Bald Eagle

Pre-FEED Assessment Report

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Table of Contents

Figures

Tables

1. Executive Summary

The purpose of this report is to describe the approach, list assumptions, and highlight results of Project Bald Eagle, a new-build Allam-Fetvedt Cycle (AFC) power production facility at the Dave Johnston Power Station in Glenrock, Wyoming. The power island will generate roughly 287 MWe while inherently capturing carbon dioxide (CO_2) emissions. The captured CO_2 will be compressed and transported locally for enhanced oil recovery (EOR).

The AFC is a transformational technology that has the potential to enable a step change in the performance, efficiency, and cost of electricity from coal electrical generating units by using direct-fired supercritical CO_2 (sCO_2) as the working fluid in the turbine for oxy-combustion power generation, enabling inherent carbon capture.

The following pre-Front-End-Engineering-Design (pre-FEED) report provides a sufficiently detailed engineering package to deliver an AACE Class 4 estimate for the AFC-C facility and the Balance of Plant (BoP). The resulting levelized cost of electricity will enable 8 Rivers Capital, LLC and the Project team to assess both the economic and environmental advantages of the Project to inform a FEED decision.

This report explores the feasibility of a first-of-a-kind (FOAK) AFC-C facility using a conservative approach that prioritizes operability, by making tradeoffs in efficiency optimization.

A technical performance summary including power and byproduct streams is provided below in Table 1. Two cases are shown – including and excluding the Fuel Supply Plant (FSP) which generates clean syngas and oxygen for use by the AFC-C. Separating the FSP allows for evaluation of the core AFC-C power island and provides the framework for a competitive, two-entity commercial structure. The FSP groups established, low-risk technology and is attractive to infrastructure investors with a modest merchant appetite. The AFC-C plant holds the novel process and generates returns aligned with utility owners.

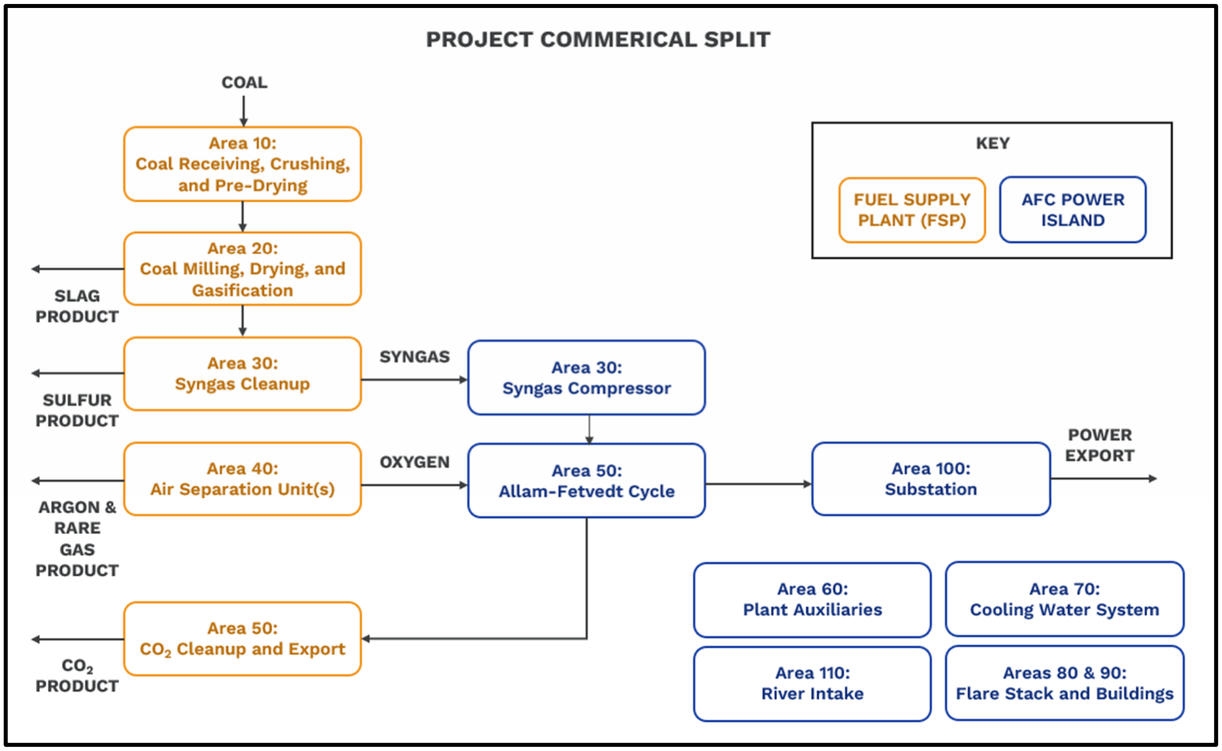

Figure 1: Project commercial split

The Technical summary for both cases is provided in Table 1. Note that the product streams from the overall project (power and byproducts) are the same. The major difference is accounting for the parasitic load of the FSP, which can be supplied by AFC-C or by an alternative source depending on the target carbon intensity.

Table 1: Technical summary

	Units	Including Fuel Supply Plant	Excluding Fuel Supply Plant
Turbine Fuel Input	MWt, HHV	[redacted]	[redacted]
Coal Thermal Input	MWt, HHV	[redacted]	[redacted]
Gross Power Generation	MWe	[redacted]	[redacted]
Power Consumption	MWe	[redacted]	[redacted]
Net Power Output	MWe	[redacted]	[redacted]
Efficiency (LHV)	%	[redacted]	[redacted]
Efficiency (HHV)	%	[redacted]	[redacted]
Heat Rate	btu/kWh	[redacted]	[redacted]
Coal Input (wet)	tons / day	[redacted]	
CO_2 Emissions[1]	tons / day	[redacted]	
CO_2 Export	tons / day	[redacted]	
CO_2 Capture Rate	%	[redacted]	
Coal Ash Export (dry)	tons / day	[redacted]	
Slag Export (dry)	tons / day	[redacted]	

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[1] *Includes CO_2 from natural gas for coal drying, SRU, and flare*

Argon Export	tons / day	[redacted]	
Sulfur Export	tons / day	[redacted]	
Crude Rare Gas Export[2]	tons / day	[redacted]	

The buildups for Total Plant Cost, Excluding FSP Cost, and FSP with 30% Biomass blending are provided in Table 2, using a 9.5% return on equity and a conservative assumption of 6.50% for debt.

The major difference between the Total Plant Cost and Excluding FSP Cost case is the Capex / Opex split. Rather than purchasing coal for [redacted]/mmbtu, AFC-C purchases [redacted]/mmbtu syngas from FSP but does not have the associated Capex. In this case, the FSP monetizes all non-power product streams including CO_2. The final case (FSP with 30% Biomass blending) shows additional EOR value from the input of biomass reducing the LCOE costs significantly.

Table 2: Economic summary

	Units	Including Fuel Supply Plant	Excluding Fuel Supply Plant	Including Fuel Supply Plant with 30% Biomass Blending
Plant Capex Buildup				
Direct Costs	$MM	[redacted]	[redacted]	[redacted]
Construction Indirects	$MM	[redacted]	[redacted]	[redacted]
Owner's Costs	$MM	[redacted]	[redacted]	[redacted]
Escalation	$MM	[redacted]	[redacted]	[redacted]
Contingency (15%)	$MM	[redacted]	[redacted]	[redacted]
Soft Costs (License fees, Development costs and EPCM)	$MM	[redacted]	[redacted]	[redacted]
Total Plant Cost	**$MM**	[redacted]	[redacted]	[redacted]
	$/kW	[redacted]	[redacted]	[redacted]
Levelized Cost of Electricity (LCOE)				
Capex		[redacted]	[redacted]	[redacted]
Fixed Costs	$/MWh	[redacted]	[redacted]	[redacted]
Variable Costs	$/MWh	[redacted]	[redacted]	[redacted]
Fuel Costs	$/MWh	[redacted]	[redacted]	[redacted]
CO_2 T&S Cost	$/MWh	[redacted]	[redacted]	[redacted]
Property Taxes	$/MWh	[redacted]	[redacted]	[redacted]
Insurance Cost	$/MWh	[redacted]	[redacted]	[redacted]
LCOE (excluding Value-Add Streams)	**$/MWh**	[redacted]	[redacted]	[redacted]
45Q	$/MWh	[redacted]	[redacted]	[redacted]
Argon Value	$/MWh	[redacted]	[redacted]	[redacted]

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[2] *Includes Neon and a combined Krypton and Xenon stream*

CO_2 EOR value-add	$/MWh	[redacted]
LCOE (including Value-Add streams)	**$/MWh**	[redacted]

Finally, a FOAK project for a technology will be its most expensive deployment. To decrease LCOE, alternative project configurations were explored using feedstock selection and carbon capture rate as levers to increase FOAK competitiveness.

Gasifier vendors have indicated the ability to guarantee equipment performance at blends of up to 30% biomass, which would produce carbon negative power by permanently sequestering biogenic CO_2. Blending biomass to produce carbon negative power has benefits which the Project could realize through three pathways:

1) To produce ultra-negative carbon power up to -400kg CO_2/MWh that could be sold at a premium.
2) To generate additional revenue through the sale of carbon dioxide removal (CDR) credits which currently trade for $100-200/mt[3] CO_2.
3) To offset additional, unabated generation while maintaining the same carbon intensity profile. For example, at a 30% biomass blend, an additional 200MW of natural gas combined cycle (NGCC) power could be included while maintaining a net zero facility.

Figure 2 summarizes the LCOE of different AFC-C project configurations. Shown are the LCOE for (A) AFC-C + FSP (B) AFC-C standalone (C) AFC-C + FSP with internal gas-fired generation for fuel-supply loads[4] for combined 90% capture and (D) AFC-C + FSP with 30% biomass blending[5].

Case D illustrates blending different generation sources to meet a carbon capture target. In this example, additional gas-fired generation is added until the Plant's carbon capture rate reaches 90% (from 97% AFC-C capture). This results in additional 37MW from gas-fired generation and reduces the LCOE by [redacted]/MWh. The carbon intensity - LCOE trade-off can be tuned based on Owner preference.

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[3] *Bioenergy with Carbon Capture and Sequestration (BECCS) average price on CDR.fyi as of December 2025*
[4] *Assumes 55% NGCC efficiency and $2,500/kW*
[5] *Assumes $60/ston biomass as received and $150/mt CO_2 CDR price*

[redacted]

Figure 2: LCOE summary showing Utility and Rocky Mountain Power financing cases

Further potential for cost and efficiency improvements in follow-on study work remains high. Subsequent efforts will increase design certainty and boost project economics through:

1) Improved commercial terms with key equipment vendors to reduce Capex: 8 Rivers currently has strategic agreements for [redacted] supply. Next steps will pursue gasifier and heat exchanger vendors whose combined scope is [redacted] (total installed cost or "TIC"). For both packages, AFC-C represents a new, high-potential market opportunity for those vendors which would help accelerate their partnership.
2) Refined turbine specifications: Given the novelty of developing a fundamentally new turbine, the primary goal of the Siemens Energy's development program is operational certainty rather than operational efficiency. As confidence in base performance is improved, either through detailed design or early turbine operations, it is expected that conservative assumptions, such as stringent syngas specifications, will be relaxed and improvement opportunities will be pursued.
3) Commercial opportunities to help FOAK deployment: AFC-C is well-positioned to create and supply high-quality and highly desirable carbon dioxide removal credits (CDRs) to emissions conscious, power hungry technology companies. AFC-C is fuel flexible, and co-firing biomass (woody biomass, crop residue, etc) with coal generates incremental CDRs which can be sold on the voluntary market for \$100-\$200/mt CO_2.
4) Value Engineering: Included as an addendum to this Pre-FEED report is a value engineering study with approximately [redacted] capital cost savings. These potential savings were identified but deferred to the FEED phase for further evaluation.

2. Description and Scope of AFC Project

2.1. Project Details and Description

8 Rivers is developing Project Bald Eagle, a new-build power production facility at the Dave Johnston Power Station in Glenrock, Wyoming. The primary objective of the project is to generate clean, low-emission electricity from coal while achieving near-complete carbon capture, thereby demonstrating the viability of a modern-day, clean coal-based power plant.

The facility will utilize locally sourced Powder River Basin coal as the primary feedstock, which will be processed through gasification to produce synthesis gas (syngas). This syngas will serve as the fuel for the innovative Allam-Fetvedt Cycle (AFC) power plant, a transformational technology designed to enable industrial-scale power generation with inherent carbon capture.

The AFC process is a transcritical, semi-closed loop, direct oxy-fired cycle that employs supercritical CO_2 (sCO_2) as the working fluid. See Figure 3 below for more details.

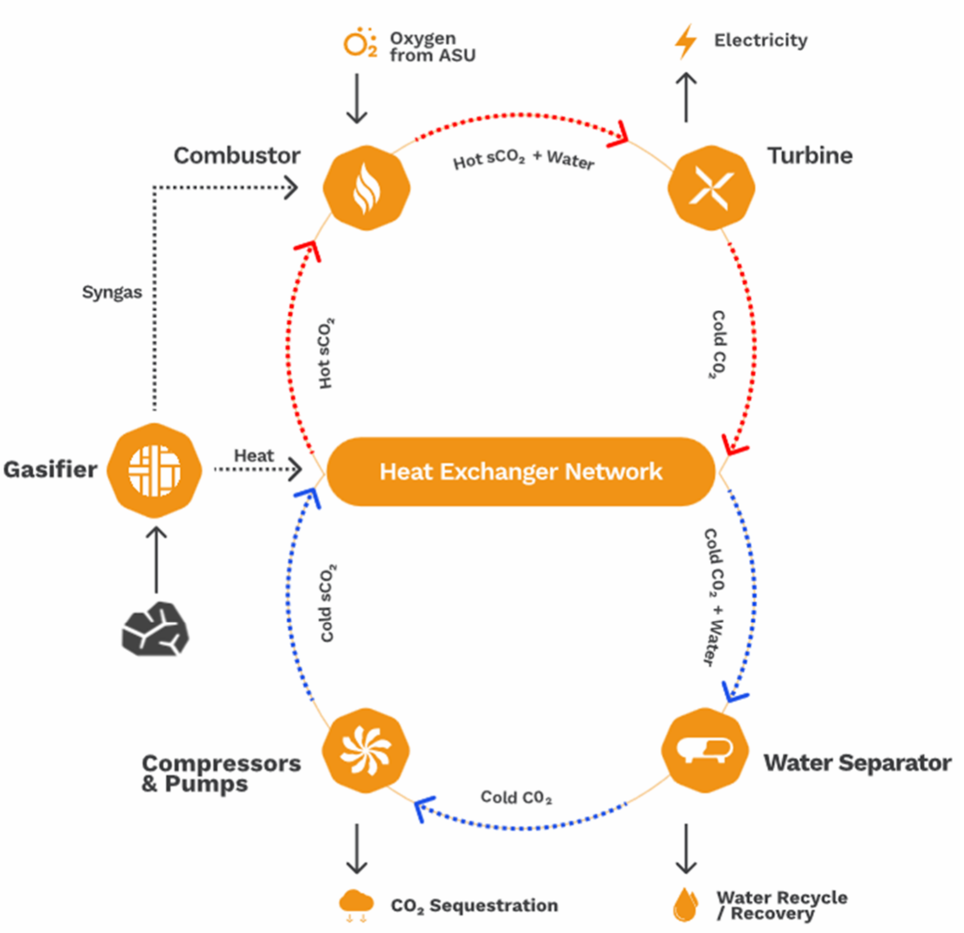

Figure 3: Allam-Fetvedt Cycle

In the combustor, syngas is combined with recycled CO_2 and artificial air oxidant, which is a mixture of 23% oxygen (near pure oxygen is supplied by an Air Separation Unit, or ASU) and 77% carbon dioxide, to form a heated sCO_2 stream at high pressure and temperature. This stream expands through a specialized turbine being developed by Siemens Energy, driving a generator to produce electrical power. The turbine exhaust is then routed to a recuperative heat exchanger network (HEXN), where heat is recovered to preheat incoming streams, enhancing overall cycle efficiency. The process inherently separates and captures nearly all CO_2 emissions, which are compressed and pumped into a pipeline for permanent sequestration through EOR sale or Class VI well storage. Byproducts such as argon, elemental sulfur, slag, and ash will also be produced and marketed where feasible, contributing to an uplift in the project's economic viability.

