PRE-FEED STUDIES FOR THE COAL-FIRST INITIATIVE DRAFT FINAL REPORT

Coal-Based Power Plants of the Future – Hybrid Coal and Gas Boiler and Turbine Concept with Post Combustion Carbon Capture (HGCC) Contract Number 89243319CFFE000017

Prepared by

Barr Engineering Co. with Doosan Heavy Industries, Envergex, Microbeam Technologies, University of North Dakota – Institute of Energy Studies, and MLJ Consulting

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Acronyms

AACE	Association for the Advancement of Cost Engineering
ACM	Administrative Controls Management Inc.
AFUDC	Allowance for Funds Used During Construction
AQCS	Air Quality Control System
ASU	Air Separation Unit
ATWACC	After-Tax Weighted Average Cost of Capital
BDL	Blowdown Losses
BEC	Bare Erected Cost
BFW	Boiler Feedwater
BMCR	Boiler Maximum Continuous Rating
BOP	Balance of Plant
CBM	Condition Based Monitoring
CCS	Carbon Capture System
CCSEM	computer-controlled scanning electron microscopy
CCW	Closed Cycle Water
CEMS	Continuous Emissions Monitoring System
CF	Capacity Factor
CFD	Computational Flow Dynamics
CL	Closed loop
CND	Condenser
COE	Cost of Electricity
CQMS	Coal Quality Management System
CRF	Capital Recovery Factors
CSPI	Combustion System Operational Performance Indices
CTG	Combustion Turbine Generator
CW or C.W	Cooling Water
CWP	Circulating water pumps
CWS	Cooling Water System
DCC	Direct Contact Cooler
DCS	Distributed Control System
DEA	Deaerator
DEMIN	Demineralizer
DHI	Doosan Heavy Industries
ELG	Effluent Limitation Guideline
EME	Electrostatic Mist Eliminator
EOR	Enhanced Oil Recovery
EPC	Engineering, Procurement, and Construction
EPCM	Engineering, Procurement, and Construction Management

ESP	Electrostatic Precipitator
ESS	Energy Storage System
ETR	Effective Tax Rate
FCR	Fixed Charge Rate
FD	Forced Draft
FEED	Front-End Engineering Design
FEGT	Furnace Exit Gas Temperature
FGD	Flue Gas Desulfurization
FSEA	Full Stream Elemental Coal Analysis
FWH	Feedwater Heater
GAH	Gas Air Heater
GE	General Electric
GEN	Power Generator
GGC	Gas to Gas Cooler
GGH	Gas to Gas Heat Exchanger
GGH	Gas to Gas Heater
GT	Gas Turbine
HGCC	Hybrid Coal and Gas Boiler and Turbine Concept with Post Combustion Carbon Capture
HHV	Higher Heating Value
HX	Heat Exchanger
ID	Induced Draft
IOU	Investor-Owned Utility
KO	Knockout
LHV	Low Heating Value
LNB	Low NO_x Burner
LP	Low Pressure
LRVP	Liquid Ring Vacuum Pump
LTE	Low Temperature Economizer
MCM	Thousand Circular Mils
MCR	Maximum Continuous Rating
ME	Mist Eliminator
MW	Megawatt
OC	Operating Cost
OEM	Original Equipment Manufacturer
OFA	Overfire air
PA	Primary Air
PAC	Powdered Activated Carbon
PC	Pulverized Coal
PCC or PCCC	Post Combustion Carbon Capture

PCS	Power Conversion System
QGESS	Quality Guidelines for Energy Systems Studies
RFP	Request for Proposal
RO	Reverse Osmosis
SCR	Selective Catalytic Reduction
SFC	Submerged Scraper/Flight Conveyor
SJAE	Steam-Jet Air Ejectors
STG	Stream Turbine Generator
TASC	Total As Spent Cost
TMCR	Turbine Maximum Continuous Rating
TOC	Total Overnight Cost
TPC	Total Plant Cost
TR	Transformer
UCC	United Conveyor Corporation
VFDs	Variable Frequency Drives
WASC	Wet Surface Air Cooler
ZLD	Zero Liquid Discharge

Executive Summary

This material is based upon work supported by the U.S. Department of Energy (DOE), Office of Fossil Energy (FE) and National Energy Technology Laboratory (NETL) under the Coal FIRST initiative Contract Number 89243319CFFE000017. The Coal FIRST (Flexible, Innovative, Resilient, Small, and Transformative) initiative aims to develop coal plants of the future that will provide secure, stable, reliable power with near zero emissions.

The proposed plant focuses on achieving power generation with high-efficiency and load cycling capability and combines a state-of-the-art ultra-supercritical (USC) coal power plant with a natural gas combustion turbine and energy storage system (ESS), and emissions and waste reduction including carbon capture (CC) to form Hybrid Gas/Coal Concept (HGCC). The typical role of the heat recovery steam generator (HRSG) in a normal natural gas firing combined cycle (NGCC) power plant will be replaced by a coal boiler, resulting in a hot windbox repowering of the coal boiler. The proposed plant will consist of a 270-MW USC power plant, an 87-MW gas turbine, and 50-MW ESS battery storage system for a nominal output of 350 MW net.

The combined system will effectively handle variable power demand driven by the increased use of renewable power plants. The exhaust gas from the 87-MW gas turbine will feed the 270-MW USC coal boiler furnace. An economizer gas bypass system is adopted to increase the gas temperature over 300°C at low load for effective selective catalytic reduction (SCR) operation. Should power demand be lower than minimum load, the remaining electricity will be stored in an ESS. The improved thermal efficiency of the boiler-gas turbine configuration is expected to mitigate the energy penalty associated with installing a CO_2-capture system, which will be further optimized in ongoing studies. The concept also includes advanced control systems using full-stream elemental analyzers to monitor fuel properties and condition-based system monitoring to improve plant performance and decrease maintenance frequency.

The following process flow diagram depicts the configuration of the concept.

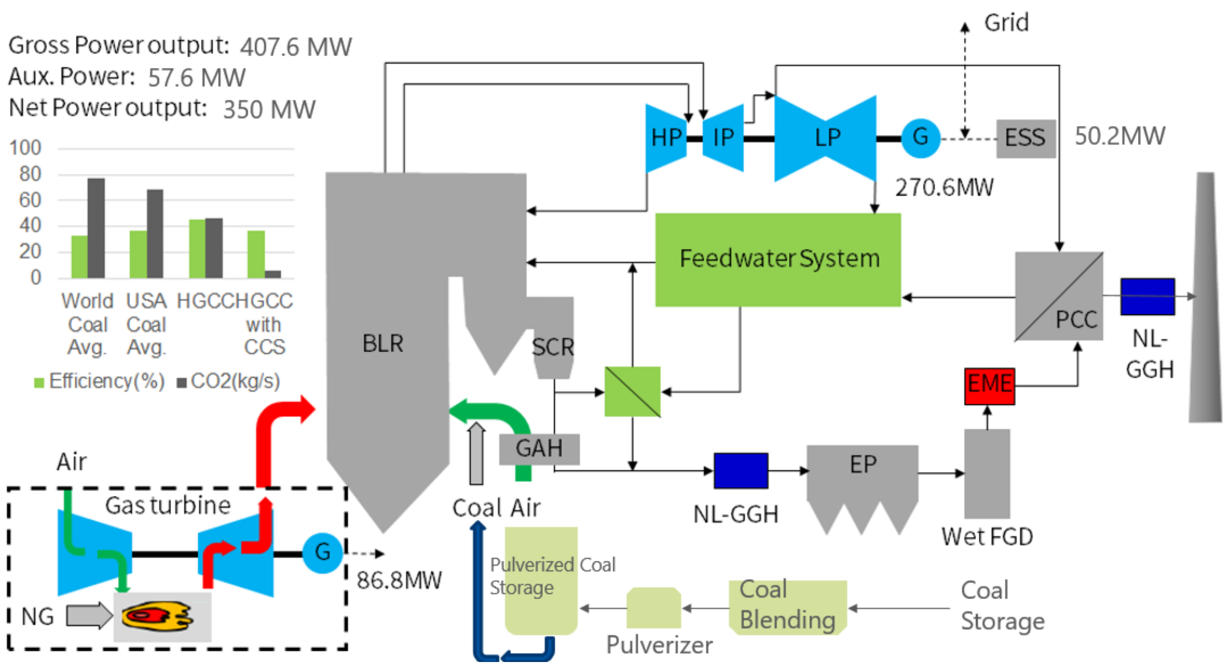

Figure 0-1 HGCC Schematic Overview

Key Findings from the study are listed below:

- HGCC offers significant improvement in the areas of ramp rate, turndown, and startup flexibility (cold and warm) compared to USCPC and IGCC (Overall plant efficiency of 43% with ESS, 37% without ESS (RFP value 40% without carbon capture))

- HGCC components are commercially available today with the ability to streamline construction schedule with one (1) equipment manufacturer (DOOSAN) providing the boiler, steam turbine, environmental systems including carbon capture, and the energy storage system (ESS)

- HGCC has the ability to be integrated into existing power plants and repurpose existing infrastructure, such as coal handling and cooling water systems

- The Indirect Coal Firing System decouples the pulverizer operation from the boiler operation allowing improved ramp rates and turndown when compared to the USCPC

- The HGCC is capable of using <30% natural gas, but is still able to produce power at high capacities in the event of loss or low availability of natural gas supply

- The overall carbon usage and emissions presented is much lower than a typical USCPC

- Water has been recycled and reused resulting in much lower usage rates / MWnet than the standard USCPC
- The HGCC optimizes recycling and reuse as much as possible to aim towards low solid and liquid rates
- HGCC includes integrated energy storage system (ESS) with 50 MW Lithium Ion / Vanadium Redox Hybrid System
- Enhanced maintenance features are considered to improve monitoring and diagnostics such as coal-quality impact modeling and monitoring, advanced sensors, and controls, which target one (1) outage per year

