<u>Wet Bulb (F)</u>	<u>Rel. Hum. (%)</u>
65.0	59.9	75.0
<u>Capacity</u>		
		<u>MW (gross)</u>
Combustion Turbine A		232
Combustion Turbine B		232
Steam Turbine		310
Plant Station Service		-250

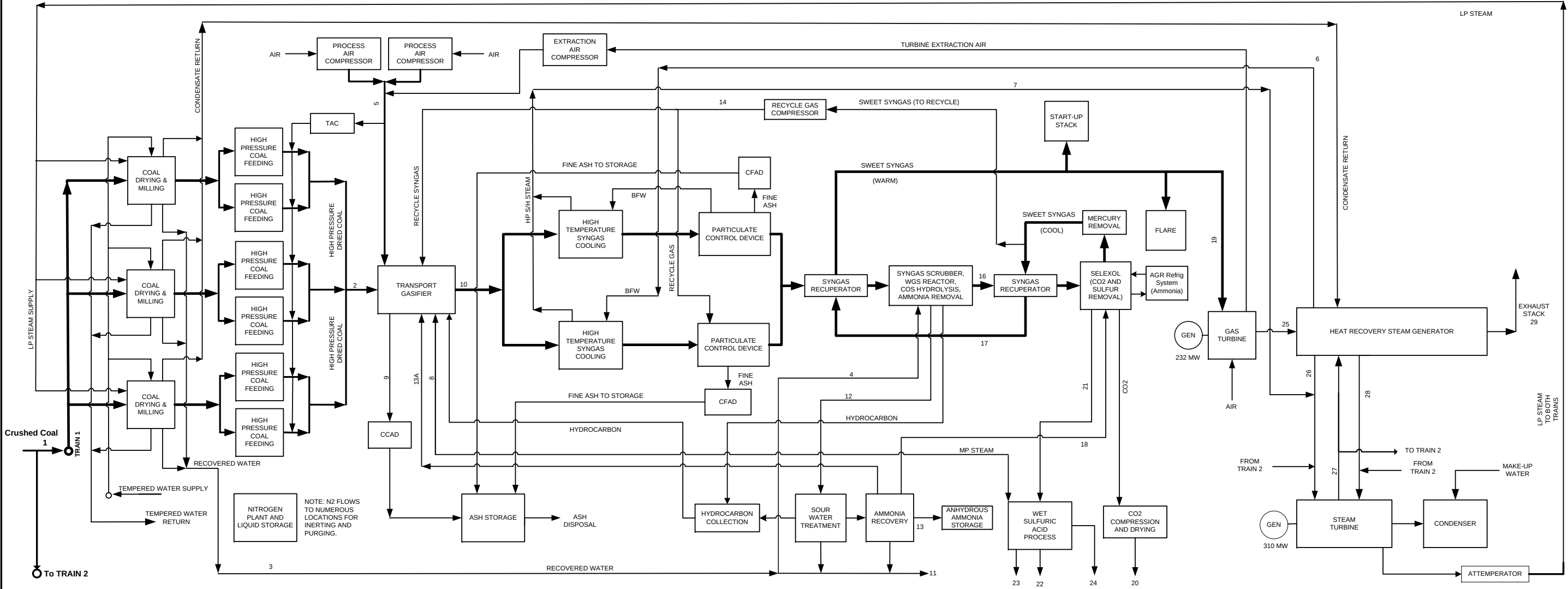


FIGURE A.1 – HEAT AND MATERIAL BALANCE DIAGRAM

	Crushed Coal	HP Dried Coal	Recovered Water from Coal Prep	Recovered Water to Gas Cleanup	Process Air	Boiler Feedwater (BFW)	HP Superheated Steam	MP Steam to Gasifier	G-ASH
Stream #	1	2	3	4	5	6	7	8	9
Mass Flow, lb/hr	1,203,108	840,626	58,393	304,000	1,477,607	849,954	849,954	47,664	155,153
Temperature, F	65	150			542	255	1,002	750	349
Pressure, PSIA	16	15			697	2,090	1,860	820	14
Mole Fraction									
CH4									
CO									
CO2					0.0003				
COS									
H2									
HCl									
HF									
HCN									
H2O			1.0000	1.0000	0.0044	1.0000	1.0000	1.0000	
H2S									
N2					0.7773				
NH3									
Ar					0.0094				
O2					0.2086				
NaOH									
H2SO4									

* All streams flow rates are total for both trains.

Figure A.2 - Material Balance
Sheet 1

	Raw Syngas	Water To Treatment	Sour Water from Gas Cleanup	Ammonia Product	Sour Water to Gasifier	Recycle Gas	Recycle Gas to PCD	Sour Syngas to Syngas Recuperator	Sweet Syngas	Sour Water Vent
Stream #	10	11	12	13	13A	14	15	16	17	18
Mass Flow, lb/hr	2,695,112	162,778	197,767	4,863	6,196	98,353	60,180	2,880,854	1,970,393	15,581
Temperature, F	600	180	103	109	327	153	153	102	77	195
Pressure, PSIA	620	190	30	287	728	732	732	520	498	190
Mole Fraction										
CH4	0.0272	0.0012				0.0308	0.0308	0.0252	0.0308	0.0273
CO	0.1792	0.0006				0.0200	0.0200	0.0162	0.0200	0.0138
CO2	0.0864	0.0390			0.0004	0.0480	0.0480	0.2240	0.0480	0.8821
COS	0.0002	0.0000		0.0005	0.0001					0.0001
H2	0.1116	0.0001				0.3139	0.3139	0.2542	0.3139	0.0024
HCl		0.0005	0.0004							
HF		0.0002	0.0002							
HCN	0.0002	0.0000			0.0001					
H2O	0.0781	0.9167	0.9988	0.0029	0.8114	0.0002	0.0002	0.0024	0.0002	0.0569
H2S	0.0033	0.0006			0.0071			0.0031		0.0065
N2	0.5048	0.0001				0.5804	0.5804	0.4693	0.5804	0.0031
NH3	0.0031	0.0408	0.0002	0.9965	0.1808					0.0033
Ar	0.0058	0.0002				0.0067	0.0067	0.0054	0.0067	0.0046
O2										
NaOH										
H2SO4										

* All streams flow rates are total for both trains.

Figure A.2 - Material Balance
Sheet 2

	Sweet Syngas to Turbine	CO2 to Pipeline	Acid Gas to WSA	Vent from WSA	Air to WSA	Acid Product	Combustion Turbine Exhaust	HP Steam	Cold Reheat	Hot Reheat	Exhaust Stack
Stream #	19	20	21	22	23	24	25	26	27	28	29
Mass Flow, lb/hr	1,763,259	935,956	46,975	9,170	12,654	38,691	8,304,652	1,721,500	1,689,850	1,622,047	
Temperature, F	450	110	115	176	65	104		1,001	580	1,000	277
Pressure, PSIA	467	2,200	25	14.5	14.5	50		1,830	362	327	
Mole Fraction											
CH4	0.0308	0.0019	0.0098								
CO	0.0200	0.0006	0.0034								
CO2	0.0480	0.9895	0.5683	0.0924	0.0005	0.0001					
COS			0.0001								
H2	0.3139	0.0025	0.0357								
HCl											
HF											
HCN											
H2O	0.0002	0.0027	0.0468	0.0773	0.0099	0.2955					
H2S			0.2923		0						
N2	0.5804	0.0026	0.0406	0.7367	0.7476	0.0001					
NH3			0.0009								
Ar	0.0067	0.0002	0.0010	0.0088	0.0128						
O2				0.0846	0.2291						
NaOH											
H2SO4						0.7043					

* All streams flow rates are total for both trains.

Figure A.2 - Material Balance
Sheet 3

Appendix B.1

Process Flow Diagrams – Gasifier Island

- Figure B.1.1 – Coal Preparation
- Figure B.1.2A – Coal Preparation
- Figure B.1.2B – Coal Preparation
- Figure B.1.3A – Coal Feed and Transport Gasifier
- Figure B.1.3B – Solids Management
- Figure B.1.4 – Syngas Cooling and Particulate Removal
- Figure B.1.5A – Syngas Cooling and Water Gas Shift and Mercury Removal
- Figure B.1.5B – Syngas Cooling and Water Gas Shift, Mercury Removal, and Acid Gas Removal
- Figure B.1.6 – Not Used
- Figure B.1.7 – Air Supply System
- Figure B.1.8 – Acid Gas Removal
- Figure B.1.9 – Acid Gas Removal
- Figure B.1.10 – Wet Sulfuric Acid
- Figure B.1.11 – CO₂ Compression and Refrigeration
- Figure B.1.12 – Not Used
- Figure B.1.13 – Not Used
- Figure B.1.14 – Sour Water
- Figure B.1.15 – Waste Water
- Figure B.1.16 – Steam/Condensate
- Figure B.1.17 – Steam/Condensate
- Figure B.1.18 – Chemical Storage
- Figure B.1.19 – Tempered Water and Cooling Water
- Figure B.1.20 – AGR Utilities
- Figure B.1.21 – Nitrogen
- Figure B.1.22 – Flare