The project scope encompasses the full balance of plant (BoP), including coal handling and preparation, gasification island, ASUs, syngas cleanup, AFC power island, CO_2 compression and export, electrical systems, instrumentation and controls, and supporting infrastructure. Environmental permits will address temporary emissions during startup (e.g., SO_2 from H_2S-containing syngas flaring). The facility's location at the Dave Johnston site leverages existing infrastructure for coal supply, water access from the North Platte River, and grid connectivity, while site options (brownfield vs. greenfield) are evaluated to optimize layout, integration, and costs.

2.2. Site Selection Criteria for Brownfield versus Greenfield

Two potential site locations have been identified for Project Bald Eagle. The first is a brownfield option located adjacent to and integrated with the existing Dave Johnston facility. While the brownfield option offers significant benefits in terms of integration, it also presents drawbacks related to plant layout and civil/structural design. Consequently, a second greenfield option was evaluated. The greenfield option eliminates the layout, civil, and structural drawbacks but requires longer lengths of coal conveyors and piping. Detailed comparisons of these two options are provided below and in the pertinent engineering discipline sections of this report. Refer to overall site Plot Plan drawing 265467-00-MEC-PLP-0001. The greenfield option is considered the baseline option for the Pre-FEED study and therefore the overall project performance metrics included in this report, including levelized cost of electricity (LCOE), are based on the greenfield option.

2.2.1. Brownfield Option

Figure 4 below locates the AFC plant northwest of the existing Dave Johnston site, with utilities, coal supply, and power feed all coming from the existing plant nearby. This location is roughly 41 acres (excluding Coal Pile, Stormwater Ponds and construction laydown areas).

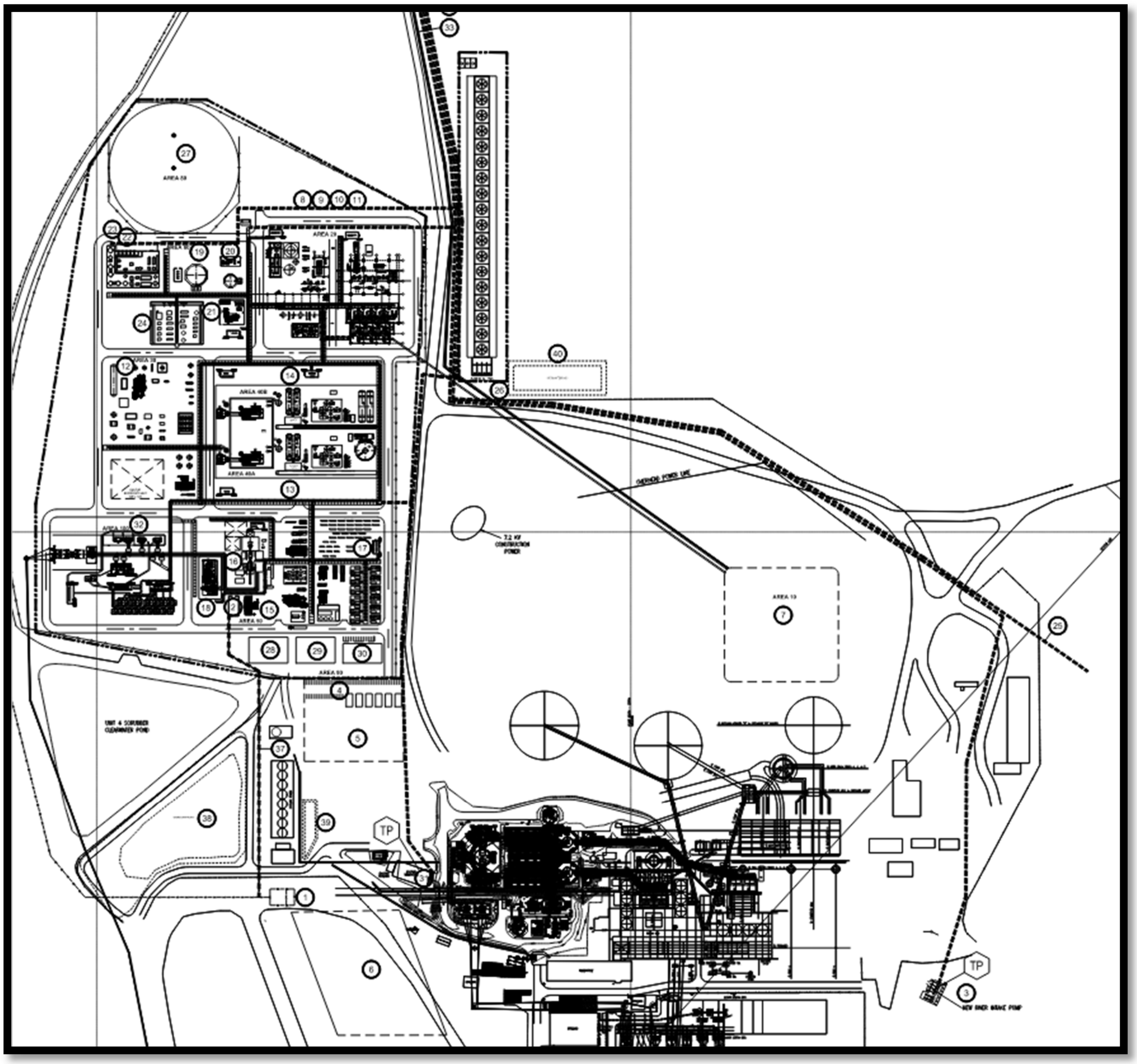

Figure 4: Brownfield Layout

2.2.2. Greenfield Option

Figure 5 below locates the AFC plant southwest of the existing Windstar Substation. Power would be supplied from the nearby Windstar substation. Other utilities, including coal supply, would be routed along the access road about two miles from the Dave Johnston plant. This location is roughly 52 acres (excluding Coal Pile and Construction Laydown Areas).

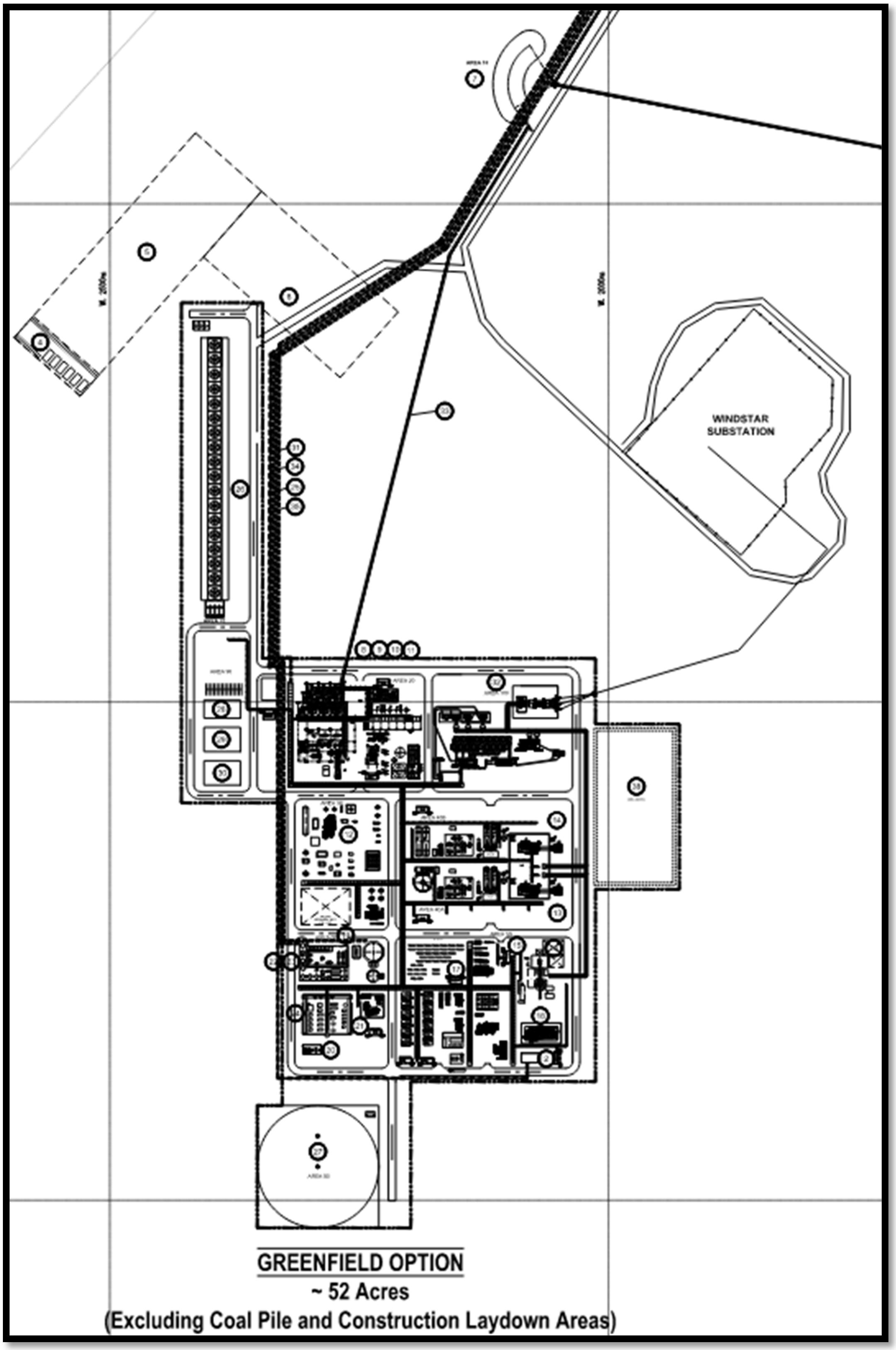

Figure 5: **Greenfield Layout**

2.3. Pre-Selection of Key Technologies

2.3.1. Gasifier

A gasifier pre-selection effort was performed to evaluate Western based gasifier manufacturer technologies. An entrained flow gasifier with syngas cooler, an entrained flow gasifier with bottom quench, and a fluidized bed gasifier with syngas cooling was evaluated as part of the gasifier pre-selection efforts. Based on the desire to maximize superheated steam output and the associated benefits of a high working pressure, the entrained flow gasifier with syngas cooling was selected for our Pre-FEED efforts. The superheated steam was desired for generating additional power in a steam turbine generator. The high-level results of the selection can be found below in Table 3 with a detailed report of the evaluation in 265467-000-PRO-RPT-001 Gasifier Pre-Selection report.

Table 3: Gasifier Comparison

Regime of flow in gasifier	Entrained Flow	Entrained Flow	Fluidized bed
Feed Transport system	Dry	Dry	Dry
Syngas cooling type	Syngas cooler	Bottom Quench	Syngas cooler
Vessel type	Membrane carbon steel pressure shell, internally lined with cooled refractory and enclosed in a carbon steel pressure vessel	Membrane carbon steel pressure shell, internally lined with cooled refractory and enclosed in a carbon steel pressure vessel	Pressure vessel internally lined with refractory, not cooled
Fuel flexibility	No potential feed coal limitations, if ash feed components do not jeopardize the operation of cooler	No potential feed coal limitations. Bottom quench line-up widens coal suitability by eliminating the fouling risk in the syngas cooler	Fuel flexible due to high residence time and high degree of mixing of the reactor inventory. Non-slagging fluidized bed is capable of gasifying all ranks of coal
Efficiency or Cold Gas Efficiency, %	>80	>80	<80
Superheated steam production (Yes/No)	Yes	No	Yes
Single gasifier availability	High	High	Low
Oxygen requirement	Medium	Medium	Low

Max working pressure (barg)	44	44	10
Expected suitability for Thermal Integration with Allam-Fetvedt Cycle	High	High	Low
Expected Investment Cost	High	Low	Medium
Expected Operating Cost	Low	High/Medium	Medium

2.3.2. Acid Gas Removal

Two different Acid Gas Removal (AGR) technologies were evaluated – Selexol and Rectisol. The primary criterion for selecting the AGR technology is the ability to achieve a residual total sulfur concentration of 1 ppmwt in the treated gas. Secondarily, we evaluated each technology's specific power consumption, capital cost, and CO_2 co-absorption. Because it is desired to send all CO_2 present in the syngas to the AFC system rather than to the sulfur recovery unit, and ultimately the atmosphere, the latter criteria was particularly important.

Selexol was chosen for its potential to limit both capital and operating expenditures while enabling selective H_2S absorption down to the required 1 ppm. The Selexol system can easily be dissected into two sub-units, H_2S removal and CO_2 removal. The latter section can be removed without losing the H_2S removal functionality, but enables >90% CO_2 slip into the syngas. That CO_2 is then compressed along with the syngas into the AFC system, used as a working fluid, and ultimately exported for sequestration. This flexibility enables the AGR cost and power consumption to be drastically reduced. Furthermore, the high operating pressure enables a low recompression duty downstream. The Selexol operating conditions yielded lower operating costs relative to Rectisol, which must operate as low as -60 °C. A high-level analysis can be found in Table 4 below with the full results of the evaluation in 265467-000-PRO-RPT-002 AGR Pre-Selection report.