Table 0-1 HGCC Performance Summary

Overall Performance Summary			
Coal Type	**Bituminous**	Sub-bituminous	Lignite
Total Gross Power Output, MWe	407.6	408.2	354.2
CO_2 Capture/Removal auxiliaries, kWe	5,128	5,420	4,979
CO_2 Compression, kWe	17,622	19.067	17,123
ZLD System, kWe	1,850	1,955	1,796
Balance of Plant, kWe	32,974	35,109	30,347
Total Auxiliaries, MWe	57.6	61.6	54.2
Net Power, MWe	350.0	346.6	300.0
HHV Net Plant Efficiency, % with CO_2 capture, with ESS	43.2	41.8	40.1
HHV Net Plant Heat Rate, kJ/kWh (BTU/kWh) with CO_2 capture, with ESS	8,342 (7,907)	8,620 (8,170)	8,983 (8,515)
LHV Net Plant Efficiency, %	45.7	44.3	42.6
LHV Net Plant Heat Rate, kJ/kWh (BTU/kWh)	7,877 (7,466)	8,125 (7,701)	8,452 (8,011)
HHV Net Plant Efficiency with CO_2 capture without ESS, %	37.0	35.7	34.6
HHV Net Plant Heat Rate with CO_2 capture without ESS, kJ/kWh (BTU/kWh)	9,739 (9,321)	10,080 (9,554)	10,404 (9,861)
HHV Net Plant Efficiency, % w/o CO_2 capture, w/o ESS	43.6%		
HHV Net Plant Heat Rate w/o CO2 capture & w/o ESS kJ/kWh (BTU/kWh)	8,267 (7,835)		
HHV Boiler Efficiency, %	89.7	87.6	85.6
LHV Boiler Efficiency, %	92.3	90.4	88.1
Steam Turbine Cycle Efficiency, %	56.5	56.8	56.4
Steam Turbine Heat Rate, kJ/kWh (BTU/kWh)	6,366 (6,034)	6,335 (6,004)	6,382 (6,049)
Condenser Duty, GJ/hr (MMBTU/hr)	896 (849)	902 (855)	762 (722)

Overall Performance Summary			
Coal Type	**Bituminous**	Sub-bituminous	Lignite
As-Received Coal Feed, kg/hr (lb/hr)	72,504 (159,844)	102,096 (225,083)	113,119 (249,385)
NG fuel Feed, kg/hr (lb/hr)	18,144 (40,001)	18,144 (40,001)	18,144 (40,001)
Limestone Sorbent Feed, kg/hr (lb/hr)	7,300 (16,094)		
HHV Thermal Input, kWt (MMBTU/hr)	811,064 (2767)	829,939 (2832)	748,624 (2554)
LHV Thermal Input, kWt (MMBTU/hr)	765,849 (2613)	782,262 (2669)	704,339 (2403)
Emissions			
SO_2 kg/MWh (lb/MWh) (gross output)	0.000 (0.000)	0.000 (0.000)	0.000 (0.000)
NO_x kg/MWh (lb/MWh) (gross output)	0.056 (0.123)	0.059 (0.129)	0.062 (0.137)
Particulate kg/MWh (lb/MWh) (gross output)	0.002 (0.005)	0.003 (0.006)	0.003 (0.006)
Hg tonne/yr(ton/year) at 85% capacity factor	0.0034 (0.0037)		
Hg kg/MWh (lb/MWh)	$9.2x^{10-7}$ $(2.0x^{10-6})$		
CO_2 kg/MWh (lb/MWh) (gross output)	63 (139)	67 (149)	69 (153)
Solid Waste Projected (excludes saleable) tonne/day (tpd)	55 (61)		
Water Withdrawal	<9 (gpm)/ MWnet		

Table 0-2 HGCC Cost Summary

Description for HGCC Plant	Greenfield-Bituminous (Base Case)	Demonstration at Existing Facility - Bituminous (Base Case)	Greenfield- Sub-bituminous	Greenfield-Lignite with Coal Drying
Total Project Cost ($\$/MW_{net}$-w/ ESS, $\$/MW_{net}$-w/o ESS)	$1.86 Billion ($5,300, $6,200)	$1.26 Billion ($3,600, $4,200)	$1.86 Billion ($5,300, $6,200)	$1.86 Billion ($5,300, $6,200)
Total Overnight Cost ($\$/MW_{net}$-w/ ESS, $\$/MW_{net}$-w/o ESS)	$2.25 Billion ($6,400, $7,500)	$1.53 Billion ($4,400, $5,100)	$2.25 Billion ($6,400, $7,500)	$2.25 Billion ($6,400, $7,500)
Total As Spent Cost ($\$/MW_{net}$-w/ ESS, $\$/MW_{net}$-w/o ESS)	$2.80 Billion ($8,000, $9,300)	$1.90 Billion ($5,400, $6,300)	$2.80 Billion ($8,000, $9,300)	$2.80 Billion ($8,000, $9,300)
Total Annual O&M	$111,500,000		$91,700,000	$96,900,000
Cost of Electricity (COE, $\$/MW_{net}h$-w/o ESS)	$160	$126	$154	$178
Cost of Electricity (COE, $\$/MW_{net}h$-w/ ESS) 1 hour per day	$138	$108	$132	$153
Cost of Electricity (COE, $\$/MW_{net}h$-w/o ESS) 47% Load	$303	$233		
Cost of Electricity (COE, $\$/MW_{net}h$-w/o ESS) $7 /MMBTU N.G.	$173	$138		
Cost of Electricity (COE, $\$/MW_{net}h$-w/o ESS) $35/ton CO_2 Credit	$154	$118		
Cost of Electricity (COE, $\$/MW_{net}h$-w/o ESS) $50/ton CO_2 Credit	$151	$115		

Table 0-3 HGCC Technology Pathway Summary

Technical pathway	Technical agendas	Key activities	Target
Research & Development	Optimize heat absorption profile	CFD modeling of boiler; burner tuning for GT flue gas; pilot demonstration to validate CFD modeling and identify fouling/slagging issues.	Identify optimal integration of GT flue injection to boiler
FEED	Demonstration and new build project feasibility	Basic design and critical component detail design for the targeted concept demonstration and new build power plant.	Confirm the technical and economic feasibility of demonstration and new project
	Flexibility improvement- Startup time	Advanced boiler model design with drainable superheater and advanced control system/logic.	2 hours full load for warm start
Potential 2030 Status	Concept demonstration if necessary	Verify the technology benefit by demonstration on an existing facility. Adding gas turbine to an existing power plant with some modification.	Technical proof and component reliability verification
	Full Scale Commercial Greenfield Construction	Commercial demonstration by applying the FEED study result and concept demonstration experience developed technology. The project will be conducted by commercial contract except for developed components.	350MW Scale commercial

1.0 Original Concept Background

This section summarizes the conceptual phase design completed by the Barr Engineering Co. team, with Doosan Heavy Industries, Envergex, Microbeam Technologies, University of North Dakota – Institute of Energy Studies, and MLJ Consulting, prior to the preFEED study. Therefore the information may be different than what has been developed during the preFEED. PreFEED design details begin with Section 2.

1.1 Coal-Fired Power Plant Scope Description

The proposed HGCC plant combines a state-of-the-art ultra-supercritical (USC) coal power plant with a natural firing gas turbine and energy storage system (ESS). The typical role of the heat recovery steam generator (HRSG) in a normal natural gas firing combined cycle (NGCC) power plant will be replaced by a coal boiler. The plant is proposed to have a combination of a USC boiler/ steam turbine, a combustion turbine, and an ESS battery storage system for a net total of 350MW. This configuration is expected to reach 45.5% plant efficiency based on higher heating value (no CO_2 capture) with less than 30% natural gas use.

Two unique features of this power plant design will enable rapid startups and load changes. The first is an indirect coal preparation and firing system. The system will allow pulverized coal to be prepared and stored independently from the boiler/steam turbine system. This will address natural limitations in ramp rate caused by placing pulverizers into and out of service. The coal bunker that feeds into the mill can hold enough coal for 12 hours of firing. The coal storage used for indirect firing can hold enough for up to 2 hours of storage capacity provide fast start up and load change achievement. Silo plugging can be prevented by installing equipment to vibrate pulverized coal in the coal bunker. The second feature is utilizing the traditional gas turbine, which has an inherently fast startup and ramp rate capability.

The combined system will effectively handle variable power demand driven by the increased use of renewable power plants. The exhaust gas from the 88 MW gas turbine will feed the 263 MW USC coal boiler furnace. An economizer gas bypass system is incorporated to increase the gas temperature over 300°C at low load for effective selective catalytic reduction (SCR) operation. Should power demand be lower than minimum load, the remaining electricity will be stored in an ESS, which will assist in initial ramp-up during load ramp-ups such as morning or evening peaks.

1.2 Plant Production / Facility Capacity

Table 1-1 below summarizes the plant production properties provided in the conceptual design report.

Table 1-1 Plant Properties – Conceptual Design

Total plant load	MCR	71%	57%	45%	30%	Units
Coal power plant load	MCR	92%	67%	49%	28%	
Ambient dry bulb temperature	59.0	59.0	59.0	59.0	59.0	° F
Ambient relative humidity	60.0	60.0	60.0	60.0	60.0	%
Barometric pressure	14.7	14.7	14.7	14.7	14.7	psi
Gas turbine load	100.0	0.0	0.0	0.0	0.0	%
Gas turbine power output	88.2	0.0	0.0	0.0	0.0	MW
ST power output	263.3	242.9	177.6	128.5	72.6	MW
ESS power output	51.8	51.9	51.9	51.9	51.9	MW
Plant gross power output	403.3	294.8	229.5	180.4	124.6	MW
Auxiliary power consumption	53.3	45.5	30.9	21.4	12.2	MW
Plant net power output	350.0	249.3	198.6	159.0	106.4	MW
Natural gas heat input	265.0	0.0	0.0	0.0	0.0	MW
Coal heat input	539.8	613.2	462.2	339.2	205.0	MW
Plant gross eff. (HHV)	50.1	48.1	49.6	53.2	60.8	%
Plant net eff. (HHV)	43.5	40.7	43.0	46.9	54.7	%
Plant net eff. without ESS (HHV)	37.1	32.2	31.7	31.6	29.4	%

Table 1-2 lists the auxiliary power requirements at different load rates. These are estimates and will be further refined during the preFEED study.