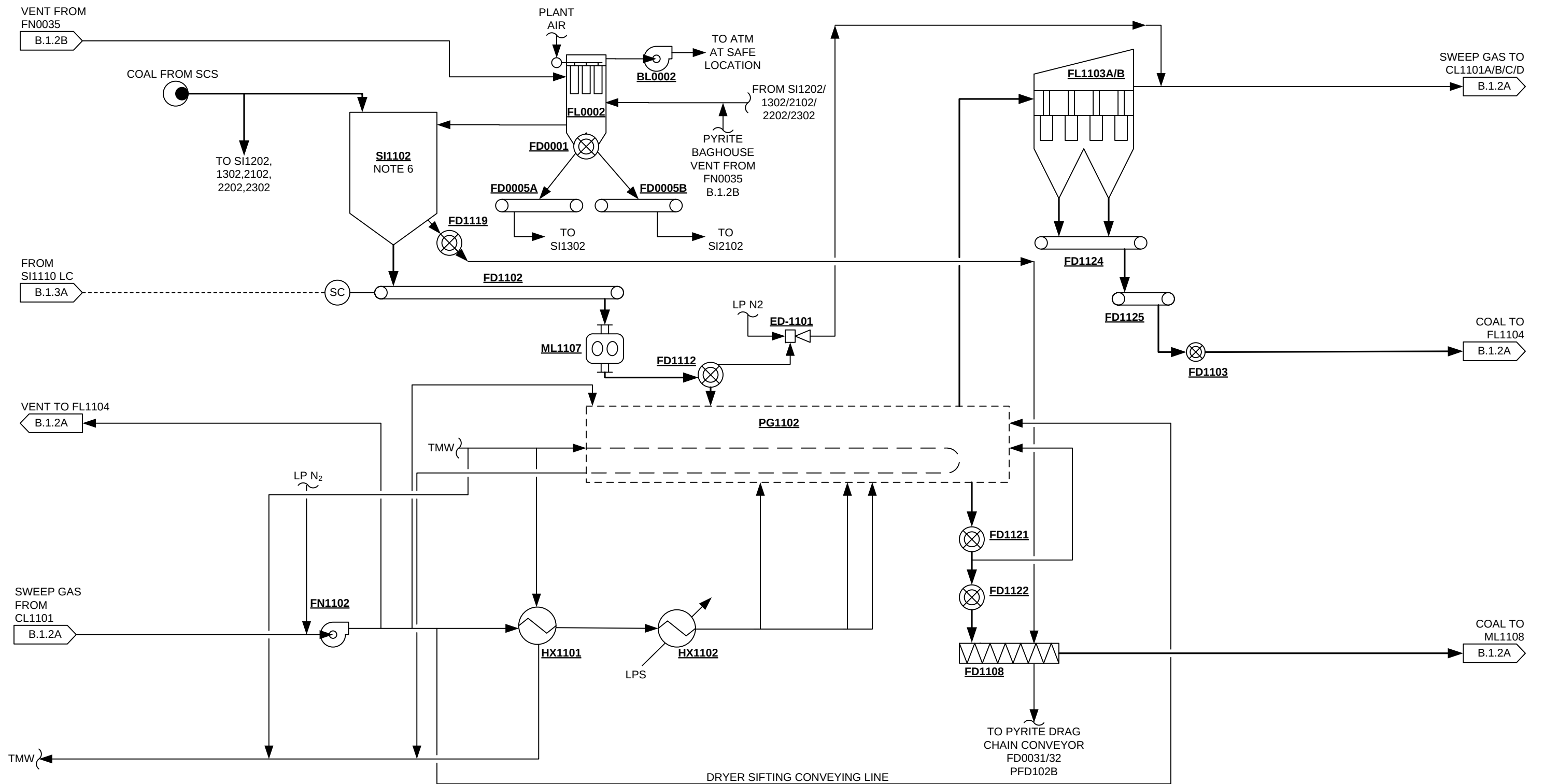


FIGURE B.1.1 COAL PREPARATION

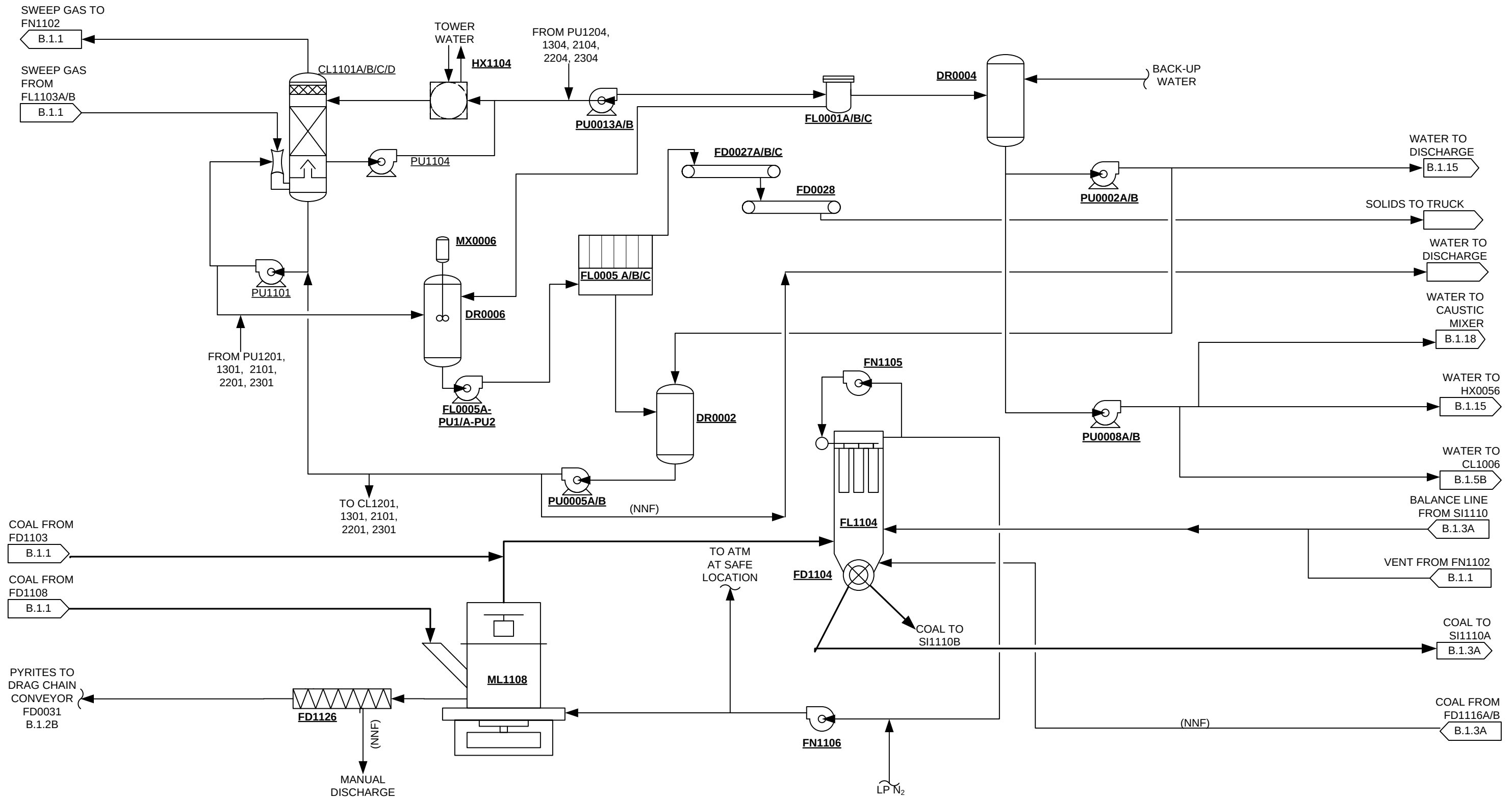


FIGURE B.1.2A COAL PREPARATION

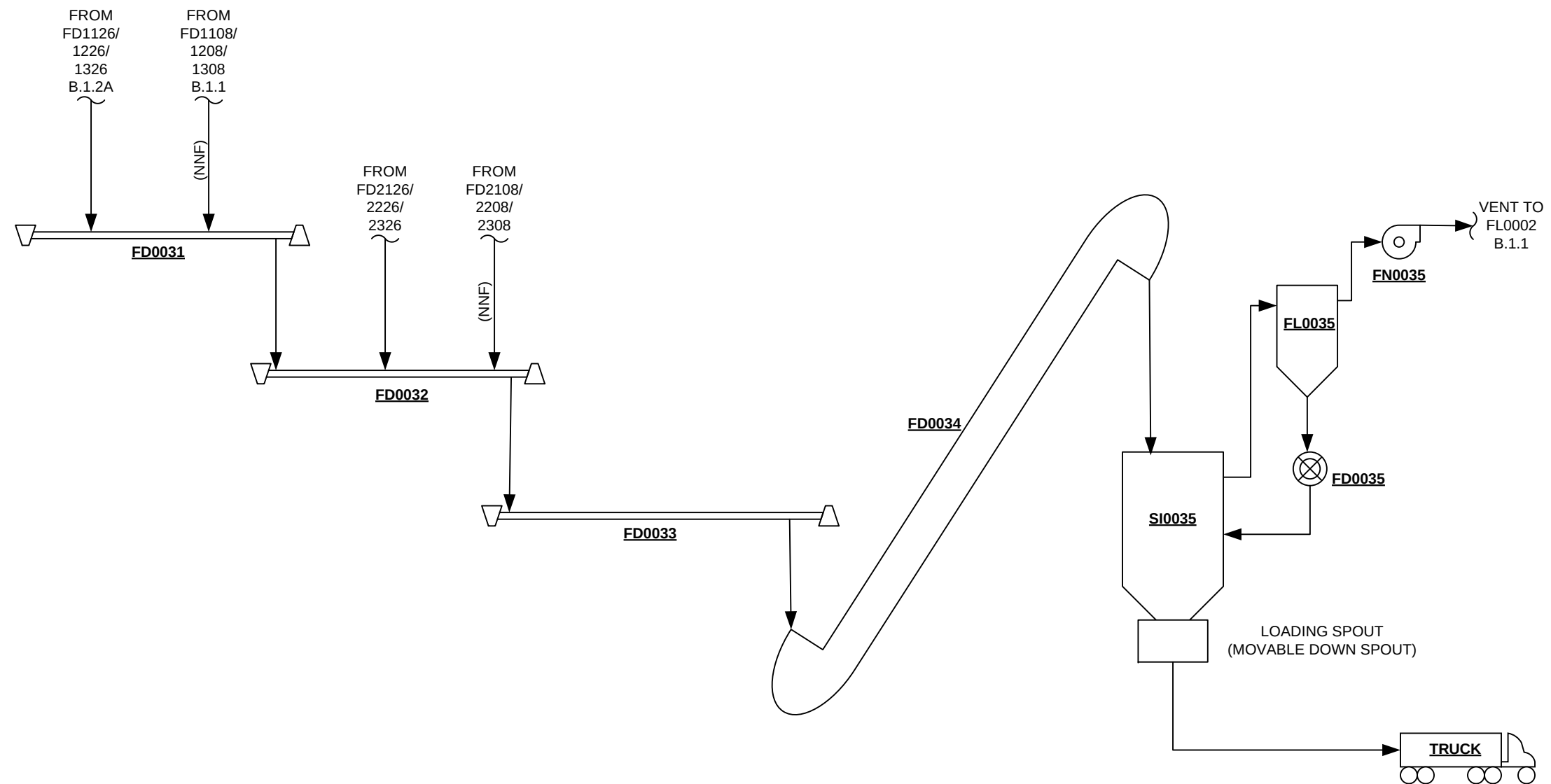


FIGURE B.1.2B COAL PREPARATION

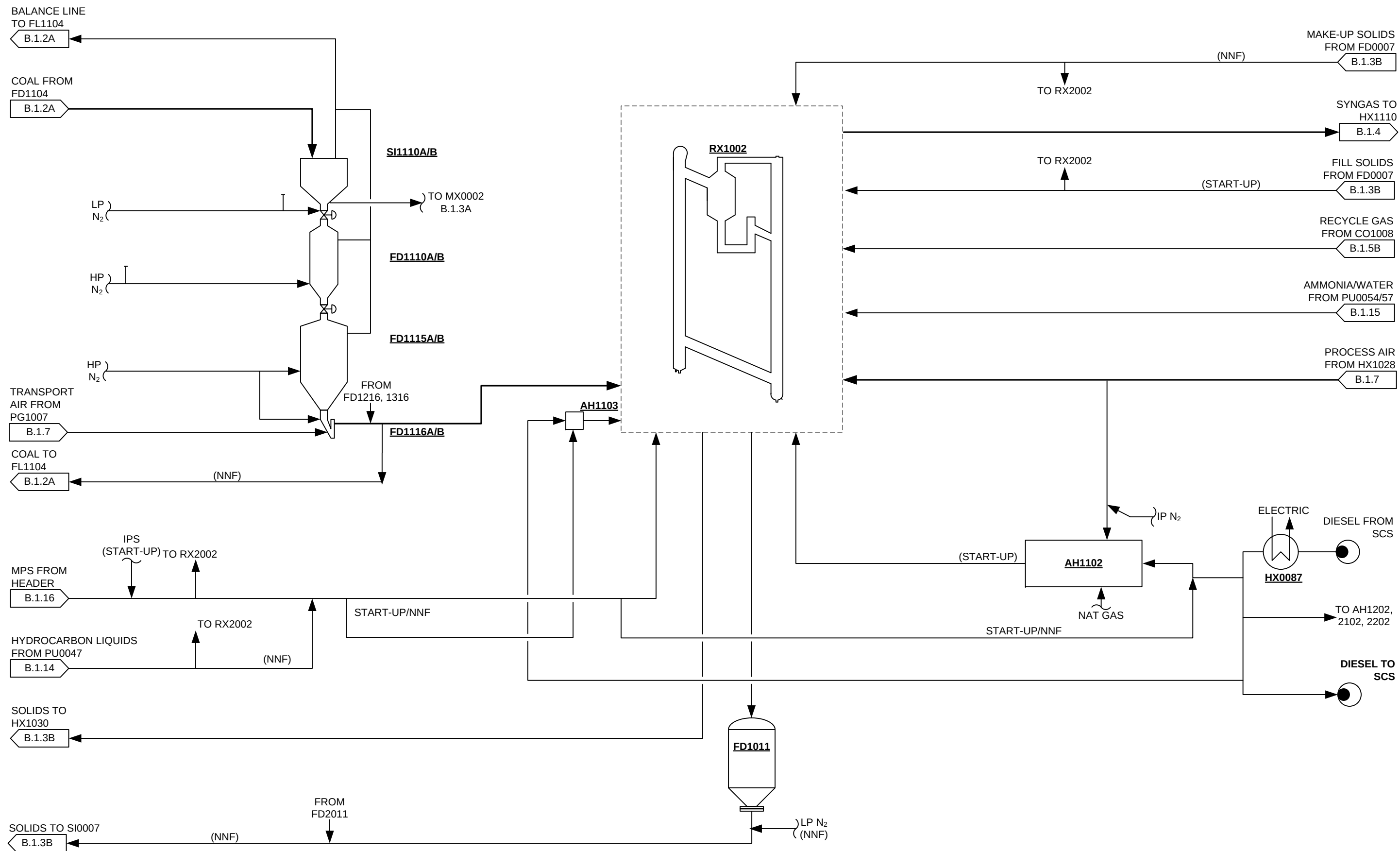


FIGURE B.1.3A COAL FEED AND TRANSPORT GASIFIER

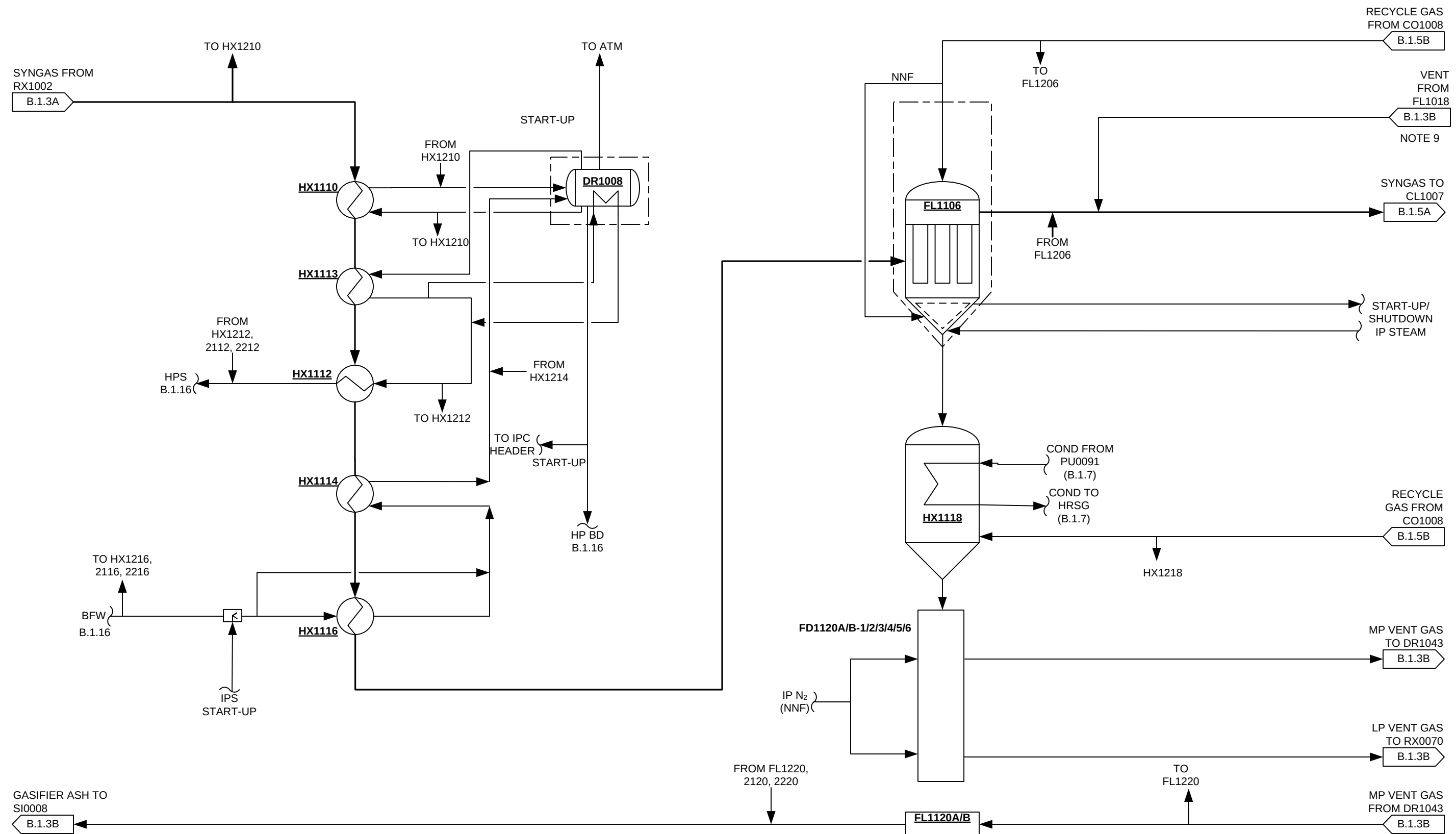


FIGURE B.1.4 SYNGAS COOLING AND PARTICULATE REMOVAL

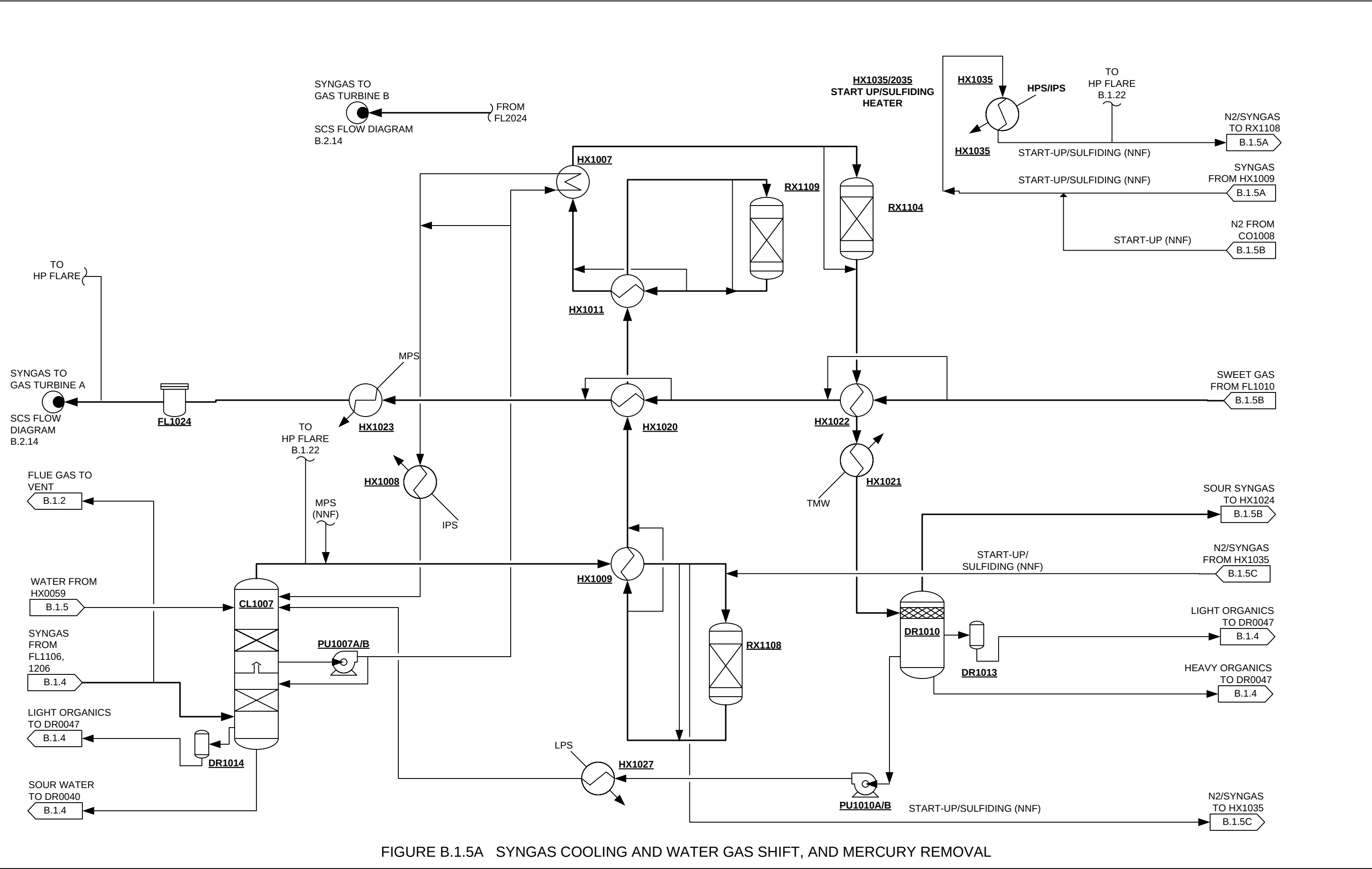


FIGURE B.1.5A SYNGAS COOLING AND WATER GAS SHIFT, AND MERCURY REMOVAL

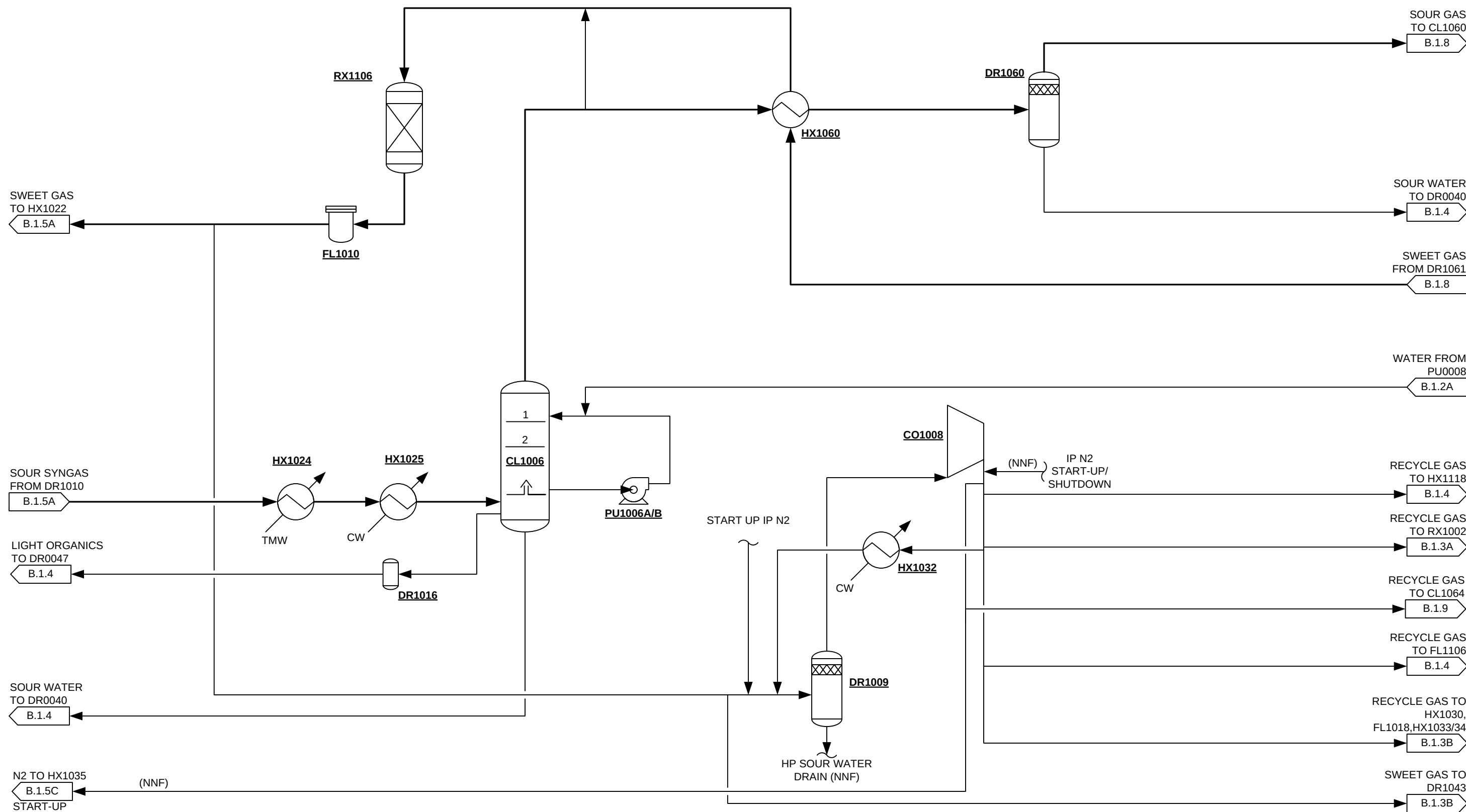


FIGURE B.1.5B SYNGAS COOLING AND WATER GAS SHIFT, MERCURY REMOVAL, AND ACID GAS REMOVAL