Table 4: AGR comparison

ITEM	Selexol	Rectisol
Operating Temperature	Sub-ambient (Typically, 5 to 40 °C)	Low temperature (Typically, -40 to -62 °C)
Operating Pressure	20 to 138 bar	30 to 70 bar
H_2S residual content in treated gas	< 1 ppmv	< 0.1 ppmv
Solubility (H_2S/CO_2)	9:1 (@ 25 °C)	7:1 (@ -25°C)
CAPEX	Low	High
OPEX	Low	High
Power Consumption	Low	High
Flow scheme complexity	Low	High

Removal of COS, CS_2 and Mercaptans	Low	High

2.4. Basis of Design

The Process Basis of Design for Project Bald Eagle establishes the foundational criteria for process systems and equipment selection, ensuring alignment with technical feasibility, operational efficiency, and regulatory compliance at the PacifiCorp Dave Johnston Power Station in Glenrock, Wyoming. For detailed information, reference the Process Design Criteria document 265467-00-PRO-DSC-0001.

The design is anchored in the Heat and Material Balance (HMB) derived from an Aspen HYSYS simulation of the Allam-Fetvedt Cycle (AFC) combustion turbine, jointly developed by 8 Rivers, Siemens Energy, and other partner OEMs.

Overall, the plant is designed to meet all applicable industry and regulatory codes and standards for continuous operation with a 30-year life for electrical, mechanical, cladding system, instrumentation and controls (260,000 operating hours), 50 years for civil works, and 15 years for painting/coating systems, assuming regular maintenance.

The site conditions are:

- Latitude: 42.839072, Longitude: -105.777397
- Elevation: 5,030 feet (1533 meters)
- Summer high average: 12.26 psig (0.845 barg), 88.3°F (31.3 °C), 69% RH
- Winter low average: 12.26 psig (0.845 barg), 16.52 °F (-8.6 °C), 45% RH
- Yearly average: 12.26 psig (0.845 barg), 47.3 °F (8.5 °C), 57.1% RH
- ASHRAE 2% design conditions, cooling: 89.8 °F (32.1 °C) DB, 60.3 °F (15.7 °C) MCWB
- ASHRAE 2% design conditions, evaporation: 62.4 °F (16.9 °C) DB, 81.5 °F 27.5 °C) MCWB

2.5. Process Systems and Equipment

2.5.1. Overview

The project is a coal-based power generation facility designed to integrate a gasification technology with the Allam-Fetvedt Cycle (AFC) and provide Enhanced Oil Recovery (EOR). This configuration enables electricity generation while achieving near-complete carbon capture and minimizing pollutant emissions. The plant targets a gross output of approximately [redacted] MW from the turbines, supported by a network of auxiliary systems and heat recovery units.

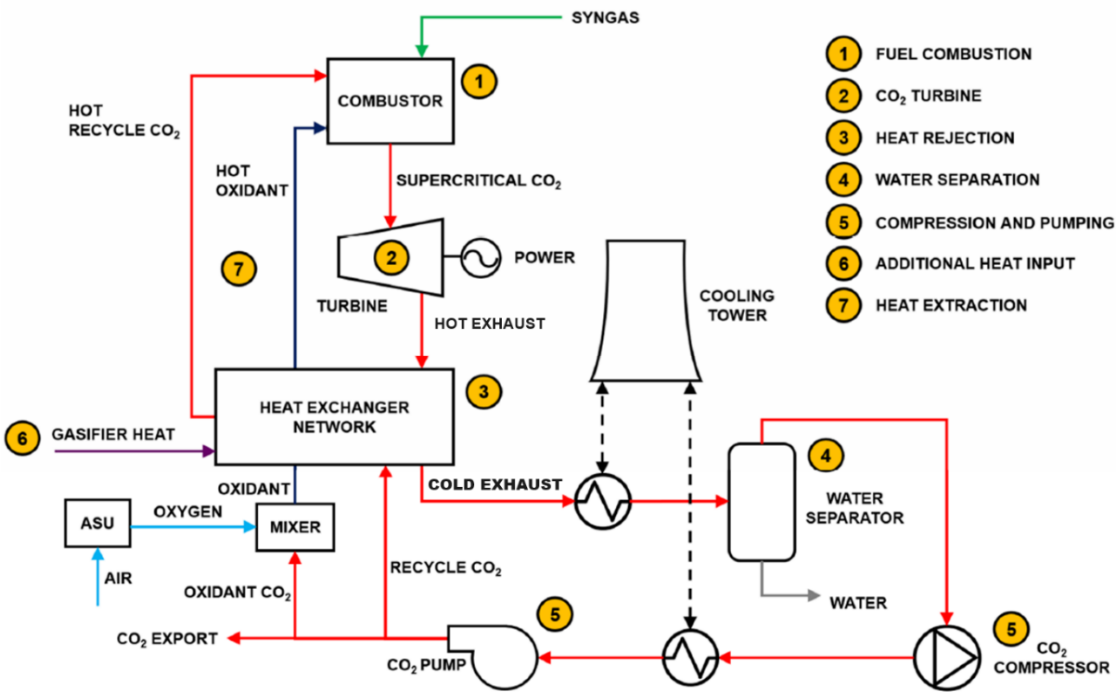

Figure 6: AFC Simple Block Diagram

The AFC utilizes sCO_2 as the working fluid and as an oxygen diluent. Pure oxygen from an Air Separation Unit (ASU) is mixed with a portion of the recirculating CO_2. This diluted stream, known as the oxidant, mitigates risks associated with high-pressure pure oxygen by reducing the overall oxygen concentration to levels comparable to that of air. A dedicated oxidant compressor compresses and discharges the oxidant through the recuperative heat exchangers for preheating prior to injection into the combustor. The oxidant combines with fuel gas in a direct fired oxy-combustor to form a heated, supercritical gas that expands through a sCO_2 turbine and exhausts into the Heat Exchanger Network (HEXN). The combusted gas mixture drives the turbine-generator set to produce electrical power.

The turbine exhaust stream then enters the Heat Exchange Network (HEXN) where it is cooled against the recycle and oxidant streams. After leaving the main recuperative heat exchangers, the stream enters a Direct Contact Cooler where the water produced in the combustion process is liquified for removal from the cycle. The CO_2 stream is then compressed and split into a recycle stream and a diluent stream for the oxidant supply. The main recycle stream is densified in an aftercooler to form a dense phase fluid and is then pumped up to pressure. After pumping, the recycle stream is heated against the turbine exhaust stream in the HEXN. From there the recycle stream enters the combustors to be mixed with the other streams during the combustion process. The diluent portion of the stream is mixed with oxygen and then follows a similar process as the recycle stream. The oxidant is also heated in the HEXN, before entering the combustor.

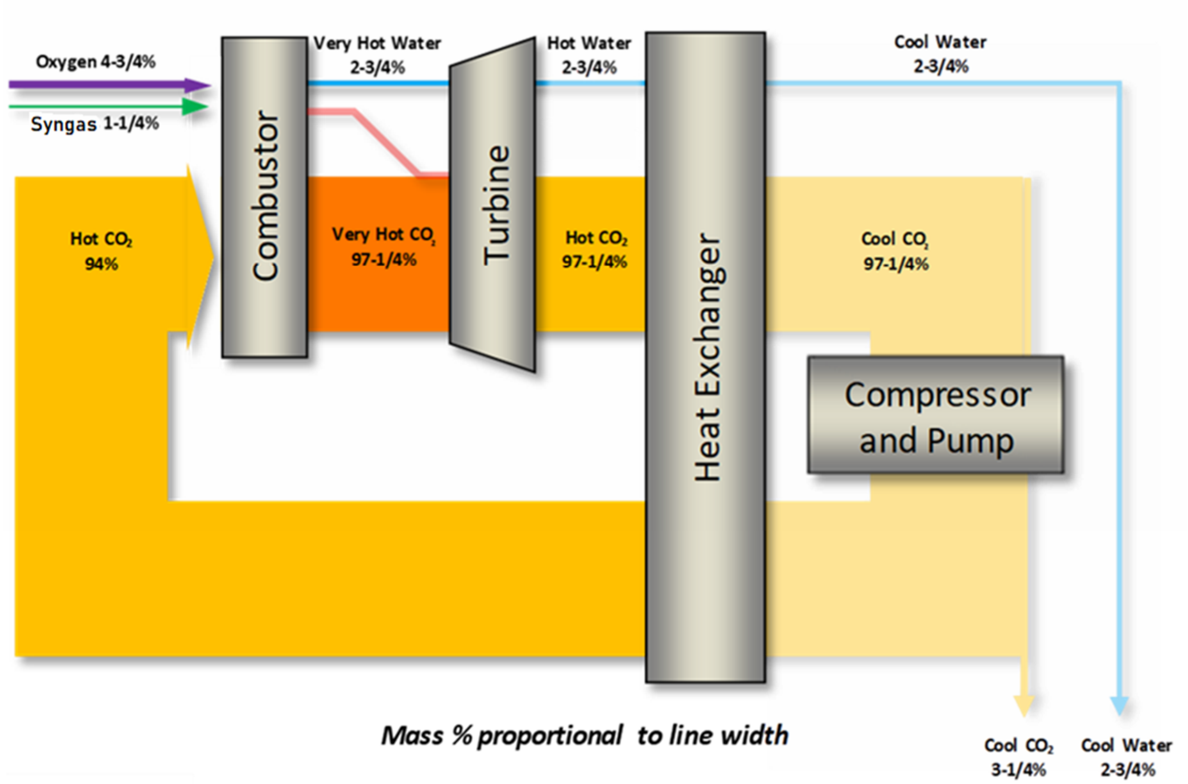

Figure 7: AFC Sankey Diagram

References:
For this section use as reference the following documents:

- Block Flow Diagram	265467-00-PRO-BFD-0001
- Process Flow Diagrams	265467-50-PRO-PFD-0005
	265467-50-PRO-PFD-0006
	265467-50-PRO-PFD-0007
	265467-50-PRO-PFD-0008
- General Arrangement	265467-50-MEC-GAD-0013

2.5.2. Coal Handling and Delivery

The Brownfield concept will reclaim coal from the on-site surface storage pile with a Reclaim Feeder Breaker. The reclaimer will discharge onto standard belt Conveyor BC-1. The conveyor will transport coal to a hammermill crusher in the crusher tower. The crusher will reduce the ± 1 ½" (38mm) size coal down to ¼" (6.3mm) size. The crusher will discharge to standard belt Conveyor BC-2 which will transport the coal to the gasifier coal silo (bunker). Each of the standard belt conveyors are mounted in a tubular gallery.

The Greenfield concept will reclaim coal from the same on-site surface storage pile as the Brownfield concept with a Reclaim Feeder Breaker. The reclaimer will discharge onto Pipe Conveyor BC-1. The 1.9 mile (3 km) long pipe conveyor will transport and discharge coal onto the standard belt Overland Conveyor BC-2 for delivery to a short-term storage pile.

A luffing radial stacker will build the short-term storage pile. Coal will be reclaimed from the short-term storage pile with a Reclaim Feeder Breaker which will discharge onto standard belt Conveyor BC-3. The conveyor will transport coal to a hammermill crusher in the crusher tower. The crusher will reduce the ± 1 ½" (38mm) size coal down to ¼" (6.4mm) size. The crusher will discharge to standard belt Conveyor BC-4 which will transport the coal to the gasifier coal silo (bunker). Each of the standard belt conveyors are mounted in a tubular gallery.

Coal Handling Basis of Estimate is the Mechanical Plot Plan (Greenfield & Brownfield), Equipment Specification, and Foundation Location Plan 265467-00-STR-SKE-0001 (Greenfield Pipe Conveyor).

2.5.3. Coal Preparation and Feed

Coal with size of less than 2 inch (~50 mm) is delivered from the onsite storage area and conveyed to a coal bunker, which serves as the initial buffer for the milling and drying process. A separate bunker stores the fluxant additive, which is used to reduce the ash fusion temperature and facilitate slag flow in the Gasifier.

Both coal and fluxant are metered via screw feeders into a rolling mill, where the coal is crushed to a fine particle size suitable for entrained-flow gasification, approx. <0.004 inch (0.1 mm).

To ensure proper combustion and gasification, the coal must be dried to a moisture content of 2–3% by weight. This is achieved within the rolling mill using a hot inert gas stream generated by an inline heater. The heater uses natural gas, ambient air and recirculated exhaust gas.

The hot gas is injected into the rolling mill, simultaneously drying and conveying the crushed coal. The resulting mixture of dry pulverized coal and exhaust gas is routed to a pulverized coal baghouse, where fine coal particles are separated from the gas stream. A portion of the baghouse exhaust stream is purged to atmosphere to remove moisture and make up LP N_2 is provided to maintain an inert atmosphere mitigating the highly combustible nature of finely pulverized dry coal particles.

The separated coal is dosed into a pulverized coal storage vessel, which is pressurized using low-pressure nitrogen. This vessel marks the first stage of the coal feeding system to the gasifier. Two additional pressure vessels follow, each increasing the coal pressure using high-pressure CO_2. This multi-stage pressurization ensures the coal reaches the required pressure for injection into the Gasifier.

2.5.4. Gasification Island

2.5.4.1. Gasifier

After coal milling and drying, coal in dust form is fed into a lock hopper sluicing system to pressurize batches of coal into a storage hopper with metering capabilities. The coal dust is pressurized with utility CO_2 from the AFC plant which pneumatically conveys the dust into the burner system.

The pressurized coal is introduced into the coal burner of a single entrained-flow gasifier, along with:

- Preheated high-pressure oxygen.
- Superheated medium-pressure moderator steam.

These oxidants moderate the reaction and support syngas formation. The Gasifier system is designed for a net syngas output of [redacted] LHV and the Gasifier operates at approximately 2732°F (1500°C). To minimize downstream compressor loads, the Gasifier is designed to maximize syngas delivery pressure. The syngas is cooled before leaving the Gasifier which is essential to protect downstream equipment and prepare the syngas for cleanup.

