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Project Title:
Small-Scale Flexible Advanced Ultra-Supercritical Coal-Fired Power Plant with Integrated Carbon Capture

Pre-FEED Contract:
Coal-Based Power Plants of the Future – Design Basis Report

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1 Concept Background

1.1 Coal-fired Power Plant Scope Description

The concept for the "Small-Scale Flexible Advanced Ultra-Supercritical Coal-Fired Power Plant" is a pulverized coal power plant with superheat (SH) temperature/reheat (RH) temperature/SH outlet pressure of 1202°F/1238°F/4800 psia (650°C/670°C/330 bar) steam conditions, capable of flexible and low-load operation, consistent with the stated goals of the Department of Energy's (DOE's) Coal FIRST (Flexible, Innovative, Resilient, Small, Transformative) initiative.

The major components of the plant include a pulverized coal-fired boiler in a close-coupled configuration; air quality control system (AQCS) consisting of an ultra-low NOx firing system, selective catalytic reduction (SCR) system for NOx control, dry scrubber/fabric filter for particulate matter (PM)/SO2/Hg/HCl control; an amine-based post combustion carbon capture system; and a synchronous steam turbine/generator. A block diagram of the overall plant (Concept 1) is shown in Figure 1-1. Note that the block diagram shows only the steam extractions for the carbon capture system for simplicity and clarity of the diagram. The boiler/AQCS, steam turbine and carbon capture sub-systems are discussed in more detail in the following sections.

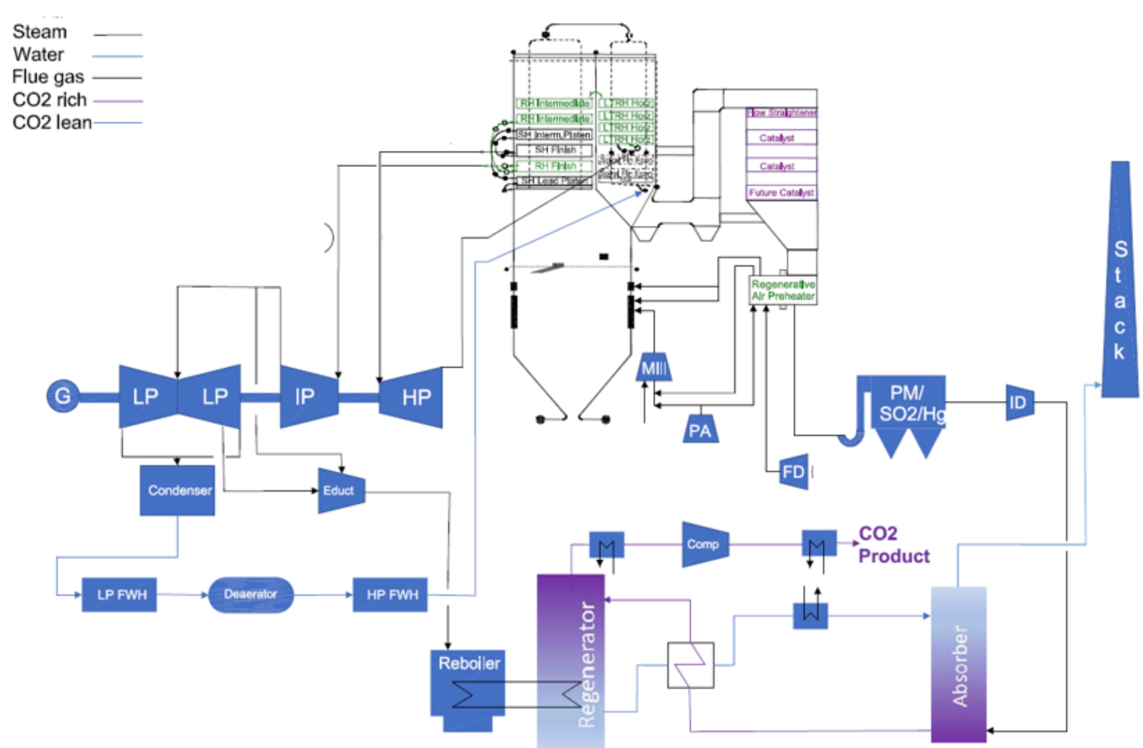

Figure 1-1 Small, Flexible AUSC Coal Power Plant Block Diagram (Concept 1)

A second plant concept (Concept 2) incorporates the addition of a gas turbine heat recovery boiler to supply process steam to separate carbon capture systems for removal of carbon dioxide (CO_2) from the flue gas of the AUSC coal power plant and from the flue gas of the gas turbine/heat recovery boiler. This allows the AUSC coal plant steam turbine to operate at its highest efficiency by eliminating steam extractions for process steam. A block diagram of the overall plant is shown in Figure 1-2.

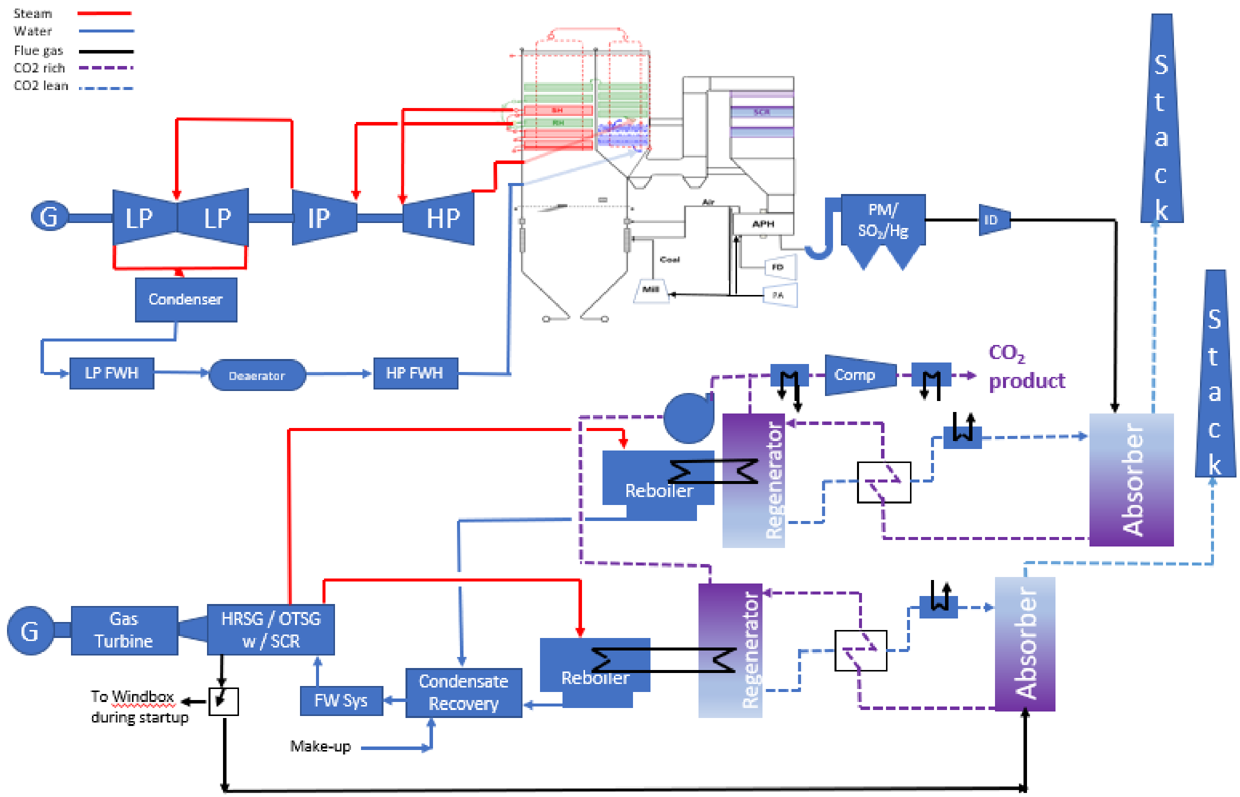

Figure 1-2 AUSC Coal plus Gas Turbine/Heat Recovery Boiler Power Plant Block Diagram (Concept 2)

1.2 Plant Capacity

The AUSC coal plant steam cycle has a gross generation capacity of 300 MW in both Concept 1 and Concept 2. Because of the auxiliary load requirements and process steam extractions, the AUSC coal plant has a net generation capacity of 209 MW in Concept 1. Because of the auxiliary load requirements, the AUSC coal plant has a net generation capacity of 276 MW in Concept 2. Additionally, the gas turbines in Concept 2 have a gross generation capacity of 121 MW.

This small, flexible AUSC boiler concept was chosen because it is a reasonable compromise between the DOE goals of small plant MW capacity and high plant net efficiency. An AUSC turbine island smaller than 300 MW gross would require decreasing main steam temperature and pressure to maintain the minimum steam volumetric flow rate at the HP turbine inlet geometry required for minimum bucket lengths and nozzle carrier clearances.

In Concept 2, two gas turbines are required to supply flue gas volumetric flow to the two heat recovery boilers. Supplemental natural gas duct firing is required in two heat recovery boilers to supply sufficient process steam for two carbon capture systems.

Overall generation capacities of the power plants are 300 MW gross / 209 MW net for Concept 1, and 413 MW gross / 389 MW net for Concept 2.

1.3 Plant Location

The plant location is a 300 acre greenfield site in the Midwestern U.S. with level topography. Coal is supplied by rail or truck delivery, and natural gas is supplied by pipeline. Fly ash and bottom ash disposal is off-site. Plant water needs are assumed to be 50% from municipal water supply and 50% from ground water.