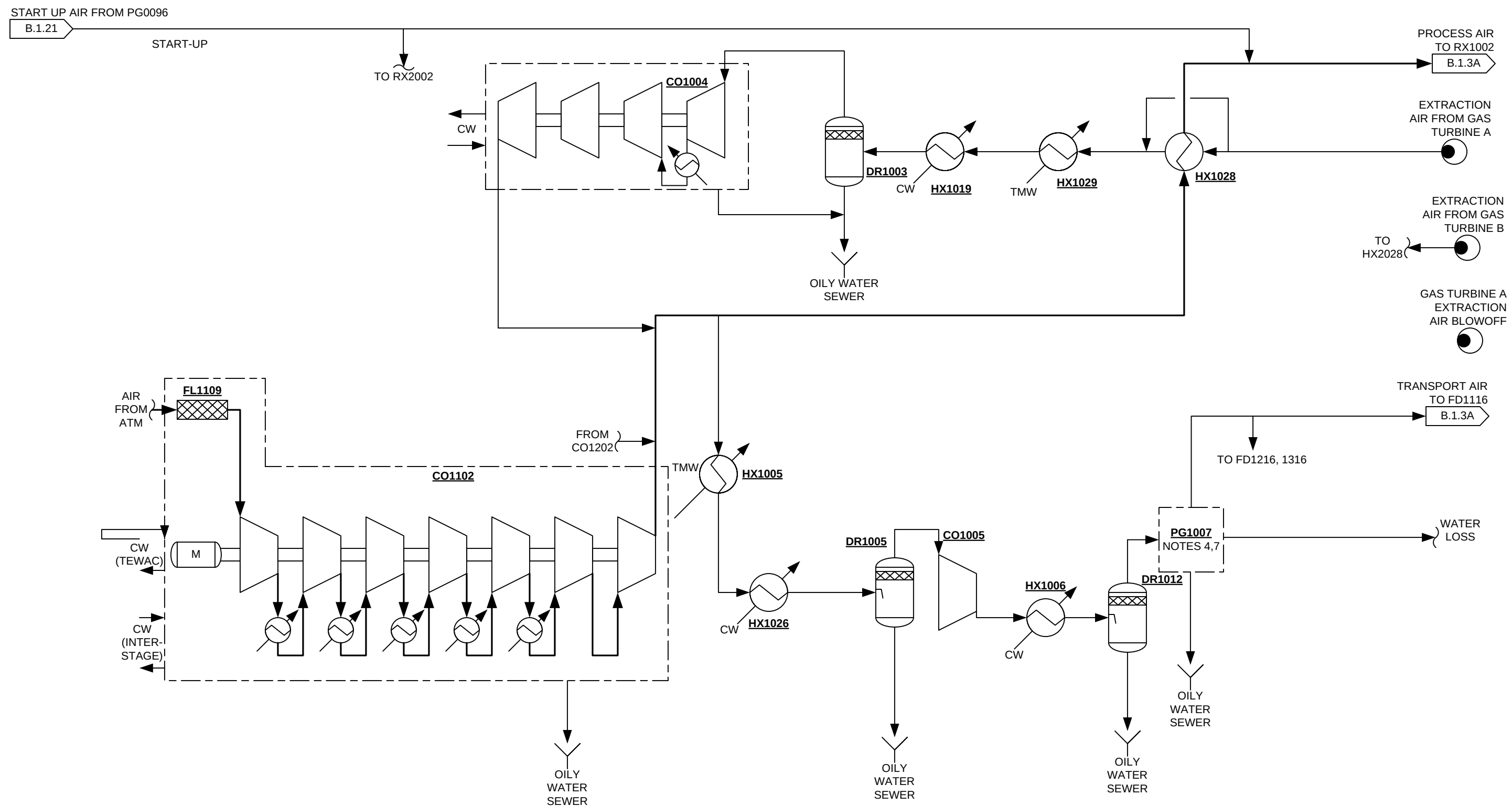


FIGURE B.1.7 AIR SUPPLY SYSTEM

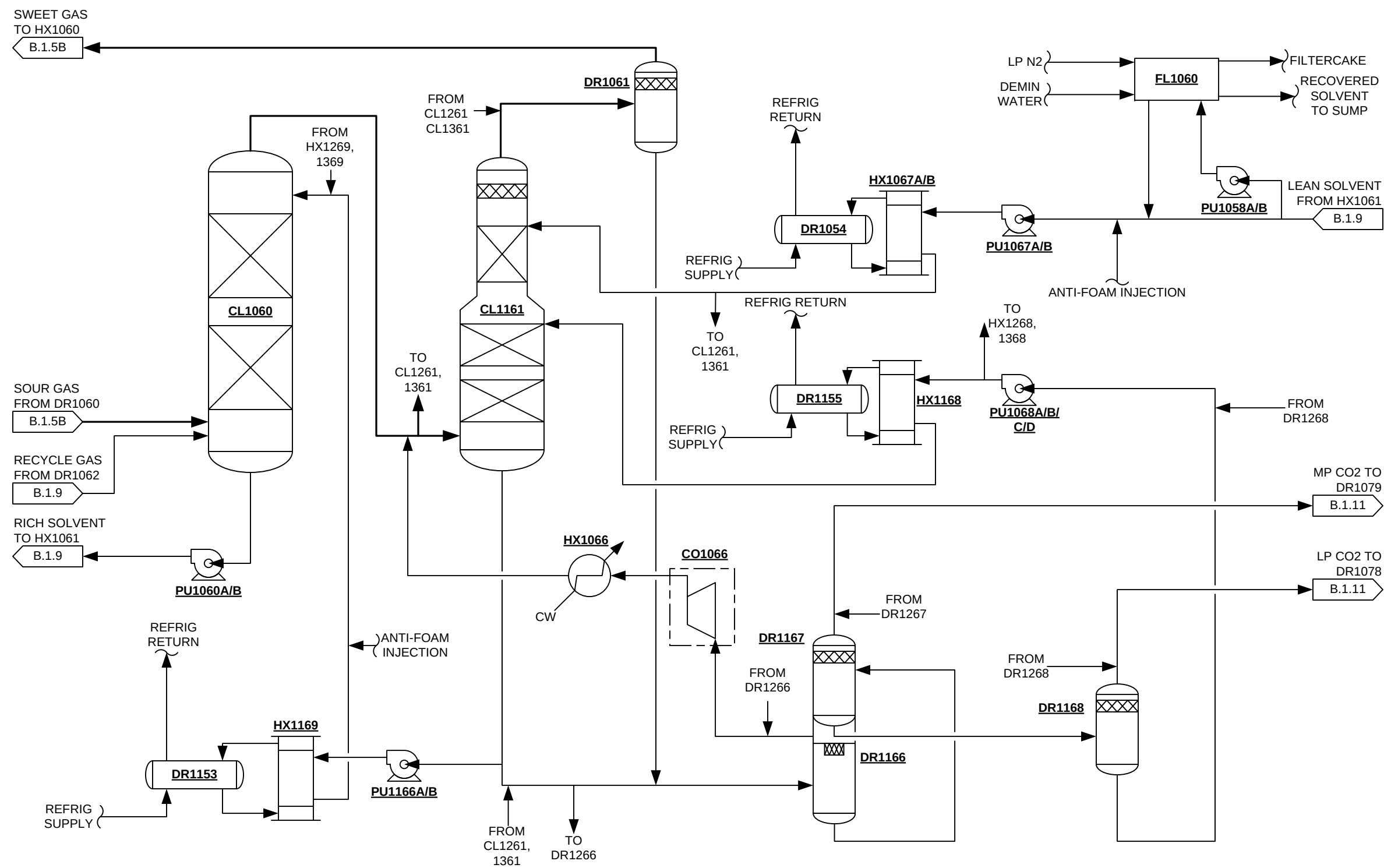


FIGURE B.1.8 ACID GAS REMOVAL SYSTEM

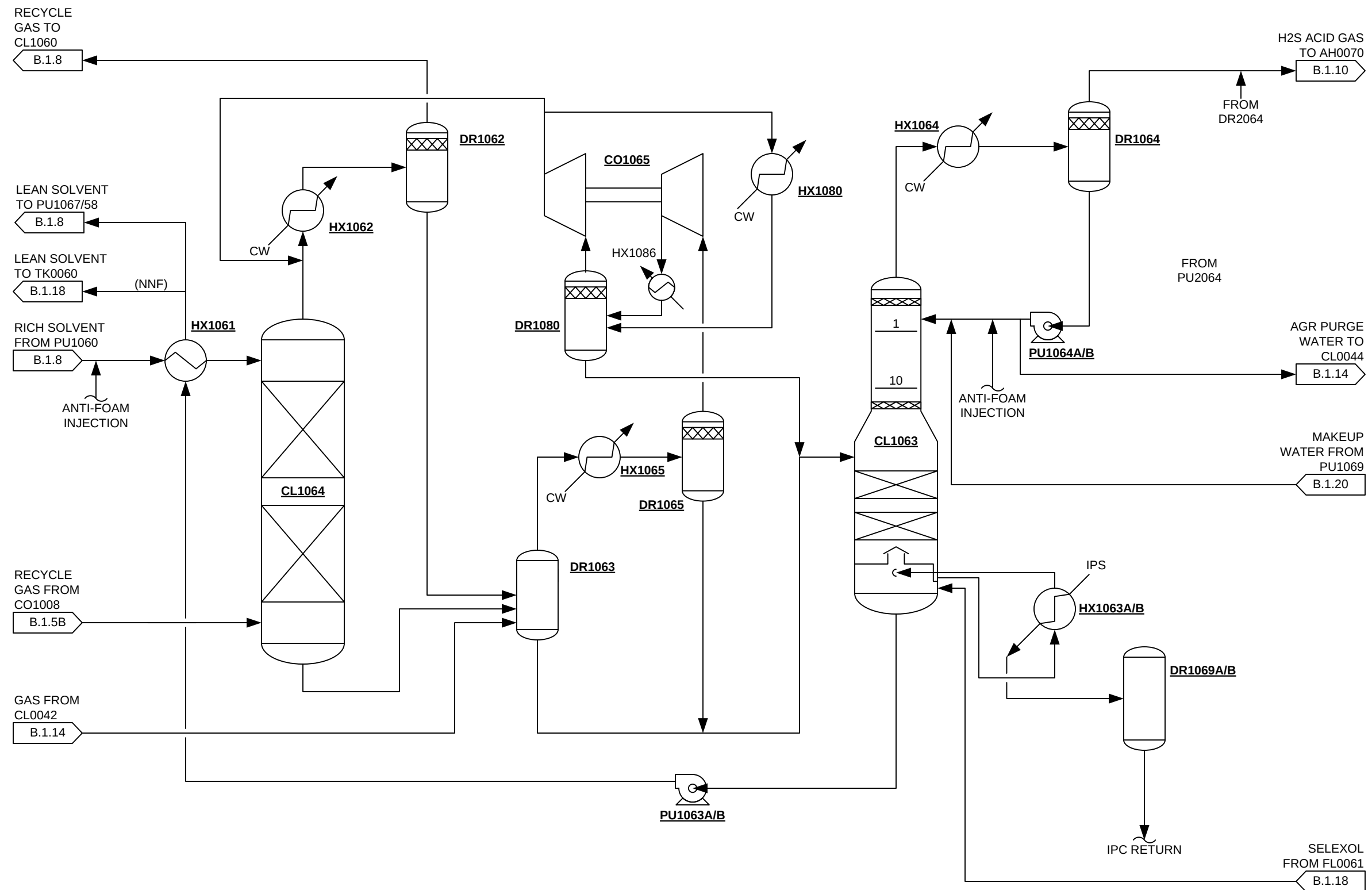


FIGURE B.1.9 ACID GAS REMOVAL SYSTEM

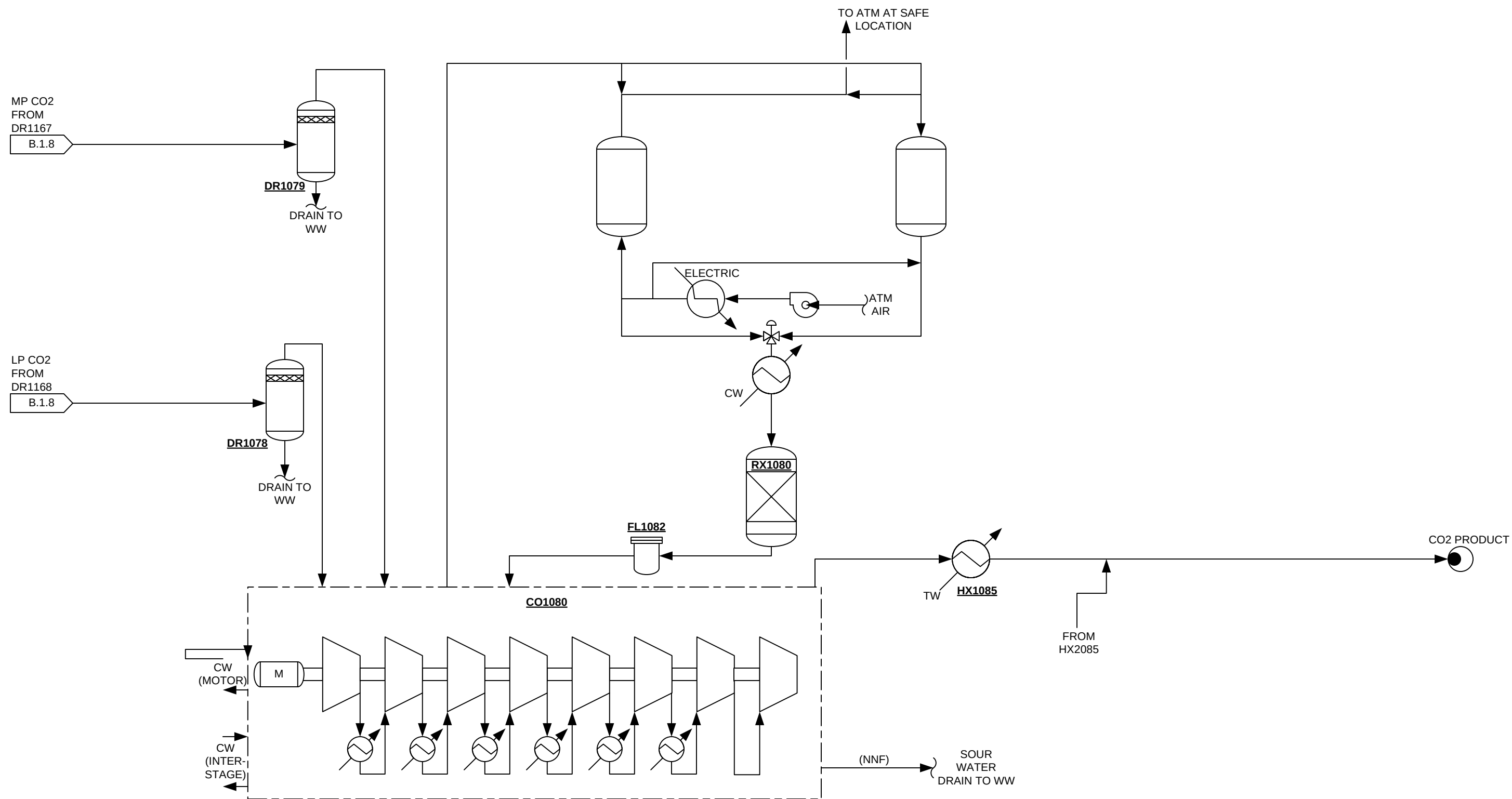


FIGURE B.1.11 CO₂ COMPRESSION AND AGR REFRIGERATION

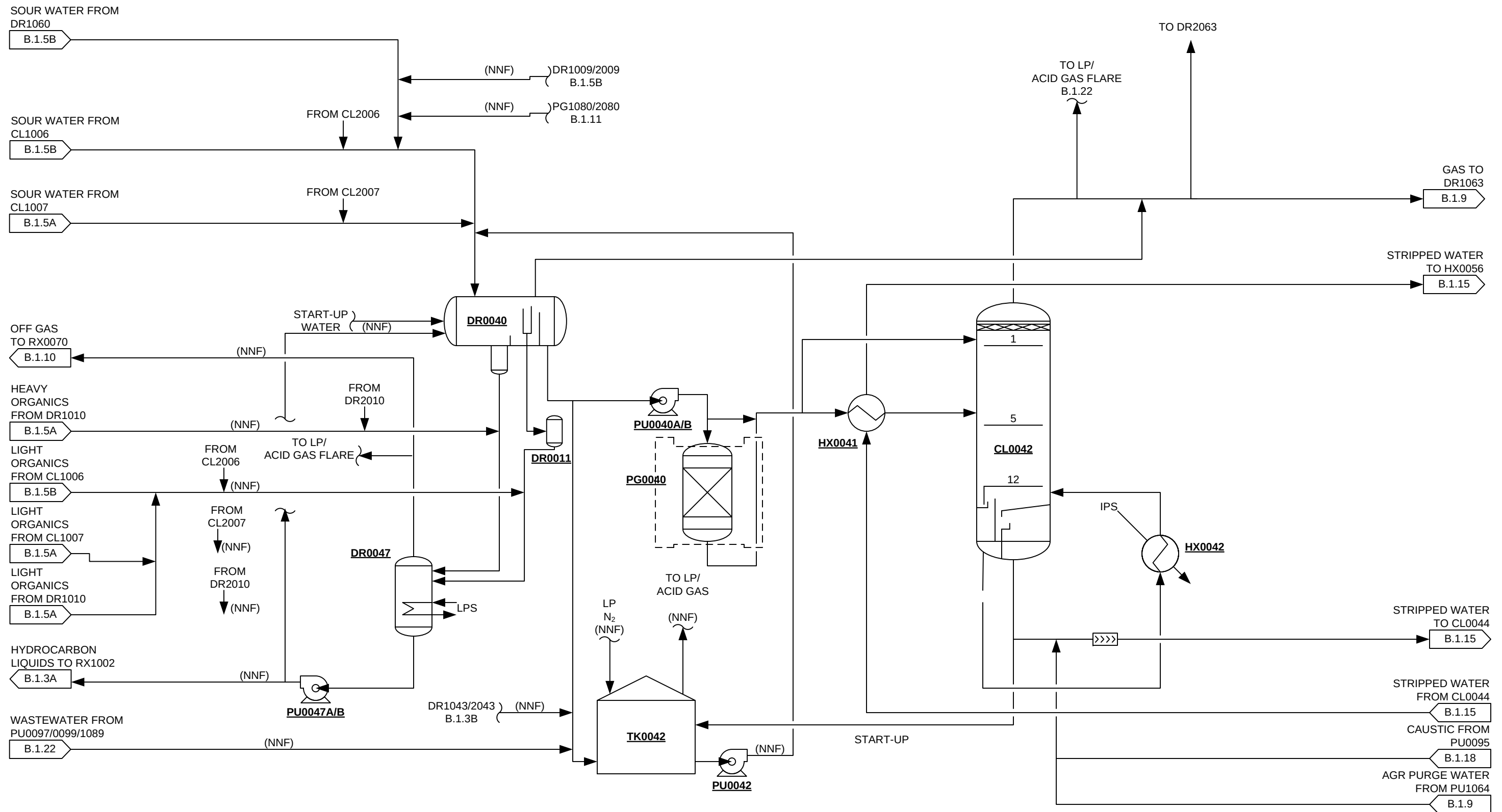


FIGURE B.1.14 SOUR WATER SYSTEM

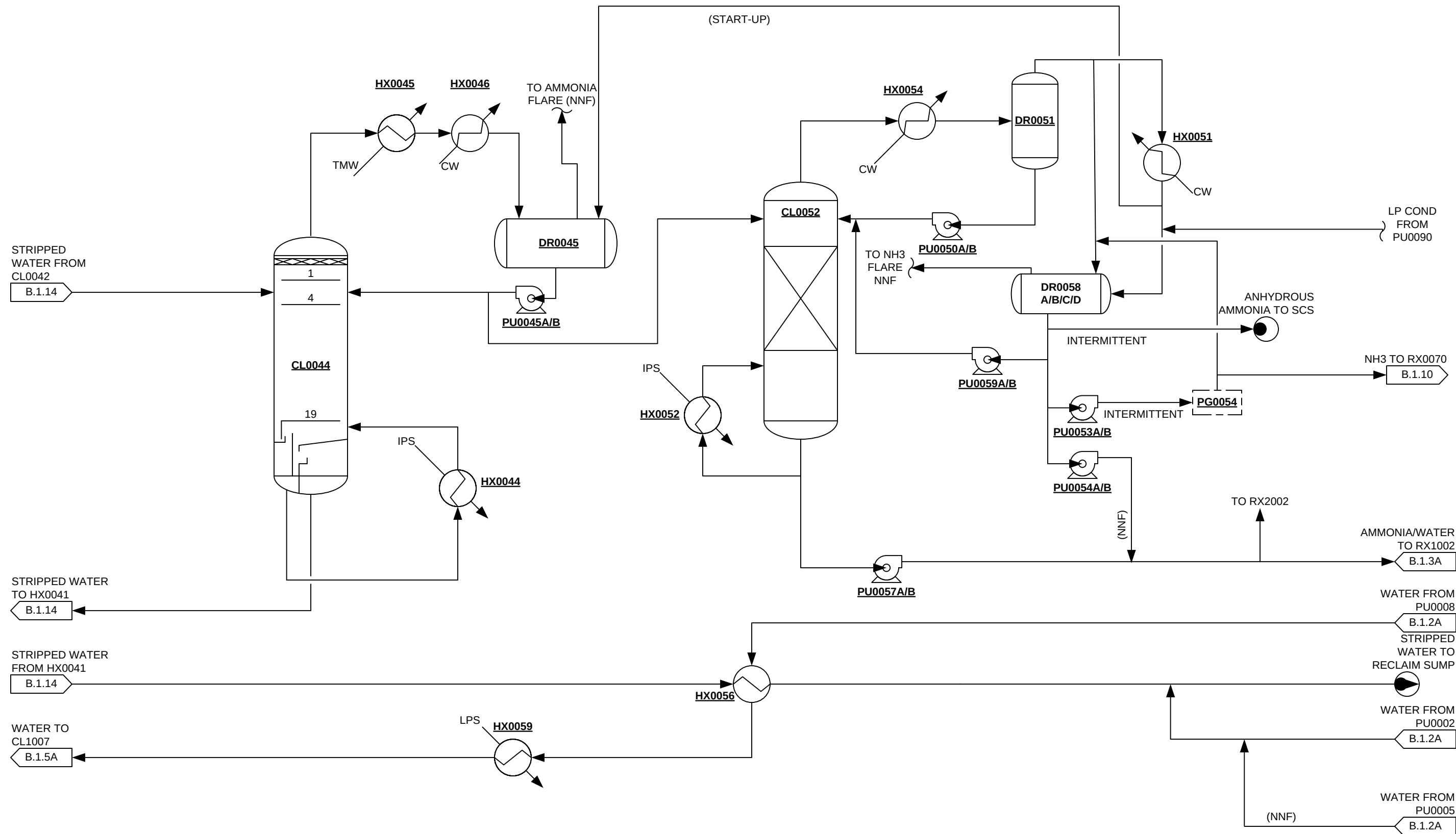


FIGURE B.1.15 WASTE WATER SYSTEM

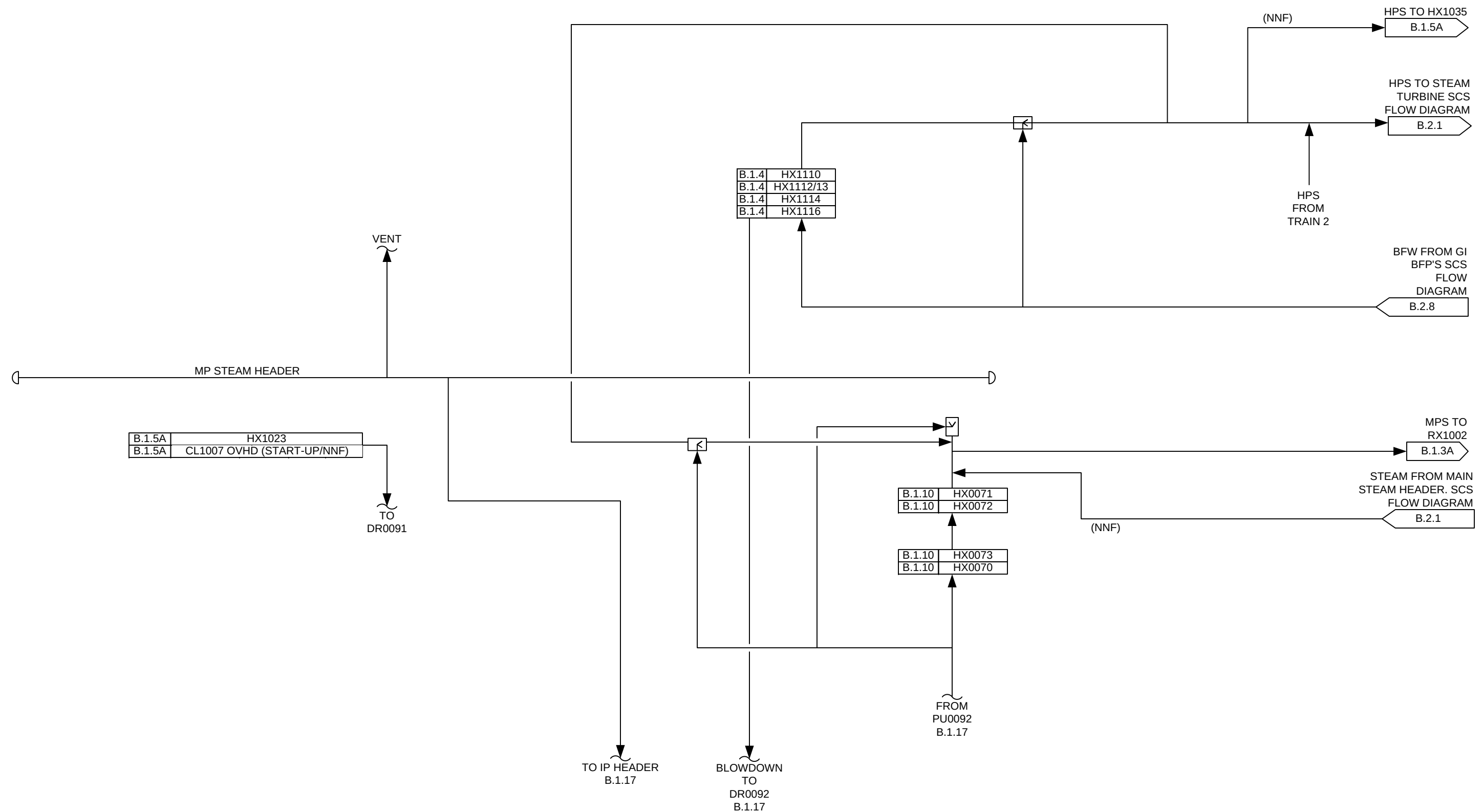
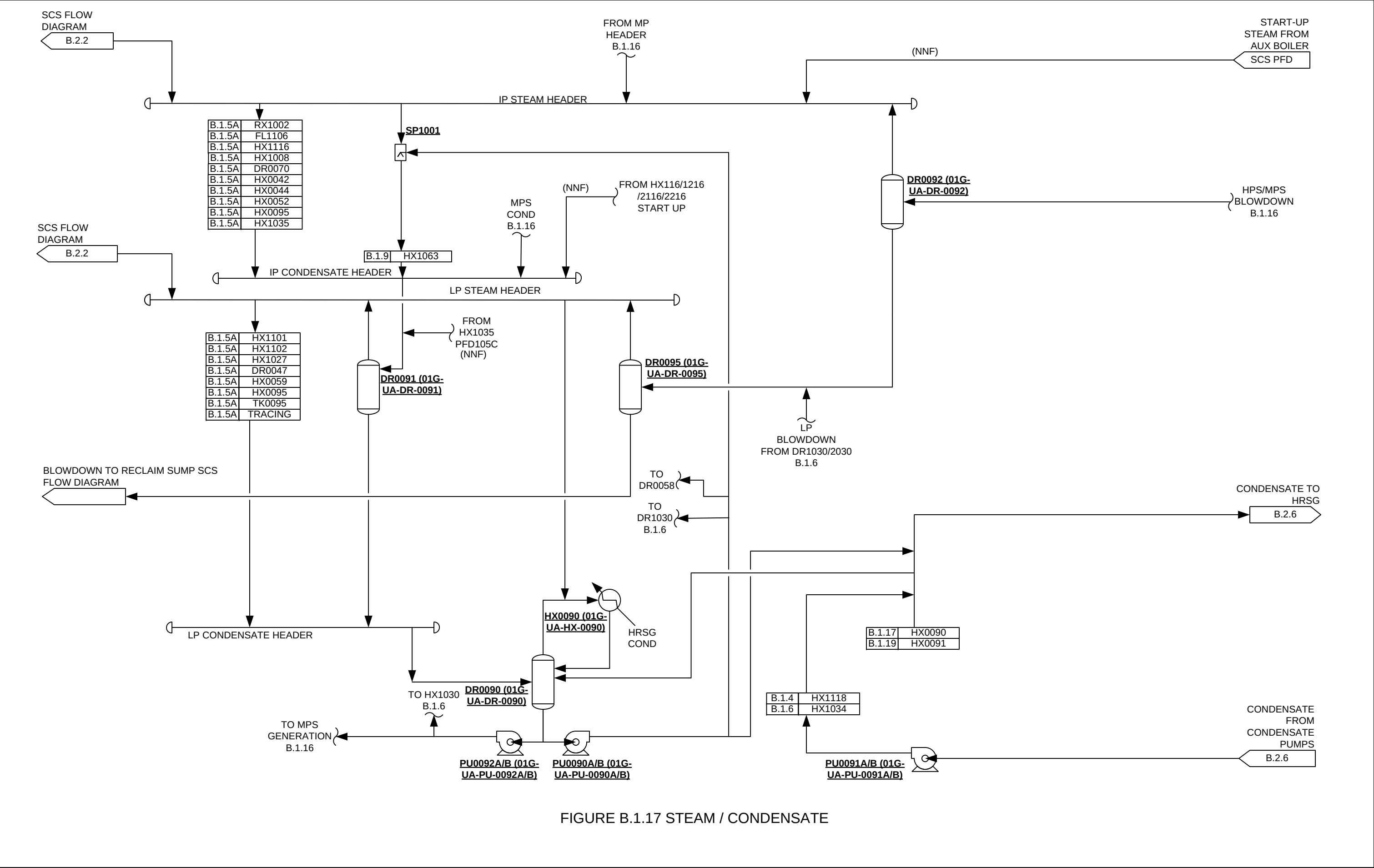