2.5.4.2. Convective Syngas Cooler

The upper section of the Gasifier, known as the gas quench area, cools down the syngas with a recycle flow of cool syngas mixing with the hot reaction gases until approximately 1652°F (900°C). This cools the gases and helps to knock out any remaining fly ash from the reaction gases to minimize fouling in the downstream section. This upper section connects directly to the syngas convective cooling section of the Gasifier, where the temperature is reduced further to around 644°F (340°C) via a series of internal heat exchangers in boiler feed water (BFW)/steam service. This second chamber contains heat exchangers that recover thermal energy to produce superheated medium-pressure steam at 716°F (380°C) and saturated medium-pressure steam at 518°F (270°C).

Saturated steam is routed to the plant's steam network, supporting auxiliary systems, and superheated steam is routed to the steam turbine.

Part of the steam produced in the gasifier is used internally, as moderator for the reaction and as heating medium. This steam is obtained by mixing Superheated and Saturated steam to achieve 572°F (300°C) temperature.

2.5.4.3. Slag Handling

The bottom of the first section of the Gasifier, the slag bath, collects molten ash and fluxant residues. These are quenched using water at 122°F (50°C) sourced from the Gasifier primary water treatment system. The water is recirculated and cooled via the cooling water system.

After the slag bath, slag is crushed in the slag crusher, then is transported to the slag accumulator vessel where the slurry flows into the slag sluice vessel. Water is removed and the cooled, dewatered slag is conveyed to the slag storage.

2.5.4.4. Syngas Filter

Syngas exiting the Gasifier goes to the fly ash filter which utilizes metal candle filters. The ashes fall and are depressurized through a set of vessels until it can be conveyed out of the system for disposal. Pressurized CO_2 will clean the candles intermittently by backflowing the filters with pulses of high-pressure gas. A portion of the ash-free syngas at 572-662°F (300-350°C) is recirculated into the quench section of the Gasifier to cool the syngas below the ash fusion temperature, utilizing a recirculation blower. The remainder of syngas continues to Wet Scrubbing.

2.5.4.5. Wet Scrubbing

The purpose of the Wet Scrubbing section is to further cool the syngas, remove fine particulate matter that has passed through the candle filter, and provide bulk removal of various contaminants.

The syngas exiting the fly ash filtration unit enters a venturi scrubber, where it is contacted with a recirculating water solution (pH controlled with sodium hydroxide) in a venturi throat to enhance collisions of tiny water droplets with airborne particles and aerosols. This captures particulate matter in droplets and neutralizes acid gases such as HCl, HF, and SO_2. In this stage, several key reactions occur:

- Hydrogen chloride reacts with sodium hydroxide to form sodium chloride and water ($HCl+NaOH \rightarrow NaCl+H_2O$).
- Sulfur dioxide reacts to form sodium sulfite ($SO_2+2NaOH \rightarrow Na_2SO_3+H_2O$), which may further oxidize to sodium sulfate (Na_2SO_4).
- Ammonia, commonly present in coal syngas due to fuel-bound nitrogen, is partially absorbed into the scrubbing liquid and forms ammonium hydroxide ($NH_3+H_2O \rightleftharpoons NH_4++OH^-$), stabilized under alkaline conditions.
- Other trace acid gases such as hydrofluoric acid may also be neutralized ($HF+NaOH \rightarrow NaF+H_2O$).

The Venturi scrubber uses high-velocity gas-liquid interaction to enhance mass transfer and ensure efficient removal of these corrosive species. The caustic is supplied from dedicated storage and injected into the scrubber throat, where the turbulent mixing promotes rapid neutralization reactions. This step is critical for protecting downstream equipment and maintaining environmental compliance by reducing hazardous air pollutants.

Following the venturi stage, the syngas flows into the main packed bed scrubber, which operates under the same temperature and pressure conditions. Cyclonic nature of the inlet device helps to separate water droplets and particulate matter into the collection sump and further scrubbing occurs in the packed bed. Make-up water is supplied from the plant's distribution system to maintain liquid inventory and compensate for losses, and the water is recycled. After treatment, the cleaned syngas exits the scrubber system and is routed toward the next process block, the Syngas Cleanup. The scrubber water is sent to the gasifier primary water treatment system.

2.5.4.6. Gasifier Primary Water Treatment

The scrubber blowdown water, enriched with sodium salts, ammonium compounds, and suspended solids from the syngas cleaning process, is routed to a neutralization and stripping system that is called the gasifier Primary Water Treatment system. The first stage is the Syngas Scrubber Water Neutralizer, where acid is added to lower the pH of the high-alkalinity water resulting from prior caustic scrubbing. This acidification step is essential to convert ammonium salts back into free ammonia (NH_3), and sulfates/sulfides into H_2S, enabling removal in the subsequent stripping stage. The acidified water is then sent to the Sour Slurry Stripper (SSS), which removes volatile contaminants such as NH_3, H_2S, and trace hydrocarbons. A bleed stream from the slag bath is also purged to the SSS to prevent build-up of solids and other contaminants. Low-pressure steam is introduced into the stripping column and the sour gas overhead from the stripper is routed to the Sulfur Recovery Unit (SRU), where H_2S is converted to elemental sulfur and NH_3 are thermally decomposed. The stripped water is cooled in the SSS Effluent Cooler, using cooling water before entering the clarification stage.

The cooled effluent flows into the Clarifier, where suspended solids settle out and are collected for disposal. Clarified water is transferred to the Clarified Water Recycle Tank for reuse or further treatment. Off-spec or overflow water is directed to the Wastewater Tank, which feeds into the plant's wastewater treatment block for final treatment. Settled solids from the clarifier are pumped to a Sludge Storage Tank and then dewatered using a Sludge Vacuum Belt Filter, producing a solid cake suitable for landfill or other disposal methods. This integrated system ensures that contaminants in the scrubber water are effectively neutralized, stripped, and separated, protecting downstream equipment and enabling environmental compliance.

2.5.5. Air Separation Unit (ASU)

The gasifier uses oxygen to produce syngas and the AFC uses oxygen to combust the fuel. Currently, two equal sized Air Separation Units are provided to cryogenically distill air to provide pure oxygen for the AFC & gasifier as well as various pressure levels of nitrogen for utility use within the plant. A nitrogen tank and vaporizer are included as part of the ASU. The ASU will also be the primary supplier of instrument air although a backup system is envisioned for start-up scenarios. An oxygen storage tank is provided to allow the gasifier and AFC to continue operating at full load for 16 hours with one ASU down.

Argon is a byproduct from the separation of air. Argon is a salable byproduct. A cryogenic tank and railcar loading equipment is supplied to load tank cars for shipment.

2.5.6. Syngas Cleanup Section

Following gasification and wet scrubbing, the raw syngas contains a variety of contaminants including sulfur compounds, mercury, and trace organics. These must be removed to meet the stringent specifications required for combustion in the AFC turbine. The cleanup process is divided into several key stages, each designed to target specific impurities and prepare the syngas for compression and combustion.

2.5.6.1. HCN and COS Hydrolysis

Hydrogen cyanide (HCN) is a toxic and corrosive compound that must be removed from the syngas stream to prevent damage to downstream equipment and ensure safe operation. Its presence in the syngas can interfere with combustion and catalyst performance, and poses environmental and safety risks. A portion of the HCN, along with other volatile contaminants such as ammonia (NH_3) and chlorine, is removed in the Syngas Scrubber inside Gasification Island (see Wet Scrubbing section 2.5.4.5), however a residual quantity of HCN (around 200 ppmv) remains in the gas. HCN could be removed in downstream Selexol Unit, however this requires an increase in solvent circulation rate.

Coal-derived syngas also contains trace amounts of carbonyl sulfide (COS), a sulfur compound that must be removed prior to acid gas removal. Although COS is not effectively captured by physical solvents like Selexol, it must still be removed to protect downstream equipment to appropriate specification. If left unconverted, a major portion of the COS can pass through the Acid Gas Removal (AGR) system and reach the gas turbine, where it may cause corrosion, deposit formation, and long-term degradation of hot gas path components. Additionally, COS contributes to SOx emissions upon combustion and may interfere with sulfur recovery catalysts in the Sulfur Recovery Unit (SRU) for the portion that Selexol does absorb.

For these reasons, COS and HCN are hydrolyzed in a catalytic reactor according to following reactions:

$$\mathbf{COS + H_2O \rightarrow H_2S + CO_2}$$

$$\mathbf{HCN + H_2O \rightarrow NH_3 + CO}$$

Water is a required reactant for hydrolysis, but its concentration must be carefully controlled. Excess water vapor can condense inside the reactor, especially at lower temperatures, leading to liquid water intrusion that can deactivate the catalyst and cause physical deterioration. To avoid this, the water content in the syngas should be maintained between 3 molar excess to COS and below 80% of saturation, ensuring sufficient reactant availability without risking condensation.

The COS and HCN Hydrolysis unit includes the following main equipment:

1- Syngas Heater: the syngas entering the unit from the scrubber around 354°F (179°C) is heated up to 392°F (200°C) using medium pressure steam, both to reduce relative humidity below 80% and to achieve the right temperature for the reaction.

2- The Syngas is then sent to a Chloride Guard Bed, that adsorbs residual HCl in a disposable adsorbent bed. This step is needed to avoid HCl poisoning of the hydrolysis catalyst.

3- Syngas enters the Catalytic Reactor where the hydrolysis reactions take place. For the current project two reactors in parallel are used to reduce size of the equipment for transportation.

2.5.6.2. Syngas Cooling

Following HCN and COS hydrolysis, the syngas enters a multi-stage cooling system designed to reduce its temperature, prior to mercury removal and AGR. The initial cooling stage utilizes medium-pressure boiler feed water (MP BFW) as the heat sink, recovering thermal energy from the syngas while preheating the BFW for use in the steam cycle. In this first step the Syngas is cooled down to [redacted], then sent to a separator where process condensate, containing some ammonia and H_2S is collected and pumped back to the Gasifier at [redacted] for use as Wet Scrubber makeup water.

The Syngas from the separator is sent to further cooling in the following steps:

1- Syngas is cooled to [redacted]

2- Syngas then is cooled down to [redacted]

3- Finally, Syngas is cooled to [redacted]

The process condensate obtained from these cooling steps is collected in a separator, and since it has higher H_2S and NH_3 content, it needs to be treated in the Sour Water Stripper (SWS) unit before being sent back to the Gasifier, while the cold syngas is sent to mercury removal section.

2.5.6.3. Sour Water Stripping

In the SWS, the sour water undergoes thermal stripping to remove volatile contaminants. The stripper condensate, which contains a small residual amount of ammonia, is recycled back to the gasification block. The stripper overhead gas, referred to as SWS Acid Gas (SWS AG), contains a high concentration of ammonia and some H_2S, and is sent to the Sulfur Recovery Unit (SRU) for further processing. The SRU is designed to handle this mixed acid gas stream, converting H_2S to elemental sulfur and managing ammonia through thermal decomposition or absorption.

The allowable ammonia concentration in the recycled stripper condensate is governed by specifications provided by the gasification block vendor. These limits directly influence the design capacity of the Sour Water Stripper, as higher ammonia rejection requirements necessitate larger stripping duty and potentially more complex downstream handling. This integrated cooling and sour water management system ensures syngas conditioning for mercury removal, supports water reuse, and maintains environmental compliance.

The sour process condensate is sent to SWS from the second separator of the cooling section under level control and is pre-heated to [redacted]against the stripped condensate before entering the SWS column. The combined effect of temperature increases and pressure reduction across the valve (SWS column works around [redacted]) causes some evaporation of dissolved gas from condensate.

The SWS column is provided with random packing to enhance the contact between liquid and gas phases, the liquid phase trickles down the column in countercurrent with the vapors coming from the reboiler, causing the evaporation of dissolved gases such as NH_3 and H_2S. The reboiler is a shell & tube exchanger fed with low-pressure steam (LPS) as heating medium.

From the bottom of the column the hot stripped condensate, around [redacted], is pumped up to [redacted], and is cooled down to [redacted] by pre-heating the column feed, before being mixed with the process condensate from the first separator of the syngas cooling unit. The contaminants of the mixed condensate will be according to the following limits:

NH_3, ppmw	[redacted]
CO_2, ppmw	[redacted]
H_2S, ppmw	[redacted]
O_2, ppbw	[redacted]
CH_3OH, ppmw	[redacted]
Chlorides, ppmw	[redacted]

The vapors from the top of the SWS column are partially condensed using cooling water:

- The liquid is refluxed to the top of the column by means of reflux pump.

- The vapor, rich in NH_3 and H_2S, is sent to the Sulfur Recovery Unit (SRU) for further processing.

2.5.6.4. Mercury Removal

The cooled syngas enters the Mercury Removal Unit (MRU), which consists of a single fixed-bed adsorbent vessel designed to reduce mercury concentrations from approximately 5 μg/Nm^3 to 0.01 μg/Nm^3. This unit ensures compliance with environmental and equipment protection standards, particularly for the gas turbine and downstream catalysts. The system operates under single-phase flow conditions, which are essential for maintaining uniform contact between the syngas and the adsorbent material and avoiding channeling or bypassing. The adsorbent bed is designed for a service life of approximately 10 years, minimizing maintenance and replacement frequency (the adsorbent is disposable and is not regenerated on-site).

2.5.6.5. Acid Gas Removal

The Acid Gas Removal (AGR) unit plays a vital role in conditioning the syngas stream by removing sulfur compounds to meet turbine requirements. In this project, the AGR system employs the SeparALL process—a physical solvent-based technology derived from the Selexol family—designed to selectively extract hydrogen sulfide (H_2S) and other trace contaminants while preserving the integrity of the carbon dioxide content. This is a critical distinction, as CO_2 is not treated as a waste stream but rather as a working fluid within the AFC, where it is recycled and compressed for power generation. The AGR unit is therefore configured to minimize CO_2 removal, focusing instead on achieving ultra-low sulfur levels (≤1 ppmw) in the treated syngas. This ensures compatibility with downstream components, including the AFC combustor.

Sour syngas enters the AGR block after being cooled in a heat exchanger that uses clean, cold syngas exiting the absorber tower—typically at 50°F (10°C)—as the cooling medium. This pre-cooling step reduces the temperature of the incoming feed to enhance solvent absorption efficiency. The cooled sour syngas then enters a Feed Knockout Drum to separate liquid water from the sour syngas stream. The separated water, or process condensate, is sent to waste water treatment.

The cooled sour syngas is introduced into the SeparALL absorber tower, where it flows countercurrently to a chilled lean solvent stream. Within the tower, H_2S, other acid gases, and water are absorbed into the solvent, while the treated syngas exits from the top with low sulfur content. A portion of this clean syngas is recycled to the H_2S Concentrator, while the remainder is routed to a Product Gas Knockout (KO) drum, where entrained solvent is separated and returned to the SeparALL sump. The clean syngas then proceeds to the Sulfur Guard Bed.