Table 1-2 Auxiliary Power Summary for Plant Properties – Conceptual Design

Total plant load	MCR	71%	57%	45%	32%	Units
Coal power plant load	MCR	92%	67%	49%	28%	
BFPM	8,213	8,192	3,984	2,024	709	kW
Condensate Pump	402	337	246	183	116	kW
CO_2 Compressor	17,044	14,985	11,229	8,200	4,915	kW
SCR	199	149	105	75	45	kW
Dry ESP	2,988	2,235	1,569	1,120	672	kW
Wet FGD including NL GGH, ZLD, EME	4,681	3,502	2,458	1,755	1,053	kW
Ash handling system	700	700	490	350	210	kW
Coal handling system	201	201	140	100	60	kW
Pulverizers	952	952	666	476	286	kW
Primary & Forced Air Fans	1,273	952	668	477	286	kW
Other Fans	643	479	336	240	144	kW
Induced Draft Fans	4,144	3,100	2,176	1,554	932	kW
Circulating Water Pumps	2,212	2,212	1,548	1,106	664	kW
Ground Water Pumps	228	228	160	114	68	kW
Cooling tower Fans	1,145	1,145	801	572	343	kW
PCC	6,500	4,863	3,413	2,438	1,463	kW
Miscellaneous Balance of Plant	912	682	479	342	205	kW
Transformer Losses	830	621	436	311	187	kW
Total	53,268	45,536	30,903	21,439	12,358	kW

1.3 Plant Location Consistent with the NETL QGESS

The conceptual study highlighted the opportunity of existing power plants that could be retrofitted with HGCC technology using existing infrastructure and access to established supply chains. The current high level assumption is a greenfield plant location in the Midwest where there are opportunities for using captured CO_2 and proximity to coal mines. This is subject to change with ongoing discussions during the FEED study.

1.4 Original Concept Business Case

Table 1-3 Market Scenario Baseline – Fuel plus O&M cost/MWH Comparisons – Conceptual Design

Generation Type	Heat Rate (BTU/kWh)	Variable O&M ($/MWh)	Fuel Cost ($/MWh) Coal - $3/MMBtu		Total Variable Cost	Total Variable Cost
			($3/ NG)	($6/ NG)	($3/ NG)	($6/ NG)
HGCC with PCC	**9,199**	**15.2**	**21.4**	**30.5**	**36.6**	**45.7**
USC Boiler Steam Turbine with PCC	10,508	16.8	21.0	21.0	37.8	37.8
CC with PCC	7,466	4.6	22.5	44.9	27.0	49.5

Total Cost of Electricity is are compared in Table 1-4 using fuel costs of $2/MMBtu for coal and $3/MMBtu for natural gas. The HGCC cost is close the USC boiler/steam turbine and higher than combined cycle due to capital cost considerations which are summarized in Table 1-5.

HGCC's business case is comparable to existing coal technologies using current metrics, and also provides better turndown, faster startup times at warm or cold conditions, better spinning reserve capability, and higher ramp rates than either the USC boiler/steam turbine or the combined cycle. In addition, the HGCC can be retrofitted within a retired coal-fired facility of the proper size (300-400MW). Use of existing infrastructure and systems can reduce capital cost by up to 30%. Under this scenario, the Total Cost of Electricity would be approximately **$115/MWh.** The capital cost provided in Table 1-5 has a comparable cost at $3,303/kW.

Table 1-4 Total Cost of Electricity (2019 Dollars) – Conceptual Design

Generation Type	Capital Cost ($/MWh)	Fixed O&M ($/MWh)	Variable O&M Cost ($/MWh)	Fuel Cost ($/MWh)	Total Cost of Electricity ($/MWh)
HGCC Base (350 MWe Net)	**77.1**	**22.1**	**15.2**	**21.4**	**135.8**
USC Boiler Steam Turbine with PCC[i]	82.7	17.6	16.8	21.0	**138.1**
IGCC with PCC[ii]	83.5	20.1	11.9	22.5	**137.3**

Table 1-5 Total Plant Cost and output (2019 dollars) – Conceptual Design

Generation Type	MWe Net	Total Plant Cost	Plant Cost ($/kW)
HGCC (Peak)	**350**	**$1,156,000,000**	**$3,303**
USC Coal w/PCC	550	$2,222,000,000	$4,036
NGCC w/PCC	559	$948,000,000	$1,695
IGCC w/PCC	497	$1,907,000,000	$3,837

1.4.1 Coal Types and Cost

In 2017, the mine average sales prices were:

- Sub-bituminous: $14.29 per short ton (2,000 lbs.)
- Bituminous: $55.60 per short ton,
- Lignite: $19.51 per short ton, and
- Anthracite: $93.17 per short ton.

Though lignite is a cheaper coal, it is less efficient and requires an additional process to dry it. As a result, while the national average sales price of coal at coal mines was $33.72 per short ton, the average delivered coal price to the electric power sector was $39.09 per short ton.[iii]

1.4.2 Natural Gas Price

The EIA report shows that natural gas prices are expected to be between $3/MMBtu and $8/MMBtu based on the Low and High Oil and Gas Resource and Technology cases, respectively.

1.4.3 Renewables Penetration

In the *Annual Energy Outlook 2019 with Projects to 2050*, the U.S. Energy Information Administration (EIA) predicts increasing share of both renewables and natural gas in electricity generation. Primary causes are lower natural gas prices and decreasing renewable capacity costs influenced by tax credits that will continue into the mid-2020s.

1.5 CO_2 Market Prices

It is anticipated, U.S. energy-related CO_2 emissions will need to decrease by 2.0% in 2019 and by 0.9% in 2020[iv]. Carbon taxes have been suggested to help achieve this reduction[v]. No credit for CO_2 has been taken for the purposes of cost comparison. 45Q tax credit is estimated at $10-$20 per ton stored CO_2. The C_2PH concept compresses CO_2 at a purity of greater than 95% which, today, can be sold for $15-$40 / ton CO_2.

1.6 CO_2 Market Prices

The O&M costs for the HGCC are very similar for the USCPC as shown previously in Table 1-3. This is expected since the equipment line up for the HGCC is very similar to the USCPC. The exception is the use of the General Electric F6.03 combustion turbine as part of the HGCC configuration. Fixed and variable O&M costs for the combustion turbine have been included in the O&M cost calculations. Details of the calculations are provided in Appendix C.

O&M cost increases from increased cycling operation are a concern for the existing coal-fired fleet for base load operation. In the case of the HGCC cycling duty parameters are known at the beginning of the design process and will be addressed in the preFEED study and refined during the FEED study. The design approach in the preFEED and FEED studies will explore upgraded materials, improved machine design, component flexibility to allow greater thermal movements, advanced sensors to monitor equipment, and artificial intelligence to aid in predictive maintenance.

1.7 Domestic & International Market Applicability

The EIA's Annual Energy Outlook 2019[vi] projects renewable energy growth through 2050. Renewable energy is expected to reach 48% of US installed generation, led by wind and solar. In 2018, coal provided 27% of the energy for the U.S. but is projected to reduce to only about 17% in 2050.

As more renewable resources are added, there will be an additional need for combustion resources such as the HGCC to provide for grid reliability when the output of renewable generation is low or zero.

2.0 Business Case

The business case has been updated to reflect the latest findings in the preFEED case. Many of the key points are similar as the original concept, but the cost and key points have been revised.

2.1 Market Scenario

Traditional coal-based power plants were designed for base-load, always-on operation. As renewable energy sources become more cost effective and a larger part of energy production, coal-based generation will need greater flexibility to rapidly cycle on and off. The proposed plant design, a Hybrid Gas/Coal Concept (HGCC), focuses on achieving power generation with high-efficiency and load cycling capabilities combined with carbon dioxide (CO_2) capture. The HGCC concept combines an 87 MWe combustion gas turbine an ultra-supercritical (USC) coal boiler with a 270 MWe steam turbine, and 50 MWe of battery energy storage. The HGCC concept is unique and presents a strong business case because it is:

- **Flexible**
  - Combination of technologies and battery capacity provides high turndown (5:1).
  - Battery storage enables system to provide 50 MWe almost instantly for one hour.
  - Combustion turbine can achieve 30 minute ramp up to 87 MWe from initial fire.
  - Indirect coal firing allows for smooth boiler ramp rates and lower minimum load.
  - Combination of gas turbine and coal boiler technologies boosts efficiency to 37% (without ESS) including CO_2 capture and compression.
  - Diverse forms of power generation via ESS, natural gas, or coal, and the advanced equipment and controls allow for a larger range in quality of fuels during operation.
- **Innovative**
  - Decoupling coal pulverizers from boiler firing reduces or eliminates time constraint associated with placing pulverizers in/out of service.
  - Three power source components (gas turbine, steam turbine, and batteries) provide an instant response with increasing output as slower starting components ramp up.
- **Resilient**
  - Turbine and boiler technologies are well developed and reliable.