FIGURE B.1.16 STEAM / CONDENSATE



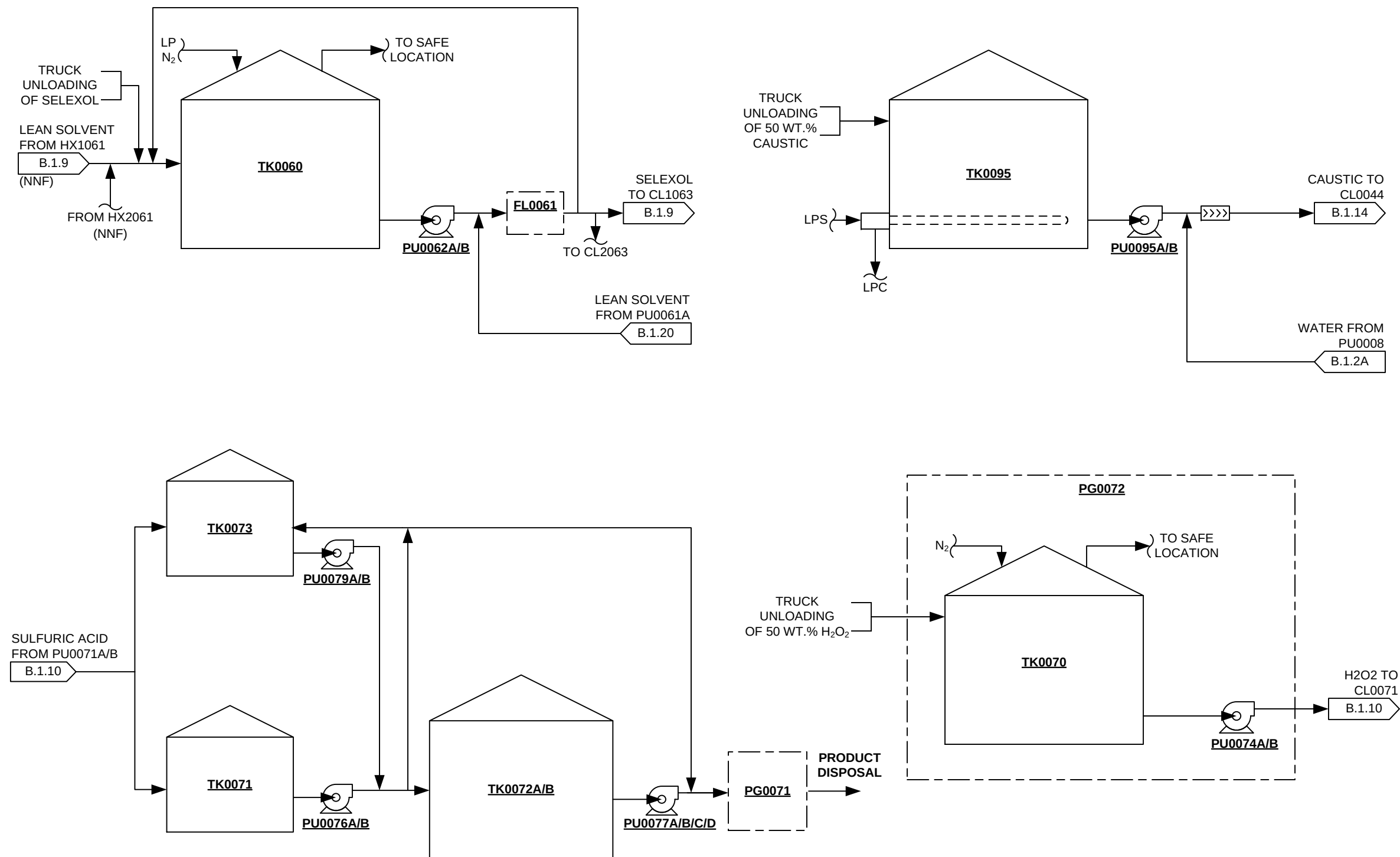


FIGURE B.1.18 CHEMICAL STORAGE

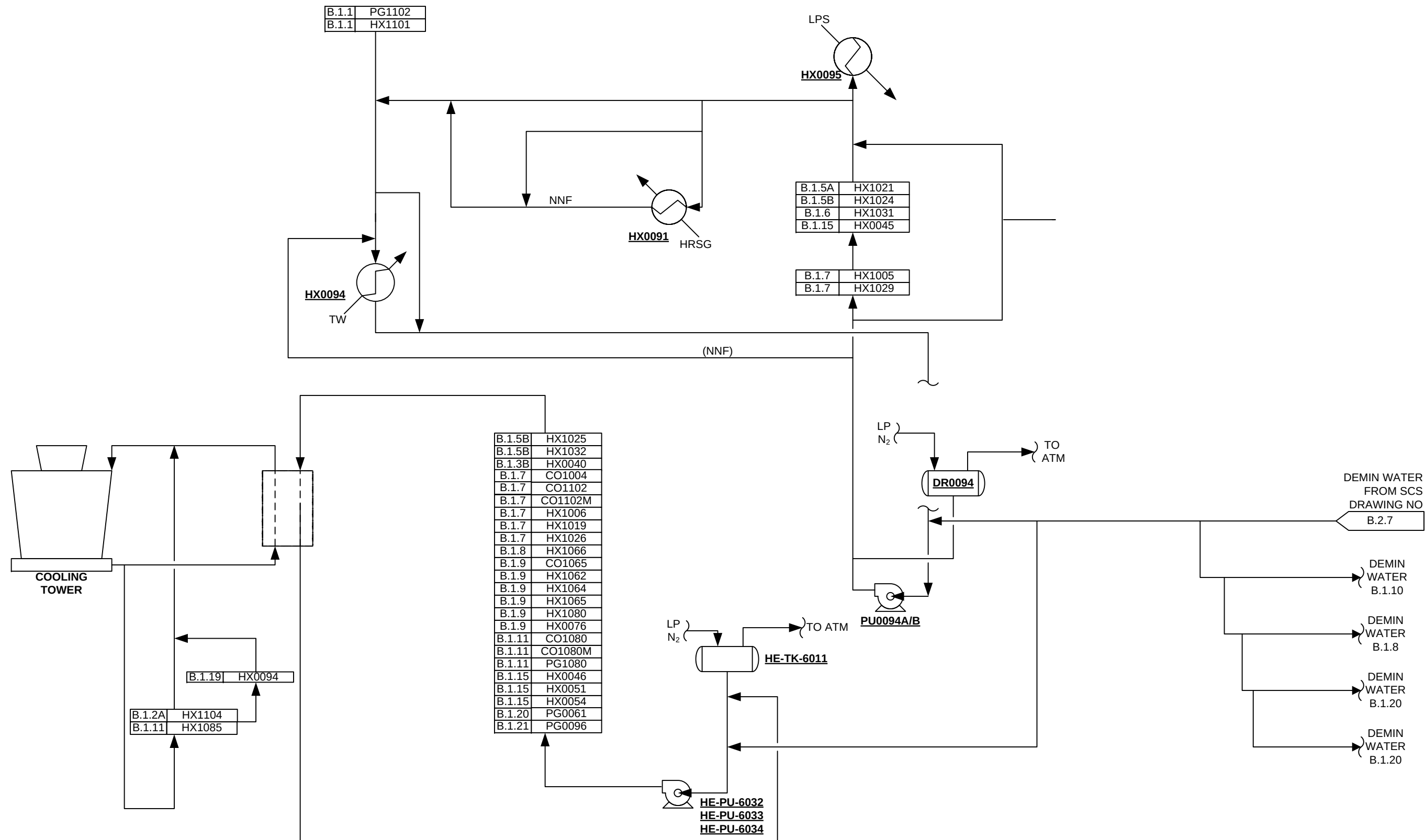


FIGURE B.1.19 TEMPERED WATER AND COOLING WATER SYSTEM

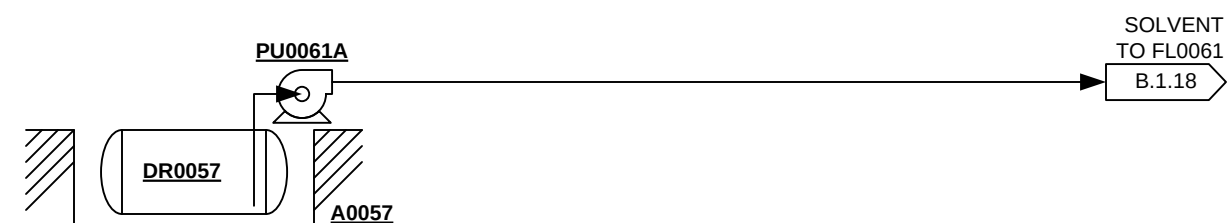
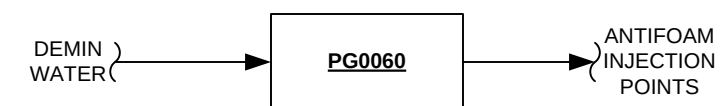
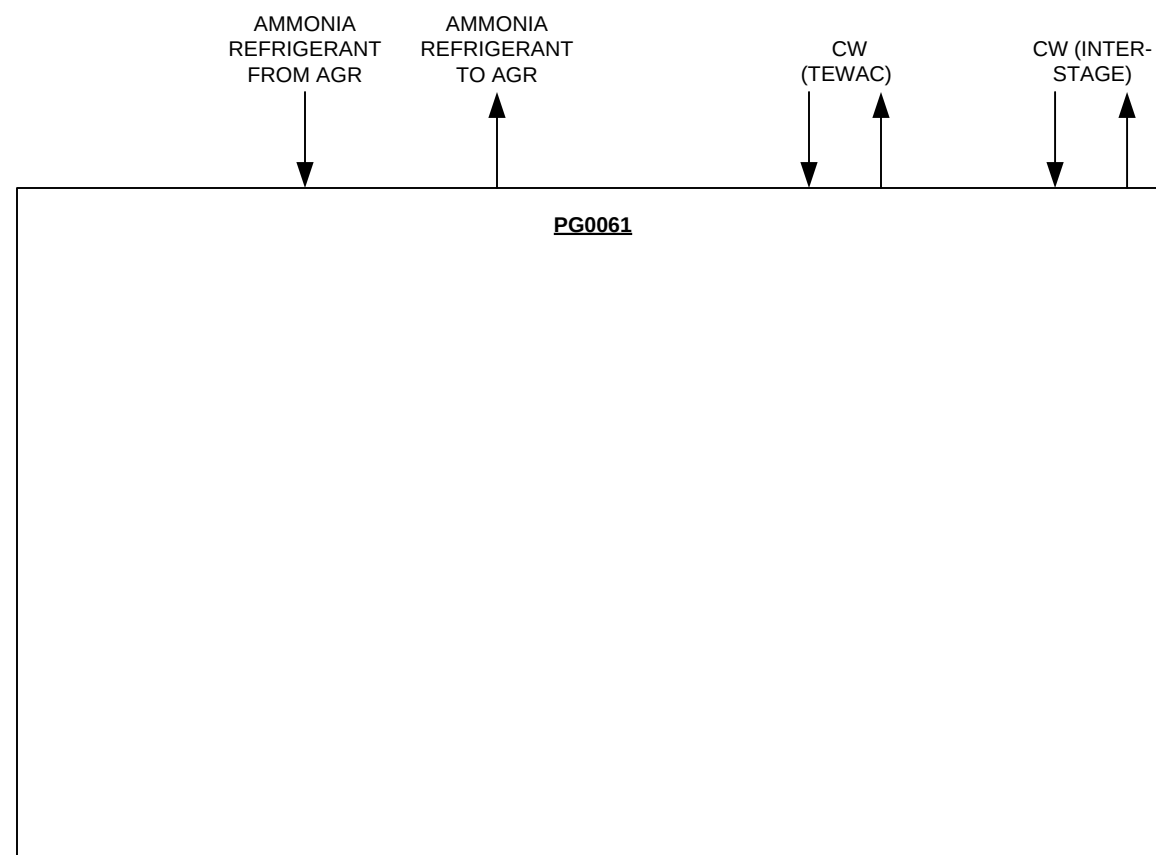


FIGURE B.1.20 AGR UTILITIES

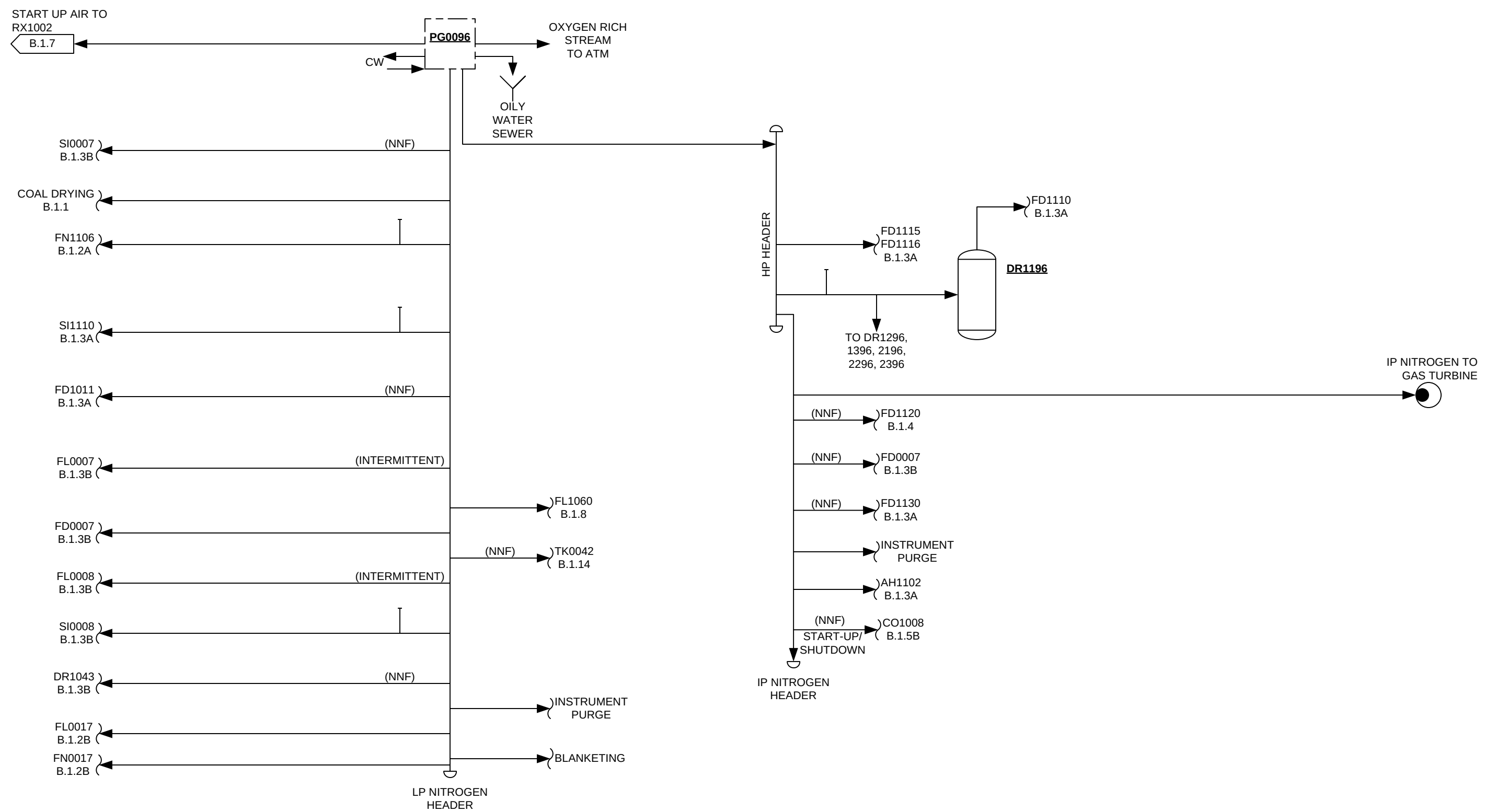


FIGURE B.1.21 NITROGEN SYSTEM

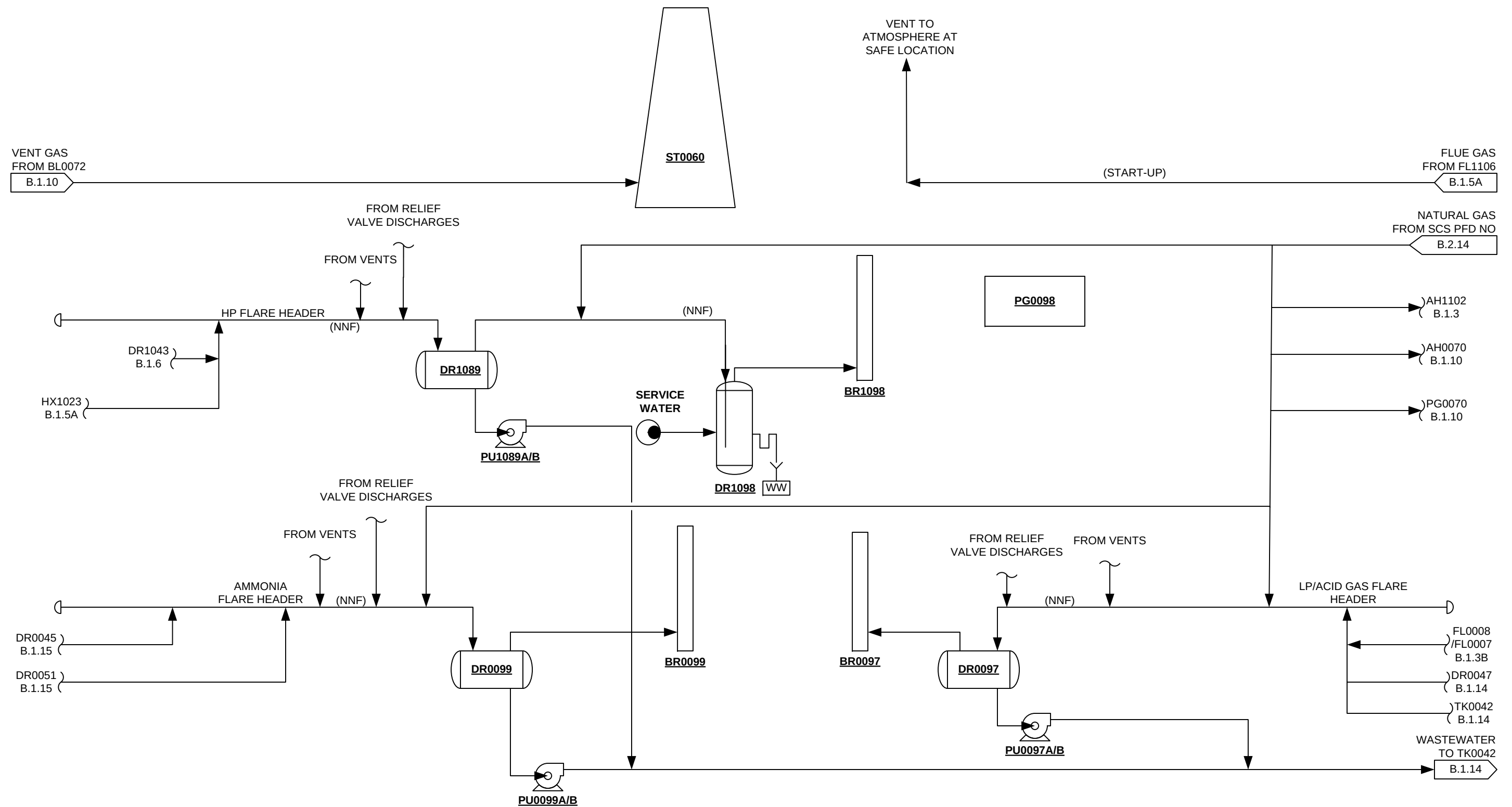


FIGURE B.1.22 FLARE SYSTEM

Appendix B.2

Process Flow Diagrams – Power Island

- Figure B.2.1 – Combustion Turbine, Steam Turbine Generator, and HRSG
- Figure B.2.2 – Steam Turbine Generator and HRSG
- Figure B.2.3 – Not Used
- Figure B.2.4 – Steam Condenser
- Figure B.2.5 – Auxiliary Boiler
- Figure B.2.6 – Condensate
- Figure B.2.7 – Condensate Makeup
- Figure B.2.8 – Feedwater
- Figure B.2.9 – Makeup Water and Waste Water
- Figure B.2.10 – Circulating Water
- Figure B.2.11 – GI Cooling Water
- Figure B.2.12 – Closed Loop Service Water
- Figure B.2.13 – Auxiliary Circulating Water
- Figure B.2.14 – Fuel Gas