1.4 Business Case from Conceptual Design

1.4.1 Market Scenario

The proposed coal power technology for this project is a Small-Scale Flexible Advanced Ultra-Supercritical Coal-Fired Power Plant with post-combustion carbon capture at nominal 300 MWe gross size. This section describes the circumstances around the current coal power market place and how the proposed technology will be designed to counteract scenarios. Factors include:

- Coal type(s)
- CO_2 constraint and/or price
- Domestic and/or international market applicability
- Estimated cost of electricity (and ancillary products) that establishes competitiveness
- Market advantage of the concept
- Natural gas (NG) price
- Renewables penetration

The current market place for coal power varies widely on a regional basis, but in all cases, one or more of the following drivers impact its future viability:

- **Competition against other power sources –** In some regions, coal remains a low-cost generator, while in others, NG-based power is typically more economical due to the availability of low-cost NG (e.g., in the U.S., NG is about half the cost of elsewhere).
- **Drive towards low carbon –** 179 countries have signed the Paris Accord, whose goal is to reduce greenhouse gas (GHG) emissions (typically, countries have pledged to reduce CO_2 emissions on the order of 20–40% from 2012 levels). While the U.S. has not signed the accord, multiple states have enacted low-carbon initiatives including several that have committed to 80% reductions by 2040. Coal, as a fossil fuel, and one that produces double the CO_2 per MWh that NG does, is therefore a bigger target related towards reducing CO_2.
- **Energy security –** In some regions, coal is an abundant natural resource, representing energy security and reducing the need for reliance on fuels or energy from foreign countries. Finding ways to use it more effectively can be critical for these regions.
- **Environmental regulations –** Coal emission regulations – CO, NO_X, hazardous air pollutants, mercury, particulate matter, and SO_X – vary globally, but coal universally remains a tougher permitting challenge than NG.
- **Financing –** Financing is becoming more challenging for larger plants as the future power market has significant uncertainties, especially around carbon. Coal power plants are a

particular challenge (30 banks have stopped financing coal). Smaller plants are thought to be lower risk since they require less capital, and hence have a better opportunity for financing.

- **Meeting a changing market –** The energy market is changing, largely due to the growth of variable renewable energy (VRE). Intermittency requires grid protection provided by dispatchable sources, which largely comes from fossil-based units. In the U.S., some coal power plants are providing such grid support, requiring them to operate more flexibly than they were designed for, which is deleterious to performance. Such operating behavior will likely also occur in other regions as renewables grow, reducing the need for base-load fossil power, while putting extra importance on their ability to provide grid resilience.

1.4.2 Domestic and International Market Applicability

1.4.2.1 United States

New coal power generation deployment has stagnated in the U.S., where coal is often not competitive with NG, or presents significant future environmental risk. There are few known coal power projects advancing in the U.S. and some utilities have pledged to eliminate coal power plants from their portfolio. Several things are likely needed for a significant resurgence in new coal:

- **Increase in the relative price of NG compared to coal –** While this has not been forecasted, it remains a possibility, especially as the demand for NG grows internationally.
- **Larger value for CO_2 either by regulation or for utilization –** If a significant market for CO_2 develops, this could help drive new coal power with carbon capture and storage (CCS). Enhanced oil recovery (EOR) remains the primary form of utilization and tapping into this market will likely be a necessity for any new coal plants with CCS in the short term. Governmental programs like 45Q provide a value for captured CO_2 as well, which aids in the overall project economics. In general, the worth of capturing CO_2 must be greater than the cost, which is not the case in most circumstances. Hence, the value must increase (perhaps by regulation) and/or the cost must decrease for coal CCS projects to be viable.
- **Regulatory certainty –** Uncertainty in future regulations increases risk, which makes coal power projects difficult to finance and generators more reticent to build them. Recent revisions to the Clean Air Act section 111(b) have been proposed to alter the definition of best system of emission reduction for new coal units to the most efficient demonstrated steam cycle in combination with best operating practices, instead of requiring partial CCS as was the case in the previous version. Getting this in place and adding certainty around the low-carbon future may be important for growth in coal power.

1.4.2.2 Outside the U.S.

Outside the U.S., different regions have different appetites for coal. A summary is given below.

- **China –** China is the largest coal producer and consumer in the world and coal accounts for 70% of its total energy consumption. Although China anticipates coal capacity growth of about 19% over the next five years, this comes at a time of slowing electricity demand. As a result, many coal plants have been operating at reduced capacity factors. Due to this, and growing environmental concerns, the Chinese government has announced it will postpone building some coal plants that have received approval and halt construction of others. However, there is still a need for new power, especially in the west, and a large supply of coal exists in China.

Coal plants that are efficient (a key criterion) and smaller will likely be of appeal. CO_2 utilization for EOR and enhanced gas recovery are also growing possibilities.

- **Europe –** In Western Europe, following the Paris Accord, several countries announced plans to end coal-fired generation within their borders or set in place emissions reductions targets that would effectively require an end to coal without CCS: France by 2023, the United Kingdom and Austria by 2025, the Netherlands by 2030, and Germany by 2050. This makes new coal power difficult in the region. In Eastern Europe, there is more potential for new coal as brown coal resources are abundant and cheap. Efficiency and cleanliness will be keys in this region. CCS may be a challenge, however, as underground storage is not popular, although Norway is developing a potential sink for CO_2 in the North Sea.
- **India –** India has large domestic coal reserves and recently had the largest growth in coal use of any country. India's draft National Electricity Plan indicates that the 50 GW of coal capacity in construction is sufficient to meet the country's needs for the next decade, but new coal remains a possibility. Most new coal plants proposed are supercritical units as India has imposed a carbon tax on coal, which is about \$6.25/tonne-CO_2, making efficiency important in the region. Work has also been done to locate reservoirs for CCS.
- **Japan –** As of 2018, Japan had over 44 GW of coal plants in operation, with over 6 GW permitted or in construction. Japan's climate pledge is to reduce GHG emissions by 26% from 2013 levels by 2030, so improving efficiency and potentially performing CCS are important factors in Japan. Smaller-scale plants are also likely, in part because space is an issue. Japan is very interested in novel coal power cycles, including sCO_2 power cycles.
- **Korea –** Coal produces over 40% of Korea's power and the country still has plans for additional coal power, despite having a climate pledge with a 30% reduction in GHG emissions by 2030. Efficiency is also important in Korea, and they have strong interest in sCO_2 power cycles, having invested in the Department of Energy's (DOE) STEP program.
- **Others –** Coal is growing in some regions in Africa (e.g., Kenya and Zimbabwe) and Southeast Asia (e.g., Indonesia and Vietnam), which presents opportunities, although low-cost coal power will be critical in these areas. Smaller-scale plants will be a definite plus.

1.4.3 Market Advantage of the Proposed Concept

- The proposed concept consists of a pulverized coal power plant with superheat (SH) temperature/reheat (RH) temperature/SH outlet pressure of 1202°F/1238°F/4800 psia (650°C/670°C/330 bar) steam conditions with 41.3% (HHV) plant net efficiency, capable of flexible and low-load operation. The cycle has a gross generation capacity of 300 MW and optimizes the trade-off between maximum efficiency and minimum MW rating to achieve high efficiency while maintaining the high-pressure steam turbine inlet size within design and manufacturing limits as far as blade length and rotor diameter. This smaller size also reduces the financing hurdle and makes the system a better fit for niche locations that lack a low-cost NG supply, where power demands are typically lower.
- The steam cycle conditions selected for the proposed concept do not represent the upper range of AUSC conditions. By limiting the superheat steam temperatures in the proposed concept to 650°C, and reheat steam temperatures to 670°C, the amount of higher-cost, nickel-based alloy materials required is limited, thus helping to control capital costs. Further, the ability to use nickel-based alloys, such as Inconel 740H (IN740H), below their maximum operating range allows the designer to take advantage of their mechanical properties to support faster operational transitions,

while minimizing fatigue damage and extending component life. Based upon market experience, GE sees the present cycle conditions for this concept as a sweet spot for small scale AUSC technology deployment in the future.

- The system provides enhanced cycling flexibility for an optimized operation regime for transient operation (i.e., faster start-up and load changes) and allows for flexible response to grid requirements, savings at start-up of initial power and thermal power consumption, and a more agile power plant that can provide more opportunities to bid in power markets. This plant incorporates stringent grid code compliance with dynamic cycles developed for optimal primary, secondary, and tertiary frequency support, minimum-load operation on coal or coal and auxiliary fuel at lowest cost, ability to reduce start-up times, ramp-up times to maximize dispatch times, and automatic switchover between operating modes for better dispatch.
- With proper design and equipment specification, the pulverized coal combustion technology being used for this system can burn most types of coal, including variants with higher sulfur, moisture, and/or ash. The technology can also co-fire biomass, providing further fuel flexibility.
- The system includes an amine-based carbon capture system that has been proven in a 25 tonne CO_2 per day slip-stream. Thermal performance of 2.3 to 2.4 GJ/tonne CO_2 at 90% capture was consistently demonstrated. Mixed steam turbine extractions are utilized to optimize the carbon capture plant operation at variable loads. Net plant HHV efficiency with 90% carbon capture is expected to be 33.8%.

1.4.4 Estimated Cost of Electricity to Establish Competitiveness of Concept

An 84-MWth coal-fired combined-heat-and-power plant was recently built at the University of Alaska Fairbanks for $248M, which equates to ~$8000/kW. In this area, the relative annual fuel costs for the plant were about $5M for coal and $20M for NG. In such areas where NG supply is not available or is inconsistent, if coal can be delivered cheaply, smaller-scale coal power plants have an opportunity.

This example shows that dis-economies-of-scale increase the $/kW cost by nearly 80-100% for much smaller, 100 MW class coal plants. For the proposed 300 MW class coal plant, dis-economies of scale will be much less, with perhaps only a 30% increase in $/kW cost for conventional coal plants.

DOE's Low Rank Coal Baseline studies[1] show total plant costs (TPC), escalated to 2019 dollars of $2406/kW and $4243/kW, respectively, for a 550-MWe net supercritical coal power plant without (Case S12A) and with CCS (Case S12B). The resulting cost of electricity (COE) values are $74.3/MWh and $143/MWh, respectively, with a CO_2 captured cost of $52/tonne. DOE's atmospheric oxy-combustion baseline plant[2] (Case S12F) has a 2019 TPC of $4,084 with a COE of $133/MWh. Of relevance in the U.S., DOE's nominal 630-MWe net NG power plant[3] has 2019

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[1] "*Cost and Performance Baseline for Fossil Energy Plants Vol 3b: Low Rank Coal Electricity: Combustion Cases",* DOE/NETL-2011/1463, March 2011

[2] "*Cost and Performance for Low-Rank Pulverized Coal Oxycombustion Energy Plants"*, NETL Report No. 401/093010

[3] "*Cost and Performance Baseline for Fossil Energy Plants, Volume 1a: Bituminous Coal and Natural Gas to Electricity, Revision 3*, DOE/NETL-2015/1723, July 2015

COE values of \$48/MWh and \$83/MWh without and with CCS and CO_2 captured cost of \$87/tonne. EPRI has analyzed these data from DOE and determined:

- The NG price to make the NG with CCS COE equal to PRB coal (at \$1.15/MBtu) with CCS COE must go from \$4.39/MBtu to \$11.11/MBtu (approximately a 2.5 times increase)
- TPC for the proposed technology to equal the COE of supercritical coal with CCS is \$4475/kW, and is \$4000/kW to match the COE of an atmospheric oxy-combustion plant.