The rich solvent exiting the bottom of the absorber is first flashed to recover dissolved gases in the HP H_2S Flash Drum and then sent under level control to the H_2S Concentrator, a packed column where the solvent is stripped using part of the clean gas from the absorber.

The gas from the H_2S Concentrator is sent under flow control to the Recycle Compressor, compressed and cooled in the stripper gas air cooler, then mixed with the flash gas from HP H_2S Flash Drum.

The mixed gas is further compressed and cooled with cooling water before being recycled back to the bottom of the absorber.

The remaining rich solvent from H_2S Concentrator is pumped by Rich Solvent Pumps and pre-heated in the Lean-Rich Solvent Exchanger (Compabloc type) by cooling the Lean Solvent.

Re-heated rich solvent goes to the SeparALL stripper, a column with two beds of random packing, where it flows downwards countercurrent to the vapors from the reboiler.

The reboiler is a shell and tube type heat exchanger using LPS as heating medium to drive off the absorbed acid gases and water. Hot lean solvent from the column bottom is pumped by Lean Solvent LP pumps and sent to Lean-Rich Solvent Exchanger where it's cooled by heating the rich solvent.

The lean solvent flow is then divided: a sidestream is sent to a filtration system to avoid build up of solids and contaminants in the solvent, then mixed back with the main stream to be sent to Lean Solvent HP Pumps, cooled in the Lean Solvent Chiller using a refrigerant from a dedicated refrigeration package (usually propane) and finally is sent to the top of absorption column where it is contacted with the Syngas.

In the top section of the SeparALL stripper, the vapors exiting the top of the random packing are washed by reflux water, then exit from the top of the stripper.

These gases are cooled in the Reflux Condenser (air cooled) and further cooled in the Reflux Trim Condenser using cooling water and then pass through a Reflux KO drum. The resulting acid gas stream—composed of approximately 44 mol% H_2S and 41.7 mol% CO_2—is sent under pressure control to the Sulfur Recovery Unit (SRU) for further processing. The Reflux KO drum operates around 10 psig (0.7 barg).

Water condensed in the Reflux KO drum is partially refluxed by means of a Reflux Pump into the top of the stripper column to wash acid gases and reduce solvent entrainment. Downstream of the pump, a demineralized water make-up stream is added to reflux water and the excess water is purged and sent to the waste water treatment unit.

Makeup solvent is stored in the SeparALL Storage Tank and pumped as needed to the stripper. Additional support systems include the Solvent Filtration System, Antifoam mixing and injection (particularly at the H_2S concentrator), and the SeparALL area collection sump and sump pump system.

2.5.6.6. Sulfur Guard Bed

The Sulfur Guard Bed is installed downstream of the Acid Gas Removal (AGR) unit as a preventive measure to protect the combustion system from trace sulfur compounds that may bypass the AGR under abnormal conditions. It also allows for future optimization of the SeparALL unit outlet concentration and OPEX while still meeting the H_2S requirements of downstream equipment.

The system considers [redacted] adsorbent, configured in two parallel trains, each with two vessels in a Lead/Lag arrangement. This setup allows for continuous operation with redundancy and staged breakthrough monitoring.

Under normal conditions, the adsorbent is expected to last for multiple years without replacement and lead/lag configuration gives the ability to change a bed online. However, in the event of AGR malfunction or unexpected sulfur carryover, the guard bed provides a final barrier to prevent sulfur from reaching the combustor.

2.5.6.7. Sulfur Recovery Unit

The Sulfur Recovery Unit (SRU) receives two acid gas streams: one from the Acid Gas Removal (AGR AG) unit, and another from the Sour Water Stripper (SWS AG), which is high in ammonia. Other Acid Gas streams may be considered in future stages. The selected configuration is the [redacted] process followed by a caustic scrubber.

The AGR acid gas stream is first combusted in a thermal reactor using a sub-stoichiometric amount of air. This partial combustion converts a portion of the H_2S to SO_2 while maintaining a reducing environment. The SWS AG is not routed to the thermal reactor; instead, it is sent directly to the Incinerator to avoid ammonia decomposition issues. This consideration will be confirmed at later stages after knowing the exact NH_3 and H_2S concentration.

Thermal Reactor: $\mathbf{H_2S+O_2 \rightarrow SO_2+H_2O}$

The hot gas from the thermal reactor passes through a waste heat boiler and enters two or three Claus reactors in series. These reactors contain Claus catalysts that promote the reaction of H_2S and SO_2 to form elemental sulfur. Reheaters are installed between reactors to maintain reaction temperatures. Sulfur is condensed and recovered after each reactor.

Claus reactors: **$H_2S+SO_2 \rightarrow S_2+H_2O$**

Tail gas from the Claus reactors, typically containing 0.5–1.0 vol% H_2S, enters a "Selective Oxidation Reactor". This reactor contains a catalyst that oxidizes the remaining H_2S to elemental sulfur with an efficiency greater than 85%.

Selective Oxidation Reactor: **$H_2S+O_2 \rightarrow S+H_2O$**

The gas stream from the selective oxidation reactor, along with the SW AG stream, is sent to an Incinerator. In this unit, all remaining sulfur compounds and ammonia are oxidized. The resulting gas contains SO_2 and is prepared for final treatment.

Complete oxidation of H_2S: **$H_2S+1.5O_2 \rightarrow SO_2+H_2O$**
Oxidation of elemental sulfur: **$S+O_2 \rightarrow SO_2$**
Ammonia oxidation (idealized): **$NH_3+O_2 \rightarrow N_2+H_2O$ +NOx**

The SO_2-rich gas from the Incinerator is cooled in a quench venturi and then scrubbed countercurrently with a caustic solution in a packed bed. This process converts SO_2 to sodium sulfate. The scrubbed gas exits through demisters and is released to atmosphere with a residual SO_2 concentration typically below 50 ppmv, and potentially as low as 10 ppmv. The scrubbing liquid is collected in a sump, where oxidation air converts sulfites to sulfates before the liquid is sent to wastewater treatment.

Primary scrubbing reaction: **$SO_2+NaOH \rightarrow Na_2SO_3+H_2O$**
Oxidation of sulfite to sulfate: **$2Na_2SO_3+O_2 \rightarrow 2Na_2SO_4$.**
(in sump with air)

2.5.6.8. Syngas Compressor

The outlet stream of the Sulfur Guard Bed is compressed in a 4-stage multistage compressor up to [redacted] and approx. [redacted]. The intercoolers use cooling water at design conditions. In order to make the downstream cycle more efficient, the syngas temperature is then raised to [redacted] by LP and MP steam heat exchangers, as required by the AFC combustor. The maximum operation temperature limit for equipment design is considered as [redacted].

2.5.7. AFC Power Plant

2.5.7.1. Combustor and Turbine

Syngas fuel and oxidant, a mixture of oxygen and carbon dioxide, are combusted in the combustion chamber of the combustion turbine along with a large amount of recycled carbon dioxide to moderate temperature and form the working fluid. The working fluid entering the combustor is maintained at [redacted]. The hot high-pressure combustor exhaust is expanded to [redacted] through the turbine section of the combustion turbine. The rotating turbine shaft spins a generator to generate electric power. The turbine-generator system also includes a [redacted] to mitigate any potential overspeed conditions.

2.5.7.2. Heat Exchanger Network

The hot exhaust gases exit the combustion turbine and enter the Heat Exchanger Network (HEXN). The HEXN is a set of heat exchangers that exchange heat from exhaust gases [redacted] with the oxidant and carbon dioxide recycle streams going to the combustion chamber and the turbine cooling passages. Both the oxidant and recycle streams are preheated to [redacted] against the exhaust stream. Due to the mismatch of heat capacities between the low-pressure exhaust and the supercritical recycle and oxidant streams along with water condensation, heat is added to the HEXN in the range of normally [redacted] Additionally, heat can be sourced from the Gasifier in the form of steam if available. [redacted]

2.5.7.3. Recycle Direct Contact Coolers

After exiting the heat exchanger network, the turbine exhaust stream enters the Direct Contact Coolers (AFC DCCs), which consist of four pressure vessels with packing. These vessels are designed to maximize heat exchange between the hot exhaust gases and water. There is a counter flow of water that cools the exhaust gas after the water is injected at the top. As the exhaust gas flows through the packing, it is cooled below its dew point, causing water vapor—originating from combustion—to condense. This process also facilitates the absorption of soluble trace contaminants such as SOx and NOx into the condensed water.

The condensed water and dissolved species are removed from the exhaust gas via being pumped out of the DCC sump. Blowdown from the DCCs, along with the collected condensate, is routed to the Wastewater Treatment unit for processing.

Once the exhaust stream is stripped of bulk moisture and contaminants, the remaining CO_2 gas—now at ambient temperature—is sent to the Main Recycle Compressor. The cooled low moisture stream is now called Recycle.

2.5.7.4. CO_2 Main Recycle Compressor and Pumps

The CO_2 exiting the DCC is sent to the Main CO_2 Recycle Compressor, where the pressure is elevated to approximately [redacted] [redacted]. Then a CW exchanger is leveraged to liquefy the stream prior to the Main CO_2 Pumps that finish the pressurization for subsequent recirculation within the cycle. This approach optimizes the compression parasitic load. The recycle stream is split into two portions for varying purposes:

- A portion mixes with pure oxygen to form an oxidant / synthetic air stream
- A portion flows through the heat exchanger network for preheat and is recycled to the turbine in various locations

2.5.7.5. CO_2 Purification Unit and Export

Combustion-derived CO_2 is used as the working fluid within the cycle. As additional fuel is combusted, CO_2 must be purged from the system to maintain constant cycle inventory. Excess CO_2 must be treated and compressed for export to sequestration, enhanced oil recovery or other uses.

Part of the turbine exhaust coming from the Heat Exchanger Network, as well as the CO_2 coming from the Gland Seal Compressor, are routed to the CO_2 Purification Unit (CPU) line.

The first operation is the CO_2 Purification Unit Direct Contact Cooling (CPU DCC). This works in a similar fashion as described above for the AFC DCCs. The cooled CO_2 goes then to the CPU.

The CPU reduces the amount of oxygen, moisture and other trace compounds from the CO_2 stream to meet pipeline specifications. The CPU is a "Deoxo-Dryer" that removes oxygen and moisture in two distinct sections.

The first step is the Deoxo section, where the CO_2 Stream, mixed with a small amount of natural gas, is heated to around [redacted] in the Economizer (shell & tube type) while cooling reactor effluent, then is sent to an electric heater to achieve [redacted] and sent to the Reactor. Inside the Reactor, a catalytic bed promotes the oxidation of natural gas, reducing oxygen level below [redacted], increasing the temperature of the stream due to reaction exothermicity. The effluent from the reactor is cooled down to [redacted] in the Economizer and then sent to a shell and tube Water Cooler which cools the gas down to around [redacted].

Cool gas is sent to a Moisture Separator to remove condensed water and sent to the dryer section. The dryer uses a two bed Temperature Swing Adsorption (TSA) system to remove water from the CO_2 below [redacted], one bed is always in operation while the other is regenerated.

The gas is mixed with regeneration stream and filtered then sent to the TSA vessel in operation, where water is adsorbed. Dry gas is then sent to a filter to remove adsorbent particles which may be entrained in the gas and finally goes to Export CO_2 Compressor. CO_2 is compressed to pipeline pressure by the Export Compressor and Export Pump. The same approach to compression (initial compression, liquefaction, pumping) is taken as with the main CO_2 recycle stream.

When the adsorption cycle is terminated, the adsorbent is regenerated using hot CO_2 taken upstream the Deoxo Water Cooler and further heated up to [redacted] by means of Regeneration Heater (electrical heater type). Hot regeneration stream enters the TSA vessel from the bottom, heats up the adsorbent causing water desorption and the wet CO_2 is cooled in the Regeneration Water Cooler (shell and tube) to condense the water that is removed in Regeneration Separator. Finally, it's mixed with the dryer feed stream and sent to the TSA vessel in operation.

After the heating phase is over, cool CO_2 taken downstream Deoxo Water Cooler is used to cool the adsorbent, flowing from the top of the TSA vessel which has been regenerated, then is cooled in Regeneration Water Cooler and mixed with dryer feed stream.

After the cooling phase is concluded, the regenerated TSA vessel is put on operation, receiving the feed stream while the exhausted TSA vessel starts the regeneration cycle. The sequence is managed by the unit control panel, which operates a set of ON/OFF valves to modify the path of the gas in each phase.

2.5.7.6. Oxidant

A portion of the recycle stream from the discharge of the Main Recycle Compressor is mixed with oxygen from the Air Separation Unit to form oxidant with a composition roughly approximating air. The mixture composition is controlled to [redacted] of oxygen to provide similar combustion properties to air while staying below an oxygen concentration that would require additional safety considerations for the piping.

2.5.7.7. Oxidant Booster Compressor

The oxidant is compressed to an intermediate pressure of approximately [redacted] by the Oxidant Boost Compressor.

2.5.7.8. Oxidant Compressor

The oxidant is compressed from the intermediate pressure to combustion chamber feed pressure by the Oxidant Compressor. The oxidant exiting the Oxidant Compressor is then sent through and heated in the AFC heat exchanger network (HEXN).

2.5.7.9. Gland Seal Compressor

The combustion turbine seals are designed such that a small portion of exhaust gas flows through the labyrinth seal chambers and is exhausted. The gland seal compressor scavenges the exhaust seal gas and compresses it to system pressure. The scavenged gas exits the turbine below atmospheric pressure and thus risks contamination with atmospheric air. Thus, it is sent directly to the CO_2 Export Compressor to prevent N_2 from accumulating in the cycle. The Gland Seal Compressor's second function is to charge the system with CO_2 at start up.

2.5.8. Other Systems

2.5.8.1. Flare

A standard flare system is provided to allow an outlet for safety relief loads, off-specification intermediate product streams, and startup/shutdown flaring. A low pressure and high pressure flare header is assumed with liquid knock-out prior to routing to an elevated flare located at the edge of the plot plan with appropriate radius for heat radiation protection.

2.5.8.2. CO_2 Vent Stack

A CO_2 vent stack is required for emergency depressurization may be used during upset scenarios. Streams which are predominantly CO_2 cannot be routed to the flare as it would snuff out the pilot flame or require excessive support fuel. The CO_2 vent stack will be located near the flare with sufficient distance for dispersion of CO_2 without interrupting the flare pilot system.