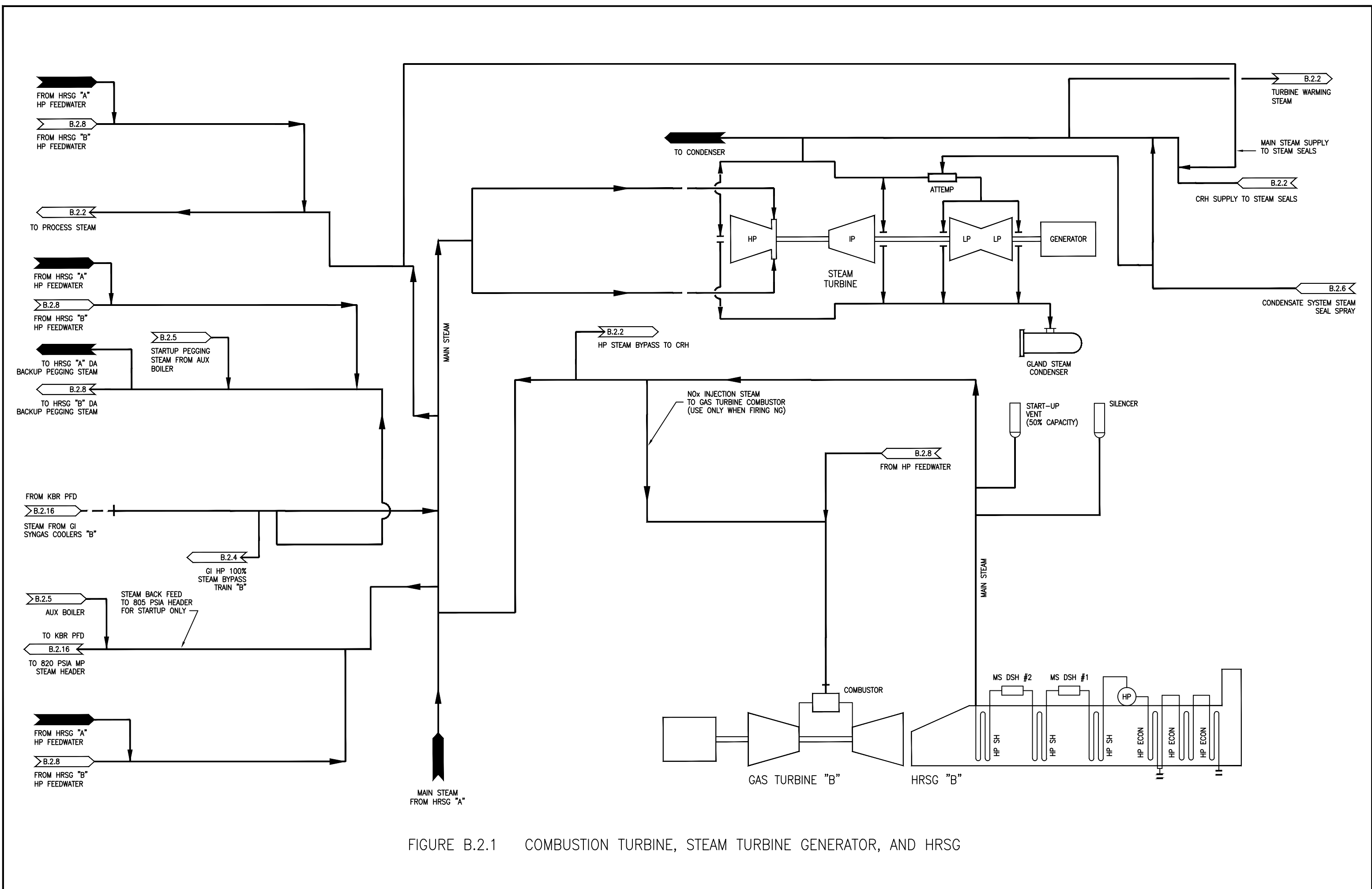


FIGURE B.2.1 COMBUSTION TURBINE, STEAM TURBINE GENERATOR, AND HRSG

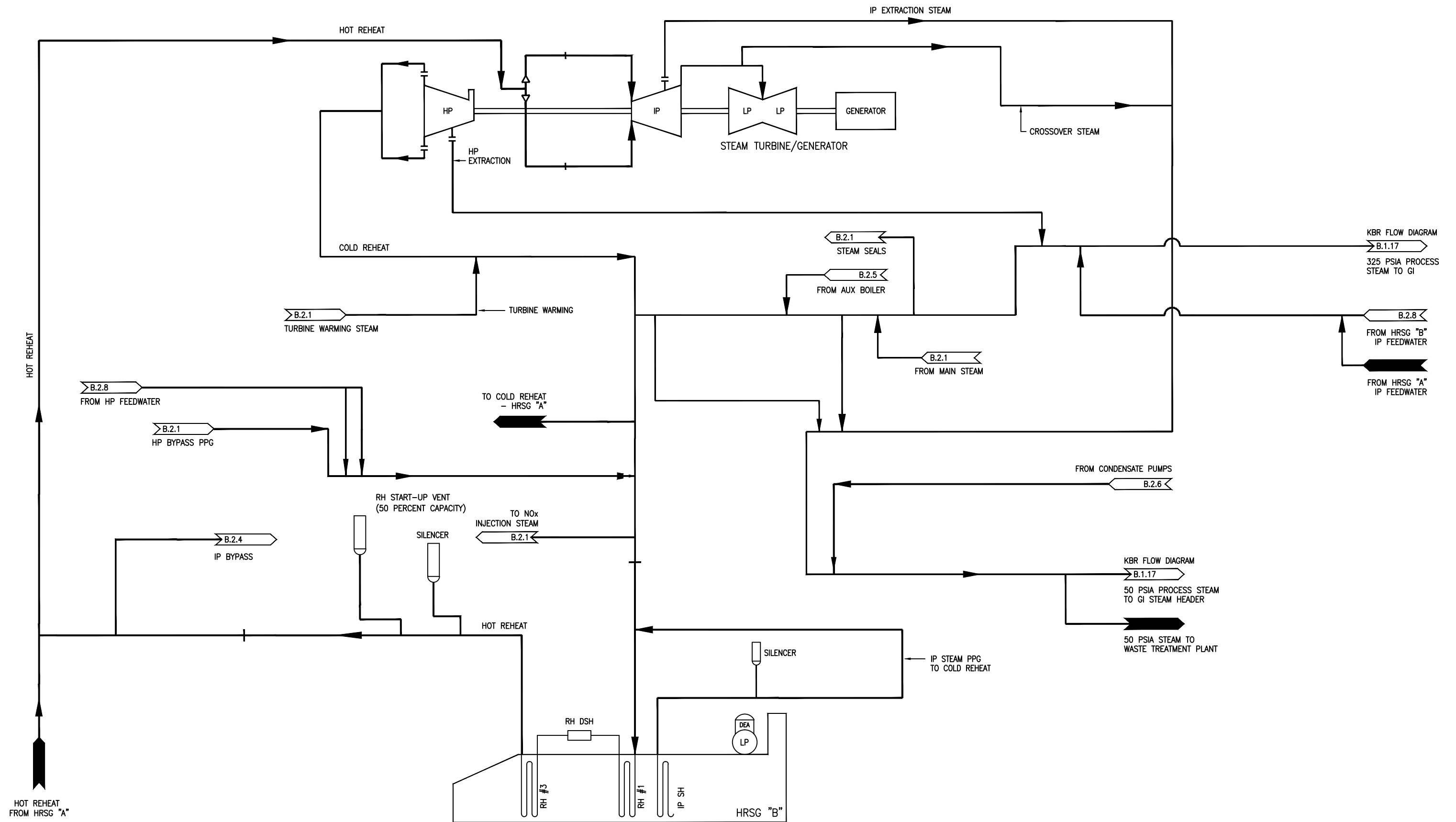


FIGURE B.2.2 STEAM TURBINE GENERATOR AND HRSG

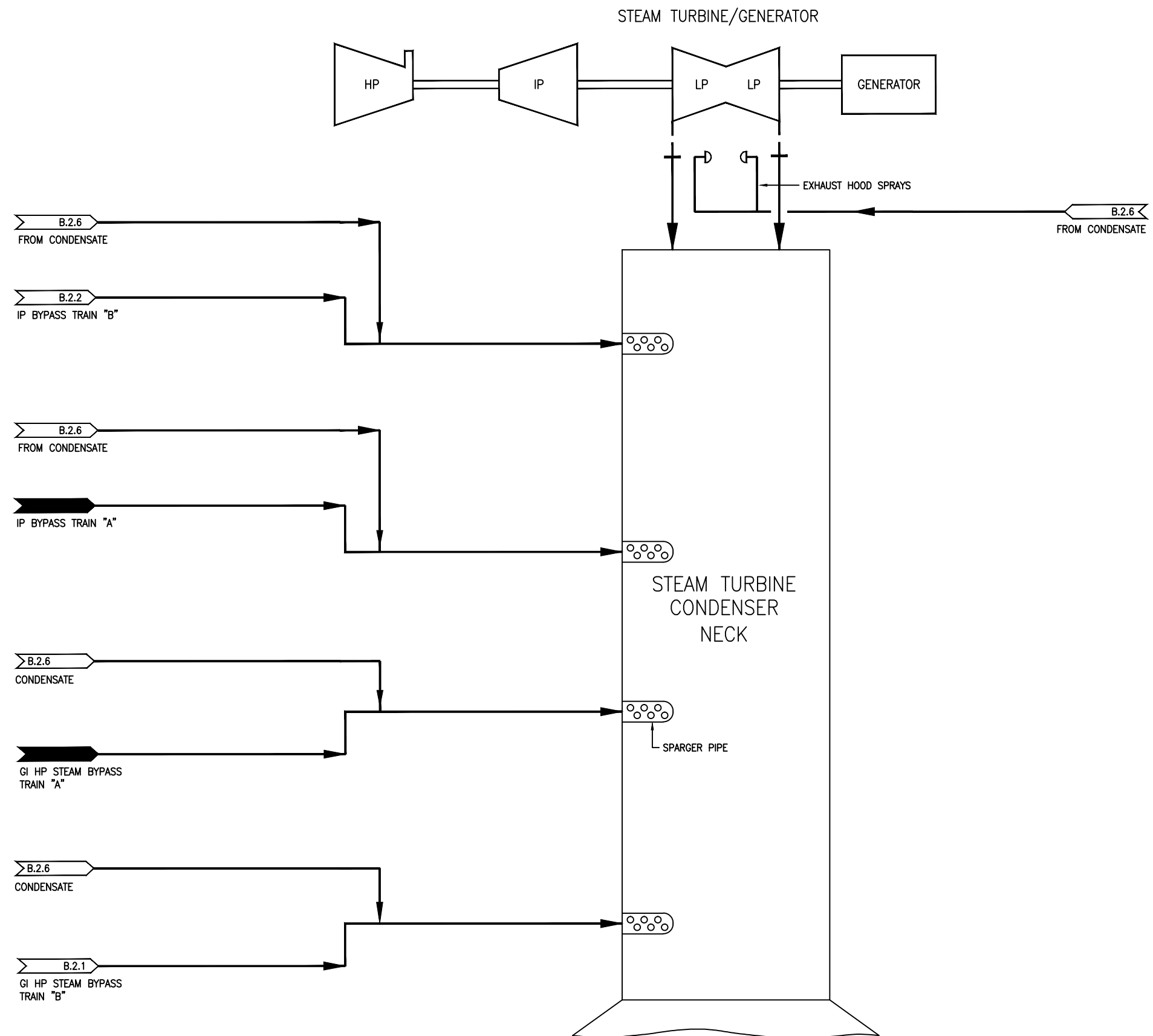


FIGURE B.2.4 STEAM CONDENSER

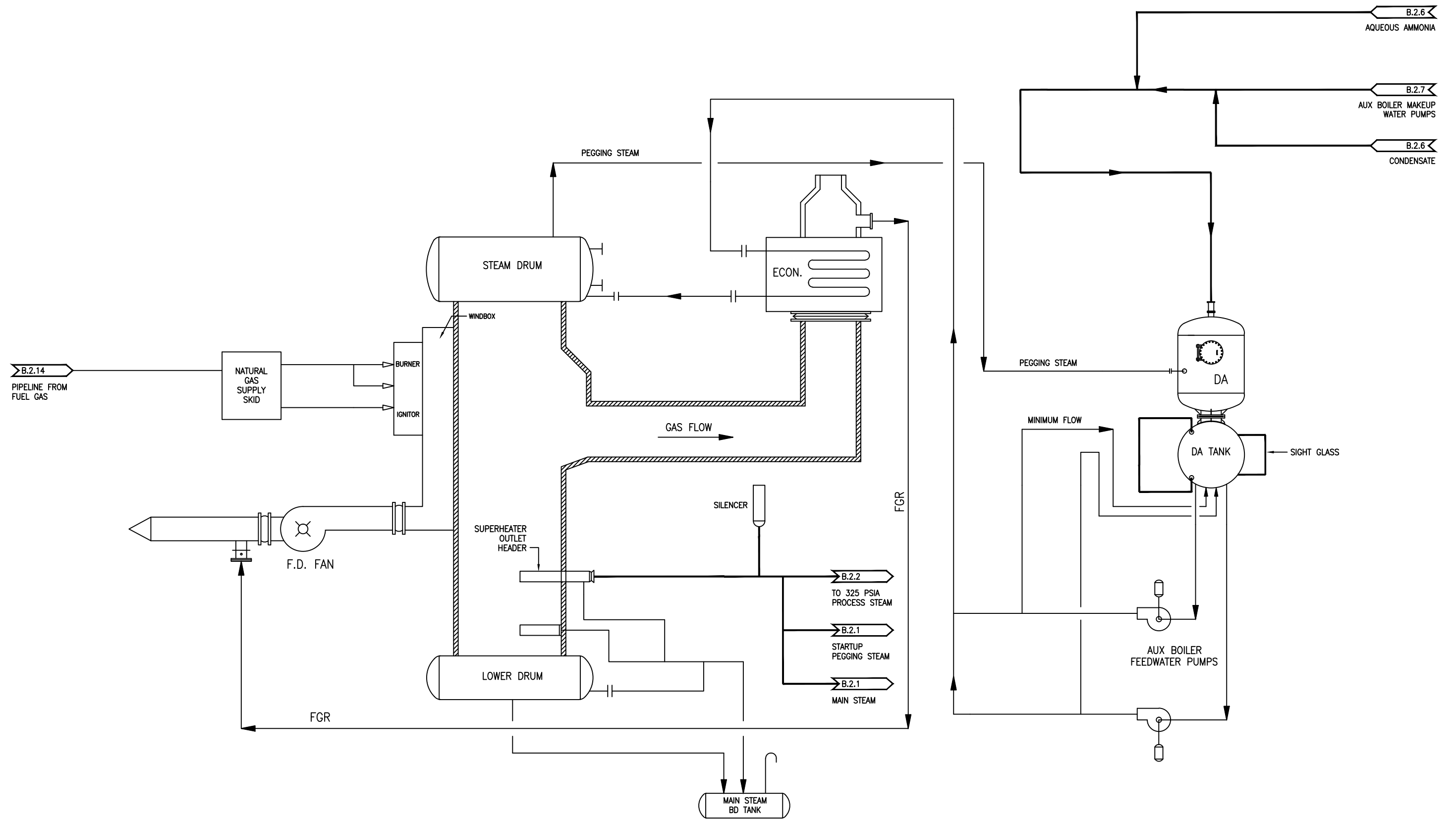


FIGURE B.2.5 AUXILIARY BOILER

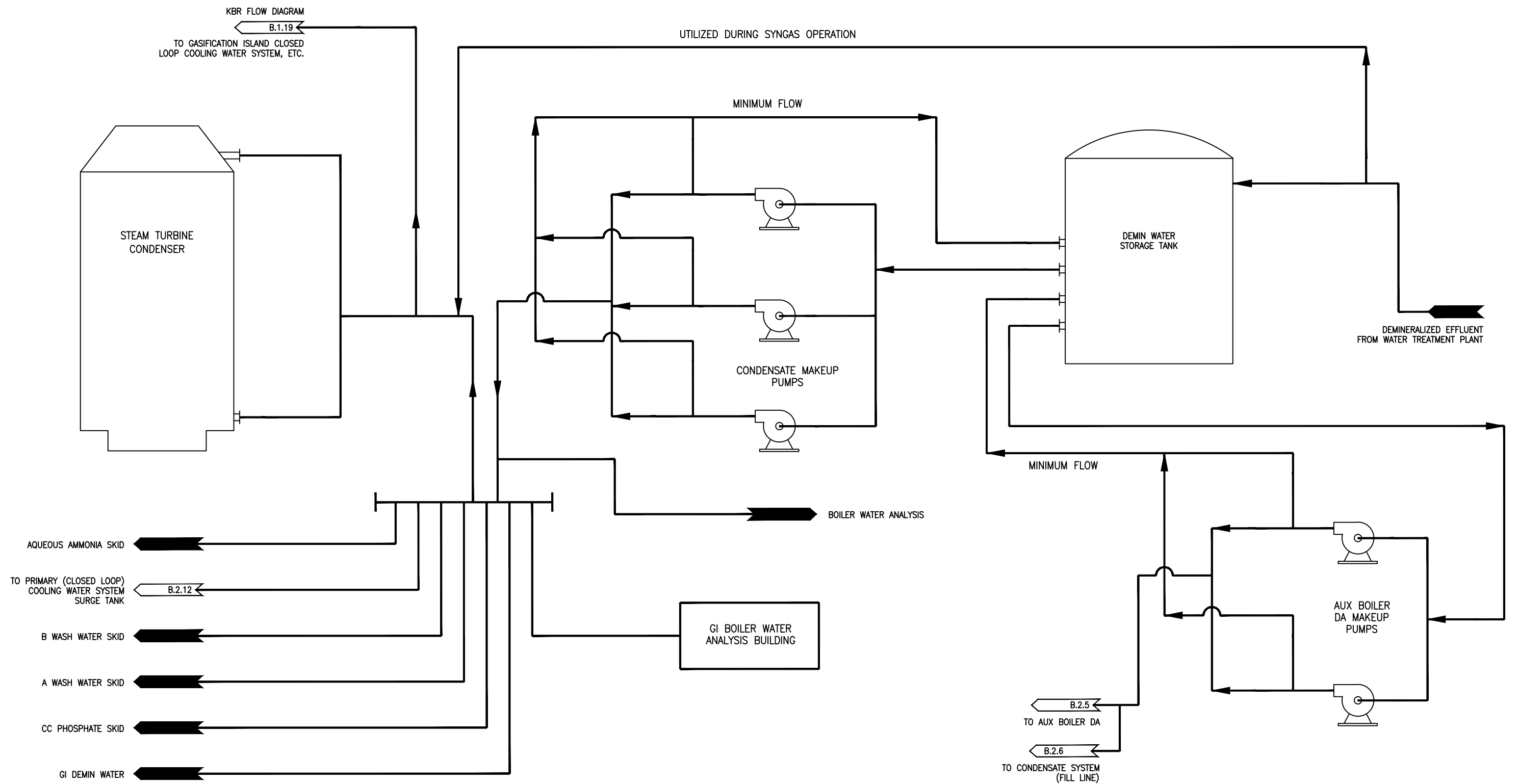


FIGURE B.2.7 CONDENSATE MAKEUP SYSTEM

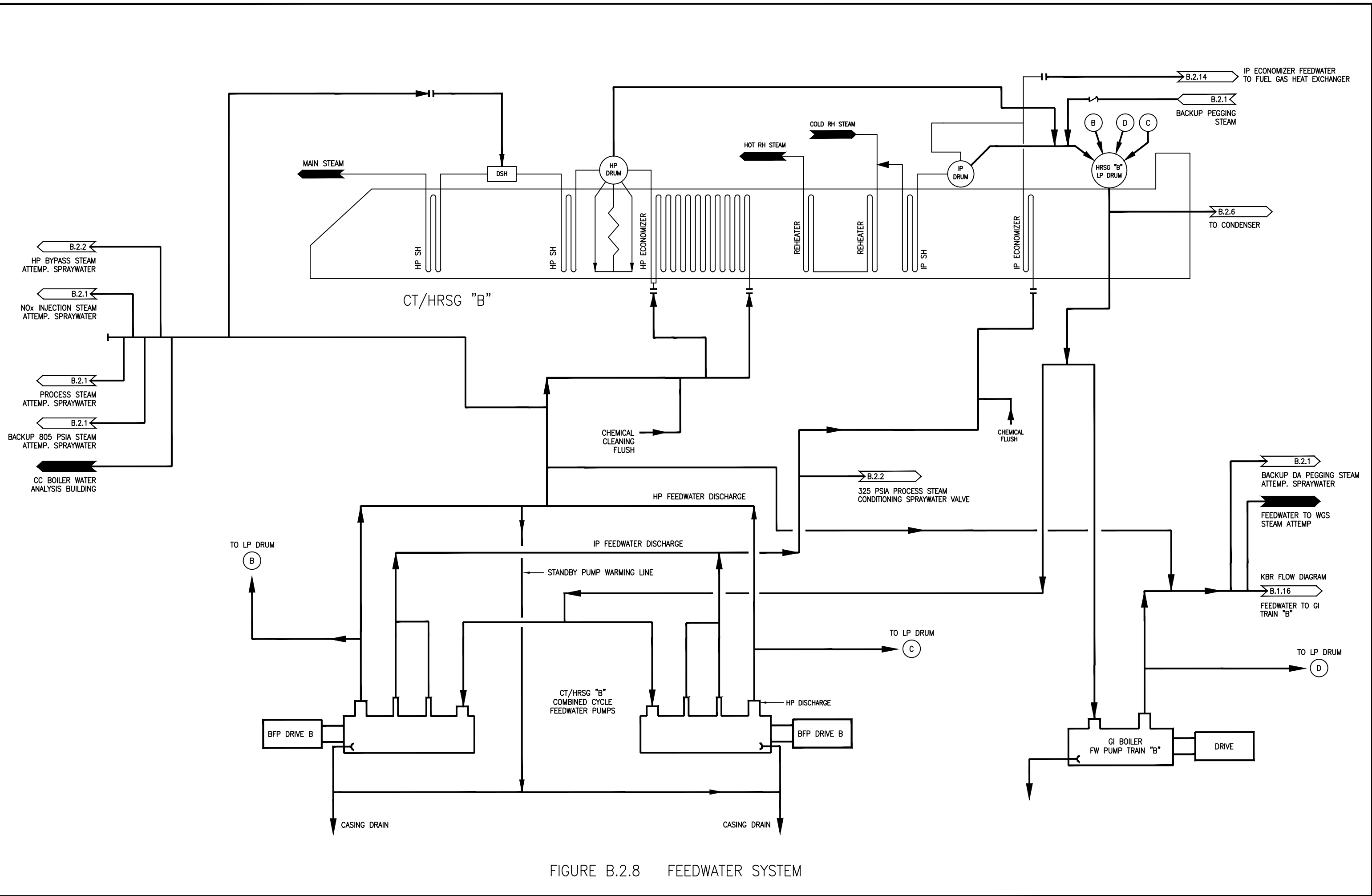
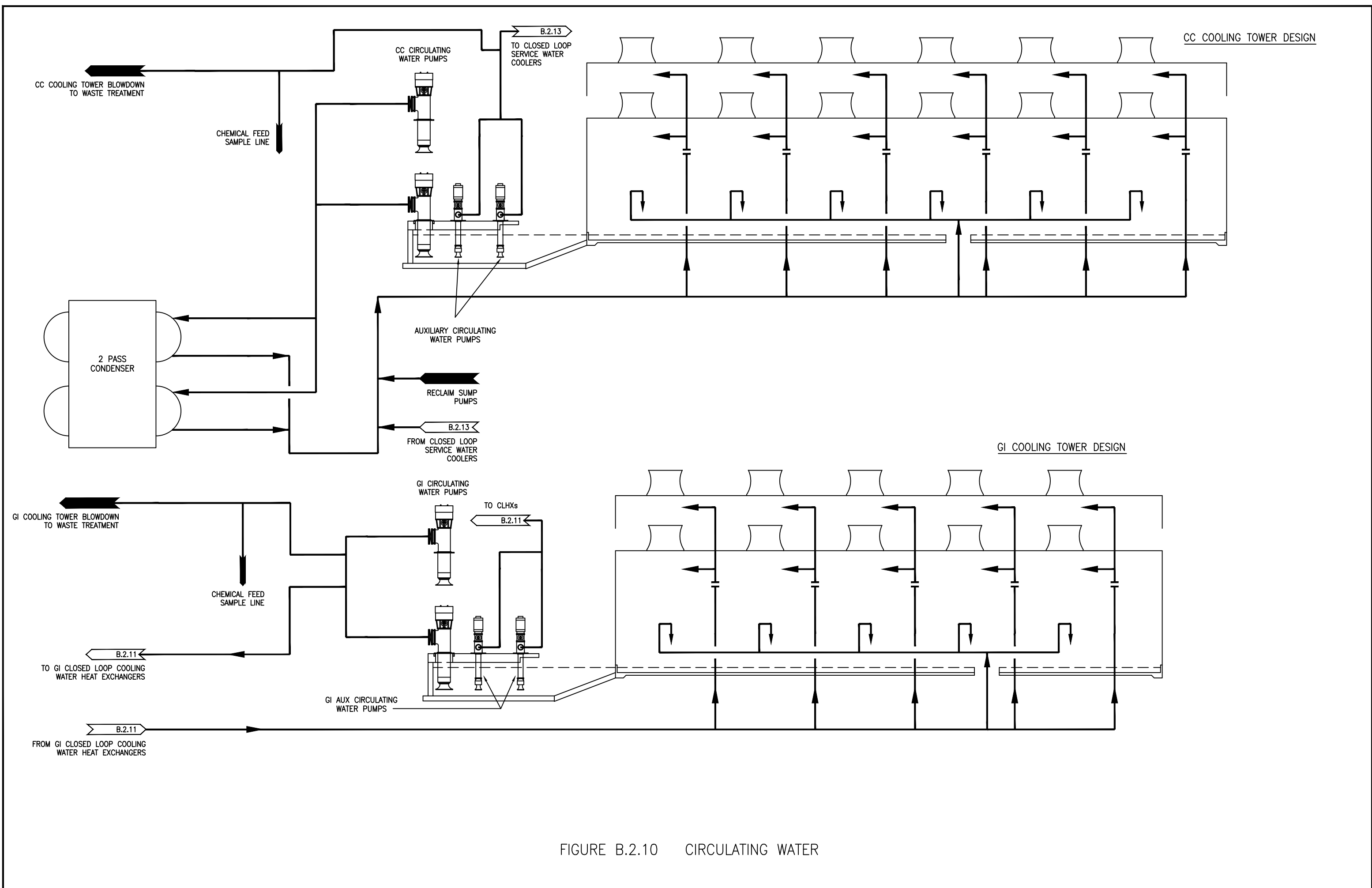