TPC for the proposed technology to get the cost of CO_2 captured to \$40/tonne is \$3275/kW. Based on this high-level review, for the proposed system to be competitive, beyond achieving the performance characteristics that have been set for this project, the table below provides cost targets for the technology in various regions and scenarios.

Region	Scenario	Competition	Cost Targets
U.S.	NG not available, coal and EOR / 45Q available	Small coal (300 MWe)	TPC < \$4500/kW
U.S.	NG < \$4.4/MBtu (coal \$1.2/MBtu) and no CO_2 value	NG with CCS	COE < \$80/MWh
U.S.	NG < \$4.4/MBtu (coal \$1.2/MBtu) and CO_2 value of \$50/tonne	NG with CCS	TPC < \$3300/kW; CO_2 cost < \$40/tonne
Africa, Asia, Europe	NG > \$13/MMBtu (coal \$1.2/MBtu)	Coal with CCS	COE< \$120/MWh; TPC < \$4000/kW
Anywhere	CO_2 value of \$50/tonne	Any CCS	CO_2 cost < \$40/tonne
Anywhere	Non-base load operation with CCS	Coal FIRST technologies	TPC < \$4000/kW; CO_2 cost < \$40/tonne;

The first 5 cases in the table assume a base-load unit with 85% capacity factor and ~3M tonnes of CO_2 captured annually. The \$50/tonne value for CO_2 is roughly a summation of EOR with 45Q credits (or 45Q credits for storage only). Option 2, with low NG price and no value for CO_2, is not a competitive option for this technology. So, the cost targets for the technology are TPC = \$4000/kW, COE = \$120/MWh, and CO_2 cost = \$50/tonne. Several additional comments:

- One of the short-term markets will be niche areas where NG supply is limited or unavailable without significant infrastructure investment, where coal can be supplied. In the U.S., this is largely in the west. Opportunities may also exist in Mexico. These applications will be small, perhaps smaller than 300 MWe net. In these cases, the capital costs must be lower than \$5000/kW. The other potential short-term market is in regions where there is an EOR play, e.g., Texas and Wyoming. As a result, this small-size, 300 MW AUSC is likely a better fit in oil & gas markets than larger plants.
- In regions where NG is more expensive (e.g., Africa, Asia, and Eastern Europe), or if NG prices should rise in North America, the technology will be competing directly with other post-combustion capture systems for coal. In these cases, the proposed technology must have

efficiencies that are higher and capital costs that are comparable, and preferably superior (given that small-scale AUSC might be perceived to be higher risk).

- Another factor is if the value of CO_2 is increased (either by a CO_2 price or value) in comparison to the cost of CO_2 captured, then this proposed CCS technology will have more opportunities. Conversely, this system can be constructed or operated without the carbon capture system, if the region does not have a significant CO_2 policy or utilization opportunities (e.g., India or South Africa), or is not focused on low carbon but rather just cheaper power production (e.g., developing nations like Kenya).

2 Process Description

2.1 Proposed Plant Concept

Concept 1 for the "Small-Scale Flexible Advanced Ultra-Supercritical Coal-Fired Power Plant" is a pulverized coal power plant with SH temperature/RH temperature/SH outlet pressure of 1202°F/1238°F/4800 psia (650°C/670°C/330 bar) steam conditions, with appropriate turbine steam extractions for carbon capture system process steam demand. Concept 2 has the same AUSC coal plant without turbine steam extractions, and includes the addition of a gas turbine heat recovery boiler system to supply process steam to separate carbon capture systems for removal of CO_2 from the flue gas of the AUSC coal power plant and from the flue gas of the gas turbine/heat recovery boiler.

The power plant concepts being proposed provide enhanced cycling flexibility for an optimized operation regime for transient operation (i.e., faster start-up and load changes) and allow for flexible response to grid requirements, savings at start-up of initial power and thermal power consumption, and a more agile power plant that can provide more opportunities to bid in competitive power markets. These plant concepts incorporate stringent grid code compliance with dynamic cycles developed for optimal primary, secondary, and tertiary frequency support, minimum-load operation on coal or coal and auxiliary fuel at lowest cost, ability to reduce start-up times, ramp-up times to maximize dispatch times, and automatic switchover between operating modes for better dispatch.

This section lists how the small-scale flexible AUSC coal power plant concept described in this Design Basis Report meets the traits enumerated in RFP 89243319RFE000015.

- High overall plant efficiency (40%+ HHV or higher at full load, with minimal reductions in efficiency over the required generation range). The Concept 1 achieves 33.8% net plant efficiency with integration of carbon capture, which is slightly higher than the average efficiency of the US coal fleet without CO_2 capture. By supplying process steam with a gas turbine/heat recovery boiler system, Concept 2 achieves an overall 38.3% net plant efficiency with integration of carbon capture for both the AUSC coal boiler and gas turbine systems. The AUSC coal boiler net plant efficiency is 41.3% at full load (276 MW net), while the simple cycle gas turbine and heat recovery boiler net system efficiency is 30.6% at full load (110.6 MW net).
- Modular (unit sizes of approximately 50 to 350 MW), maximizing the benefits of high-quality, low-cost shop fabrication to minimize field construction costs and project cycle time. The concept is 300 MW gross capacity and incorporates shop modularization of selected boiler convective pass, AQCS and steam turbine components. Gas turbine capacities are 56.6 MW gross and these units are highly modular.
- Near-zero emissions, with options to consider plant designs that inherently emit no or low amounts of carbon dioxide (amounts that are equal to or lower than natural gas technologies) or could be retrofitted with carbon capture without significant plant modifications. The concept includes selective catalytic reduction for NO_x control and a NID™ dry scrubber/fabric filter for particulate matter, SO_2, mercury and acid gas control.

The concept also includes post-combustion capture for CO_2 control, with 90% carbon capture rate for both the AUSC coal boiler and the gas turbine/heat recovery boiler.

- The overall plant must be capable of high ramp rates and achieve minimum loads commensurate with estimates of renewable market penetration by 2050. The conceptual boiler design for both Concept 1 and Concept 2 includes use of nickel superalloys for selected thick walled components to minimize thermal stress during load cycling, and digital solutions for achievement of the target ramping rates. GE is developing digital technologies to assist existing units in achieving less minimum load of 20% (60 MW gross for Concept 1) or lower. One western US utility has achieved 15-18% minimum load with use of a digital product Digital Boiler + that is under active development. Continuous operation of steam turbine at 20% load is possible, however exact operational requirements for such operation will be finalized in this Pre-FEED stage. The minimum load for Concept 2 is estimated at 20 MW gross, which is one gas turbine operating at 40% load. Since the waste heat boiler has supplemental duct firing, carbon capture process steam requirements can be met at this load as well.

  While the carbon capture process operates below approximately 90% load, steam extraction in Concept 1 has to be moved from IP/LP crossover to IP turbine extraction in order to maintain the 5 bar minimum pressure for the carbon capture process. The additional extraction steam requirement is ~25% of LP inlet flow. This extraction amount is not considered an issue for operation of the LP turbine. Concept 2 eliminates any concerns associated with turbine steam extraction location and flows.

  Methods to reduce cold and warm unit startup times are the subject of present development activities within GE. Unit startup times for Concept 1 presented herein are four (4) hours for cold start and two (2) hours for warm start for Concept 1. These startup times are projected based on previous development activities of units with similar steam conditions. Further reduction of the cold start time requires deeper analysis during the later stages of this Pre-FEED study.

  The plant cold startup times for Concept 2 are as a low as 10 minutes to start the gas turbines and achieve 56.5-113 MW gross generation.

- Integration with thermal or other energy storage to ease intermittency inefficiencies and equipment damage. This is not directly addressed by either of these concepts, and it is anticipated that the proposed concepts have an appropriate size, and sufficient turn-down, to meet the needs of the future power markets, with intermittent renewable generation. However, these concepts would generally be compatible with future advances in thermal or other energy storage.

- Minimized water consumption. This is addressed by use of GE's NID™ technology for flue gas desulfurization. Various waste water stream integration techniques are also used.

- Reduced design, construction, and commissioning schedules from conventional norms by leveraging techniques including but not limited to advanced process engineering and parametric design methods. This is addressed by modular shop fabrications concepts for selected boiler convective pass assemblies, the NID™ system, steam turbine modules, the gas turbines, and the waste heat boiler.

- Enhanced maintenance features including technology advances with monitoring and diagnostics to reduce maintenance and minimize forced outages. This is addressed by including GE's digital tools for condition monitoring and asset management.
- Integration with coal upgrading, or other plant value streams (e.g., co-production). This is not addressed by these concepts.
- Capable of natural gas co-firing. This concept includes side horn gas ignitors for up to 10% natural gas cofiring of the AUSC coal boiler on a heat input basis.

2.2 Target Level of Performance

Table 2-1 below shows the expected plant efficiency range at full and part load and a summary of the emissions control, including CO_2 emissions control.