    - Utility-scale application of battery technology continues to improve and provide immediate response to demand.
    - The variability of coal properties is managed using on-line analyzers, fireside performance indices, and condition-based monitoring.
- **Small with the Potential for Brownfield Demonstrations**
    - Boiler/steam turbine, combustion turbine, and batteries provide 350 MWe net.
    - Aligns coal as a diversified backup to less-reliable renewables.
    - Capacity aligns well with legacy sites and/or potential cogeneration opportunities.

2.1.1 Business Development Pathway

Coal-based technology faces a challenging future due to high capital cost, environmental constraints (emissions and carbon capture), low natural gas prices, and declining cost of renewable resources. The current base case assumption is a greenfield site, however there could be a scenario of a utility using the HGCC technology within an existing site with a minimum set of existing infrastructure. A sensitivity analysis assumes that the following equipment/infrastructure at a retired plant is available: cooling tower/circulating water, exhaust gas stack, coal processing, boiler/turbine building, environmental controls except carbon capture and EME, water/wastewater treatment, ash handling, in-plant electrical breakers/motor control centers, and a substation. The retired boiler, turbine, high energy piping, feedwater heaters, etc. would be removed as part of the HGCC project.

The preFEED work demonstrates that this concept can feasibly generate electricity at comparable but better economics to an USC Rankine Cycle plant. Compared to the standard USC plant, HGCC has better flexibility, turndown, efficiency, and capability to follow an aggressive load-following curve. The work also identified a list of value engineering improvements that can improve the economics more.

The move away from power-only projects and toward cogeneration is an important trend to consider. The flexibility and modularity of this configuration has great potential to serve as the core engine of an industrial complex supplying reliable electric energy with the potential for the added efficiency of combined heat and power. Integrating this concept into an industrial complex introduces other advantages, which are described in detail in the following business case options.

2.2 Baseline Scenario

2.2.1 Coal Types and Cost

In 2017, average mine sales prices were[vii]:

- Sub-bituminous: $14.29 per short ton (2,000 lbs.)
- Bituminous: $55.60 per short ton

- Lignite: $19.51 per short ton
- Anthracite: $93.17 per short ton

The coal used as the baseline for this work is Illinois #6, which is a medium sulfur bituminous coal. It is anticipated that the coal will be delivered by rail for a price of $2.25/MMBTU, which is equivalent to about $52/ton, which is the same as the Case B12B case. Lignite and sub-bituminous coal can be available at a lower cost, but these will require additional drying to achieve the optimal heat rate. Other technologies such as conditioning the lower ranked coals to remove fouling impurities was considered, however, due to the technology readiness level and the scale of these technologies, additional systems were not considered in process and cost.

2.2.2 Natural Gas Price

The EIA report shows that natural gas prices are expected to be between $3/MMBTU and $8/MMBTU based on the Low and High Oil and Gas Resource and Technology cases, respectively. We used a price of $3.00/MMBTU for our baseline cost.

2.2.3 Renewables Penetration

In the *Annual Energy Outlook 2019 with Projects to 2050*, the U.S. Energy Information Administration (EIA) predicts an increasing share of both renewables and natural gas in electricity generation. Primary causes are lower natural gas prices and decreasing renewable energy costs that are influenced by tax credits continuing into the mid-2020s.

The increasing share of non-dispatchable energy sources will likely drive revisions to the pricing structure of the market. Electric generators derive their revenue from both capacity payments and energy sales. Historically, energy sales are the much larger fraction. As the dispatchable fraction of the installed capacity is reduced, the value of dispatchable capacity is expected to increase. Dispatchable generation provides important grid services such as load following (frequency regulation), VAR support (voltage regulation), spinning reserve, and non-spinning reserve. And regulated electric utilities have a legal obligation to maintain these parameters within specified limits whether or not the merchant power market recognizes their value. We have not evaluated the impact of renewables penetration in our business case. As renewables increase and combustion sources decrease, grid operators will have to develop options for the supply of these necessary resources.

2.2.4 CO_2 Market Prices

Certain influential organizations are advocating that U.S. energy-related CO_2 emissions should be decreased by 2.0% in 2019 and by 0.9% in 2020. Carbon taxes have been suggested to help achieve this reduction[viii]. No credit for CO_2 has been taken for the purposes of cost comparison. The 45Q tax credit is estimated at $35/per ton CO_2 when used for enhanced oil recovery (EOR) or $50 per ton for stored CO_2. The HGCC concept compresses CO_2 at a purity of greater than 95%, which, today, can be sold for $15-$40/ton CO_2. [ix]

2.3 Business Case Options

2.3.1 Base Case

The base case is for a greenfield installation in the central portion of the continent. The selected site would have access to rail, a gas pipeline, adequate water, and be in proximity to a large electricity market. Sites in Ohio, Indiana, Illinois, Missouri, east Texas, Montana, North Dakota, Wyoming, Arizona, Louisiana, or Minnesota would fit these requirements. These regions are characterized by abundant wind, solar, and natural gas resources and so pricing of electric energy is low. But the principal advantage of this concept is its flexibility and fast load response, so it is expected that the majority of its revenue will be derived from capacity payments to back up unreliable renewables. Additionally, there may be circumstances where this is the most feasible means of meeting state and federal regulations for voltage and frequency control and grid stability.

2.3.2 Demonstration or Retrofit

The repowered case is expected to be 31% lower in capital cost and, consequently, will be more economically attractive. As there are numerous potential sites in the region discussed in Section 2.3.1, repowering an existing facility appears to be more promising than a greenfield installation.

2.3.3 Co-generation

Refineries have a large requirement for steam and electricity and also have a number of streams that can be considered opportunity fuels. Some of these fuel streams are burned to provide steam needed by the refinery, but a considerable quantity is flared off. Depending on whether the fuel stream is pet-coke, vacuum bottoms, or residual gas, it could be burned either in the combustion turbine or blended with the coal and fired in the boiler.

Routing the fuel streams through the power plant enables capture of the nitrogen, sulfur, and carbon compounds, which otherwise would be emitted into the atmosphere, reducing overall air emissions. Value is provided to the refinery by letting it outsource its energy supply and waste stream disposal and allowing its people to focus on their core business.

The business case for a cogeneration plant supplying steam to a refinery must consider the capital cost savings from shared infrastructure, the reduced fuel cost, and the added revenue from steam sales. And there may be other opportunities for shared savings on a site by site basis.

2.3.4 Byproduct Sales

The cost for disposal of saleable byproducts have not been included in the annual O&M expenses. Gypsum, fly ash, and bottom ash are estimated to achieve at least $1MM in annual sales. This cost considers gypsum to be sold at $0/ton pricing, which has the potential to increase in some areas of the Midwest U.S. This value does not include other potential beneficial carbon or metal byproducts that could be extracted through added processing. [x]

- Bottom ash at $5.00/ton is estimated to provide $62,000 annual sales
- Fly ash at $20.00/ton is estimated to provide $937,000 annual sales

The salt cake from the ZLD has the potential for beneficial reuse such as de-icing and commercialization as salt as well as chloro-alkali processes. However, this value engineering was not considered for this project based on the progress in technology and current economic considerations. The largest byproduct sales for HGCC is the EOR, pipeline-ready CO_2 that is produced from the amine capture system. A sensitivity analysis has been performed to highlight the range of possible credits in Section 5.7 (Sensitivity Analysis).

2.4 Domestic and International Market Applicability

2.4.1 Domestic Applicability

The EIA's Annual Energy Outlook 2019 projects domestic renewable energy growth through 2050. Renewable energy is expected to reach 48% of U.S. installed generation, led by wind and solar. In 2018, coal provided 27% of the energy for the U.S. but is projected to reduce to only about 17% in 2050.

As more renewable resources are added, there will be an additional need for combustion resources, such as the HGCC, to provide grid reliability when the output of renewable generation is low or zero.

2.4.1.1 Concept Advantages

HGCC's business case is comparable to existing coal technologies (using current metrics), but provides better turndown, faster startup times at warm or cold conditions, better spinning reserve capability, and higher ramp rates than a conventional ultra-supercritical (USC) boiler/steam turbine. In addition, the HGCC can be demonstrated in a retired coal-fired facility of the proper size (300-400MW), or it can be incorporated on the back end of a simple cycle CTG. Use of existing infrastructure and systems can reduce capital cost by up to 31%, and, under this scenario, the total cost of electricity would be approximately **$126/MWh** as discussed later in Section 2.6 (Estimated Cost of Electricity (COE)).

2.4.2 International Applicability

The HGCC concept will apply internationally to countries that are developing renewable portfolios similar to the United States. These countries will require flexible combustion resources to support increasing levels of renewable market penetration. Europe would be a logical market extension for the HGCC concept considering goals to reduce CO_2 emissions.

2.4.2.1 Concept Advantages

The advantage of the HGCC concept internationally is the fuel flexibility, better turn down, faster startup times, better spinning reserve capability, and higher ramp rates. Internationally, developed countries are typically characterized by higher fuel costs and lower fuel choices compared to North America. They are driven to elevated levels of renewables penetration because of their limited fuel supplies. This makes the value of firm capacity even higher, without diminishing the value of energy.

The choices that these nations have to meet the requirement for firm capacity are power plants fueled by either LNG or coal. Since LNG must be transported on specialized tankers and supplied from a limited number of sources, its cost is high. The HGCC concept provides the advantages of a hybrid fuel mix resulting in lower fuel cost.

2.5 Market Advantage of the Concept

2.5.1 Market Advantage – Cycling Attributes

Renewable energy sources are less reliable than combustion-based power. As renewables become more cost effective and a larger part of the generation mix, additional cycling requirements are being imposed on historic base-load coal units. This was not anticipated when the coal units were designed. System operators meet the expected demand by using a day-ahead projection of electrical demand to develop a generation resource stack. Resource stacks start with the lowest operating cost and add resources until the demand is met. As more, non-dispatchable renewables are added to the generation portfolio, utilities respond by adjusting the commitments to combustion-type generating resources. This has required coal units to transition from base load operation to frequent cycling at certain times of the year.