FIGURE B.2.8 FEEDWATER SYSTEM



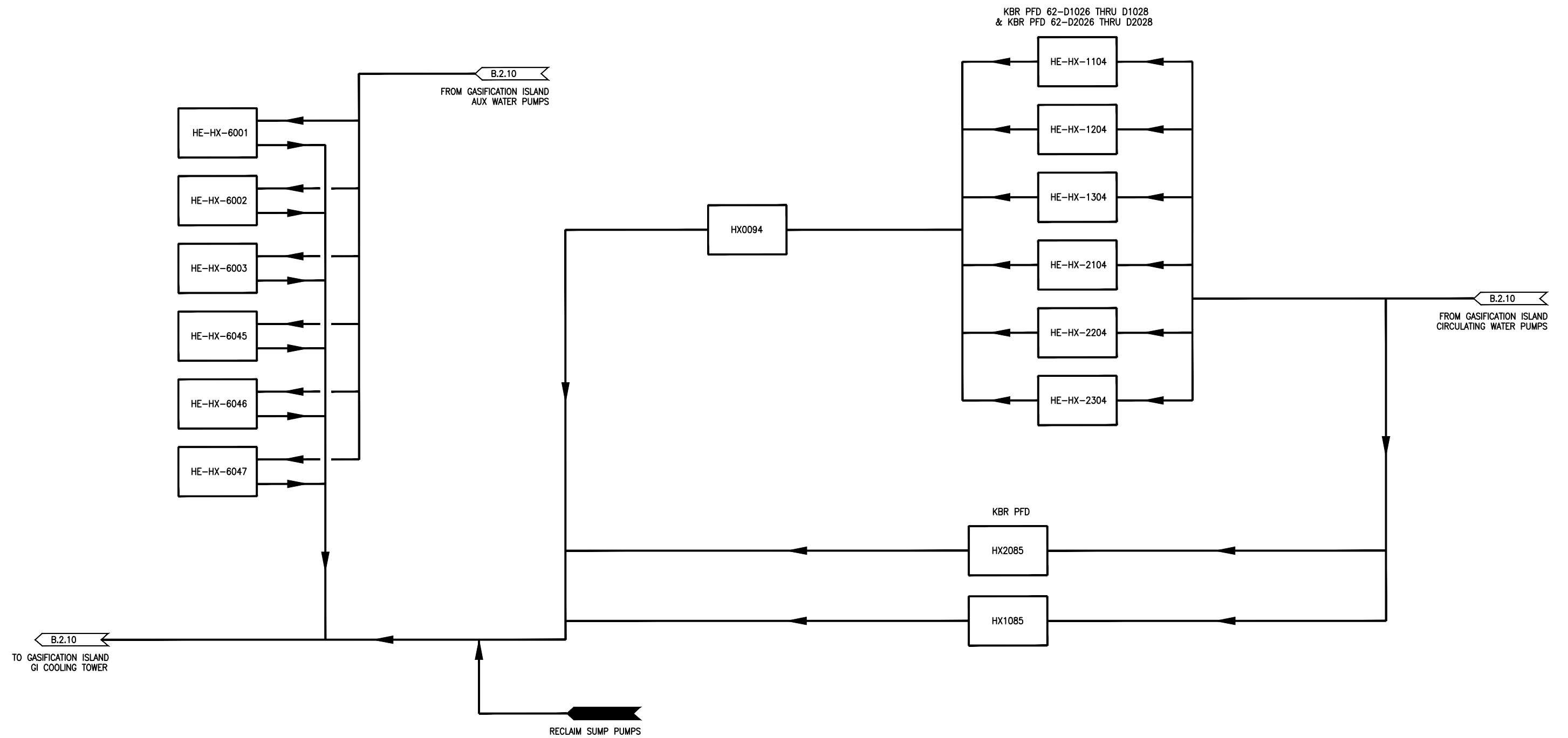


FIGURE B.2.11 GI COOLING WATER

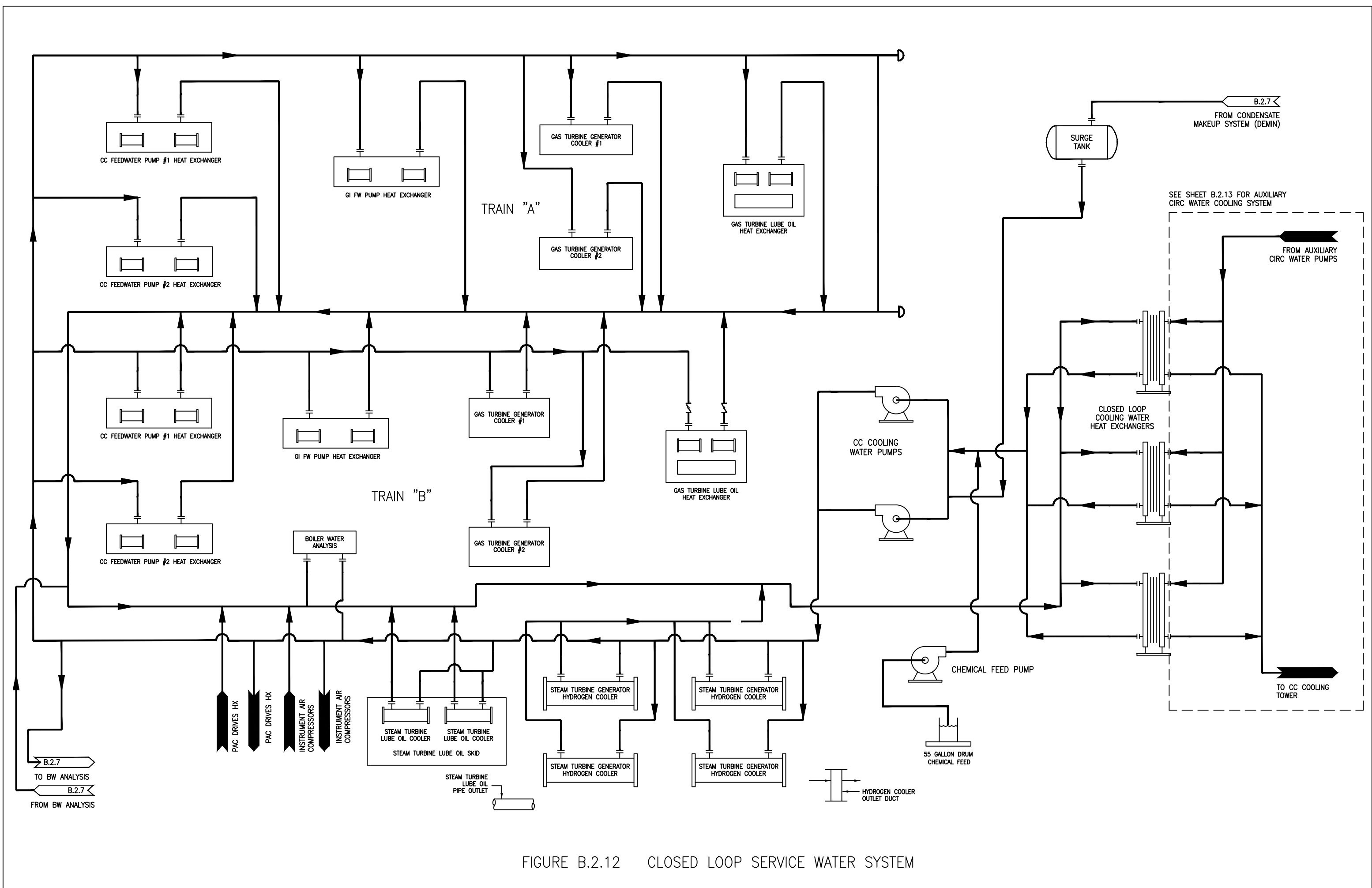


FIGURE B.2.12 CLOSED LOOP SERVICE WATER SYSTEM

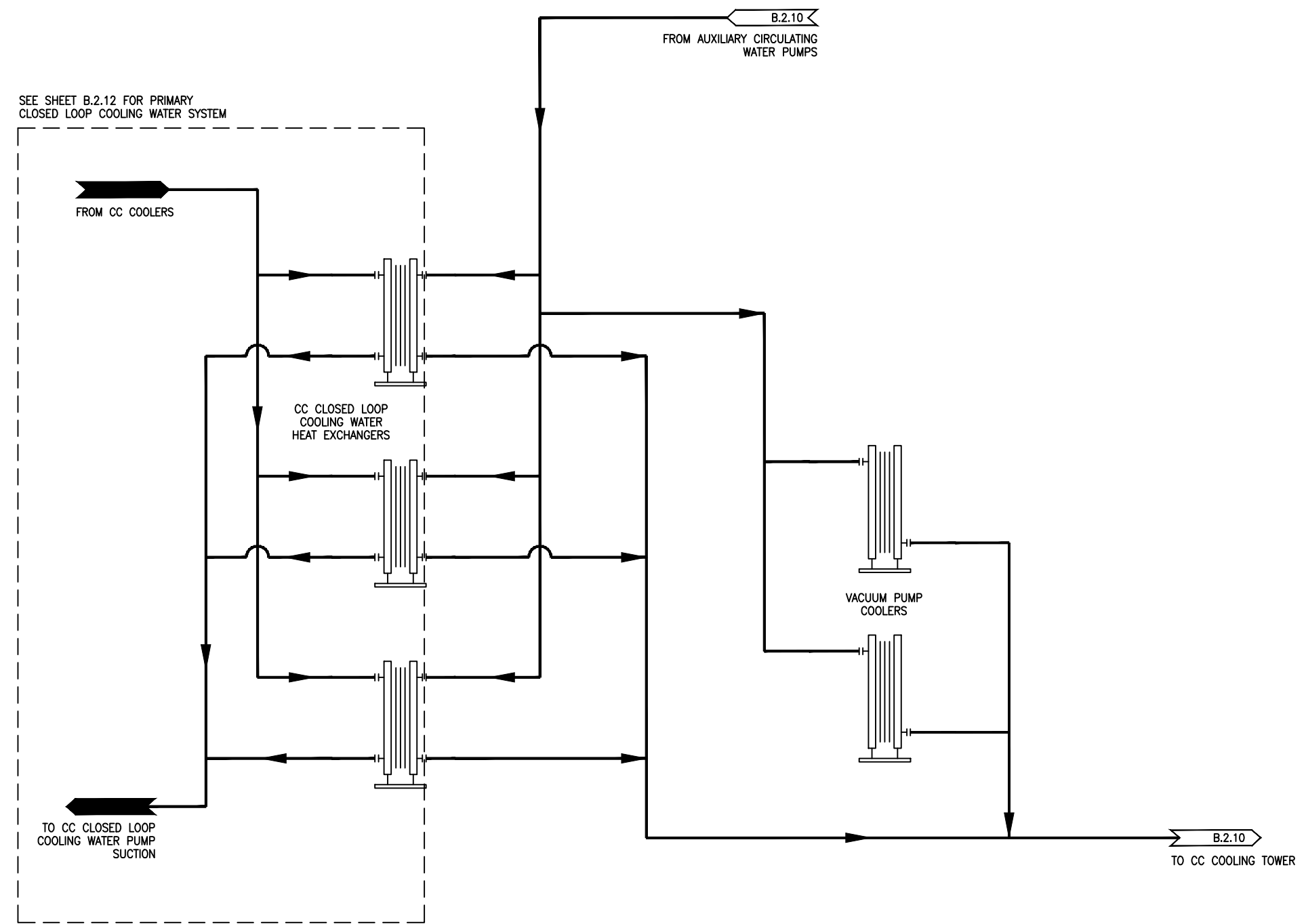


FIGURE B.2.13 AUXILIARY CIRCULATING WATER COOLING SYSTEM

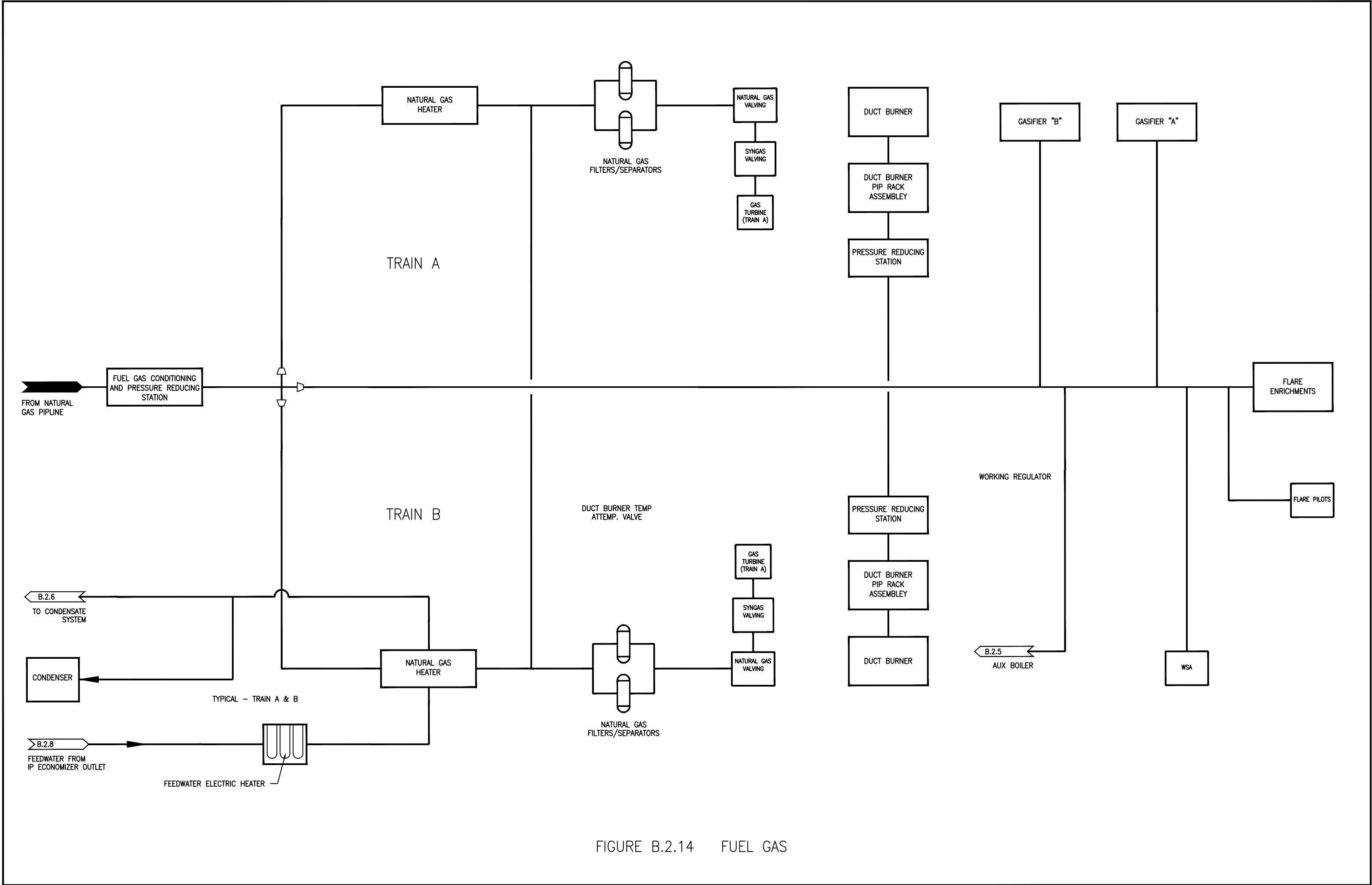


FIGURE B.2.14 FUEL GAS

Appendix C

Water Balance

- Figure C.1 – Site Overall Water Balance Diagram
- Figure C.2 – Water Balance

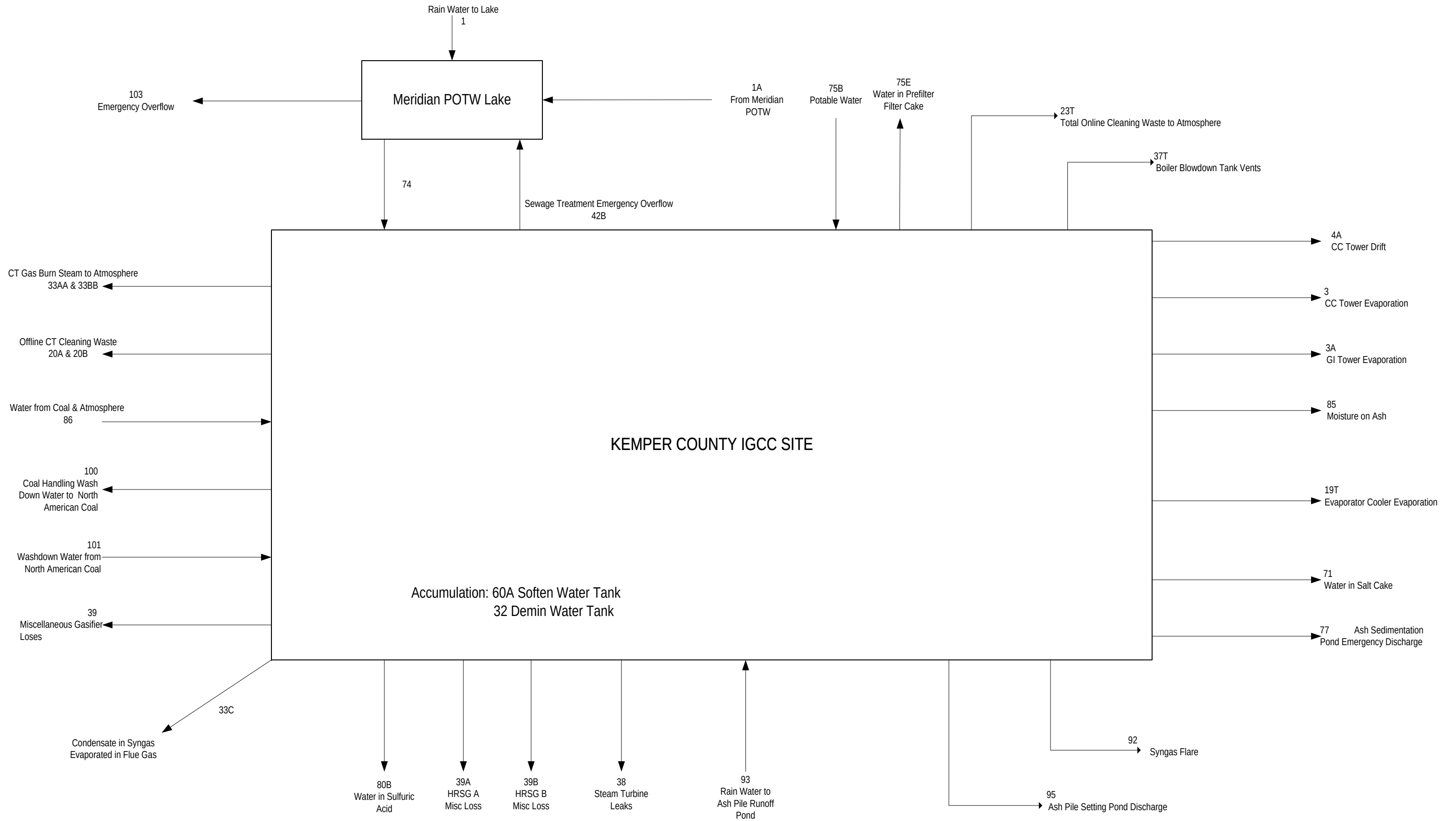


Figure C.1- Overall Site Water Balance Diagram

Kemper County IGCC ^{1,2}		
Line No.		Flow, gpm
1	Rain fall to makeup reservoir	513.4
1A	Water required from Meridian POTW	2893.3
3	CC Cooling tower evaporation	2483.0
3A	Gasifier Island Cooling tower evaporation	1862.0
4	CC Cooling tower drift	0.8
4A	Gasifier Island Cooling tower drift	0.6
19T	Total evaporative cooler evaporation	54.0
20A	CC CT-A off line wash water and waste	0.00
20B	CC CT-B off line wash water and waste	0.00
23T	total on line waste to atmosphere	0.0
32	Demin water tank accumulation	244.7
33AA	Condensate in syn gas evaporated in flue gas CTA	26.1
33BB	Condensate in syn gas evaporated in flue gas CTB	26.1
33C	Total condensate in syn gas to atmosphere	52.2
37T	Total HRSG blowdown tank vents	2.04
38	Steam turbine leaks	2.0
39	Misc. losses at Gasifier A&B	12.0
39A	Misc. losses at HRSG A	10.0
39B	Misc. losses at HRSG B	10.0
42B	Sewage to treatment	0.0
60A	Filtered water tank accumulation	0.0
71	Filter press to salt storage	0.02
74	Water from Meridian POTW Lake	3406.7
75B	potable water to site	0.0
75E	dewatered filtered back wash solids	0.3
77	Ash sedimentation basin emergency discharge	0.0
80B	Water in Sulfuric Acid	24.0
85	Future water to moisturized gasification ash	0.0
86	Water from coal and atmosphere	1091.0
92	Syn gas flare	0.0
93	Rain water to ash pile runoff pond	260.0
95	Ash sedimentation basin recycle	260.0
100	Coal handling wash water	98.0
101	Coal handling wash water returned from Mine wash water collection sump	98.0
103	Meridian POWT storage reservoir emergency over flow	0.0

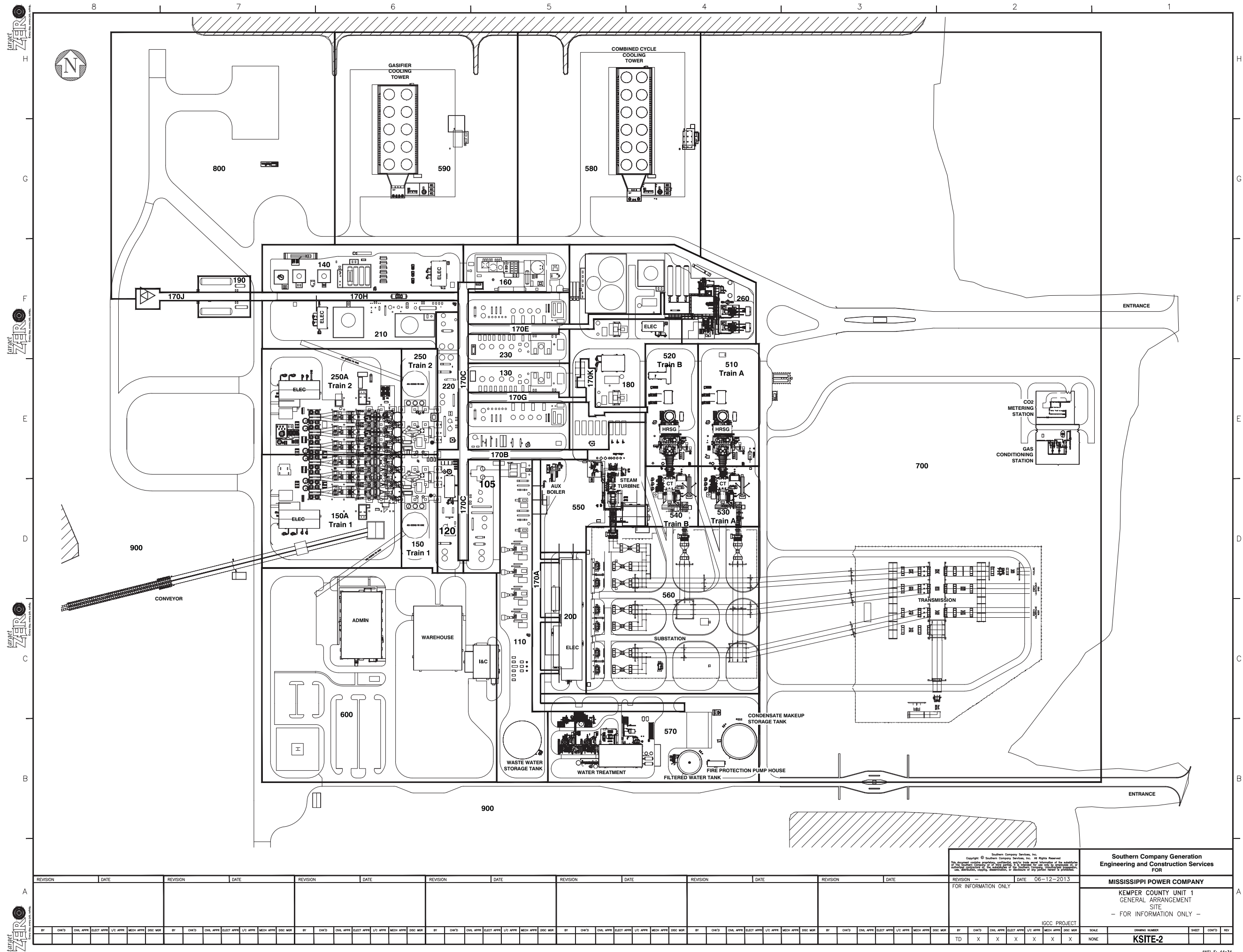
¹Flows are block flows unless otherwise noted