Table 2-1 Expected Plant Performance and Emissions

Parameter	Concept 1	Concept 2
Size MW gross/net	300 / 209	410 / 386
Ramp rate up/down MW/min	15	15
Cold/Warm start time hours	4 / 2	0.25 / 0.25
	Firing PRB coal	Firing PRB coal / natural gas
Full load net HR MMBtu/MWH	9.908	7.939 / 11.1
Full Load Plant net efficiency %	33.8	41.3 AUSC coal / 30.6 GT
50% Load Plant net efficiency %	33.1	40.3 AUSC coal / 29.6 GT
SO_2 lb/MWh-gross	1.00	0.75
NO_x lb/MWh-gross	0.70	0.70
PM (Filterable) lb/MWh-gross	0.09	0.06
Hg lb/MWh-gross	$3x10^{-6}$	$2x10^{-6}$
HCl lb/MWh-gross	0.010	0.075
CO_2 Capture Rate %	>90%	>90%

The boiler concept for both Concept 1 and Concept 2 includes an innovative close-coupled arrangement. The horizontal high temperature convective surfaces have SH and RH header outlets at the front wall instead of the top of the boiler, yielding 25-30% shorter high energy piping runs than a typical arrangement. Elimination of the tunnel between the furnace exit vertical plane and low temperature convective pass results in a more compact boiler footprint.

The furnace front, rear and side walls along with the first pass front wall, first and second pass division wall and side walls are all up flow fluid cooled. Only the roof and second pass rear wall and are the first circuits after the separator are steam cooled. This innovative arrangement essentially eliminates differential expansion between wall sections allowing faster start-up and higher load ramp rates.

The position of the shared wall between the high temperature and low temperature convective sections can be adjusted during design phase to achieve the convective section cross-sectional area required by design standards for convective pass flue gas velocity to be met independently of tube spacing and furnace plan area design standard requirements for coal type and slagging propensity. The design is highly customizable for different coals or biomass and can be optimized as required. The minimize plant foot print provided by this concept is a better arrangement from a cost perspective than a traditional 2-pass pulverized coal boiler design.

The proposed boiler concept is based on a reference advanced Ultra-Supercritical (USC) boiler with steam parameters of 650°C/670°C/330 bar, but downscaled to an output of 1,704,870lb/hr main steam flow with 300 MWe gross generating capacity. Potential material selections and temperature/pressure conditions for the boiler concept are shown in Figure 2-1**Error! Reference source not found.**. Final material choices, to be completed in the Pre-FEED, will balance the need for operating flexibility and material cost to meet flexibility goals at the lowest cost.

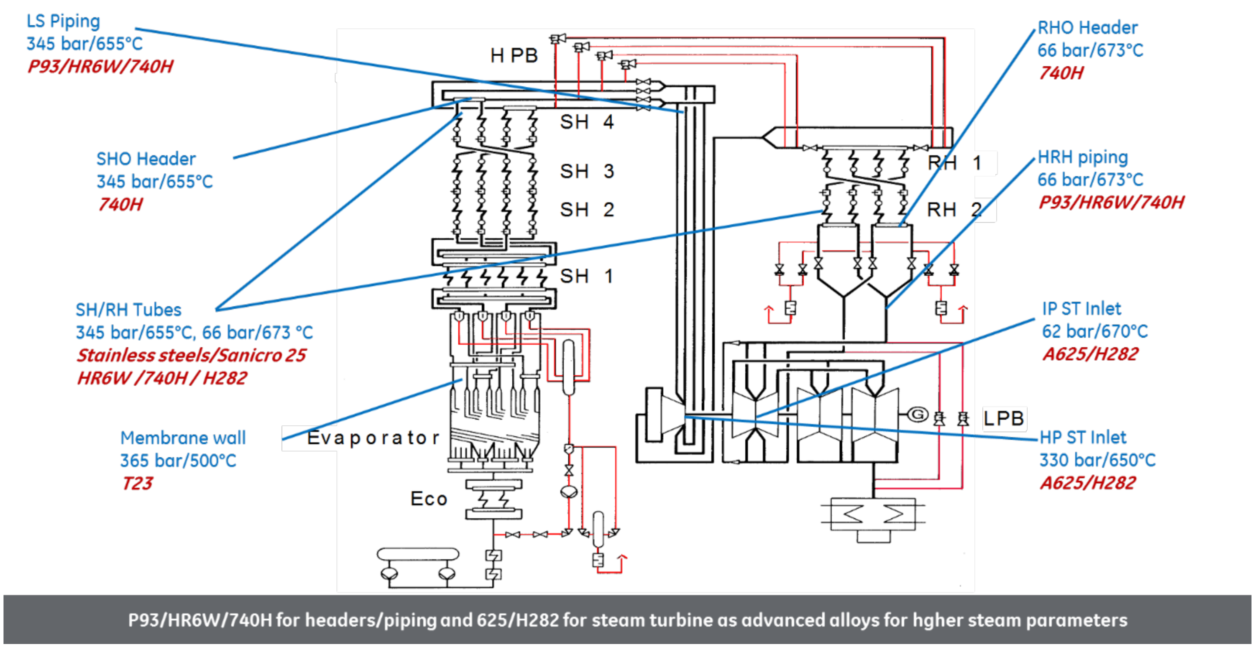


Figure 2-1 Small-Scale Flexible AUSC Coal-Fired Boiler Concept

The air preheater design will be optimized (for example, tri-sector versus quad-sector designs) to gain a maximum heat recovery that allows for an overall reduced heat rate. In general, this will reduce the flue gas temperature leaving the air preheater that will also have a system benefit of reducing the water consumption in the flue gas desulfurization (FGD) system. Air preheater materials that are suitable for a lower flue gas temperature, such as enamel coated heat transfer plates, will be incorporated and the potential impact of mercury oxidation additives on the air preheater will be considered. Corrosion of air preheater plates has been an issue when calcium bromide has been added to the coal in many US power plants using subbituminous coal, and improved designs for corrosion tolerance in this area will be considered.

The particulate control and flue gas desulfurization (FGD) system design approach to be used will be GE's Novel Integrated Desulfurization (NID™) dry FGD/fabric filter system. This is a proven overall design that incorporates multiple modularized gas-solid entrained reaction sections followed by fabric filter modules. The NID™ system modular design fits well with the objectives of the Coal FIRST program, and the modular design allows for ease and speed of constructability. The entrained reactor section along with connected mechanical equipment can be pre-assembled in a workshop and transported to site. The fabric filter is built as modules on site and joined with the reactor section. The total NID™ module is lifted into place onto structural steel, then connected to flue gas inlet and outlet ductwork. The NID™ system process flow diagram is shown in Figure 2-2.

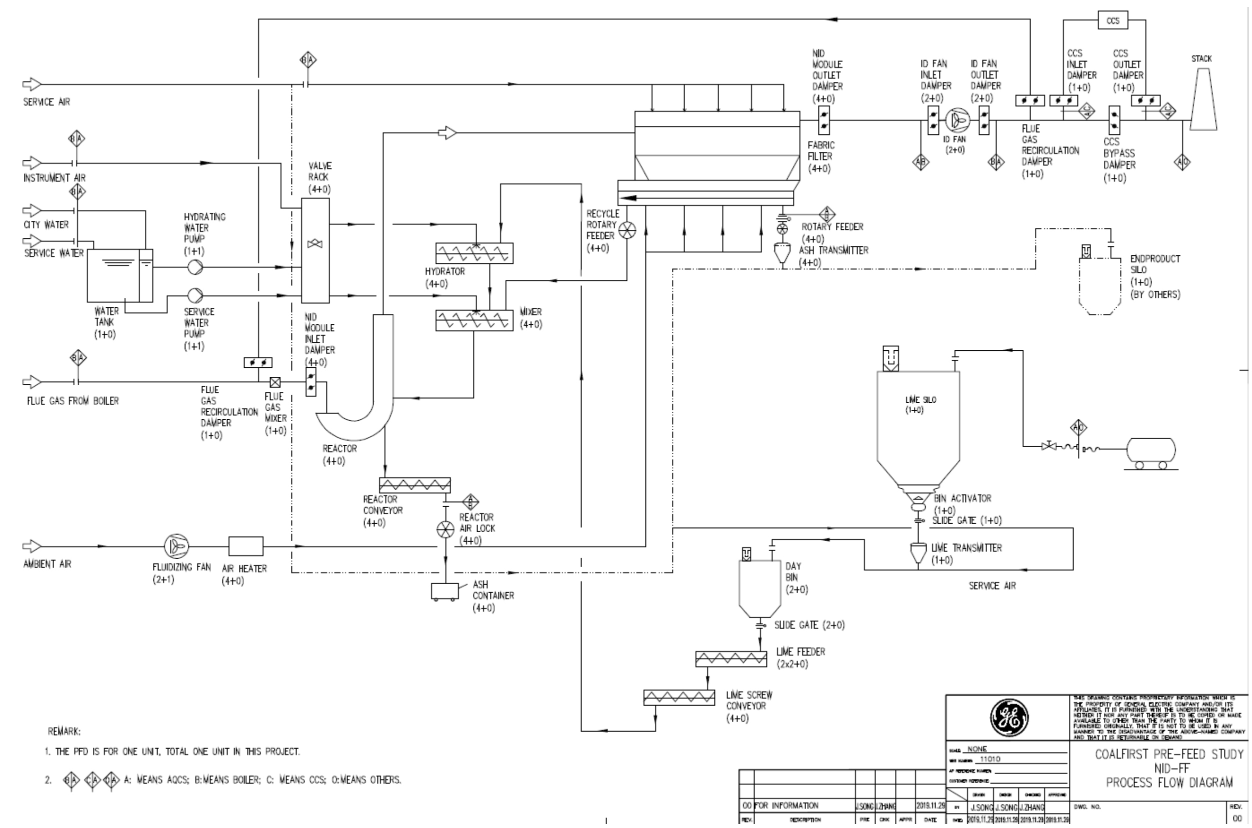


Figure 2-2 NID™ system Process Flow Diagram

The NID™ system operates routinely with very low particulate and sulfuric acid emissions. Acid gas emissions can be controlled through the addition of lime reagent to reach high removal rates. Sulfur dioxide removal of greater than 98% is proven for long-term operation at a NID™ installation at a large Eastern US power plant. Additionally, SO_2 removal of 99% has been validated with pilot testing at GE's AQCS R&D center in Sweden. Additional design and controls concepts that require further full-scale implementation are anticipated to allow cost effective removal at greater than 99% on a continuous basis. Addition of hydrated lime to the ash recirculation duct allows use of higher sulfur content fuels. In addition to SO_2, the NID™ system has demonstrated long-term emission limits for HCl and Hg of <0.0001 lb/MMBtu and 0.4 lb/TBtu, respectively. This is a corresponding Hg removal rate of 96%. These very low emissions levels are important for consideration of downstream carbon capture technology where very low acid gas levels are generally preferred..