The HGCC uses three distinct and unique approaches to maximizing cycling flexibility (turndown and ramp rate). In order of decreasing flexibility, the concept incorporates the following features:

- Energy storage system (ESS) (batteries) – 50 MW gross
- Combustion turbine (GE 6F.03) – 87 MW gross
- Indirect fired USC boiler/steam turbine cycle – 270 MW gross

The combustion turbine can operate independently from the USC boiler as needed during the startup process. From a cold start, the full exhaust of the combustion turbine will be directed to a bypass stack. As the USC boiler is warmed, routing of exhaust gas from the combustion turbine will be gradually transitioned to the boiler until all the exhaust is routed to the USC boiler and the bypass stack is closed. It is anticipated that the bypass will be used for approximately two hours during a warm start until the steam turbine is synchronized to the grid. The bypass stack will be used during cold start times for 6–8 hours until the steam turbine is synchronized to the grid. It should be noted that it is not necessary to start the combustion turbine in advance of firing the boiler. If output from the combustion turbine is not needed, the USC boiler can start and operate independently. Provisions will be included in the air permit that will allow the combustion turbine to operate using the bypass stack for a specified period of time before the exhaust is routed into the USC boiler. The combustion turbine comes standard with burners that minimize CO and NO_x emissions.

The USC boiler is equipped with an indirect coal-firing system to decouple coal milling from boiler firing that is not found on current U.S. coal-fired boilers. Existing boiler configurations require that pulverizers be placed into or be taken out of service at certain load points, causing operating constraints. The indirect firing system allows for smooth ramp rates unencumbered by the need to take pulverizers in and out of service. In addition, the indirect firing system reduces the boiler minimum load by 20%.

When the plant is called upon to begin operation from a cold start, the following startup order is envisioned:

- ESS: immediate
- Combustion turbine: 30 minutes to full load
- USC boiler steam cycle: 6–9 hours to full load from cold start, approximately 3 hours and 40 minutes from warm start

Anticipated startup times and ramp rates are summarized in Figure 2-1. This plant shows that it is capable of following the projected steep load swings anticipated throughout the day as more renewables are added to the market. Overall plant turndown when ESS is considered is approximately 5 to 1.

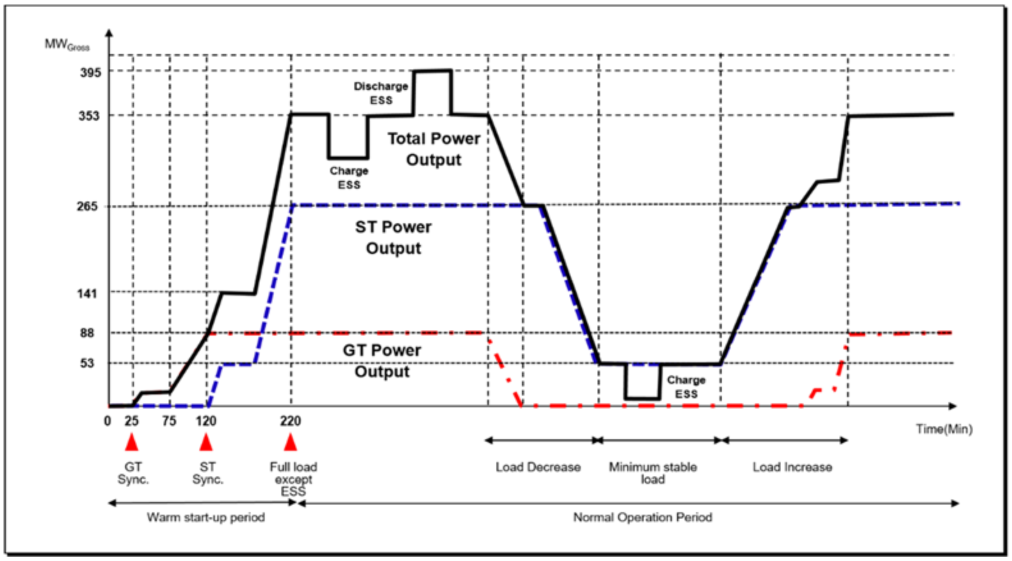

Figure 2-1 HGCC Daily Power Output

In the event of abrupt loss of renewable energy, the HGCC plant load can be increased more rapidly than the normal operation scenario depicted in Figure 2-1 with combination of ESS, steam turbine and gas turbine. The plant can reach full load from the minimum load within 10 minutes (Figure 2-2), which can provide steep ramp rate response. ESS will take an initial load increase and the steam turbine ramp up before the gas turbine startup.

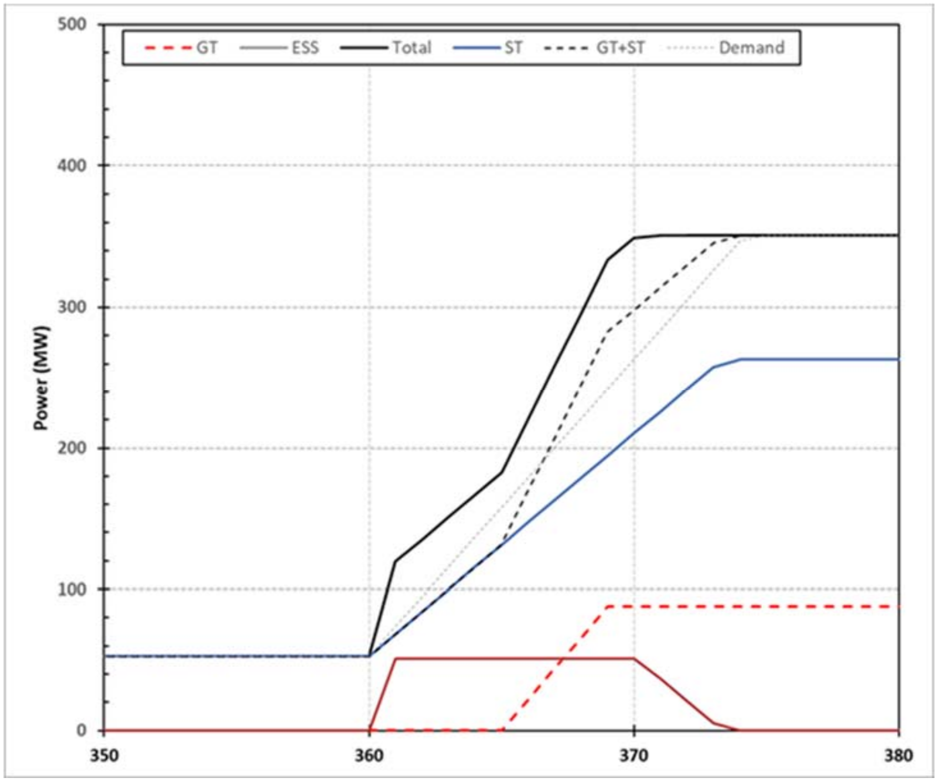

Figure 2-2 Rapid Load Increase Capability of HGCC

During startup period, the plant can be ready to supply electricity quickly with the support of ESS and gas turbine. ESS will take an initial load increase and the gas turbine will take a role before the steam turbine startup (Figure 2-3). A combination of Lithium-ion with rapid load increase capability and Vanadium Redox flow Battery with long discharge capability can give a better performance than a single battery system.

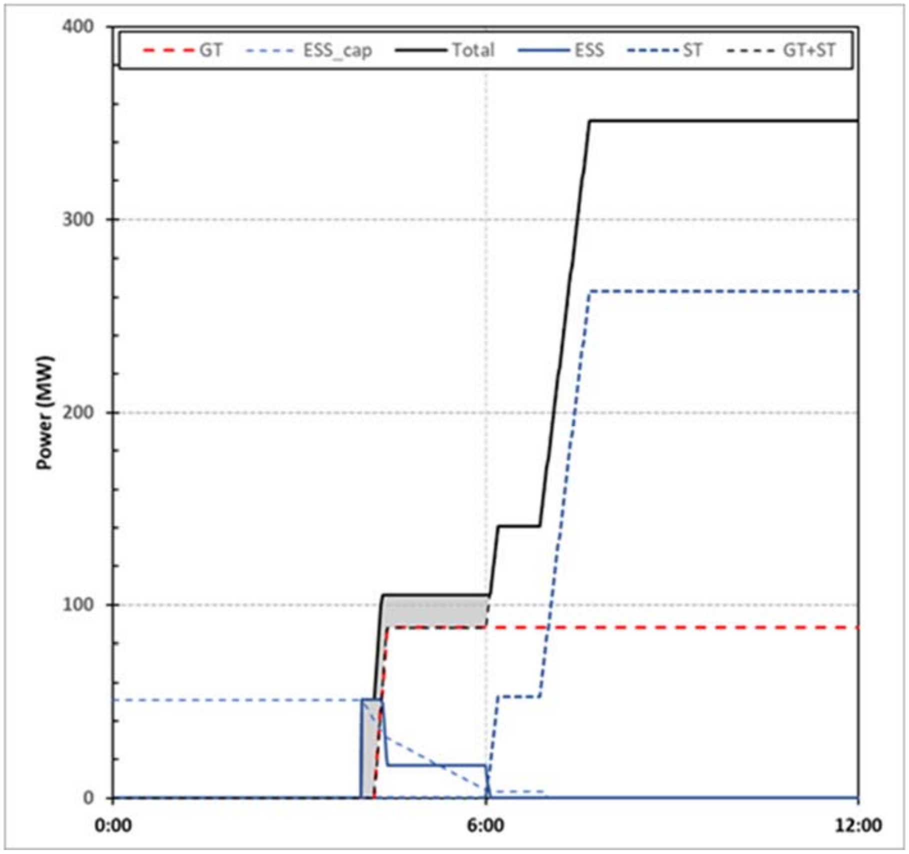

Figure 2-3 Rapid Startup Capability of HGCC

Renewables are often touted as having a cheaper cost of electricity than competing technologies like coal combustion. This comparison is somewhat misleading, as it discounts the value of other necessary services that the transmission system requires to fully function, such as load following, turndown, voltage support, and spinning reserve. Unfortunately, the value of these additional services is not well monetized in the existing rate structure. Table 2-1 compares the types of services offered by different technologies.