²Syn Gas- HHV Coal

Figure C.2- Water Balance

Appendix D

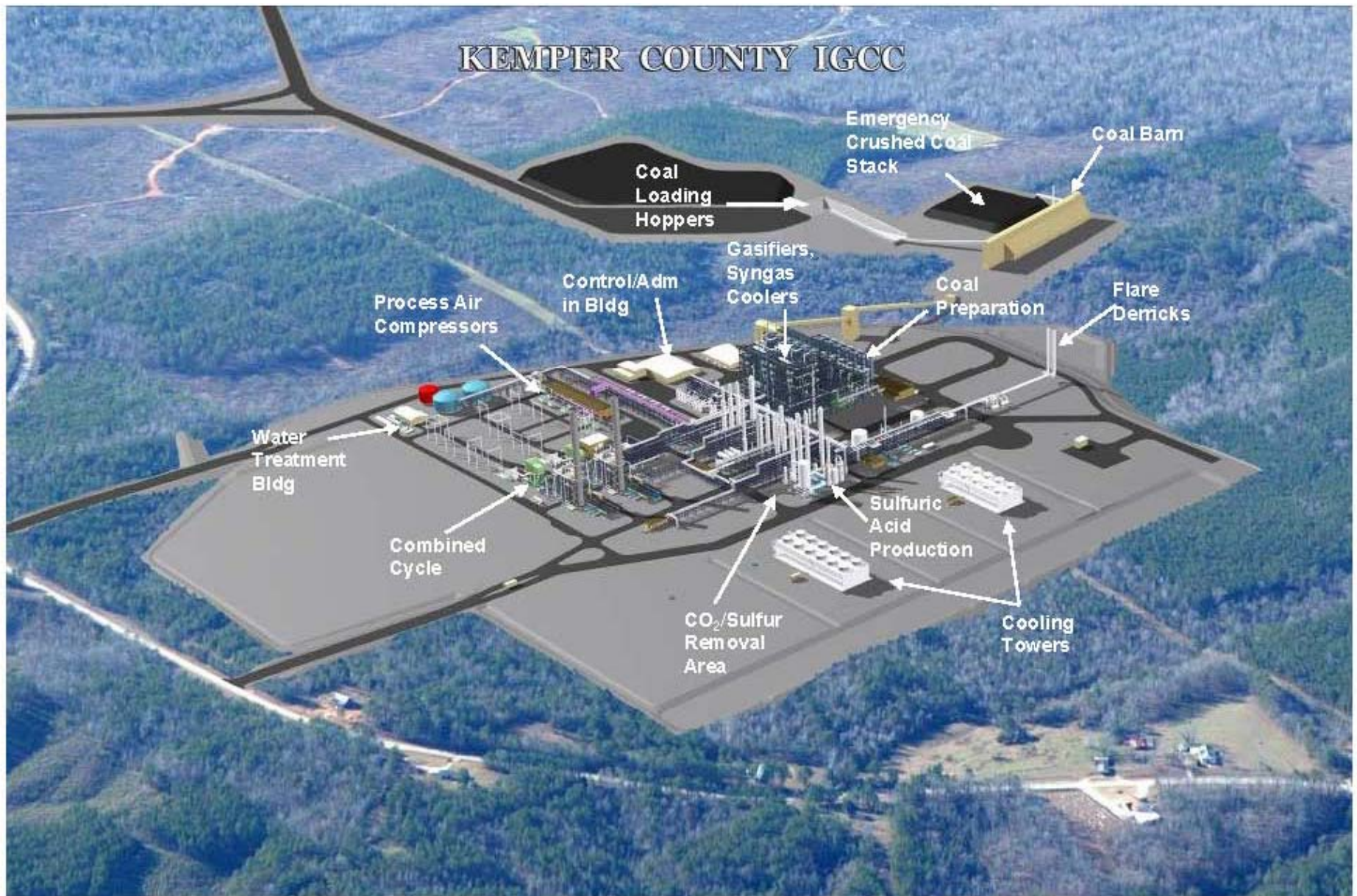
Site Layout Drawing



Appendix E

Site Renderings

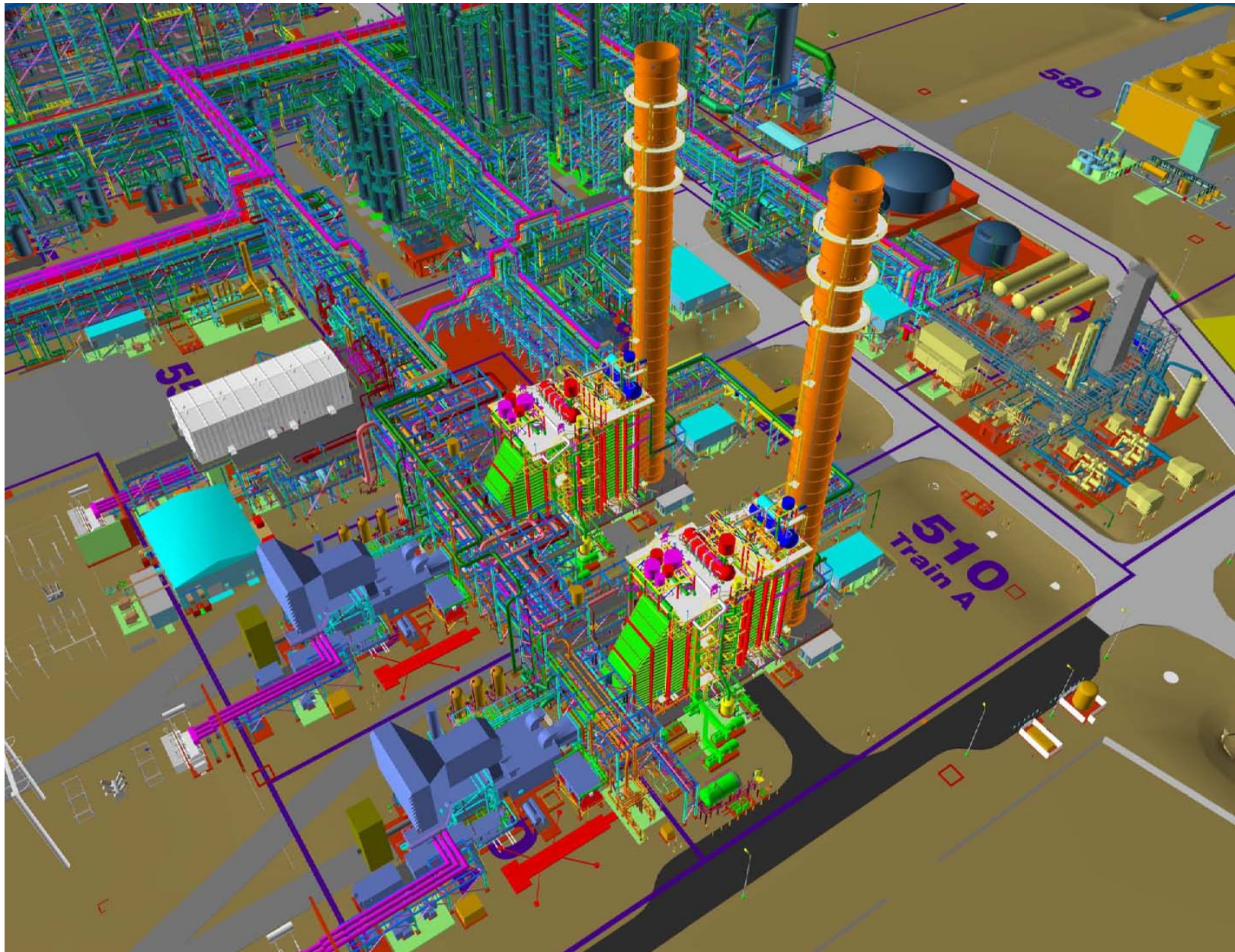
- Figure E.1– Overall site looking southwest
- Figure E.2 – Site looking southwest
- Figure E.3 – Power Island
- Figure E.4 – Site looking southeast
- Figure E.5 – Site looking north



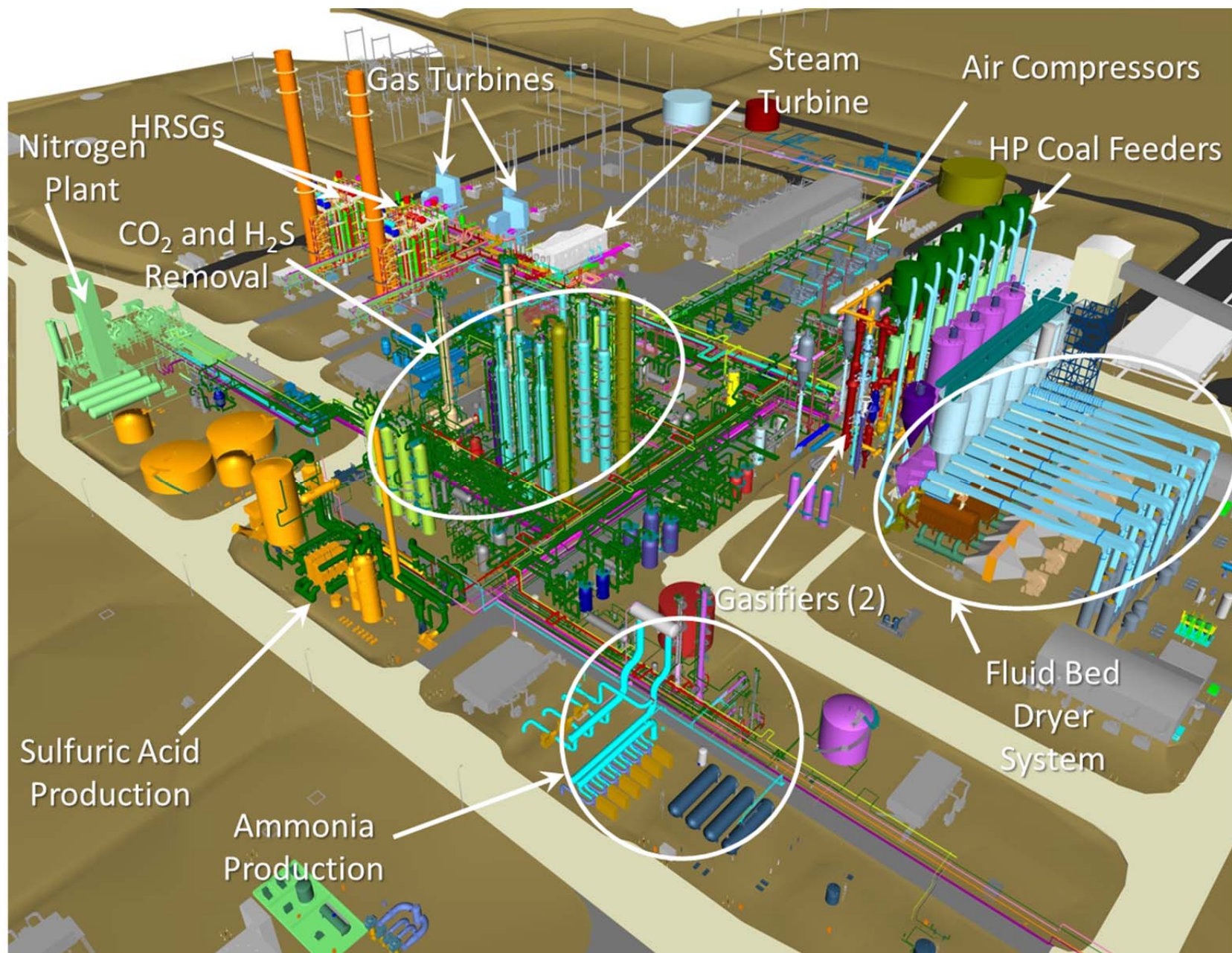
Rendering E.1 – Overall site looking southwest



Rendering E.2 – Site looking southwest



Rendering E.3 – Power Island



Rendering E.4 – Site looking southeast



Rendering E.5 – Site looking north

Appendix F

Site Pictures

- Picture F.1 – Site looking southwest
- Picture F.2 – Gas cleanup
- Picture F.3 – Overall site picture