The NID™ dry FGD system helps minimize water consumption because it has no waste water stream. GE even has three installations using dry FGD technology to evaporate waste water from wet FGD systems and in one case cooling tower blowdown thus having advantage of eliminating or reducing another waste water stream from power plant. The extent to which water consumption is mimimized will be determined in the future Pre-FEED phase.

The NID™ modular design is also a key feature for the system turndown. For the AUSC Coal FIRST conceptual design, GE expects the system to include 3 or 4 operating NID™ modules at the full-capacity, and in turndown the controls can allow just one NID™ module to be in service. Additional controlled turndown of each entrained gas-solid reaction chamber for each NID™ module is a relatively new feature in the GE design. Further development of the mechanical and control aspects of this module turndown feature that maintains the fluidized reactor functionality would be addressed later during the Coal FIRST Pre-FEED effort. Gas-solid CFD and/or flow modeling of the individual module turndown response is an area that is recommended as part of this further design improvement.

For Concept 2, the gas turbine and heat recovery boiler plant is comprised of two LM6000 gas-turbine generator sets and two single-pressure heat recovery steam generators with duct burners.

The initial heat balance iteration shown in Figure 2-3 includes the following information:

- DLE gas turbine requiring no water
- Fuel gas flow and composition
- Gross power output, gross heat rate and gross efficiency
- Flue gas flow and composition from the GT/HRSG
- Carbon capture process steam demands to be supplied via the GT/HRSG

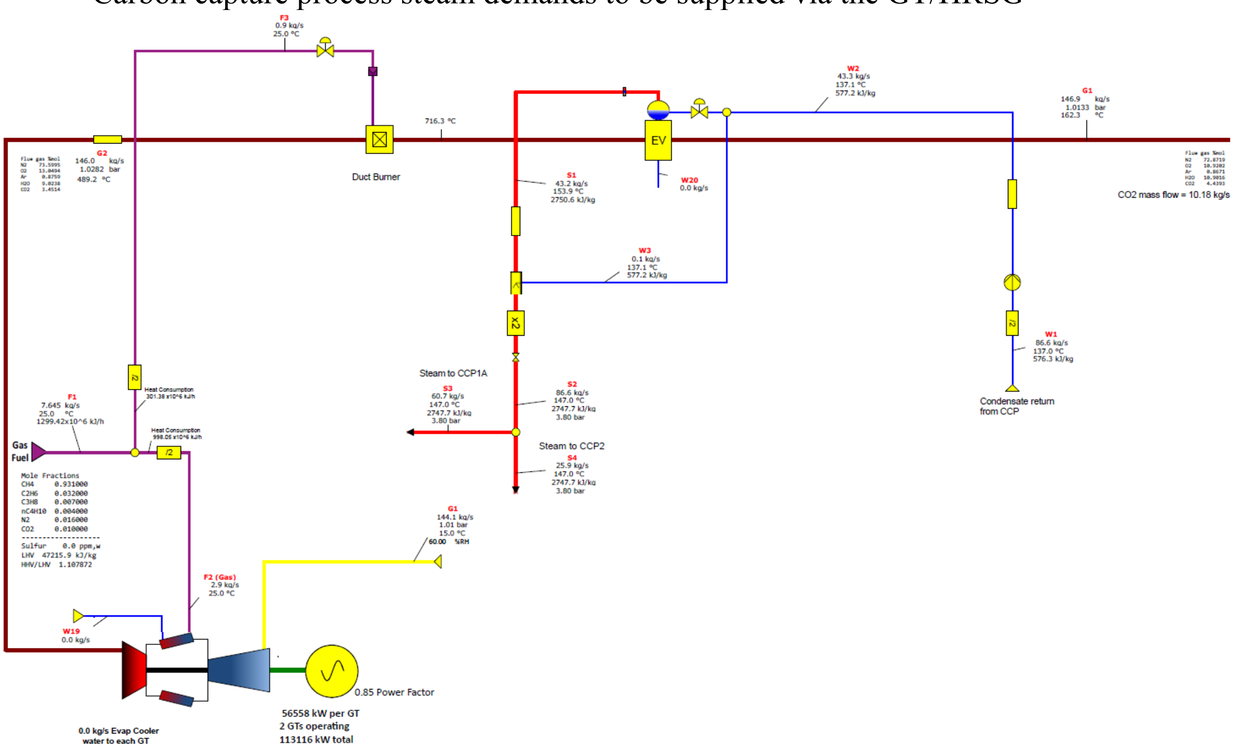


Figure 2-3 Initial Heat Balance for Gas Turbine/Heat Recovery Boiler

The simplistic version of the proposed carbon capture system Process Flow Diagram (PFD) is shown in Figure 2-4. A typical post combustion carbon capture system (CCS) consists of two main blocks, as follows:

- The CO_2 Absorber, in which the CO_2 from the power plant flue gas is absorbed into a solvent via fast chemical reaction, and
- A regenerator system where the CO_2 absorbed in the solvent is released, and then the sorbent is sent back to the absorber for further absorption.

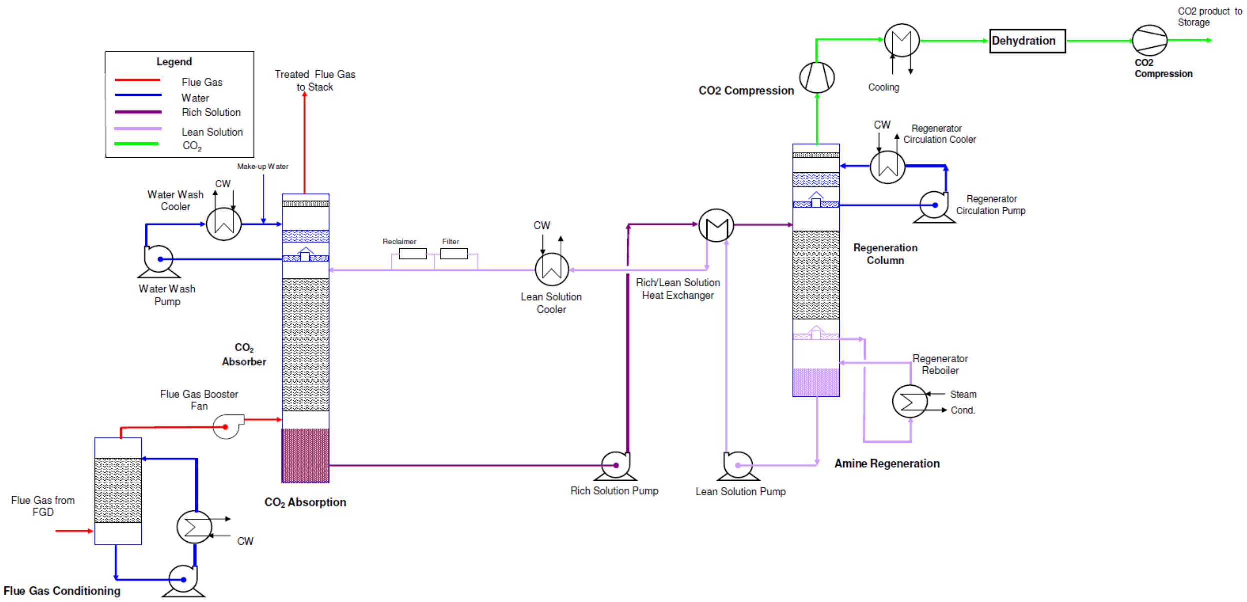


Figure 2-4 Process Flow Diagram of the proposed carbon capture technology

The carbon capture plant (CCP) is part of the planned air quality control system (AQCS) with the specific target to reduce the CO_2 emissions of the host power plant. The proposed CCP concept utilizes a proven Advanced Amine Process (AAP), comprising a proprietary amine-based solvent in a proprietary flow scheme for flue gas applications. The AAP technology applied is based on a reference design for large scale post-combustion capture plants, but downscaled to process the flue gas from target host plant capacity (equivalent of 300 MWe).

The main CCP plant performance target is 90% CO_2 capture from the pretreated flue gas of up-stream AQCS components, while producing a CO_2 product with specified quality in terms of composition and battery limit conditions – pressure and temperature – for further utilization.

These targets are accomplished with the objectives to achieve minimized utility consumptions, primarily steam and electrical power, but also cooling water and chemical consumptions, primarily amine make-up. Additional CCP plant integration options with the host power plant water/steam cycle could further improve the overall operations expenditures (OPEX) on cost of additional capital expenditures (CAPEX). Generally, amines-based processes are proven technologies for decades in the Oil & Gas industry. In this application, the process has been optimized to combustion flue gas under atmospheric pressure and power plant operations.

The main emission target for the CCP is a 90% reduction of CO_2 emissions for the AUSC coal plant in Concept 1 and for both the AUSC coal plant and the gas turbine/heat recovery boiler system in Concept 2. A validated solvent and emission management is utilized to keep the emissions generated from the CCP below tolerable limits, typically defined for amines and ammonia.

The individual CCP equipment design is considering a well-balanced techno-economical solution (CAPEX/OPEX-ratio) to achieve the performance targets, like CO_2 capture, CO_2 product quality and emissions, while keeping the OPEX on a low level. This comprises the following components:

- Flue gas conditioning system for an optimized CO_2 absorption performance
- Improved absorber design maximizing the CO_2 loading in the rich solvent
- Advanced regeneration concept minimizing steam consumption and CO_2 product compression power demand
- High efficiency heat exchanger network maximizing heat recovery from the hot lean solvent from the regenerator
- Advanced solvent management
- Efficient CO_2 product compression & dehydration system to accommodate CO_2 pipeline conditions

All equipment of the CCP is designed to meet these targets. The interplay of its different components is harmonized for operation within the required operating range. Figure 2-5 shows the specific advantages and features of the AAP technology outlined in the bullets above.