2.5.8.3. Natural Gas Compressor

The Natural Gas Compressor is provided to compress natural gas to AFC pressure. During start-up, natural gas is used to fire the combustor up to 50% load. Additionally, the natural gas compressor functions as a standby compressor. If syngas is unavailable due to gasifier trip or other problems the natural gas compressor can supply fuel to the combustion chamber to keep the combustion turbine operating at reduced load and through transient conditions.

2.5.8.4. CO_2 Storage

A CO_2 storage tank is supplied to store CO_2 to charge the system for start up. The tank contains sufficient CO_2 to charge the system. Once the plant is operating, the CO_2 tank is filled with CO_2 from the Export Compressor.

2.5.8.5. Steam Turbine Generator

A steam turbine generator system is provided. The gasifier generates excess medium pressure superheated (MP SH) steam which is exported to a steam turbine where electric power is generated. The steam turbine generator system includes the turbine, generator, water cooled condenser, and associated equipment. The steam turbine includes one auto-controlled extraction with a desuperheater that feeds into the low pressure (LP) steam header. When there is a trip of the steam turbine, a bypass valve around the steam turbine will dump the MP SH steam through a desuperheater into the MP saturated steam header.

2.5.8.6. Auxiliary Boiler

A natural gas fired Auxiliary Boiler and supporting equipment, including deaerator, boiler feed water pumps, and feed and storage systems for boiler chemicals is provided to furnish steam for start-up and as needed during standby periods.

2.5.8.7. Raw Water Supply

The facility includes Raw Water Pumps and associated structure, river water strainers, etc. to pump river water from the river to water treatment and to the cooling tower.

2.5.8.8. Water Treatment

The water treatment system consists of pumps, chemical addition systems, filters, a reverse osmosis (RO) unit, a continuous electrodeionization (CEDI) system, and storage tanks. The water treatment system supplies demineralized BFW makeup to the gasifier block, auxiliary boiler, and equipment in the AFC and other areas that need high quality water. Water treatment filters river water for cooling tower make-up and other process water users.

River water from raw water treatment is added with coagulant to increase TSS removal efficiency and sent to the Ultrafiltration (UF) section. Booster pumps increase feedwater pressure to meet UF requirements. The water then passes through strainers to remove large particulates and protect the UF modules. Turbidity and pH of the feedwater are monitored downstream of the strainers.

The UF process includes the following steps: filtration, backwash, chemically enhanced backwash (CEB), and standby mode. Backwash pumps are equipped with VFDs to adjust the flow rate for backwash to the optimal membrane flux. Separate CEB pumps supply cleaning solutions to the UF modules for periodic CEB.

UF backwash is sent to WWT, while UF filtrate is used as RO feed, delivered by dedicated feed pumps. RO feed pumps supply RO units, operating at 80% recovery. Upstream of the RO units, antiscalant is added to minimize mineral scaling and caustic is injected to convert dissolved CO_2 to carbonates. RO reject water is sent to the Cooling Towers as make-up, while RO permeate flows to the RO permeate tank.

CEDI feed pumps supply the three Continuous Electrodeionization (CEDI) units with RO permeate. The CEDI modules use electric potential and ion exchange resin to remove remaining ions from the RO permeate to produce demineralized (“demin”) water, which is stored in a demin water storage tank.

The concentrate stream from CEDI is recycled to the UF filtrate tanks to improve overall system recovery.

2.5.8.9. Condensate Collection and Boiler Feed Water System

This system produces the BFW which is used in the plant to generate steam and for make-up to the Gasifier water systems.

The condensate from the network is collected and cooled down in two steps, the first is against the deaerator feed and second using cooling water. Then the condensate enters a polishing section where impurities are eliminated by filtration and ion exchange.

Polished condensate is mixed with make-up demin water and sent to a deaerator, after being preheated by the condensate from the network. Inside the deaerator LPS is used to strip oxygen from the condensate and demin water and the following chemicals are injected:

1- Phosphates (injected to Gasifier steam drum)
2- Oxygen Scavenger
3- Neutralizing amine

The BFW from the deaerator is pumped by two different set of pumps to be distributed to users at two different pressure levels:

1- MP BFW at 1102 psig (76 barg)
2- LP BFW at 217 psig (15 barg)

2.5.8.10. Wastewater Treatment

Effluent streams routed to the Wastewater Treatment (WWT) plant include purge water from the AGR, Gasifier, and AFC DCCs as well as process condensate and intermittent boiler blowdowns, The wastewater treatment facility conditions the wastewater streams for biological treatment. Wastewater is biologically treated to meet effluent requirements. Biosolids generated by treatment are landfilled. Treated water is reused in the facility, and excess is sent to outfall.

The Wastewater Treatment plant is composed by the following treatment steps:

- Gasifier effluent accumulation basin
- Gasifier effluent cooling
- Dissolved air flotation
- Cyanides removal unit
- Equalization and homogenization upstream biological treatment
- Denitrification
- Oxidation / nitrification
- Membrane biological reactor
- Filters feeding tank
- Multimedia and granular activated carbon filtration
- Sludge thickening
- Sludge dewatering

The Gasifier effluent, coming from a pre-treatment unit having the aim to remove, as much as possible, the solids contained in this stream, is discharged by gravity (discharge method and discharge pressure shall be verified in the next project phase) to the Wastewater Treatment plant. Due to high solids and cyanides content of this stream, the effluent is accumulated, pumped, cooled down to 86°F (30°C) and then sent to a dissolved air flotation sub-package that will act as a pre-treatment to remove the suspended solids present in the wastewater (mainly soot) and all the floating and readily settable material present in the effluent.

This is achieved through a coagulation/flocculation process and a final physical separation. The floating and settable sludge formed in dissolved air flotation (DAF) is periodically extracted via a dedicated sludge pump and sent to the sludge line of the Wastewater Treatment plant.

The clarified water produced by the DAF is sent to the cyanide removal unit. Here, the effluent toxicity is reduced through strong oxidation (usually ozone or equivalent chemical oxidant is used – type of chemical and AOP technology selection by Vendor) of cyanides in cyanates or, if feasible, in bicarbonates, nitrogen (gas), and oxygen. The strong oxidation leads to the simultaneous partial conversion of ammonia into nitrates and of hydrogen sulfide into sulfates.

The Gasifier effluent coming from the cyanide removal section, along with the process condensate from DCC, is sent into an equalization / homogenization section where the two streams are mixed and homogenized before being sent to the biological treatment plant. The driver for sending the process condensate from DCC in the equalization / homogenization upstream biological treatment is the high nitrates content of this stream, so to allow nitrates removal in denitrification section.

Being that the CO_2 content in DCC condensate is approximately 27,000 mg/l, it must be considered that, approximately 98% of CO_2 is vented into atmosphere in equalization / homogenization section. The vendor will foresee adequate vent to a safe location, if required by local environmental regulations. The same approach shall be considered with AFC condensate that is mixed with biological treatment effluent in filters feeding station (atmospheric basin / tank).

The biological treatment uses an MBR (membrane biological reactor) designed to enable efficient reuse. It consists of a pre-denitrification stage, followed by nitrification/oxidation reactors, then a membrane reactor.

Sludge recirculation will maintain the correct biomass concentration in the biological reactors while, in steady state conditions, to avoid continuous bacterial growth as a consequence of the synthesis phenomena, it is necessary to provide a constant extraction of the surplus sludge from the membrane bioreactor.

A portion of the biological sludge will be, hence, periodically removed, by means of dedicated excess sludge pump and sent to sludge treatment, along with the previously mentioned sludge from DAF unit.

The process condensate from AFC is sent to the filters feeding tank as well. From here, water is pumped to the multimedia filters and GAC (granular activated carbon) filters.

The filtered water tank will be equipped with dedicated treated water pumps to supply the treated effluent to the water treatment unit (by others). The excess of treated water will be discharged, by overflow, from the filtered water tank to the outfall.

The sludge produced either by the DAF, the chemical-physical unit and the biological plant is sent to the sludge treatment line composed by a thickener, from where the sludge, thickened up to 2-3% wt dry solids, is extracted by a dedicated sludge pump and sent to the final mechanical dewatering equipment. The expected sludge dryness after the mechanical dewatering is approximately 30% wt (Vendor to confirm).

The supernatants discharged from the thickener and the mechanical dewatering section are recirculated back to the equalization / homogenization section for their reprocessing.

2.5.8.11. Cooling Water

The facility Cooling Water system includes a wet evaporative Cooling Tower and Cooling Water Circulation Pumps. The Cooling Water system is designed to handle the loads from the AFC equipment, syngas cooling, syngas clean-up, steam turbine condenser and other plant loads. The system includes chemical treatments for cooling water scale, corrosion and biological control. Continuous boiler blowdown and water treatment reject water will be sent to the CT basin as make-up water with the remainder of cooling water make-up provided from the raw water pumps. Cooling tower blowdown is sent to the outfall.

2.6. Piping

2.6.1. Pipe Overview

The detailed basic piping design criteria is contained in Project Document 265467-00-PIP-DSC-0001.

2.6.2. Pipe Arrangements

All piping shall be routed to provide a neat and economical layout, minimize the number of fittings, and be consistent with good piping practice.

Layout shall be rectilinear except where gravity flows or other critical flows and low differential pressures demand the shortest possible direct runs.

Overhead piping shall be routed adjacent to steelwork from which it can be supported, provided that this does not result in excessive additional cost or affect the operation of the pipeline.

Piping shall be so arranged to provide economy of pipe supports, with the larger lines routed for flexibility and economy, and the smaller lines following the route of the larger lines.

Overhead piping is preferred within plant limits except that water mains may be buried if considered necessary for safety, frost protection or economy.

Piping arrangements shall allow for removal of equipment for inspection and maintenance. Piping shall clear any area provided in plant areas for mobile equipment access, tube-bundle removal, etc. Breakout spools and routing will be used to facilitate such arrangements. Where possible, maintenance areas and lift wells shall be clear of piping.

Where possible, overhead piping shall be carried side-by-side on supports with a common bottom of piping elevation.

Sufficient clearance shall be allowed between lines to permit access for removal or repair and there should not be less than 1" (25 mm) between a pipe and the outside diameter (OD) of the largest flange or fitting on the adjacent line after making due allowance for the thickness of any insulation and lateral thermal movement. In general, an accepted standard prepared for Wood on pipe spacing shall be followed.

Pockets shall be avoided in all lines where possible, particularly those containing corrosive chemicals, slimes and materials that congeal or solidify at ambient temperatures.

Process lines within buildings or structures shall be designed and installed with a continuous slope or arranged to drain to a designated vessel or sewer where indicated on the P&IDs.

Environmental consideration shall be reviewed for all buried piping.

Piping subject to thermal expansion and/or connected to equipment subject to thermal expansion shall be arranged to provide adequate flexibility and well supported to avoid excessive strains and load on equipment.

The arrangement of piping and valves shall be such as to minimize the possibility of the line contents freezing.

Valves, control valves, steam traps, etc. should be located for easy access from platforms or grade when possible.

Locating hot pipes adjacent to electric equipment and wiring shall be avoided, or the pipes shall be thermally insulated.

Pipes on piperacks shall have no slope.

Pipes on piperacks shall have 5% spare space allotted for future piping.

Consideration shall be given to the effects of leakage from flanges, etc. on equipment and personnel. Pipelines containing toxic and corrosive fluids should not be run above walkways without adequate shielding.

Lube oil lines with flange connections and gaskets shall not be located in the vicinity of uninsulated high-temperature surfaces.

Piping arrangements shall consider and avoid potential interference with horizontal and vertical cross-bracing on structures and associated gusset plates.

Control valve top works shall not interfere with adjacent pipes, equipment and structure.

Pipe will not be routed above and along cable tray runs.

2.6.3. Piping Materials and Service index

A detailed Material Selection Diagram can be found in Project document 265467-00-PRO-MSD-0001 and Service Index can be found in Project document 265467-PIP-STY-0001.

2.6.4. Basis of Estimate

Overall Plot Plan and General Arrangement drawings were used to calculate piping material take-offs (MTOs).

Vendor PFD's, Wood AFC-C P&ID's and Reference P&ID's were used to quantify line quantities and sizes for MTOs.

Wood Preliminary Piping Service Index was used for piping material selection for MTOs.

References:

265467-00-MEC-PLP-0001	Greenfield and Brownfield Plot Plan
265467-00-MEC-GAD-0100	Key Plan
265467-20-MEC-GAD-0010	Gasifier
265467-30-MEC-GAD-0011	Syngas Cleanup
265467-40-MEC-GAD-0012	Air Separation Units
265467-50-MEC-GAD-0013	AFC-C Plant
265467-60-MEC-GAD-0014	Auxiliaries
265467-70-MEC-GAD-0015	Cooling Tower
265467-80-MEC-GAD-0016	Flare Stack
265467-90-MEC-GAD-0017	Admin/Control, Maintenance and Warehouse Bldgs
265467-100-MEC-GAD-0100	Substation

265467-00-PIP-MTO-0002	MTO – BOP/Raw Water Intake
265467-20-PIP-MTO-0020	MTO - Gasifier
265467-30-PIP-MTO-0030	MTO – Syngas Cleanup
265467-40-PIP-MTO-0040	MTO – Air Separation Units
265467-50-PIP-MTO-0001	MTO – AFC-C
265467-51-PIP-MTO-0051	MTO – HEXN Kelvion Configuration
265467-60-PIP-MTO-0060	MTO – Water Treatment and Aux Systems
265467-70-PIP-MTO-0070	MTO – Cooling Tower
265467-80-PIP-MTO-0080	MTO – Flare Stack

2.7. Civil, Structural, and Architectural Systems

2.7.1. Civil

2.7.1.1. Brownfield Site

Drawings 265467-00-CIV-DWG-0001 through 0006 were developed for grading, drainage, erosion control, site, paving, and underground utilities for the brownfield site located inside the old number 4A and 4B closed ash ponds.

Miscellaneous site items will be demolished (aggregate roads, concrete foundations, underground and above ground utilities, etc.).

An extensive amount of fill of approximately 18-ft will be required to bring the existing grade up in this existing ash pond limit up to an approximate elevation of 4963 that will require the installation of compacted backfill and geogrid.

The northern half of the project area will drain predominately through sheet flow and storm pipes to a proposed stormwater pond that will be located to the east (relative to plant north) of the proposed cooling towers. The southern half of the project area will drain predominately through sheet flow and storm pipes to a proposed stormwater pond that will be located within a closed existing process pond just south (relative to plant north) of the existing clearwater pond and west (relative to plant north) of the existing cooling towers. The construction trailer and construction fabrication yard will sheet flow to a smaller proposed stormwater pond located to the east (relative to plant north) of the existing cooling towers.