Picture F.1 – Site looking southwest



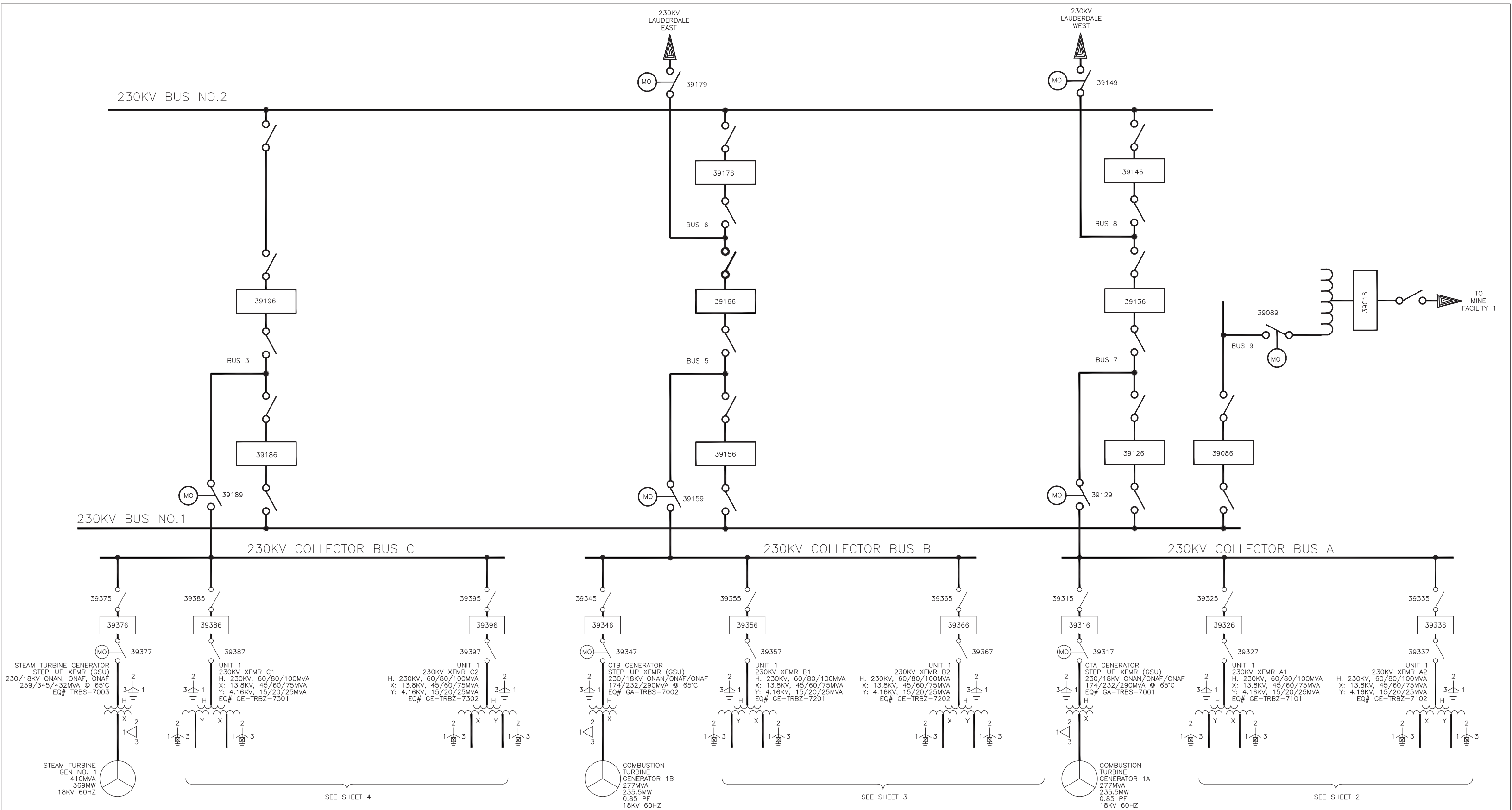
Picture F.2 – Gas cleanup

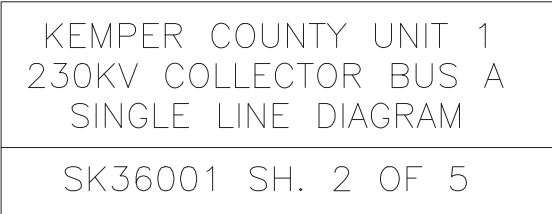


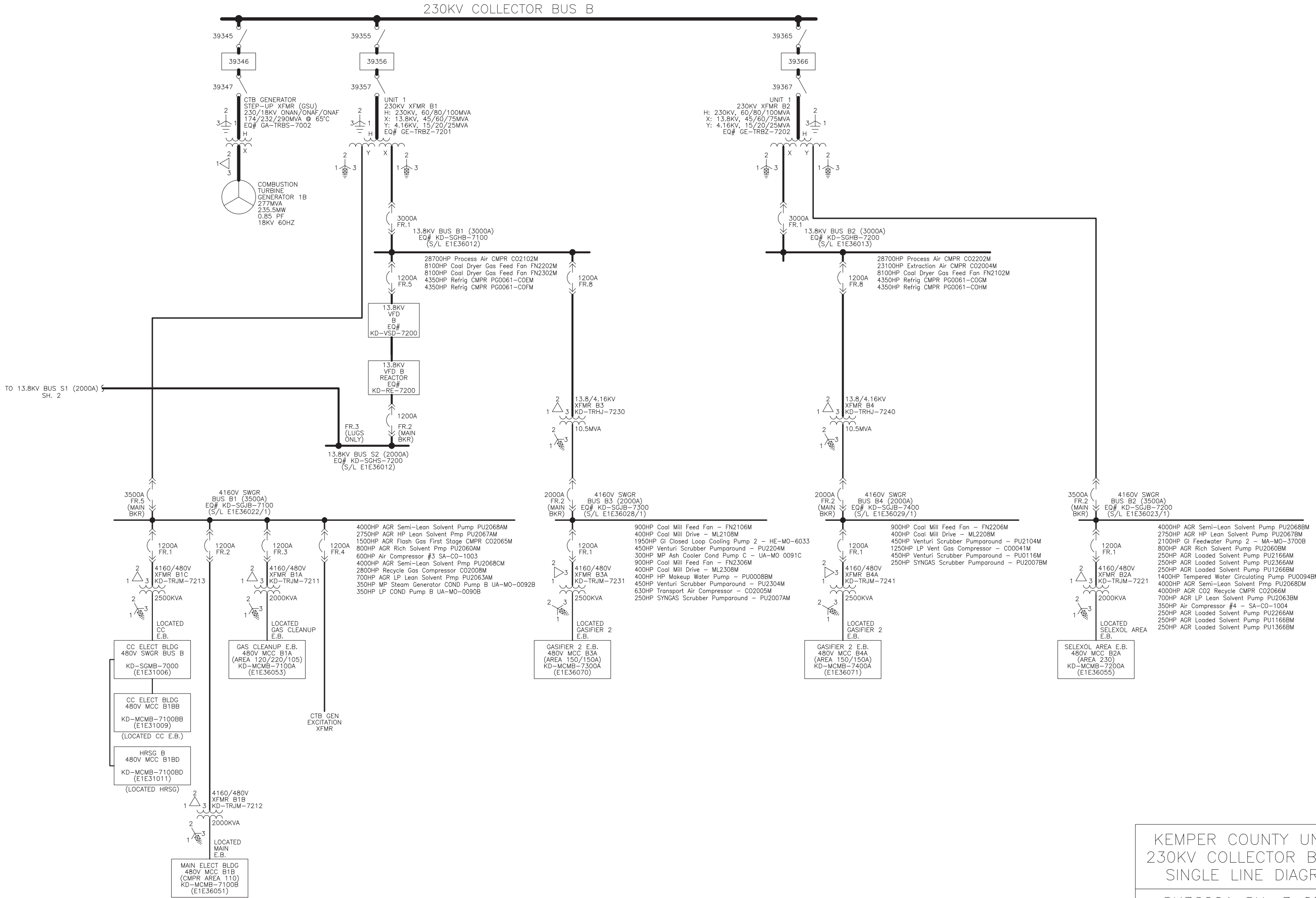
Picture F.3 - Overall site picture

Appendix G

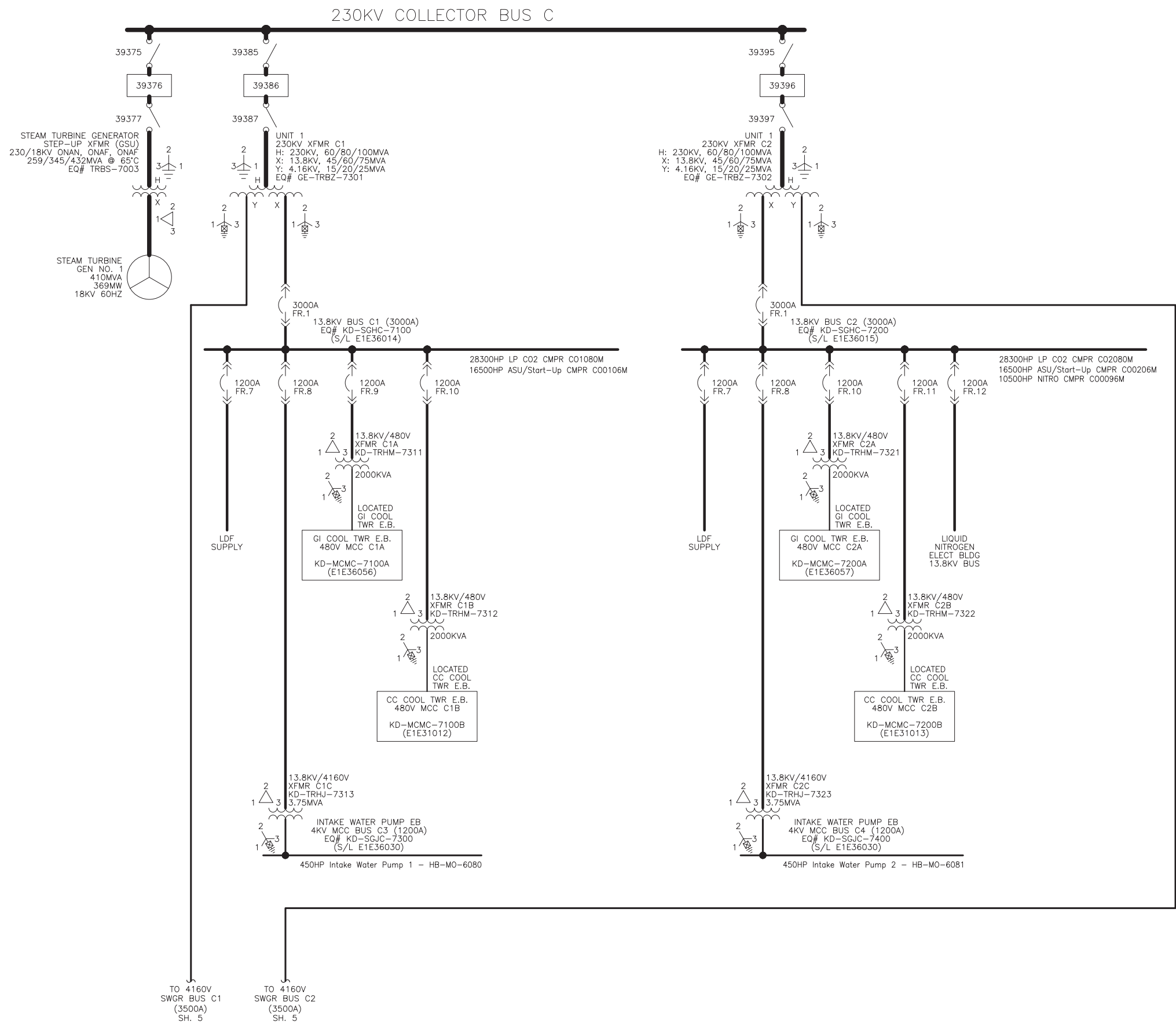
Electrical Single Line Diagram

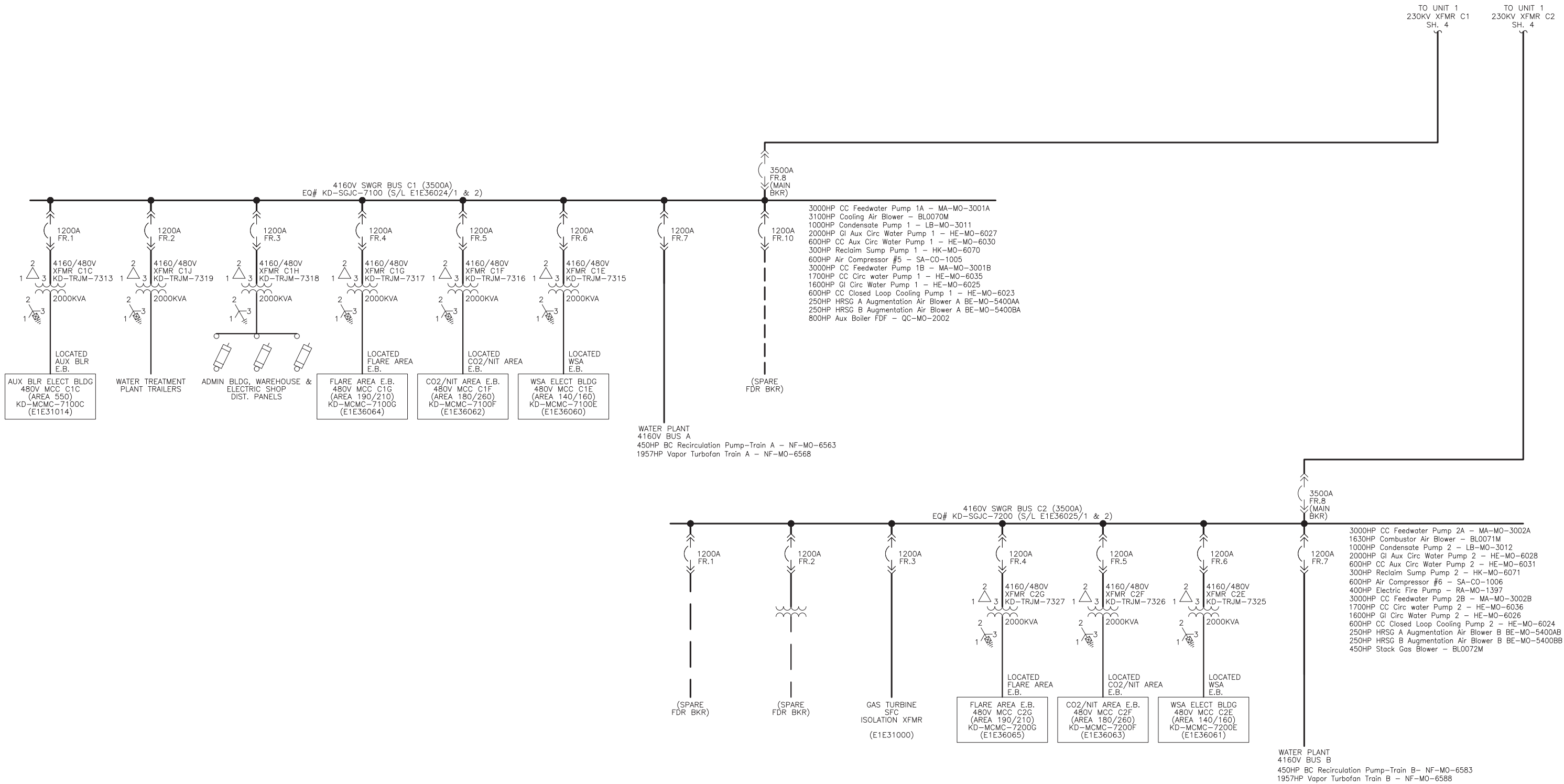






KEMPER COUNTY UNIT 1
230KV COLLECTOR BUS B
SINGLE LINE DIAGRAM





Appendix H

Equipment List

Appendix H.1 – Equipment List
Gasification Island

Equipment Tag Number	Item Description
A0057	AGR solvent sump
AH0070	WSA combustor
AH1102/1202/2102/2202	Gasifier start-up burners
AH1103/1203/1303/2103/2203/2303	Gasifier second start-up burners
BL0002	Coal silo baghouse exhaust blower
BL0009A/B	Ash moisturizer vent scrubber blower
BL0070	Cooling air blower
BL0071	Combustor air blower
BL0072	Stack gas blower
BR0097	LP/acid gas flare
BR0099	Ammonia flare
BR1098/2098	HP flare
CL0009A/B	Venturi scrubber, #1 & #2 ash conditioner discharge
CL0009A/B-TK1	Ash scrubber tank
CL0042	Hydrogen sulfide stripper
CL0044	Wastewater ammonia stripper
CL0052	Wastewater ammonia purifier
CL0070	Quench column
CL0071	Scrubber column
CL1006/2006	Ammonia scrubber
CL1007/2007	Syngas scrubber
CL1060/2060	AGR H ₂ S absorber
CL1063/2063	AGR regenerator
CL1064/2064	AGR concentrator
CL1101A/B/C/D/1201A/B/C/D/1301A/B/C/D/2101A/B/C/D/2201A/B/C/D/2301A/B/C/D	Venturi scrubber
CL1161/1261/1361/2161/2261/2361	AGR CO ₂ absorber
CO0041	LP vent gas compressor
CO0041 LO	LP vent gas compressor lube oil skid
CO0096	Nitrogen compressor
CO0096 LO	Nitrogen compressor lube oil skid
CO0106/0206	ASU/startup air compressor
CO0106/0206 LO	ASU/startup air compressor lube oil skid
CO1004/2004	Extraction air compressor
CO1004/2004 LO	Extraction air compressor lube oil skid
CO1005/2005	Transport air compressor
CO1005/2005 LO	Transport air compressor lube oil skid
CO1008/2008	Recycle gas compressor

Equipment Tag Number	Item Description
CO1008/2008 LO	Recycle gas compressor lube oil skid
CO1065/2065	AGR flash gas compressor
CO1065 LP/2065LP	AGR flash gas first stage compressor
CO1065 LP/2065LP LO	AGR flash gas first stage compressor lube oil skid
CO1065 MP/2065MP	AGR flash gas second stage compressor
CO1065 MP/2065MP LO	AGR flash gas second stage compressor lube oil skid
CO1066/2066	AGR CO ₂ recycle compressor
CO1066/2066 LO	AGR CO ₂ recycle compressor lube oil skid
CO1080/2080	CO ₂ compressor
CO1080 LO/2080 LO	CO ₂ compressor lube oil skid
CO1102/1202/2102/2202	Process air compressor package
CO1102/1202/2102/2202 LO	Process air compressor lube oil skid
DR0002	Filtrate drum
DR0004	Recovered water drum
DR0006	Filter press feed tank
DR0040	Wastewater drum
DR0041	DR0040 light HC drain pot
DR0042	HX0042 level pot
DR0044	HX0044 level pot
DR0045	Wastewater ammonia stripper reflux drum
DR0047	Hydrocarbon drain drum
DR0048	HX0095 level pot
DR0049	HX0059 level pot
DR0050	HX0052 level pot
DR0051	Wastewater ammonia purifier reflux drum
DR0056	AGR water break drum
DR0057	AGR sump drum
DR0058A/B/C/D	Ammonia storage drum
DR0070	MP steam drum
DR0071	Acid vessel
DR0090	LP condensate drum
DR0091	IP condensate drum
DR0092	Blowdown flash drum
DR0093	Cooling water drum
DR0094	Tempered water drum
DR0095	LP blowdown flash drum
DR0097	LP/acid gas flare KO drum

Equipment Tag Number	Item Description
DR0099	Ammonia flare KO drum
DR1003/2003	Extraction air compressor KO drum
DR1005/2005	Transport air compressor KO drum
DR1007/2007	HX1008/2008 level pot
DR1008/2008	HP steam drum
DR1009/2009	Recycle gas compressor KO drum
DR1010/2010	Process condensate KO drum
DR1012/2012	Transport air cooler KO drum
DR1023/2023	HX1023/2023 level pot
DR1027/2027	HX1027/2027 level pot
DR1030/2030	CCAD steam drum
DR1043/2043	PLD vent gas drum
DR1054/2054	AGR lean solvent refrigerant drum
DR1060/2060	AGR feed KO drum
DR1061/2061	AGR solvent KO drum
DR1062/2062	AGR stripped gas KO drum
DR1063/2063	AGR rich solvent flash drum
DR1064/2064	AGR regenerator reflux drum
DR1065/2065	AGR flash gas compressor first stage KO drum
DR1069A/B/2069A/B	AGR regenerator reboiler condensate drum
DR1078/2078	LP CO ₂ KO drum
DR1079/2079	MP CO ₂ KO drum
DR1080/2080	AGR flash gas compressor second stage KO drum
DR1089/2089	HP flare KO drum
DR1098/2098	HP flare seal drum
DR1153/1253/1353/2153/2253/2353	AGR loaded solvent refrigerant drum
DR1155/1255/1355/2155/2255/2355	AGR semi-lean solvent refrigerant drum
DR1166/1266/2166/2266	AGR HP CO ₂ flash drum
DR1167/1267/2167/2267	AGR MP CO ₂ flash drum
DR1168/1268/2168/2268	AGR LP CO ₂ flash drum
DR1196/1296/1396/2196/2296/2396	Nitrogen surge drum
ED1101/1201/1301/2101/2201/2301	Roll crusher airlock educator
FD0001	Coal silo baghouse airlock
FD0005A/B	Coal silo dust collection conveyors
FD0007	Coarse ash feeder
FD0009A/B/C/D	Ash storage silo discharge rotary feeder
FD0027A/B/C	Filter press transfer conveyor
FD0028	Transport conveyor

Equipment Tag Number	Item Description
FD0031	Pyrite drag chain conveyor no. 1
FD0032	Pyrite drag chain conveyor no. 2
FD0033	Pyrite drag chain conveyor no. 3
FD0034	Pyrite bucket elevator
FD0035	Pyrite baghouse
FD1011/2011	Gasifier bottoms drain pot feeder
FD1102/1202/1302/2102/2202/2302	Crushed coal feeder
FD1103/1203/1303/2103/2203/2303	Multi-clone air lock
FD1104/1204/1304/2104/2204/2304	PC cyclonic baghouse air lock
FD1108/1208/1308/2108/2208/2308	Fluid bed dryer discharge feeder
FD1110A/B/1210A/B/1310A/B/2110A/B/ 2210A/B/2310A/B	Gasifier coal feed lock vessel
FD1112/1212/1312/2112/2212/2312	Roll crusher airlock
FD1115A/B/1215A/B/1315A/B/2115A/B/ 2215A/B/2315A/B	Gasifier coal feed dispense vessel
FD1116A/B/1216A/B/1316A/B/2116A/B/ 2216A/B/2316A/B	Gasifier coal feed system (PDAC)
FD1119/1219/1319/2129/2229/2319	Crushed coal silo deinventory airlocks
FD1120A/B-1/2/3/4/5/6/1220A/B-1/2/3/4/5/6/ 2120A/B-1/2/3/4/5/6/2220A/B-1/2/3/4/5/6	CFAD pressure let-down device
FD1121/1221/1321/2121/2221/2321	Dryer outlet HP rotary valve
FD1122/1222/1322/2122/2222/2312	Dryer outlet LP rotary valve
FD1124/1224/1324/2124/2224/2324	Multiclone collection conveyor
FD1125/1225/1325/2125/2225/2325	Multiclone transfer conveyor
FD1126/1226/1326/2126/2226/2326	Coal mill pyrites conveyor
FD1130-1/2/3/4/1230-1/2/3/4/2130-1/2/3/4/ 2230-1/2/3/4	CCAD pressure let-down device
FL0001A/B/C	Recovered water filter
FL0002	Coal silo dust collection
FL0005A/B/C	Filter press
FL0007	Coarse ash silo baghouse
FL0008A/B/C/D	Ash storage silo baghouse
FL0035	Pyrite baghouse
FL0061	AGR solvent makeup filter
FL0070	Cooling air blower inlet filter
FL0071	Wet ESP
FL0111/0211	ASU/startup air compressor intake air filter
FL1010/2010	Micron filter
FL0012A/B/C/D	Ash silo secondary baghouse
FL1018/2018	CCAD cooler vent filter
FL1060/2060	AGR solvent filtration system
FL1082/2082	CO ₂ compressor inlet filter

Equipment Tag Number	Item Description
FL1103/1203/1303/2103/2203/2303	Multi-clone
FL1104/1204/1304/2104/2204/2304	PC cyclonic baghouse
FL1106/1206/2106/2206	Particulate control device (PCD)
FL1109/1209/2109/2209	Process air compressor intake air filter
FL1120A/B/1220A/B/2120A/B/2220A/B	CFAD clinker catcher
FL1130/1230/2130/2230	CCAD clinker catcher
FN0035	Pyrite baghouse fan
FN1102/1202/1302/2102/2202/2302	Coal dryer gas feed fan
FN1102/1202/1302/2102/2202/2302 LO	Coal dryer gas feed fan lube oil skid
FN1105/1205/1305/2105/2205/2305	PC cyclonic baghouse flush fan
FN1106/1206/1306/2106/2206/2306	Coal mill feed fan
FN1106/1206/1306/2106/2206/2306 LO	Coal mill feed fan lo skid
HX0003	ASU/startup compressor after cooler
HX0040	LP vent gas compressor pre-cooler
HX0041	Hydrogen sulfide stripper feed preheater
HX0042	Hydrogen sulfide stripper reboiler
HX0044	Wastewater ammonia stripper reboiler
HX0045	Wastewater ammonia stripper condenser
HX0046	Wastewater ammonia stripper trim condenser
HX0051	Ammonia product condenser
HX0052	Wastewater ammonia purifier reboiler
HX0054	Wastewater ammonia purifier condenser
HX0056	Wastewater cooler
HX0059	Makeup water trim heater
HX0070	Waste heat steam generator
HX0071	1st interbed cooler
HX0072	2nd interbed cooler
HX0073	Process gas cooler
HX0074	WSA condenser
HX0075A/B	Air heater (electrical)
HX0076	Acid cooler
HX0077A/B	Ammonia evaporator (electrical)
HX0087	Start up diesel heater
HX0090	LP condensate drum vent condenser
HX0091	HRSG condensate heater
HX0094	Tempered water trim cooler
HX0095	Tempered water heater
HX1005/2005	Transport air compressor precooler

Equipment Tag Number	Item Description
HX1006/2006	Transport air cooler
HX1007/2007	Scrubber pumparound heater
HX1008/2008	Scrubber pumparound IPS heater
HX1009/2009	Shift feed recuperator I
HX1011/2011	Shift feed recuperator II
HX1019/2019	Extraction air trim cooler
HX1020/2020	High temp. syngas recuperator
HX1021/2021	Intermediate temp. syngas cooler
HX1022/2022	Low temp. syngas recuperator
HX1023/2023	Export syngas trim heater
HX1024/2024	Low temp. syngas cooler
HX1025/2025	Low temp. syngas trim cooler
HX1026/2026	Transport air compressor trim cooler
HX1027/2027	Process condensate trim heater
HX1028/2028	Extraction air recuperator
HX1029/2029	Extraction air cooler
HX1030/2030	Primary CCAD cooler
HX1031/2031	CCAD steam condenser
HX1032/2032	Recycle gas compressor spillback cooler
HX1034/2034	Lower secondary CCAD cooler
HX1035/2035	Start up/sulfiding heater
HX1060/2060	AGR feed product exchanger
HX1061/2061	AGR lean/rich solvent exchanger
HX1062/2062	AGR stripped gas cooler
HX1063A/B/2063A/B	AGR regenerator reboiler
HX1064/2064	AGR regenerator condenser
HX1065/2065	AGR flash gas cooler
HX1066/2066	AGR CO ₂ recycle compressor after cooler
HX1067A/B/2067A/B	AGR lean solvent chiller
HX1080/2080	AGR flash gas compressor spillback cooler
HX1085/2085	CO ₂ compressor aftercooler
HX1086/2086	AGR flash gas cooler
HX1101/1201/1301/2101/2201/2301	PC drying tempered water heater
HX1102/1202/1302/2102/2202/2302	PC drying steam heater
HX1104/1204/1304/2104/2204/2304	Venturi scrubber pumparound cooler
HX1110/1210/2110/2210	Primary syngas cooler/steam generator
HX1112/1212/2112/2212	Primary syngas cooler/superheater I
HX1113/1213/2113/2213	Primary syngas cooler/superheater II
HX1114/1214/2114/2214	Primary syngas cooler/economizer I

Equipment Tag Number	Item Description
HX1116/1216/2116/2216	Primary syngas cooler/economizer II
HX1118/1218/2118/2218	PCD fines receiver
HX1168/1268/1368/2168/2268/2368	AGR semi-lean solvent chiller
HX1169/1269/1369/2169/2269/2369	AGR loaded solvent chiller
ME0001	Gasifier structure freight elevator
ME0002	Gasifier structure personnel elevator
ML1107/1207/1307 /2107/2207/2307	Roll crusher
ML1108/1208/1308/2108/2208/2308	Coal mill
ML1108/1208/1308/2108/2208/2308 LO	Coal mill lube oil console
MX0002A/B/C/D	Ash conditioner
MX0006	Filter press feed tank agitator
MX0070	Ammonia/air mixer
MX1002/2002	Upper/lower mixing zone
PG0040	Carbon bed filter package
PG0054	Anhydrous ammonia truck loading
PG0060	AGR antifoam injection package
PG0061	AGR refrigeration package
PG0070A/B/C/D	Mist control unit
PG0071	Sulfuric acid truck loading
PG0072	Hydrogen peroxide dosing package
PG0096	Nitrogen generator
PG0097	Liquid nitrogen storage
PG0098	Flame front generator
PG1007/2007	Transport air dryer
PG1080/2080	CO ₂ dehydration package
PG1102/1202/1302/2102/2202/2302	Coal drying package
PU0002A/B	Excess water pump
PU0005A/B	Filtrate pump
PU0008A/B	HP makeup water pump
PU0011A/B	Ash moisturizer vent scrubber pumparound pump
PU0013A/B	Recovered water booster pump
PU0040A/B	Wastewater bottoms pump
PU0042	Wastewater pump
PU0045A/B	Wastewater ammonia stripper reflux pump
PU0047A/B	Hydrocarbon drain pump
PU0050A/B	Wastewater ammonia purifier reflux pump
PU0053A/B	Anhydrous ammonia loading pump
PU0054A/B	Anhydrous ammonia rerun pump

Equipment Tag Number	Item Description
PU0057A/B	Wastewater ammonia purifier bottoms pump
PU0059A/B	Anhydrous ammonia reflux makeup pump
PU0061A/B	AGR sump pump
PU0062A/B	AGR solvent transfer pump
PU0070A/B	Acid pump
PU0071A/B	Acid product pump
PU0072A/B/C	Quench water pump
PU0073A/BC/D/E	Scrubber water pump
PU0074A/B	Hydrogen peroxide dosing pump
PU0075A/B	Wet ESP effluent pump
PU0076A/B	Sulfuric acid transfer pump
PU0077A/B/C/D	Sulfuric acid product pump
PU0079A/B	Sulfuric acid offspec tank pump
PU0090A/B	LP condensate pump
PU0091A/B	HRSG condensate booster pump
PU0092A/B	MP steam generation condensate pump
PU0093A/B	Cooling water circulation pump
PU0094A/B	Tempered water circulation pump
PU0095A/B	50 wt. % caustic pump
PU0096A/B	Diesel pump
PU0097A/B	LP/acid gas flare KO drum pump
PU0099A/B	Ammonia flare KO drum pump
PU1006A/B/2006A/B	Sour water pumparound pump
PU1007A/B/2007A/B	Syngas scrubber pumparound pump
PU1010A/B/2010A/B	Process condensate pump
PU1058A/B/2058A/B	AGR solvent filtration system pumps
PU1060A/B/2060A/B	AGR rich solvent pump
PU1063A/B/2063A/B	AGR LP lean solvent pump
PU1064A/B/2064A/B	Agr regenerator reflux pump
PU1067A/B/2067A/B	AGR HP lean solvent pump
PU1068A/B/C/D/2068A/B/C/D	AGR semi-lean solvent pump
PU1069A/B/2069A/B	AGR water makeup pump
PU1089A/B/2089A/B	HP flare KO drum bottoms pump
PU1101/1201/1301/2101/2201/2301	Venturi scrubber pump
PU1104/1204/1304/2104/2204/2304	Venturi scrubber pumparound
PU1166A/B/1266A/B/1366A/B/ 2166A/B/2266A/B/2366A/B	AGR loaded solvent pump
RX0070	SCR reactor
RX0071	SO ₂ converter

Equipment Tag Number	Item Description
RX1002/2002	Pressurized transport gasifier
RX1080/2080	CO ₂ mercury adsorber
RX1104/1204/2104/2204	COS hydrolysis reactor
RX1106/1206/2106/2206	Mercury adsorber
RX1108/1208/2108/2208	WGS reactor I
RX1109/1209/2109/2209	WGS reactor II
SI0007	Coarse ash silo
SI0008A/B/C/D	Ash storage silo
SI0035	Pyrite holding bin
SI1102/1202/1302/2102/2202/2302	Crushed coal silo
SI1110A/B/1210A/B/1310A/B/2110A/B/ 2210A/B/2310A/B	Gasifier coal feed storage bin
SP1001	Desuperheater
ST0060	WSA stack
TK0042	Wastewater storage tank
TK0060	AGR selexol storage tank
TK0070	Hydrogen peroxide tank
TK0071	Sulfuric acid rundown tank
TK0072A/B	Sulfuric acid product tank
TK0073	Sulfuric acid offspec tank
TK0095	50 wt. % caustic tank

Appendix H.2 – Equipment List
Power Island

Equipment Tag Number	Item Description
DD-FL-4145A/B4150A/B	Natural gas filter/separator
DD-HX-4135A/B	Natural gas heat exchanger
EF-GE-4003	Steam turbine generator
FA-HX-6001/6002	Steam turbine main oil cooler
FA-HX-6003/6004/6005/6006	Steam turbine generator hydrogen gas cooler
FA-TU-3001	HP steam turbine
FB-TU-3001	IP steam turbine
FC-TU-3001	LP steam turbine
FE-CD-3001	Gland steam condenser
HE-HX-6001/6002/6003/6045/6046/6047	Gasifier island closed loop circ water heat exchanger
HE-HX-6004/6005/6006	Combined cycle closed loop cooling water heat exchanger
HE-PU-6010	Chemical feed pump
HE-PU-6023/6024	Combined cycle closed loop cooling water pump
HE-PU-6025/6026	Gasifier island circulating water pump
HE-PU-6027/6028	Gasifier island auxiliary circulating water pump
HE-PU-6030/6031	Combined cycle auxiliary circulating water pump
HE-PU-6035/6036	Combined cycle circulating water pump
HK-CL-6000A	Gasifier island cooling tower
HK-CL-6000B	Combined cycle cooling tower
HK-PU-6070/6071	Reclaim sump pump
HK-SU-6085	Reclaim sump
LA-CD-3001	Steam turbine condenser
LB-PU-3011/3012	Condensate pumps
LE-PU-3014/3015/3025	Condensate makeup pump
LE-PU3016/3017	Auxiliary boiler Deaerator makeup pump
LG-BW-3001A/B	Gland steam exhauster
LJ-HX-3009/3010	Vacuum pump heat exchanger
MA-HX-6040A/B/6041A/B	Combined cycle feedwater pump heat exchanger
MA-HX-6042A/B	Gasifier island feedwater pump heat exchanger
MA-PU-3001A/B/3002A/B	Combined cycle feedwater pump
MA-PU-3700A/B	Gasifier feedwater pump
MD-HT-3140A/B	Feedwater electric heater

Equipment Tag Number	Item Description
NF-PU-0044A/B	Gasifier island wastewater sump pump
NF-PU-0055A/B	South gasifier structure sump pump
NF-PU-0056A/B	North gasifier structure sump pump
NF-PU-0078A/B	Sulfuric acid area sump pump
NF-PU-0085A/B	Gas cleanup area sump pump
NF-PU-1065A/B/2065A/B	AGR area sump pump
NF-PU-6002A/B/6003A/B	HRSG sump pump
NF-PU-6042A/B/6043A/B	Waste water sump pump
NF-PU-6064/6065	Steam turbine sump pump
NF-SP-6005A/B	Waste water oil water separator
NF-SU-0044	Gasifier island wastewater sump
NF-SU-0060A	South gasifier structure sump
NF-SU-0060B	North gasifier structure sump
NF-SU-0078	Sulfuric acid area sump
NF-SU-0080	Gas clean up area sump
NF-SU-1065/2065	AGR area sump
NF-SU-6001A/B	HRSG sump
NF-SU-6049A/B	Waste water sump
NF-SU-6061	Steam turbine sump
QC-AX-2001	Auxiliary boiler
QC-DA-2003	Deaerator storage tank
QC-DA-2004	Deaerator
QC-FN-2002	Auxiliary boiler FD fan
QC-HX-2006	Auxiliary boiler superheater
QC-PU-2005/2006	Auxiliary boiler feedwater pump
VB-HX-6022A/B/6025A/B	Gas turbine lube oil cooler
VG-HX-6023A/B/6024A/B	Gas turbine generator cooler
VG-TU-3010A/B	Gas turbine
WG-HR-2001A/B	Heat recovery steam generator (HRSG)
WJ-TK-2002	Main steam blowdown tank