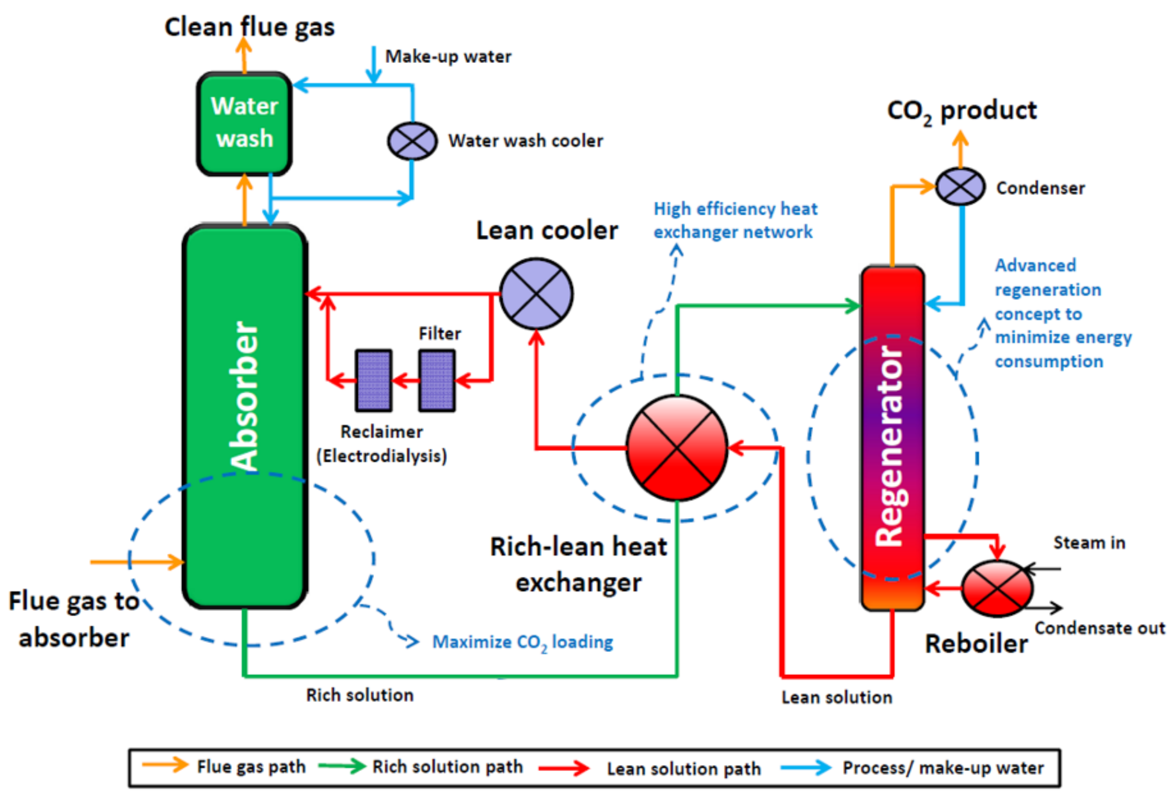


Figure 2-5 Features and Advantages of the Advanced Amine Process

The selection of a suitable solvent is crucial in terms of resistance to thermal and chemical degradation, material selection (corrosion resistance) and stable operation in term of foaming and fouling. The amine-based solvent ideally should be non-hazardous and not degrade into hazardous byproducts that could have an environmental impact.

Improved absorber design, advanced regeneration concept, high efficiency heat exchanger network, and advanced solvent management processes make this technology unique and innovative. A thermal performance of 2.3 to 2.4 GJ/tonne CO_2 at 90% capture rate was consistently demonstrated. The solvent and emissions management strategies were also validated. The plant was designed and successfully operated for a multitude of operating conditions to cover a broad test campaign. These tests demonstrated flexible operating conditions and provided an understanding of the effects of load variations, start-ups and shutdowns. All test runs showed a fast response to change in load.

To increase net plant efficiency, heat sinks of the CCS system are integrated with optimal locations of the steam cycle to recover as much energy as possible. This can be accomplished by careful design and integration of the condensate from the CCS process into the water steam cycle as well as steam extractions for reboiler heating.

The carbon capture plant (CCP) will have flexibility in terms of flue gas flow capacity (operating range) and with regards to different fuels for the AUSC coal power plant, as long as the flue gas CO_2 concentration to the CCP is close to the design case. The typical standard operating range for the CCP is approximately 50-60% of design capacity, while the best operating performance is typically at 100% capacity (at highest efficiency). Therefore, turndown is often combined with operation below the best efficiency point. Lower turndown operation (< 50%) may require additional design features, such as:

- Specific recycle arrangements for compressor and pump systems
- Multiple parallel equipment arrangement (for one service), so that partial stream flow capacity can be turned off, while the remaining equipment remain in operation
- Disproportional turndown strategy for the core absorption/regeneration cycle (this means turndown of solvent circulation lower than capacity reduction of the flue gas feed to the CCP).

Thus, the required turndown for the host power plant with its full environmental compliance of 5:1, means an operational range for the CCP of 20% to design capacity is expected to be achievable.

The required start-up time for the host power plant from cold conditions is 4 hours and from warm conditions is 2 hours, respectively. The CCP design allows for transient operating flue gas flow changes, e.g. during start-up or shut-down of host power plant. Previous test runs at pilot-scale showed a fast response of the CCP design as proposed to change in load.

For the CCP a bypass for the flue gas feed to the stack is recommended, which allows to ramp up/down the host power plant at a different ramp rate or with different cold/warm start duration than the CCP. Also, the reduction of steam flow from the power plant to the CCP Regenerator Reboiler is an option to generate more electrical power during transient operations, with resulting reduced CO2 capture rate.

The proposed steam turbine concept combines the existing capabilities of the GE USC modular steam turbine product platform with the use of high temperature materials, scaled to a plant size normally associated with much lower steam conditions.

The resulting provisional target level of performance, based on an optimization of the water steam cycle, is a gross turbine efficiency of 53.38% at full load, net turbine steam cycle efficiency without carbon capture of 51.2%, and net turbine steam cycle efficiency with steam extractions for carbon capture of 45.9%.

A schematic of the water steam cycle for the AUSC steam turbine with no steam extractions is shown in Figure 2-6.

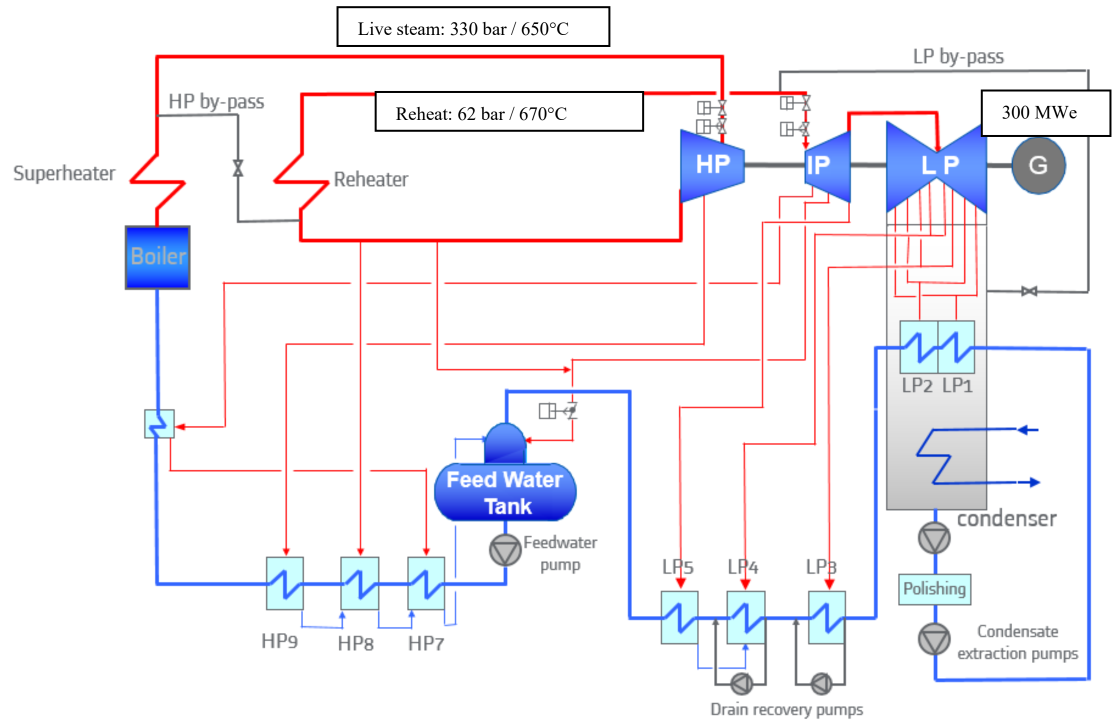
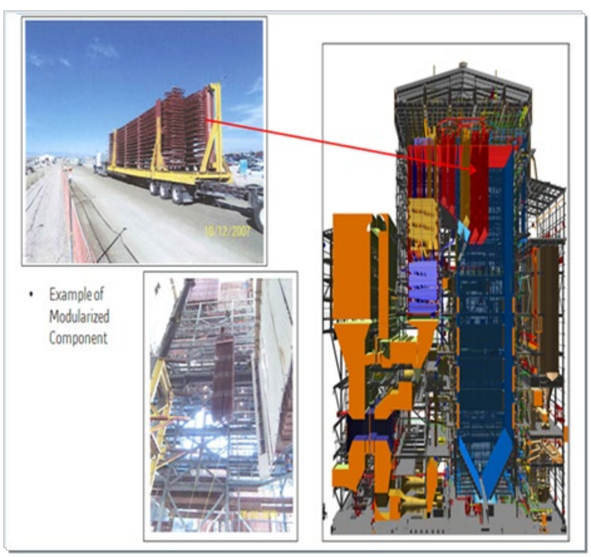


Figure 2-6 Water Steam Cycle Schematic



The boiler will use pressure part designs that are modularized, an example of which is shown in Figure 2-7. Fabrication of pressure part modules in the shop has several benefits. It reduces tube welds in on site, more difficult welds are performed more easily in the shop, and header girth welds can be done in the shop with automated machines while achieving a 0% rejection rate.