Table 2-1 Load Following Services Comparison

Generation Type	Load Following	VAR/Voltage Support	Turndown Ratio	Spinning Reserve
HGCC	X	X	5/1	x
USC Coal	X	X	3/1	x
NGCC	X	X	4/1	x
Wind	None	Marginal	None	None
Solar	None	Marginal	None	None

2.5.2 Fuel Flexibility

This concept has capability to burn any type of coal and pipeline natural gas, as well as liquid fuels and many fuels of convenience. Our base case considers pipeline natural gas for the CTG;

however, the GE 6F.03 can also burn high- or low-BTU gaseous fuels and liquid fuel. The boiler could be configured to burn blends of pet-coke and/or biomass with the coal.

2.5.3 Cogeneration

Because of its smaller size, this concept has the potential to be deployed as a cogeneration option. One of the more promising opportunities is to combine the capability for fuel flexibility with its applicability to cogeneration for installation at other plants such as refinery or other petrochemical complex where opportunity fuels are available.

2.6 Estimated Cost of Electricity (COE)

2.6.1 Market Scenario Baseline

Current EIA data on coal and natural gas costs suggests that natural gas will cost $3.00/MMBTU and coal will cost $2.25/MMBTU. EIA also provides data for heat rate and variable O&M cost/MWh. Those results are used in Table 2-2 to compare variable fuel plus O&M costs for a projected HGCC plant versus other combustion forms of generation. The table provides a sensitivity analysis for $6/MMBTU natural gas. Variable costs are used by utilities to decide the order in which generation units are brought on line to serve load (lower is better). At $3/MMBTU, estimated HGCC costs are very close to those of a USC boiler/steam turbine but higher than those of a combined-cycle unit. In contrast, at $6/MMBTU, the HGCC is more expensive to operate than the USC boiler/steam turbine but less expensive to operate than the combined-cycle unit. The economics of the HGCC will improve once the market evolves to account for the value of load following, voltage support, and spinning reserve.

Table 2-2 Market Scenario Baseline – Fuel Plus O&M Cost/MWH Comparisons

Generation Type	Heat Rate (BTU/kWh)	Variable O&M ($/MWh)	Fuel Cost ($/MWh) Coal - $3/MMBTU		Total Variable Cost	Total Variable Cost
			($3/ NG)	($6/ NG)	($3/ NG)	($6/ NG)
HGCC with PCC w/o ESS	9,200	6.2	22.7	31.6	28.9	37.8
HGCC with PCC w ESS	7,900	5.3	19.4	27.0	24.7	32.3
USC Boiler Steam Turbine with PCC	10,834	14	24.1	24.1	38.1	38.1
IGCC with PCC	10,497	22.3	23.4	46.8	46.4	69.1

The total costs of electricity are compared in Table 2-3 using fuel costs of $2.25/MMBTU for coal and $3/MMBTU for natural gas. The HGCC cost is close the USC boiler/steam Turbine and higher than combined cycle due to capital cost considerations which are summarized in Table 2-4.

HGCC's business case is comparable to existing coal technologies using current metrics, and also provides better turndown, faster startup times at warm or cold conditions, better spinning reserve capability, and higher ramp rates than either the USC boiler/steam turbine or the combined cycle. In addition, the HGCC can be demonstrated within a retired coal-fired facility of the proper size (300-400MW). Use of existing infrastructure and systems can reduce capital cost by up to 31%. Under this scenario, the total cost of electricity would be approximately $126/MWh, $108/MWh when the 50MW ESS is considered.

The cost considers the HGCC project to be a greenfield plant and does not take into account the savings of using existing infrastructure. The COE without the ESS is $160 and $138/MWh when the ESS is included. Because the ESS storage rate is limited to one hour per day, the COE is more realistically represented when the ESS is considered not to be contributing most of the day.

Table 2-3 Total Cost of Electricity of Greenfield Plant (2018/ 2019 Dollars)

Generation Type	Capital Cost ($/MWh)	Fixed O&M ($/MWh)	Variable O&M Cost ($/MWh)	Fuel Cost ($/MWh) $2.25/MMBTU-Coal $3/MMBTU-N.G.	Total Cost of Electricity ($/MWh)
HGCC Base (300 MWe Net) w/o ESS	110.1	21	6.2	22.7	**160**
HGCC Base (350 MWe Net) w/ ESS	95.3	18	5.3	19.4	**138**
USC Boiler Steam Turbine with PCC[xi]	51.1	16.1	14	24.1	**105.3**
IGCC (Shell) with PCC[xii]	88.9	31.9	22.3	23.4	**166.5**

The capital cost provided in Table 2-4 has a comparable cost at $5,300/kW.

Table 2-4 Total Plant Cost and output (2018/2019 dollars)

Generation Type	MWe Net	Total Plant Cost	Plant Cost ($/kW)
HGCC (Peak)	**350**	**$1,860,000,000**	**$5,300**
HGCC (w/o ESS electrical output)	300	**$1,860,000,000**	$6,200
USC Coal w/PCC	650	$2,446,000,000	$3,824
NGCC w/PCC	646	$1,282,000,000	$1,984
IGCC (Shell) w/PCC	519	$3,222,000,000	$6,209

The opinion of probable cost for capital and O&M provided in this report is made on the basis of the teams experience and qualifications and represents our best judgment as experienced and qualified professionals familiar with the project. The cost opinion is based on project-related information available at this time and includes vendor quotations, similar projects, and factoring literature data to 2019 values. This estimate is considered an order of magnitude or parametric type estimate of costs, with long leg cost curves, based on historical data from other projects. All within the guidelines as established by AACE for a class 4 estimate. The opinion and accuracy of cost may change as more information becomes available. In addition, since we have no control over the cost of labor, materials, equipment, or services furnished by others, or over the methods of determining prices, competitive bidding, or market conditions the team cannot and does not guarantee that proposals, bids, or actual costs will not vary from the opinion of probable cost.

2.6.2 O&M Analysis

The O&M costs for the HGCC are very similar for the USCPC as shown previously in Table 2-2. This is expected since the equipment line up for the HGCC is very similar to the USCPC. The exception is the use of the General Electric F6.03 combustion turbine as part of the HGCC configuration. Fixed and variable O&M costs for the combustion turbine have been included in the O&M cost calculations. Results of the O&M calculations are detailed in the cost results, Section 5.0.

O&M cost increases from increased cycling operation are a concern for the existing coal-fired fleet for base load operation. In the case of the HGCC, cycling duty parameters are known at the beginning of the design process and have been addressed in this report and refined during the FEED study. The design approach in the FEED study will explore upgraded materials, improved machine design, component flexibility to allow greater thermal movements, advanced sensors to monitor equipment, and artificial intelligence to aid in predictive maintenance.

3.0 Design Basis Report

3.1 Design Basis Input Criteria

3.1.1 Site Characteristics (From Addendum 1 RFP)

Table 3-1 Site Conditions from DOE/NETL RFP Requirements

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

3.1.2 Ambient Conditions (From Addendum 1 RFP)

Table 3-2 Ambient Conditions from DOE/NETL RFP Requirements

Parameter	Value
Elevation, feet	0
Barometric Pressure, MPa (psia)	0.101 (14.696)
Average Ambient Dry Bulb Temperature, °C (°F)	15 (59)
Average Ambient Wet Bulb Temperature, °C (°F)	10.8 (51.5)
Design Ambient Relative Humidity, %	60
Cooling Water Temperature, °C (°F)[1]	15.6 (60)
Air composition based on published psychrometric data, mass % (From Cost and Performance Baseline for Fossil Energy Power Plants Volume1: Bituminous Coal and Natural Gas to Electricity, 2019)	
N_2	75.042
O_2	22.993
Ar	1.281
H_2O	0.633
CO_2	0.050
Total	100.00

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

3.1.3 Water Type

3.1.3.1 Makeup Water

Table 3-3 Makeup Water Quality[xiii]

Parameter	Groundwater (Range)	POTW (Range)	Makeup Water (Design Basis – 50% Groundwater / 50% POTW
pH	6.6 – 7.9	7.1 – 8.0	7.4
Specific Conductance, µS/cm	1,096 – 1,484	1,150 – 1,629	1,312
Turbidity, NTU		<50	<50
Total Dissolved Solids, ppm			906
M-Alkalinity as $CaCO_3$, ppm*	200 – 325	184 – 596	278
Sodium as Na, ppm	102 – 150	172 – 336	168
Chloride as Cl, ppm	73 – 100	205 – 275	157
Sulfate as SO_4, ppm	100 – 292	73 – 122	153
Calcium as Ca, ppm	106 – 160	71 – 117	106
Magnesium as Mg, ppm	39 – 75	19 – 33	40
Potassium as K, ppm	15 – 41	11 – 21	18
Silica as SiO_2, ppm	5 – 12	21 – 26	16
Nitrate as N, ppm	0.1 – 0.8	18 – 34	12
Total Phosphate as PO_4, ppm	0.1 – 0.2	1.3 – 6.1	1.6
Strontium as Sr, ppm	2.48 – 2.97	0.319 – 0.415	1.5
Fluoride as F, ppm	0.5 – 1.21	0.5 – 0.9	0.8
Boron as B, ppm	0.7 – 0.77		0.37
Iron as Fe, ppm	0.099 – 0.629	0.1	0.249
Barium as Ba, ppm	0.011 – 0.52	0.092 – 0.248	0.169
Aluminum as Al, ppm	0.068 – 0.1	0.1 – 0.107	0.098
Selenium as Se, ppm	0.02 – 0.15	0.0008	0.043
Lead as Pb, ppm	0.002 – 0.1		0.026
Arsenic as, ppm	0.005 – 0.08		0.023
Copper as Cu, ppm	0.004 – 0.03	0.012 – 0.055	0.018
Nickel as Ni, ppm	0.02 – 0.05		0.018
Manganese as Mn, ppm	0.007 – 0.015	0.005 – 0.016	0.009
Zinc as Zn, ppm	0.005 – 0.024		0.009
Chromium as Cr, ppm	0.01 – 0.02		0.008
Cadmium as Cd, ppm	0.002 – 0.02		0.006
Silver as Ag, ppm	0.002 – 0.02		0.006
Mercury as Hg, ppm	0.0002 – 0.001		3E-04

* Alkalinity is reported as CaCO3 equivalent, rather than the concentration of HCO3. The concentration of HCO3 can be obtained by dividing the alkalinity by 0.82.