Perimeter fencing will be provided with at an assumed 6-ft height with 1-ft of 3-strand barbed wire for an overall height of 7-ft. Personnel gates, double swing gates, and cantilever sliding gates were assumed.

Asphalt paved roads are provided throughout the proposed project area including parking spaces adjacent to the proposed Maintenance Building. Crushed aggregate surfacing is provided in-between asphalt paved roads and foundations/equipment areas to allow access for maintenance activities. Asphalt pavement and crushed aggregate surfacing section thicknesses were assumed since no geotechnical report pavement recommendations have been provided. Concrete sidewalks are provided between the Administration Building and Control Room, Warehouse, and Maintenance Building.

A proposed underground fire water loop is provided around the project area along with appropriately spaced fire hydrants and post indicator valves (PIVs) per NFPA 24 requirements. Fire risers are provided for the Administration Building and Control Room, Warehouse, and Maintenance Building.

Additional underground utilities include cooling water supply and return, cooling tower make-up, raw water, treated waste water, potable water, and natural gas lines.

2.7.1.2. Greenfield Site

Drawings 265467-00-CIV-DWG-0007 through 0012 were developed for grading, drainage, erosion control, site, paving, and underground utilities for the greenfield site located to the south and west (relative to plant north) of the existing Windstar substation.

Existing grade slopes uniformly from northwest to southeast (relative to plant grid). The proposed grades mimic this existing drainage pattern while trying to balance the cut and fill as close as possible.

The entire project area drains predominately through sheet flow, channel flow, and storm pipes to a proposed stormwater pond that is located on the east side (relative to plant grid) of the project area.

Perimeter fencing will be provided with at an assumed 6-ft height with 1-ft of 3-strand barbed wire for an overall height of 7-ft. Personnel gates, double swing gates, and cantilever sliding gates were assumed.

Asphalt paved roads are provided throughout the proposed project area including parking spaces adjacent to the proposed Administration Building and Control Room. Crushed aggregate surfacing is provided in-between asphalt paved roads and foundations/equipment areas to allow access for maintenance activities. Asphalt pavement and crushed aggregate surfacing section thicknesses were assumed since no geotechnical report pavement recommendations have been provided. Concrete sidewalks are provided between the Administration Building and Control Room, Warehouse, and Maintenance Building.

A proposed underground fire water loop is provided around the project area along with appropriately spaced fire hydrants and post indicator valves (PIVs) per NFPA 24 requirements. Fire risers are provided for the Administration Building and Control Room, Warehouse, and Maintenance Building.

Additional underground utilities include cooling water supply and return, cooling tower make-up, raw water, potable water, and natural gas lines.

2.7.1.3. Basis of Estimate

General Arrangement drawings and underground process line routings from Wood's Mechanical/Piping discipline to perform the preliminary civil designs.

Topographic survey was not provided for the project area. Therefore, existing grade contours were obtained from online GIS data for approximate grade elevations for the greenfield site and through a culmination of existing drawings and as-builts for the brownfield site.

Geotechnical report for the project area was not provided. Therefore, pavement section thicknesses were assumed.

References:
265467-00-CIV-DWG-0001 – Brownfield Grading, Drainage, and Erosion Control Sheet 1
265467-00-CIV-DWG-0002 – Brownfield Grading, Drainage, and Erosion Control Sheet 2
265467-00-CIV-DWG-0003 – Brownfield Grading, Drainage, and Erosion Control Sheet 3
265467-00-CIV-DWG-0004 – Brownfield Site, Paving, and Underground Utilities Sheet 1
265467-00-CIV-DWG-0005 – Brownfield Site, Paving, and Underground Utilities Sheet 2
265467-00-CIV-DWG-0006 – Brownfield Site, Paving, and Underground Utilities Sheet 3
265467-00-CIV-DWG-0007 – Greenfield Grading, Drainage, and Erosion Control Sheet 1
265467-00-CIV-DWG-0008 – Greenfield Grading, Drainage, and Erosion Control Sheet 2
265467-00-CIV-DWG-0009 – Greenfield Grading, Drainage, and Erosion Control Sheet 3
265467-00-CIV-DWG-0010 – Greenfield Site, Paving, and Underground Utilities Sheet 1
265467-00-CIV-DWG-0011 – Greenfield Site, Paving, and Underground Utilities Sheet 2
265467-00-CIV-DWG-0012 – Greenfield Site, Paving, and Underground Utilities Sheet 3

265467-00-CIV-MTO-0001 – Brownfield
265467-00-CIV-MTO-0002 – Greenfield

2.7.2. Structural

2.7.2.1. Brownfield Site

The Brownfield Site is located at the [redacted]. This site will require extensive remediation. The following assumptions were made regarding this site since there was no geotechnical report available:

Dewatering of the site is required using a well point system or other appropriate method. There was standing water at the southwest end of the closed ash ponds back in April of this year.

Ground improvement may be required using compaction grouting or vibro-compaction/vibro-replacement. This work must be done by a specialty geotechnical contractor. Design & construction requires a site geotechnical investigation & report.

After dewatering and ground improvement (if required) a geogrid should be installed over the site and a layer of compacted backfill.

Install compacted backfill to raise the entire site approximately 18 feet to match the existing haul road to the southeast of the [redacted] at Elevation 4963 feet.

Install deep foundation elements (auger pressure grouted piles) embedded into the sandstone bedrock to support all heavy equipment and equipment support structures. The top surface of the sandstone bedrock is located at approximately Elevation 4924 feet. No variation in the top of bedrock elevation in the north-south nor east-west directions is assumed.

It is assumed that lightly loaded equipment and buildings such as pre-engineered metal buildings may be supported on shallow foundations bearing on the compacted structural fill over the ground improvement.

Allowable net bearing capacity of native soils and compacted structural fill is assumed to be 2500 psf for preliminary foundation design.

2.7.2.2. Greenfield Site

The Greenfield site is located close to and southeast of the existing Windstar Substation. This site requires no remediation or dewatering but earthwork cut and fill will be required since the site gently slopes downward to the south-southeast. The following assumptions were made regarding this site since there was no geotechnical report available:

It is assumed that light to moderately loaded equipment and buildings such as pre-engineered metal buildings may be supported on shallow foundations bearing on compacted structural fill.

Allowable net bearing capacity of compacted structural fill is assumed to be 3000 psf for preliminary foundation design.

Heavy equipment and equipment support structures will require deep foundation elements for support. These elements will be auger pressure grouted piles embedded into competent shale bedrock.

Shale bedrock is assumed to be a minimum of 30 feet below existing ground surface.

2.7.2.3. Basis of Estimate

The preliminary design of all buildings and equipment support structures' foundations and steel framing was done in accordance with the 2024 International Building Code, ASCE 7-22, ACI 318-19, AISC 360-22, AISC 303-22 and the 16th Edition of the Manual of Steel Construction. These structures and foundations (including piling) were designed for the loadings (dead, live, wind, seismic, ice and snow) as detailed in the attached Structural Design Criteria. Site specific loads such as wind, seismic, ice and snow were obtained from ASCE's Hazard Tool.

Preliminary structural design was done using STADD computer software, Excel spreadsheets and hand calculations. Material takeoffs for steel, concrete and piling were done manually or by spreadsheets. Steel takeoffs for large steel structures modeled in STADD were done automatically by the software.

General Arrangement drawings from Wood's Mechanical/Piping Group and vendor equipment layout drawings and loadings provided in quotes were used to perform the preliminary structural designs.

Equipment weights were estimated by the Process and Structural disciplines when not provided by the manufacturer.

Geotechnical engineering reports were not available for either the Brownfield or Greenfield sites. Existing geotechnical reports for the existing Dave Johnston Power Plant, ash ponds and Windstar Substation were used to make assumptions for the geotechnical parameters to be used in preliminary design of the foundations in this Pre-FEED Study.

The frost depth for this site is 4'-0".

2.7.3. Architectural

2.7.3.1. Basis of Estimate

Building sizes were determined based on functional requirements by Wood's Mechanical/ Piping discipline. Building construction systems were determined by Mechanical/Piping and Structural disciplines based upon building function and program complexity. Three building types were determined, with the following buildings included under each type.

- Pre-Engineered Metal Building Systems (PEMB):
    - Administration/Control Building (ACB)
    - Maintenance (MTN) building
    - Warehouse Building (WHB)
    - Compressor (CMP) building
    - Water Treatment Building (WTB)
    - Fuel Gas Conditioning (FGC) Building
    - Wastewater Treatment Building (WWT)

- Engineered steel framed structures (stick built):
    - Main Air Compressor (MAC) building.
- Modular and/or prefabricated buildings:
    - Cooling Tower Chemical Feed Enclosure (CTC)
    - Demin Tank Pump Enclosure (DTP)
    - Raw / Fire Water Tank Pump Enclosure (WTP)

For the three PEMB structures with occupied functions, the estimate quantities were based upon assumed building layouts determined by Architecture, previous project experience, and building code requirements.

The Administration and Control Building was assumed to have the following spaces:

- Control Room (with adjacent toilet room, shower room, and kitchenette)
- DCS / Electrical Room
- Reception / Entrance area
- Seven Individual Offices
- Break Room
- Conference Room
- Multi-fixture Toilet Rooms
- Custodial Closet
- HVAC Room

The Maintenance Building was assumed to have the following spaces:

- Maintenance Shop
- Maintenance Manager Office
- Seven Individual Offices
- Break Room
- Conference Room
- Multi-fixture Toilet Rooms
- Custodial Closet
- DCS / Electrical Room
- HVAC Room

The Warehouse Building was assumed to have the following spaces:

- The building overall is majority Warehouse
- Warehouse Manager Office
- This building is not provided with Toilet Rooms; facilities are provided at the adjacent Maintenance Shop

The Wastewater Treatment building is assumed to have a Manager’s Office and a Toilet room and Custodial Closet, due to the excessive distance to other plumbing facilities on the site.

The remaining non-modular buildings were estimated based on building code requirements to determine egress doors and toilet fixtures.

Building Envelope Materials:

- Envelope materials at the buildings were estimated based on the local climate, IECC requirements for conditioned space, or need for freeze protection
- Insulated metal wall and roof panels are assumed for:
    - Administration/Control Building (ACB)
        - Occupied building with conditioned space; meet IECC
    - Maintenance (MTN) building
        - Occupied building with conditioned space; meet IECC
    - Warehouse Building (WHB)
        - Partially-occupied building with freeze protection; meet IECC
    - Compressor (CMP) building
        - Typically unoccupied building with freeze protection
    - Water Treatment Building (WTB)
        - Typically unoccupied building with freeze protection
    - Fuel Gas Conditioning (FGC) Building
        - Typically unoccupied building with freeze protection
    - Wastewater Treatment Building (WWT)
        - Partially occupied building with partial HVAC and freeze protection
    - Main Air Compressor (MAC) building
        - Typically unoccupied building with freeze protection

- Modular wall systems and roof systems of insulated modular wall and roof panels are assumed for:
    - Cooling Tower Chemical Feed Enclosure (CTC)
        - Typically unoccupied equipment enclosure with freeze protection
    - Demin Tank Pump Enclosure (DTP)
        - Typically unoccupied equipment enclosure with freeze protection
    - Raw / Fire Water Tank Pump Enclosure (WTP)
        - Typically unoccupied equipment enclosure with freeze protection

2.8. Electrical

2.8.1. General

The AFC combustion turbine generator and the steam turbine generator combined generates [redacted] MW of gross power at 13.8 kV. Approximately 200 MVA of the power is stepped up to 230 kV and tied to the existing Dave Johnston Switchard. Station power is distributed by a 13.8 kV bus and stepped down to 4160V and 480V by transformers and switchgear. The project Electrical Single Line Drawing, 265467-00-EL-SLD-0001 through 0004, gives additional details.

Cabling from electrical gear to devices is routed in cable trenches or on pipe bridges. The power is routed to the greenfield site via towers and cable tray.

High voltage electrical systems are routed via cable bus or iso-phase bus and transmission poles and towers. Electrical gear is housed in Packaged Electrical Centers and manufactured offsite. Considered minimal existing infrastructure.

2.8.2. Basis of Estimate

To support the Class 4 estimate, the following engineering documents and data were developed:

- Single Line Diagram: Illustrated major electrical system components and equipment.
- Load List: Derived from the mechanical equipment list to inform electrical loads.
- UPS and Battery Backup System: Estimated using in-house historical pricing.
- MV and LV Switchgear and MCCs: Cost estimated using internal pricing databases.
- Cable Schedules: Developed for medium voltage and low voltage cable runs to estimate material and installation costs. Lengths were based on measurements from electrical equipment layout. Standard lengths were applied for LV cables larger than 1/0 AWG.
- Power Distribution Center (PDC): Estimated using historical in-house data.
- Transmission Line: Cost estimate based on internal historical benchmarks.
- Security and Surveillance Systems: Pricing derived from in-house historical data.

2.9. Instrumentation and Controls

2.9.1. Project Control Systems

The project control system consists of a distributed DCS architecture with a central control room with DCS operator interface HMIs and turbine control system interface HMIs. Adjacent to the control room is an electronics room with DCS engineering workstations/HMIs and network servers and equipment which shall permit Local Area Network interface. The application has eight Power Distribution Centers (PDCs) containing DCS controller and I/O cabinets with soft interface to vendor supplied system package PLCs, switchgear, MCCs, and UPS systems.

The DCS shall act as the primary control system and operator interface for all BOP system controls as well as supervisory interface for all vendor package based PLC based control systems. The estimate for the DCS was based on Wood historical information as well as a soft estimate from Emerson Ovation.

2.9.2. Basis of Estimate

Instrumentation and control valve estimates are based on Wood historical information. High pressure control valve estimates are based on vendor budgetary estimates.

To support the Class 4 estimate, the following engineering documents and data were developed:

- Control System Philosophy: High level overview of instrumentation and control system project ideology.
- I&C Design Criteria: Requirements for detailed design instrumentation and control systems. Identifies all deliverables and requirements for each deliverable.
- Instrumentation & Controls Architecture Drawing: Control system block diagram which identifies all major components of facility control systems including soft interconnections and interfaces.

References:

1. Control Philosophy - 265467-000-INS-PHL-0001
2. I&C Design Criteria – 265467-000-INS-DSC-0001
3. Instrument & Controls Architecture Drawing – 265467-00-INS-CSA-0001

3. Capital Cost Estimate

3.1. Overview

Two different options were evaluated for brownfield and greenfield cost estimating purposes with the greenfield being the base scope of work. While the brownfield option offers significant benefits in terms of integration, it also presents drawbacks related to plant layout and civil/structural design. Consequently, a second greenfield option was evaluated. The greenfield option eliminates the layout, civil, and structural drawbacks but requires longer lengths of coal conveyors and piping.