Figure 2-7 Example of Pressure Part Modularization

Ground modularization on site during construction of components that would be too large to ship effectively if they were shop modularized will be utilized, an example of which is shown in Figure 2-8. Ground modularization reduces the total number of pressure part lifts thus reducing schedule and allows more difficult welds to be performed more easily. Utilizing standard design modules for piping skids and instrument racks increases the flexibility schedule for design releases, fabrication releases, and erection sequencing. This allows for early turnover to electrical trades to complete and start the cold commissioning process.

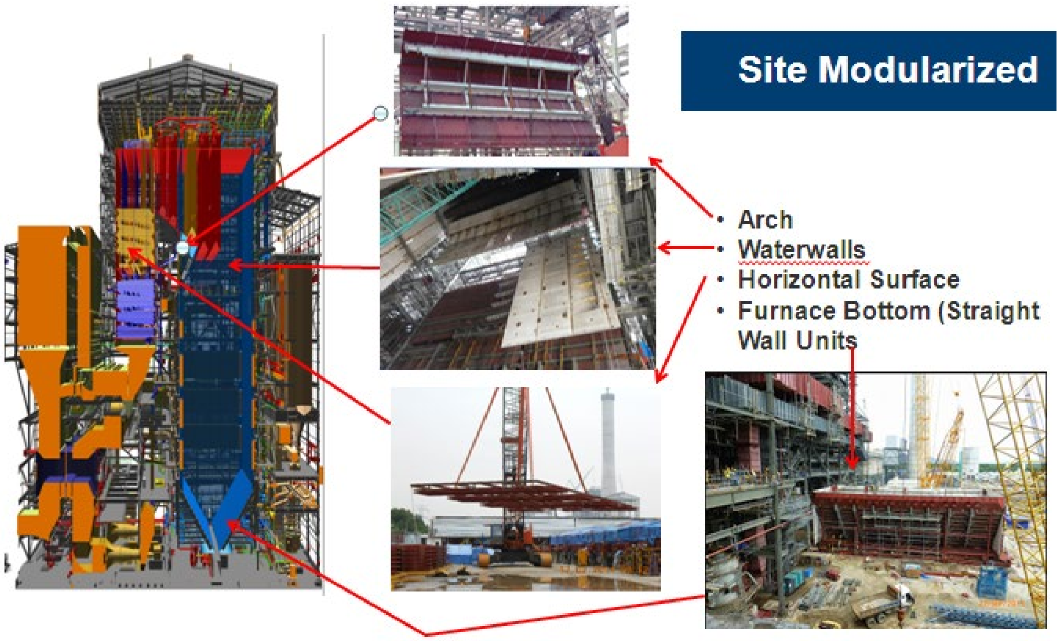


Figure 2-8 Examples of Ground Modularization

The proven modular steam turbine platform combines many design features supporting the evolution to more advanced and efficient steam cycles. Some of the features are unique to GE steam turbines and represent the best design practices developed over decades. These can be summarised as follows:

– Separated high pressure and intermediate pressure turbine modules using multiple shell casing design, with inner and outer casings cascading high temperature differences over several shells.

– Disk-type welded turbine rotors to apply new materials to the hottest and most exposed rotor sections. The optimised composition of materials in each rotor supports high operational flexibility combined with competitive product life time.

– Robust, multiple stage reaction type blading is used to moderate the pressure/ temperature drop per stage. Best suited steel alloys are available to off-set the stage specific stress levels.

– A consequent compact steam turbine and turbo-generator design in combination with the proven single bearing concept (single bearings between adjacent modules) minimises the overall shaft length.

– GE's pre-engineered and efficient low pressure steam turbine platform also offers sideways or downward exhausting steam designs to support optimised arrangement concepts and turbine hall layouts. (see Figure 2-9 and Figure 2-10)

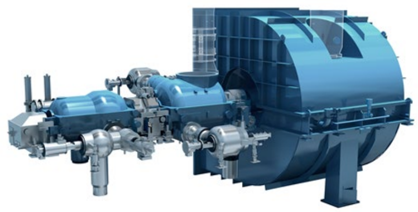


Figure 2-9 Steam Turbine Train (side exhaust option)

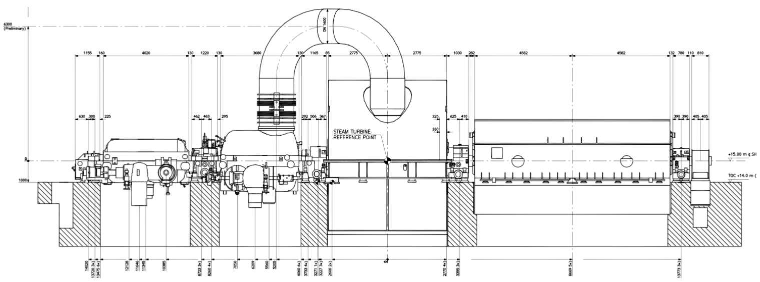


Figure 2-10 Steam Turbine Train Including Generator (downwards exhaust option)

Representative small USC HP and IP turbine modules are shown in Figure 2-11 and Figure 2-12. These modules are shop assembled and transported to site as modular units.

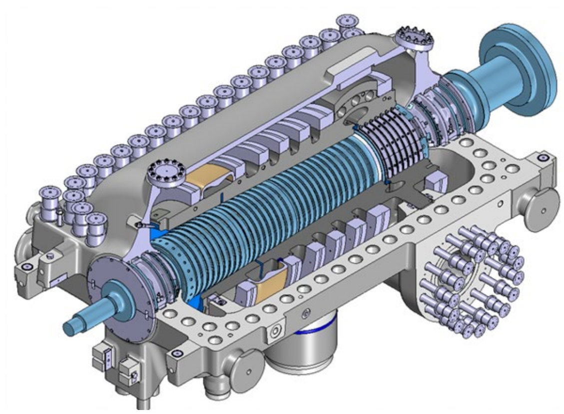


Figure 2-11 Small USC HP Turbine Module

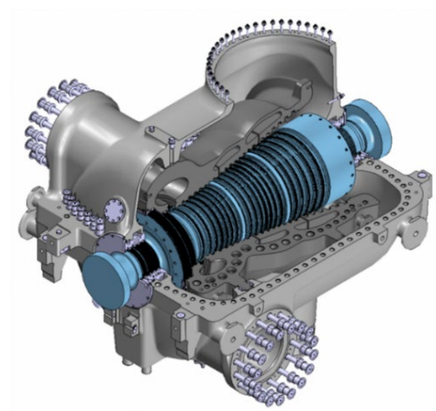


Figure 2-12 Small USC IP Turbine Module

A representative small USC LP turbine module is shown in Figure 2-13. These modules are shop assembled and transported to site as modular units.

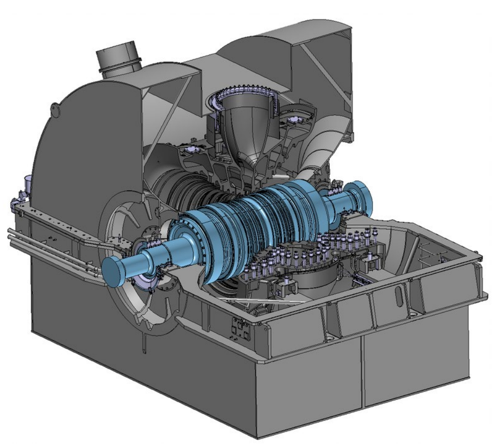


Figure 2-13 Representative LP Turbine Module (downwards exhaust option)

3 Design Basis

1. General Information

	Parameter	Value
1.1	**Plant**	AUSC Coal Plant
1.2	**Location**	Greenfield, Midwestern
1.3	Plant owner	not applicable
1.4	**Power Plant power production, MWe gross (w/o CCS) per Power Unit**	300
1.5	**Power Plant power production, MWe net (w/o CCS) per Power Unit**	
1.6	**Number of Power Units to be equipped with Carbon Capture Unit(s)**	1 (concept 1); 1 + GT (concept 2)
1.7	**Number of Carbon Capture units per Power Unit**	1 (concept 1); 1 for AUSC + 1 for GT (concept 2)
1.8	**Total number of Carbon Capture units for all Power Units together**	1 (concept 1) 1 for AUSC + 1 for GT (concept 2)
1.9	Type of fuel (coal, natural gas, etc.)	coal (concept 1); coal + natural gas (concept 2)
1.10	SCR installed (Yes/No)	assumed for AUSC flue gas: • SCR, which reduces NOx, upstream of air preheater • NID, which reduces SO2, SO3 and particulates (dust)
1.11	Particulate collection installed (ESP, fabric filter, etc.)	
1.12	SO3 control installed (lime injection, WESP, etc.)	
1.13	SO2 control installed (WFGD, etc.)	
1.14	**CO_2 capture efficiency**	90 %
1.15	**Average full load operating hours per year (for yearly consumptions/productions calculations)**	5000
1.16	Plant availability in hours per year	8000
1.17	Specific local design requirements e.g. piling, EHS, seismicity, etc.?	n.a.
1.18	Potential plant integration e.g. DCS, control room, switch room, etc. or standalone plant	no separate DCS, control room, switch room, etc. for CCS plant
1.19		

2.0 Units of Measure

	Parameter	Units
	Temperature	°C
	Pressure	bara
	Vacuum pressure	mbara
	Weight (mass)	kg
	Volume, liquids	m^3
	Volume, gases,	actual m^3
	Volume, gases, norm	Nm^3 [at 0 °C and 1013 mbara]
	Flow, liquids	m^3/h, kg/h
	Flow, gases	m^3/h, kg/h
	Flow, solids	kg/h
	Flow, steam	kg/h
	Heat	kJ
	Power	MW, kW

3.0 Flue Gas to Carbon Capture Plant (CCP) - per Power Plant unit

For Coal FIRST:

- to be provided for both, Concept 1 (Base Concept) and Concept 2 (with GT) for each load point requested to be investigated
- Note: Data to be provided at interface point/battery limit (BL) to Carbon Capture Plant (CCP).