3.1.3.2 Boiler Feed Water Quality (Based on USC 270 MW Unit)

Table 3-4 Required Feed Water Quality for Doosan Variable Pressure Once-through USC Boiler 270 MW Unit

Item	Unit	Design Value	
		Alkaline Water Treatment (AVT)	Combined Water Treatment (CWT)
pH at 25°C	-	9.3 – 9.6	8.0 ~ 8.5
Hardness ($CaCO_3$)	㎍/l (ppb)	0	0
Dissolved O_2	ppb	<10	30 ~ 150
Hydrazine (N_2H_4)	ppm	>0.01	0
Total Iron (Fe)	ppb	<2	
Total Copper (Cu)	ppb	<2	
Silica (SiO_2)	ppb	<10	
Cation conductivity at 25°C	㎲/cm	<0.2	<0.15
Sodium (Na)	ppb	<3	

3.1.4 Fuel Type and Composition

3.1.4.1 Coal Specifications

Bituminous – Base Case (From Addendum 1 RFP)

The coal selected for the base case is Illinois #6 from the Herrin seam of the Illinois Basin. The proximate and ultimate analysis is summarized in Table 3-5 (Addendum 1 of the Coal FIRST RFP). The coal is a high-volatile bituminous coal with a higher heating value (HHV) of 11,666 BTU/lb and a volatile matter content of 34.99% on an as-received basis, which is similar to reported average values for Herrin seam coal of 11,170 BTU/lb and 34.8%, respectively (Affolter and Hatch, 2010). The ash content of the coal is 9.7% (as-received), similar to reported average values for Herrin seam coals of 10.9% (Affolter and Hatch, 2010). The sulfur content of Illinois #6 is 2.51% (as-received) and is slightly lower than the average value of 3.0% reported by Affolter and Hatch, 2010. The forms of sulfur are mainly pyrite and organic sulfur. The chlorine content of the Illinois #6 coal is 0.29%, while the free-swelling index ranges from 3.5 to 4.5 (Riley, 2007).

Table 3-5 Proximate and Ultimate Analysis of Illinois #6 Bituminous Coal

Rank	Bituminous	
Seam	Illinois #6 (Herrin)	
Source	Old Ben Mine	
Proximate Analysis (weight %)[1]		
	As Received	Dry
Moisture	11.12	0.00
Ash	9.70	10.91
Volatile Matter	34.99	39.37
Fixed Carbon	44.19	49.72
Total	100.00	100.00
Sulfur	2.51	2.82
HHV, kJ/kg (BTU/lb)	27,113 (11,666)	30,506 (13,126)
LHV, kJ/kg (BTU/lb)	26,151 (11,252)	29,544 (12,712)
Ultimate Analysis (weight %)		
	As Received	Dry
Moisture	11.12	0.00
Carbon	63.75	71.72
Hydrogen	4.50	5.06
Nitrogen	1.25	1.41
Chlorine	0.29	0.33
Sulfur	2.51	2.82
Ash	9.70	10.91
Oxygen	6.88	7.75
Total	100.00	100.00

1 The sulfur content of natural gas is primarily composed of added Mercaptan (methanethiol, CH4S) with trace levels of H2S. Note: Fuel composition is normalized and heating values are calculated.

The proximate and ultimate analysis of the Illinois #6 coal was used to identify coals in Microbeam's coal database that match, where detailed analyses of the fuel impurities are available. The compositional analysis of the Illinois #6 sample from the Old Ben mine was found to be a good match. This coal sample was from a plant that fires the Old Ben coal. The composition of the ash produced at 750°C (ASTM conditions) in the laboratory is summarized in Table 3-6. The main constituents of the ash consist of SiO_2, Al_2O_3, and Fe_2O_3 with minor amounts of CaO, MgO, K_2O, and Na_2O. The composition is similar to the results of analysis conducted for other Illinois #6 coals reported by Finkelman (1978). The ash fusion temperatures are also included in Table 3-6.

Table 3-6 Composition of Ash (ASTM) Produced from Illinois #6 Bituminous Coal (wt% of ash expressed as equivalent oxides)

Ash Composition (03-168)	
Oxide	**wt% of ash**
SiO_2	52.20
Al_2O_3	17.82
TiO_2	0.89
Fe_2O_3	14.40
CaO	3.87
MgO	0.97
K_2O	2.00
Na_2O	1.28
SO_3	3.90
P_2O_5	0.15
SrO	0.03
BaO	0.05
MnO_2	0.05
Mean ash-fusion temperature °F	
Initial deformation	2,110
Softening temperature	2,165
Fluid temperature	2,290

The mineral size, composition, and abundance of the Illinois #6 coal is summarized in Table 3-7. The results show that major minerals include quartz, pyrite, clay minerals (kaolinite, K-AlSilicate (Illite), and other Al-Silicates), and unclassified. The chemical composition of the unclassified phases is known. The chemical formulas of the minerals are summarized in Appendix A. The abundance of the minerals determined with computer-controlled scanning electron microscopy (CCSEM) is similar to mineral analysis results reported in past work conducted on Illinois #6 (Finkelman, 1978).

Table 3-7 CCSEM Mineral Size, Composition, and Abundance (wt% mineral basis)

Type	Diameter in Microns						
	1.0 to 2.2	2.2 to 4.6	4.6 to 10.0	10.0 to 22.0	22.0 to 46.0	46.0 to 400.0	Totals
Quartz	1.7	8.8	5.6	4.2	0.9	0.7	22.0
Calcite	0.0	0.0	0.0	0.4	0.2	1.0	1.6
Dolomite	0.0	0.0	0.0	0.0	0.0	0.4	0.4
Kaolinite	0.1	1.9	1.3	1.6	0.5	0.3	5.8
Montmorillonite	0.1	0.9	0.3	0.1	0.1	0.1	1.7
K Al-Silicate	0.1	3.3	1.0	0.7	0.4	0.3	5.8
Fe Al-Silicate	0.1	1.2	0.3	0.0	0.2	0.2	1.9
Ca Al-Silicate	0.0	0.0	0.2	0.0	0.3	0.4	0.9
Na Al-Silicate	0.0	0.7	0.2	0.1	0.1	0.0	1.1
Aluminosilicate	0.0	0.8	0.4	0.1	0.4	0.5	2.3
Mixed Al-Silicate	0.0	1.3	0.6	0.2	0.2	0.3	2.6
Pyrite	0.1	2.0	5.3	8.3	5.4	3.8	24.9
Pyrrhotite	0.0	0.0	0.3	0.8	0.0	0.0	1.1
Gypsum Al-Silicate	0.1	0.1	0.0	0.0	0.0	0.0	0.3
Si-Rich	0.8	2.7	0.9	0.4	0.4	1.8	7.0
Ca-Rich	0.0	0.0	0.1	0.0	0.3	2.1	2.5
Unclassified	1.9	5.0	1.8	3.5	2.2	3.5	17.9
Totals	5.1	28.7	18.5	20.6	11.6	15.5	100.0

Sub-Bituminous (From Addendum 1 RFP)

The sub-bituminous coal used as a performance coal in the design basis is Montana Rosebud coal. The Rosebud coal is from the northern Powder River Basin. The proximate and ultimate analysis is summarized in Table 3-8 (Addendum 1 of the Coal FIRST RFP). The coal is a sub-bituminous coal that has 25.77% moisture, a higher heating value (HHV) of 8564 BTU/lb, and a volatile matter content of 30.34% on an as-received basis. The ash content of the coal is 8.19% (as received). The sulfur content is 0.73% (as received).

Table 3-8 Proximate and Ultimate Analysis of Montana Rosebud Sub-bituminous Coal

Rank	Sub-Bituminous	
Seam	Montana Rosebud	
Source	Montana	
Proximate Analysis (weight %)[1]		
	As Received	Dry
Moisture	25.77	0.00
Ash	8.19	11.04
Volatile Matter	30.34	40.87
Fixed Carbon	35.70	48.09
Total	100.00	100.00
Sulfur	0.73	0.98
HHV, kJ/kg (BTU/lb)	19,920 (8,564)	26,787 (11,516)
LHV, kJ/kg (BTU/lb)	19,195 (8,252)	25,810 (11,096)
Ultimate Analysis (weight %)		
	As Received	Dry
Moisture	25.77	0.00
Carbon	50.07	67.45
Hydrogen	3.38	4.56
Nitrogen	0.71	0.96
Chlorine	0.01	0.01
Sulfur	0.73	0.98
Ash	8.19	10.91
Oxygen	11.14	15.01
Total	100.00	99.88.00

1 The sulfur content of natural gas is primarily composed of added Mercaptan (methanethiol, CH_4S) with trace levels of H2S. Note: Fuel composition is normalized and heating values are calculated.