The greenfield capital cost estimate summary by area is provided as part of 265467-0000-PCC-EST-0002 – Final Summary by Area (Greenfield). The Brownfield estimate breakdown can be found in 265467-0000-PCC-EST-0003 – Final Summary by Area (Brownfield). These estimates are classified as an AACE Class 4 estimate with an assessed accuracy range of -15%/+30%.

3.2. Basis of Estimate

Refer to Project document 265467-0000-PCC-EST-0004 for the Basis of Estimate.

4. Value Engineering Summary

4.1. Cost Savings Included in the Pre-FEED

A total of 10 value engineering cost savings opportunities were identified and included in the Pre-FEED scope and cost estimate. In total, approximately [redacted] in cost savings was realized for the Pre-FEED capital cost estimate. This included the following items:

[redacted]

4.2. Cost Savings Potential Identified for FEED

A total of 7 additional potential value engineering cost savings opportunities were identified to be deferred to the FEED phase for further study and evaluation. The estimated order of magnitude potential additional cost savings for these seven items is approximately [redacted]. This includes the following items:

[redacted]

5. Conclusion

5.1. Techno-Economic Analysis

5.1.1. Technical and Auxiliary Load Summary

Table 5: Expanded Performance Summary

	Units	Including Fuel Supply Plant	Excluding Fuel Supply Plant
Turbine Fuel Input	MWt, HHV	[redacted]	[redacted]
Coal Thermal Input	MWt, HHV	[redacted]	[redacted]
Gross Power Generation	MWe	[redacted]	[redacted]
Power Consumption	MWe	[redacted]	[redacted]
Net Power Output	MWe	[redacted]	[redacted]
Efficiency (LHV)	%	[redacted]	[redacted]
Efficiency (HHV)	%	[redacted]	[redacted]
Heat Rate	btu/kWh	[redacted]	[redacted]

Coal Input (wet)	tons / day	[redacted]	
CO_2 Emissions	tons / day	[redacted]	
CO_2 Export	tons / day	[redacted]	
CO_2 Capture Rate	%	[redacted]	
Coal Ash Export (dry)	tons / day	[redacted]	
Slag Export (dry)	tons / day	[redacted]	
Argon Export	tons / day	[redacted]	
Sulfur Export	tons / day	[redacted]	
Crude Rare Gas Export[6]	tons / day	[redacted]	
Emissions Summary[7]			
CO_2	kg/h	[redacted]	
SOx	kg/h	[redacted]	
NOx	kg/h	[redacted]	
CO	kg/h	[redacted]	
PM	kg/h	[redacted]	

The total auxiliary power consumption for the facility is estimated to be approximately [redacted] MWe. Table 6 below summarizes the auxiliary power by plant area. [redacted]. Refer to Electrical Load List 265467-00-ELE-LST-0001.

Table 6: Auxiliary Load Summary

Area No.	Area Description	Fuel Supply Plant (kWe)	AFC Power Island (kWe)
10	Coal receiving	[redacted]	[redacted]
20	Coal drying and gasification	[redacted]	[redacted]
30	Syngas cleanup	[redacted]	[redacted]
30	Syngas compression	[redacted]	[redacted]
40	Air separation units	[redacted]	[redacted]
50	CPU & CO_2 export	[redacted]	[redacted]
50	AFC	[redacted]	[redacted]
60	Water treatment	[redacted]	[redacted]
70	Cooling water	[redacted]	[redacted]
00	Utilities	[redacted]	[redacted]
	Total	[redacted]	[redacted]

5.1.2. Operating & Maintenance Expenses Summary

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[6] *Includes Neon and a combined Krypton and Xenon stream*

[7] *Additional details on air emissions sources in section 5.1.4*

5.1.2.1. General

Operating and maintenance (O&M) expenses are comprised of both fixed and variable costs. Variable costs can be further broken down by non-fuel costs and fuel costs. Fixed O&M costs are considered constant over time regardless of plant production rates whereas variable O&M costs are dependent upon the plant production rates. First-year O&M costs were estimated for the Pre-FEED study based on 2025 USD and are shown below.

First-Year O&M Costs (2025 USD):

- Fixed O&M Costs: [redacted]
- Variable O&M Costs: [redacted]
- Fuel Costs: [redacted]

5.1.2.2. Fixed O&M Costs

Fixed O&M costs primarily include plant operating and maintenance labor. Total daytime and shift headcounts were estimated, and an average annual burdened wage rate was applied. The facility will incur additional fixed costs, such as property taxes and insurance, but these are excluded from the Pre-FEED estimate.

5.1.2.3. Variable O&M Costs (non-fuel)

Non-fuel variable O&M costs include maintenance materials, consumables (chemicals, catalysts, etc.), and waste disposal costs. Annual maintenance material costs are estimated as a percentage of the upfront purchased equipment costs. Consumable and disposal costs are based on estimated rates specific to the Bald Eagle study and estimated unit pricing from various sources.

5.1.2.4. Fuel Costs

Estimated fuel costs include both coal feedstock consumption as well as continuous natural gas consumption for the flare pilot burners, inert gas generator for coal drying, SRU tail gas incinerator, and CPU Deoxo unit.

5.1.3. Water Summary

5.1.3.1. Withdrawal and Consumption

The total plant raw water withdrawal and consumption is estimated to be approximately [redacted]. The primary consumers of raw water in the facility are:

- Cooling tower makeup [redacted]
- Steam cycle makeup [redacted]
- Water treatment system losses/rejection [redacted]

5.1.3.2. Recycle and Reuse

Significant water recycle and reuse is implemented to reduce overall raw water consumption. Examples include:

- Process condensates from the syngas cleanup area are used as Gasifier Wet Scrubber makeup
- Clarified water from the Gasifier Wet Scrubber and SWS is used as Gasifier Slag Bath makeup
- Water treatment (RO) rejects are used as Cooling Tower makeup

5.1.4. Levelized Cost of Electricity

The Levelized Cost of Electricity (LCOE) for an AFC power plant is driven by a combination of upfront capital costs and ongoing expenditures over the plant's lifetime including fuel, Operations and Maintenance (O&M), and other recurring costs such as CO_2 transportation and sequestration fees (T&S), and property taxes and insurance.

Section 45Q tax credits were incorporated and offset part of the generation cost the plant incurs. Argon revenue from the air separation units, another value stream, also reduces the effective LCOE.

This LCOE analysis uses the below Weighted Average Cost of Capital and annual escalation and assumes a 30-year plant life to establish a capital recovery factor and levelizing factor which serve to convert upfront capital outlays and ongoing operating expenditures, respectively, into equivalent annualized costs that are allocated across expected lifetime electricity output. Cost escalation over time is assumed to track inflation.

Table 7 summarizes the assumptions used in the LCOE analysis.

Table 7: LCOE assumptions

Assumption	Unit	Value
Plant operations		
Coal	\$/mmbtu	[redacted]
Coal	\$/ston	[redacted]
Natural gas	\$/mmbtu	[redacted]
Fixed O&M	\$MM/year	[redacted]
Variable O&M	\$/MWh	[redacted]
CO_2 T&S	\$/mt	[redacted]
Property taxes	\$MM/year	[redacted]
Insurance	\$MM/year	[redacted]
CO_2 45Q value	\$/mt	[redacted]
CO_2 EOR value	\$/mt	[redacted]
Argon price	\$/mt	[redacted]
Financing		
Plant life	years	[redacted]
Cost of debt	%	[redacted]
Cost of equity	%	[redacted]
Debt value	%	[redacted]
Equity value	%	[redacted]

Weighted average cost of capital (WACC)	%	[redacted]
Annual escalation	%	[redacted]

The LCOE breakdown is shown below. Cost is driven by Capex. The project heavily benefits from 45Q, with tax credits reducing LCOE by roughly [redacted].

Table 8: LCOE

Component	Unit	Value
Capex	$/MWh	[redacted]
Fixed O&M	$/MWh	[redacted]
Variable O&M	$/MWh	[redacted]
Fuel Costs	$/MWh	[redacted]
CO_2 T&S Cost	$/MWh	[redacted]
Property Taxes	$/MWh	[redacted]
Insurance Cost	$/MWh	[redacted]
LCOE (excluding Value-Add Streams)	**$/MWh**	[redacted]
45Q	$/MWh	[redacted]
EOR	$/MWh	[redacted]
Argon Sales	$/MWh	[redacted]
CO_2 EOR Sales	$/MWh	[redacted]
LCOE (including Value-Add streams)	**$/MWh**	[redacted]

An advantage of AFC-C is fuel flexibility. Gasification technologies are proven on a variety of feedstocks including, coal, woody biomass, agriculture waste, and other carbonaceous materials. Sustainably sourced or waste biomass is carbon negative as CO_2 uptake from biomass growth is permanently sequestered after fuel combustion. When biomass is blended with traditional fuel sources, such as coal or natural gas, it offsets other plant emissions. For example AFC-C has 97% capture, blending ~5% biomass in the fuel mix would lower the carbon intensity of the power from [redacted] [redacted] to 0kg CO_2/MWh. Blending additional biomass would produce carbon negative power.

The value of carbon negative power is typically realized through the sale of carbon dioxide removal credits (CDRs) on the voluntary market. CDRs can be stacked with the 45Q tax credit to provide additional value to the CO_2 product stream. Unlike 45Q, which is agnostic to source, CDRs are strictly for atmospheric CO_2 removal, not capture from a point source emitter. As of December 2025, over $10B has been spent on CDRs purchases globally, the majority from bioenergy with capture projects. The largest individual buyers are Microsoft, Google, and JPMorgan Chase, companies with corporate sustainability mandates. CDRs are used to supplement clean power purchases and mitigate the hard to eliminate Scope 3 emissions. To keep up with the growing demand for AI power, these companies are purchasing any available power, typically from unabated sources. As such, CDR demand for companies with strong climate commitments is also rising. However, supply for CDRs is expected to decrease with the elimination of many federal IRA programs dedicated to funding carbon removal projects. This combination presents an opportunity which AFC-C is uniquely positioned to capture.

As displayed in Figure 2 in the Executive summary, blending 30% biomass with coal reduced the LCOE to [redacted].

5.2. Emissions Summary

5.2.1. Air Emissions

Preliminary air emissions estimates from the Pre-FEED study for the three primary sources of air emissions are summarized below. Refer to the Attachments for the Emissions Summary document 265467-00-PRO-LST-0007.

Superclaus Sulfur Recovery Unit		
CO_2	kg/h	[redacted]
SOx	kg/h	[redacted]
NOx	kg/h	[redacted]
CO	kg/h	[redacted]
PM	kg/h	[redacted]

Emergency Flare Pilots		
CO_2	kg/h	[redacted]
SOx	kg/h	[redacted]
NOx	kg/h	[redacted]
CO	kg/h	[redacted]
PM	kg/h	[redacted]

Inert Gas Generator (Coal Drying)		
CO_2	kg/h	[redacted]
SOx	kg/h	[redacted]
NOx	kg/h	[redacted]
CO	kg/h	[redacted]
PM	kg/h	[redacted]

Cooling Tower Drift		
Feedwater TDS	ppm	[redacted]
Cycles of Concentration	-	[redacted]
Solids Concentration	ppm	[redacted]

CT Drift Loss	%	[redacted]
CCW Flow	gpm	[redacted]
Drift Liquid Flow	gpm	[redacted]
Drift Liquid Flow	L/min	[redacted]
Drift Mass Flow	mg/min	[redacted]
Drift Mass Flow	kg/h	[redacted]

5.3. Critical Path Schedule

[redacted]

[redacted]

[redacted]

5.4. Future Technology Development

Throughout the course of this study, the team has identified system improvements and have uncovered key equipment requiring further development to enhance performance.

The highest impact system improvements are tied to the turbine performance. The turbine is the central piece upon which rest of the process and all other plant equipment is designed. The AFC uses supercritical CO_2 [redacted] as the working fluid to drive the turbine which requires a novel, state-of-the-art turboexpander to be developed and delivered to the project. Siemens Energy is the exclusive OEM for turbine development which is occurring in tandem with the AFC plant design.

Given the novelty of developing a new turbine, the primary goal of the Siemen's Energy development program is operability. Initial assumptions and design criteria have followed a cautious approach. As confidence in base performance is improved, either through detailed design or early turbine operations, it is expected that conservative assumptions will be relaxed which will reduce syngas cleanup requirements (reducing Capex and parasitic load) and increase turbine efficiency (reducing LCOE).

Additionally, proof-of-concept will enable efficiency improvements. 8 Rivers and Siemens Energy have identified future development work to consider. [redacted] The current alloy choices are acceptable for first of a kind, but long-term development of casting and additive manufacturing processes for preventing hot corrosion and metal dusting-resistant alloy would be worthwhile as they enable higher cooling flow temperatures. Similarly, increasing the turbine inlet temperature would increase the power output.

A sensitivity analysis was conducted to evaluate the impact of gross power generation on the levelized cost of energy (LCOE), as illustrated in the accompanying chart. The analysis demonstrates that even modest improvements in plant efficiency—manifested as higher gross power output—result in substantial reductions in LCOE.

The base case LCOE is based on the AFC-C + FSP configuration [redacted] It assumes a gross power generation of [redacted] MWe, representing the power produced from syngas combustion in the turbine prior to deducting auxiliary loads of the facility. This conservative figure reflects a prioritized focus on designing a low-risk, highly operable turbine for the initial commercial unit, establishing [redacted] MWe as a realistic floor for performance.

As shown in the sensitivity curve in Figure 9, LCOE declines nonlinearly with increasing gross output, exhibiting diminishing marginal returns at higher levels of output due in part to the fixed-per-MWh value of incentives such as the 45Q tax credit. On average, each additional [redacted] MWe of gross output yields an LCOE reduction of approximately [redacted]/MWh, with the greatest benefits occurring at improvements at the lower output levels. Notably, the steepest portion of the curve occurs near the base case: an increase from [redacted] MWe to [redacted] MWe delivers a significant LCOE improvement of approximately $[redacted]/MWh. This highlights the substantial upside potential as turbine design matures, and efficiency gains are realized in subsequent development iterations.

[redacted]

Figure 9: Gross power output sensitivity analysis

The AFC is an emerging technology with the potential to deliver the lowest-cost, clean, firm power from coal. Ongoing development will inevitably surface new information that necessitates design changes, but those learnings will also unlock opportunities to improve performance and lower costs. As with any new high potential technology, maturity comes through iteration.