	Parameter	**Units**	**Design Value**
3.1a	**Description of interface point (BL connection point) proposed by Customer**	- downstream of AQCS for power plant (concept 1 and 2) and Flue Gas Blower - 103 % of guarantee rate, VWO – design case	
3.2a	**Gas flow rate to Carbon Capture Plant**	kg/h wet	1,075,084
3.3a	**Gas flow rate to Carbon Capture Plant**	Nm^3/h wet	836,724
3.4a	**Temperature at interface point**	°C	80
3.5a	**Pressure at interface point**	barg	0
3.6a	Composition		
	O_2	vol %, wet	3.5
	N_2	vol %, wet	69
	Argon	vol %, wet	---
	H_2O	vol %, wet	14.4
	CO_2	vol %, wet	13.1
	SO_2	ppmv wet	14
	SO_3	ppmv wet	0.3
	NO	ppmv wet	50
	NO_2	ppmv wet	<2
	NH_3	ppmv wet	<2
	HCl	ppmv wet	<1
	HF	ppmv wet	<1
	Total Particulate Matter	mg/Nm3 wet	10

	Parameter	Units	Design Value
3.1b	**Description of interface point (BL connection point) proposed by Customer**	- downstream of HRSG for gas turbine (concept 2, only)	
3.2b	**Gas flow rate to Carbon Capture Plant**	kg/h wet	1,057,680
3.3b	**Gas flow rate to Carbon Capture Plant**	Nm^3/h wet	841,509
3.4b	**Temperature at interface point**	°C	162.3
3.5b	**Pressure at interface point**	bara	1.013
3.6b	Composition		
	O_2	vol %, wet	10.92
	N_2	vol %, wet	72.87
	Argon	vol %, wet	0.87
	H_2O	vol %, wet	10.90
	CO_2	vol %, wet	4.44
	SO_2	ppmv wet	0
	SO_3	ppmv wet	0
	NO	ppmv wet	50
	NO_2	ppmv wet	<2
	NH_3	ppmv wet	0
	HCl	ppmv wet	0
	HF	ppmv wet	0
	Total Particulate Matter	mg/Nm3 wet	0

4.0 Treated Flue Gas from Carbon Capture plant (per Power plant Unit)

	Parameter	Units	Design Value
4.1	**Description of interface point (BH connection point) proposed by Customer**	- downstream of CCP emission control system for power plant (concept 1 and 2) - downstream of CCP emission control system for gas turbine (concept 2, only)	
4.2	**Pressure at interface point**	bara	1.000
4.3	Composition/emissions (in case max. allowed limits are defined)		
	Amines	mg/Nm³ dry	no special requirements
	NH3	mg/Nm³ dry	no special requirements
	Amine degradation products	mg/Nm³ dry	no special requirements
	Other?	mg/Nm³ dry	

5.0 CO_2 Product Specification

	Parameter	Units	Design Value
5.1	**Use of CO_2 product (saline aquifer, EOR, utilization, other?)**	Enhanced Oil Recovery (EOR)	
5.2	**Description of interface point (BH connection point) proposed by Customer**	downstream of CO2 compression and aftercooling (concept 1 and 2)	
5.3	**Temperature at interface point**	°C	40
5.4	**Pressure at interface point**	bara	120
5.5	Requested composition		
	CO_2	vol %, dry	min. 99.0
	N_2	ppm-mol, wet	N2 and Ar together < 10,000
	Argon	ppm-mol, wet	
	H_2O	ppm-mol, wet	max. 50
	O_2	ppm-mol, wet	max. 100
	NH_3	ppm-mol, wet	n.a.
	Amines	ppm-mol, wet	n.a.
	Glycol	ppm-mol, wet	n.a.
	Other?	ppm-mol, wet	n.a.

6.0 Flue Gas Condensate from Carbon Capture plant (per Power Plant)

	Parameter	Units	Min. Value	Max. Value	Design Value
6.1	Description of interface point (BH connection point) proposed by Customer	downstream of condensate pump flow control valve; condensate tank ISBL of power plant			
6.2	Temperature at interface point	°C			< 50
6.3	Pressure at interface point	bara			5.0
6.4	Any composition restrictions?				

7.0 Reserved

8.0 Steam Supply

(If steam is available, provide the following info and properties)

	Parameter	Units	Min. Value	Max. Value	Design Value
8.1	**Description of interface point (BH connection points) proposed by Customer**	downstream of de-superheating station			
8.2	**Temperature at interface point**	°C	147	160 ()	approx. 5 °C superheated, i.e. T = Tsat (@ 3.8 bara) 142 °C + 5 °C = 147 °C
8.3	**Pressure at interface point**	bara	3.8	4.5	3.8 bara @ BL CCP (assuming FCV; FI on CCP part)

9.0 Steam Condensate

For Coal FIRST:

- If required condensate return conditions are different for Concept 1 (Base Concept) and Concept 2 (with GT), please provide the conditions for both concepts.

(for condensate return, provide the following info and properties)

	Parameter	**Units**	**Min. Value**	**Max. Value**	**Design Value**
9.1	Description of interface point (BH connection points) proposed by Customer for condensate	downstream of steam condensate pump flow control valve			
9.2	Temperature at interface point	°C			137
9.3	**Pressure at interface point**	bara			7.0

10.0 Cooling Water

	Parameter	**Units**	**Min. Value**	**Max. Value**	**Design Value**
10.1	Description of interface point (BL connection point) proposed by Customer	at battery limit of CCP site			
10.2	**Type (sea water, river water, cooling tower, closed loop CW, etc.)**	cooling water			
10.3	**Temperature - supply at interface point**	°C		n.a.	15.6
10.4	**Temperature - return (if return temp has a constraint) at interface point**	°C			25.6
10.5	**Max. allowed overall CW temperature difference between supply and return (if limited)**	°C			10
10.6	**Supply pressure at interface point**	bara			5.0
10.7	**Allowable pressure drop between supply and return**	bar			1.5
10.8	**Available flow rate- if restricted**	t/h			n.a.

11.0 Electric Power

	Parameter	Units	Design Value
11.1	Description of interface point (BH connection point) proposed by Customer	at battery limit of CCP site	
11.2	Voltage	V	
11.3	Amperage	A	

12.0 Site/Climate conditions

	Parameter	Units	Min. Value	Max. Value	Design Value
12.1	Barometric pressure	bara			1.01
12.2	**Ambient temperature**	°C		n.a.	15
12.3	Relative humidity	%			60

13.0 Storage requirements

	Parameter	Design Value
13.1	Storage requirements in days for chemicals?	30

14.0 Plot space

	Parameter	Units	Min. Value	Max. Value	Design Value
14.1	Plot space will be estimated for AAP plant, inside battery limits including all required process equipment as well as storage tanks and loading/unloading facilities (subject to confirmation by detailed process design); Scope (ISBL facilities)/Terminal points according to definition in Carbon Capture Ready study. The space requirement is estimated under the assumption, that the available plot space area is located close to the tie-ins into the flue gas duct downstream the FGD and suitably shaped to allow a reasonable arrangement of the CCP equipment as typical for chemical plants; e.g. adjacent rectangular shaped area(s) of reasonable widths and lengths	m²			no limitation - greenfield

The following Exhibits 1-5 were taken from the original RFP for this Coal FIRST project.

Exhibit 1: Site characteristics

Parameter	Value
Location	Greenfield, Midwestern U.S.
Topography	Level
Size (Pulverized Coal), acres	300
Transportation	Rail or Highway
Ash Disposal	Off-Site
Water	50% Municipal and 50% Ground Water

Exhibit 2: Site ambient conditions

Parameter	Value
Elevation, (ft)	0
Barometric Pressure, MPa (psia)	0.101 (14.696)
Average Ambient Dry Bulb Temperature, °C (°F)	15 (59)
Average Ambient Wet Bulb Temperature, °C (°F)	10.8 (51.5)
Design Ambient Relative Humidity, %	60
Cooling Water Temperature, °C (°F)[A]	15.6 (60)
Air composition based on published psychrometric data, mass %	
N_2	72.429
O_2	25.352
Ar	1.761
H_2O	0.382
CO_2	0.076
Total	100.00

[A]The cooling water temperature is the cooling tower cooling water exit temperature. This is set to 8.5°F above ambient wet bulb conditions in ISO cases.

Exhibit 3: Design coal – Sub-Bituminous

Rank/Seam	**Sub-Bituminous/Montana Rosebud**	
Proximate Analysis (weight %)[A]		
	As Received	**Dry**
Moisture	25.77	0.00
Ash	8.19	11.04
Volatile Matter	30.34	40.87
Fixed Carbon	35.70	48.09
Total	100.00	100.00
Sulfur	0.73	0.98
HHV, kJ/kg (Btu/lb)	19,920 (8,564)	26,787 (11,516)
LHV, kJ/kg (Btu/lb)	19,195 (8,252)	25,810 (11,096)
Ultimate Analysis (weight %)		
	As Received	**Dry**
Moisture	25.77	0.00
Carbon	50.07	67.45
Hydrogen	3.38	4.56
Nitrogen	0.71	0.96
Chlorine	0.01	0.01
Sulfur	0.73	0.98
Ash	8.19	10.91
Oxygen	11.14	15.01
Total	100.00	100.00

Exhibit 4: Natural gas characteristics

Natural Gas Composition		
Component		**Volume Percentage**
Methane	CH_4	93.1
Ethane	C_2H_6	3.2
Propane	C_3H_8	0.7
n-Butane	C_4H_{10}	0.4
Carbon Dioxide	CO_2	1.0
Nitrogen	N_2	1.6
Methanethiol[A]	CH_4S	$5.75x10^{-6}$
	Total	100.00
	LHV	**HHV**
kJ/kg (Btu/lb)	47,454 (20,410)	52,581 (22,600)
MJ/scm (Btu/scf)	34.71 (932)	38.46 (1,032)

[A]The sulfur content of natural gas is primarily composed of added Mercaptan (methanethiol, CH_4S) with trace levels of H_2S. Note: Fuel composition is normalized and heating values are calculated.

Exhibit 5: MATS and NSPS emission limits for PM, HCl, SO_2, NOx, and Hg

Pollutant[A]	**PC limits (lb/MWh-gross)**
SO_2	1.00
NOx	0.70
PM (Filterable)	0.09
Hg	$3x10^{-6}$
HCl	0.010