The proximate and ultimate analysis of the Montana Rosebud coal was used to identify coals in Microbeam's coal database that match, where detailed analyses of the fuel impurities are available. The compositional analysis of a Rosebud seam coal sample from the Absaloka mine was found to be a good match. The coal sample was from a plant that fires the Rosebud coal. The composition of the ash produced at 750°C (ASTM conditions) in the laboratory is summarized in Table 3-9. The main constituents of the ash consist of SiO_2, Al_2O_3, and CaO with minor amounts of Fe_2O_3, MgO, K_2O, and Na_2O. The ash fusion temperatures are also included in Table 3-9.

Table 3-9 Composition of Ash (ASTM) Produced from Montana Rosebud Sub-bituminous Coal (wt% of ash expressed as equivalent oxides)

Oxide	wt% of Ash
SiO_2	47.6
Al_2O_3	18.7
Fe_2O_3	4.5
CaO	13.0
MgO	3.7
Na_2O	0.5
K_2O	1.6
TiO_2	0.7
P_2O_5	0.2
SO_3	10.5
MnO	0.1
BaO	0.4
SrO	0.3
Total	101.8
Coal Ash Properties, Ash Fusibility (reducing atmosphere)	
I.T. (°F)	2,220
S.T. (° F)	2,250
H.T. (° F)	2,260
F.T. (° F)	2,430

The mineral size, composition, and abundance of the Montana Rosebud sub-bituminous coal is summarized in Table 3-10. The results show that major minerals include quartz, clay minerals (K-AlSilicate (Illite), aluminosilicate, and other Al-Silicates), and unclassified. A minor amount of pyrite was found. The chemical composition of the unclassified phases is known. The chemical formulas of the minerals are summarized in Appendix A.

Table 3-10 CCSEM Mineral Size, Composition, and Abundance (wt% mineral basis)

Type	Diameter in Microns						
	1.0 to 2.2	2.2 to 4.6	4.6 to 10.0	10.0 to 22.0	22.0 to 46.0	46.0 to 400.0	Totals
Quartz	0.9	2.9	3.1	3.2	3.5	4.0	17.7
Calcite	0.0	0.5	0.5	0.9	2.1	5.5	9.6
Kaolinite	0.3	1.8	1.6	2.8	0.7	1.0	8.2
Montmorillonite	0.0	0.5	0.0	0.7	0.2	0.2	1.7
K Al-Silicate	0.2	0.5	1.3	1.4	2.1	4.7	10.6
Fe Al-Silicate	0.0	0.9	0.0	0.1	0.0	0.0	0.3
Ca Al-Silicate	0.1	0.1	0.2	0.2	0.2	0.4	1.2
Na Al-Silicate	0.0	0.1	0.0	0.0	0.0	0.1	0.2
Aluminosilicate	0.1	0.7	1.6	4.2	3.1	3.2	12.9
Mixed Al-Silicate	0.5	1.3	1.5	1.3	1.3	1,5	7.3
Pyrite	0.1	0.1	0.3	0.1	1.3	2.3	4.3
Pyrrhotite	0.0	0.0	0.1	0.0	0.6	0.1	0.8
Oxidized Pyrrhotite	0.0	0.0	0.0	0.0	0.2	0.2	0.4
Gypsum	0.0	0.1	0.0	0.0	0.2	0.9	1.1
Gypsum Al-Silicate	0.1	0.2	0.1	0.0	0.3	0.5	1.3
Si-Rich	0.2	0.4	0.5	0.6	1.0	1.9	4.7
Unclassified	1.0	2.9	2.4	3.0	3.1	3.7	16.1
Totals	3.8	13.0	13.7	19.0	20.5	30.0	100.0

	Na_2O	MgO	Al_2O_3	SiO_2	P_2O_5	SO_3	K_2O	CaO	TiO_2	Fe_2O_3	BaO
Bulk (minerals only)	0.7	2.9	20.0	50.1	3.1	6.9	2.0	8.9	1.0	3.1	0.9
Aluminosilicate	0.4	4.4	46.8	38.0	7.4	0.5	0.4	0.5	0.4	0.5	0.4
Unclassified	1.5	4.4	17.8	48.6	3.2	6.2	4.8	5.9	2.2	3.0	1.7

Performance Coal – Low-Sodium Lignite (From Addendum 1 RFP)

The low-sodium lignite coal used as a performance coal in the design basis is from the Wilcox formation in Texas. The proximate and ultimate analysis is summarized in Table 3-11 (Addendum 1 of the Coal FIRST RFP). The lignite has 32.00% moisture, a higher heating value (HHV) of 6554 BTU/lb, and a volatile matter content of 28.00% on an as-received basis. The ash content of the coal is 15% (as-received). The sulfur content is 0.9% (as-received).

Table 3-11 Proximate and Ultimate Analysis of Low-Sodium Texas Lignite Coal

Rank	Low-Sodium Lignite	
Seam	Wilcox Group	
Source	Texas	
Proximate Analysis (weight %)[1]		
	As Received	Dry
Moisture	32.00	0.00
Ash	15.00	22.06
Volatile Matter	28.00	41.18
Fixed Carbon	25.00	36.76
Total	100.00	100.00
Sulfur	0.90	1.32
HHV, kJ/kg (BTU/lb)	15,243 (6,554)	22,417 (9,638)
LHV, kJ/kg (BTU/lb)	14,601 (6,277)	21,472 (9,231)
Ultimate Analysis (weight %)		
	As Received	Dry
Moisture	32.00	0.00
Carbon	37.70	55.44
Hydrogen	3.00	4.41
Nitrogen	0.70	1.03
Chlorine	0.02	0.03
Sulfur	0.90	1.32
Ash	15.00	22.06
Oxygen	10.68	15.71
Total	100.00	100.00

1 The sulfur content of natural gas is primarily composed of added Mercaptan (methanethiol, CH4S) with trace levels of H2S. Note: Fuel composition is normalized and heating values are calculated.

The proximate and ultimate analysis of the low-sodium Texas lignite coal was used to identify coals in Microbeam's coal database that match, where detailed analyses of the fuel impurities are available. The compositional analysis of a Texas lignite coal sample from the Wilcox Formation was found to be a good match. The composition of the ash produced at 750°C (ASTM conditions) in the laboratory is summarized in Table 3-12. The main constituents of the ash consist of SiO_2, Al_2O_3, CaO, and Fe_2O_3, with minor amounts of MgO, K_2O, and Na_2O.

Table 3-12 Composition of Ash (ASTM) Produced from Texas Lignite Coal (wt% of ash expressed as equivalent oxides)

Oxide	wt% of Ash
SiO_2	52.65
Al_2O_3	15.22
TiO_2	1.02
Fe_2O_3	5.27
CaO	8.27
MgO	1.64
K_2O	0.70
Na_2O	0.37
SO_3	10.80
P_2O_5	0.34
SrO	0.14
BaO	0.20
MnO	0.11
Additional Data	
Base/Acid Ratio	0.24
T_{250}	2660ºF
Silica Ratio	77.62

The mineral size, composition, and abundance of the low-sodium Texas lignite coal is summarized in Table 3-13. The results show that the major minerals include quartz, clay minerals (K-AlSilicate (Illite), aluminosilicate, and other Al-Silicates), calcite, and unclassified. A minor amount of pyrite was found. The chemical composition of the unclassified phases is known. The chemical formulas of the minerals are summarized in Appendix A.

Table 3-13 CCSEM Mineral Size, Composition, and Abundance (wt% mineral basis)

Type	Diameter in Microns						
	1.0 to 2.2	2.2 to 4.6	4.6 to 10.0	10.0 to 22.0	22.0 to 46.0	46.0 to 400.0	Totals
Quartz	1.0	2.5	1.1	1.1	1.3	6.3	13.3
Calcite	0.0	0.1	0.6	0.2	1.4	7.2	11.3
Kaolinite	0.5	1.9	0.5	0.3	1.0	1.6	5.8
Montmorillonite	0.5	1.2	0.6	0.7	1.8	5.4	10.2
K Al-Silicate	0.1	1.5	0.2	0.4	0.6	2.0	4.9
Fe Al-Silicate	0.1	0.4	0.1	0.3	1.0	1.7	3.5
Ca Al-Silicate	0.4	0.8	0.2	0.3	0.5	0.8	2.9
Na Al-Silicate	0.1	0.4	0.0	0.1	0.2	0.8	1.7
Aluminosilicate	0.1	0.6	0.2	0.6	0.7	1.7	4.0
Mixed Al-Silicate	0.8	1.0	0.2	0.3	1.1	2.1	5.5
Pyrite	0.0	0.1	0.6	1.7	1.3	1.4	5.0
Pyrrhotite	0.0	0.0	0.1	0.2	0.0	0.0	0.3
Oxidized Pyrrhotite	0.0	0.0	0.1	0.0	0.0	0.0	0.1
Gypsum	0.5	0.5	0.2	0.1	0.2	0.1	1.8
Gypsum Al-Silicate	0.6	1.3	0.3	0.4	1.1	1.7	5.4
Si-Rich	0.0	0.4	0.3	0.6	0.8	2.8	4.8
Unclassified	3.1	5.8	1.2	0.8	1.3	6.4	18.5
Totals	8.0	18.5	6.6	10	14.5	42.4	100.0

Performance Coal – High-Sodium Lignite (From Addendum 1 RFP)

The high-sodium lignite coal used as a performance coal in the design basis is from the Beulah-Zap seam in the Fort Union Region in North Dakota. The proximate and ultimate analysis is summarized in Table 3-14 (Addendum 1 of the Coal FIRST RFP). The lignite has 36.08% moisture, a higher heating value (HHV) of 6617 BTU/lb, and a volatile matter content of 26.52% on an as-received basis. The ash content of the coal is 9.86% (as-received). The sulfur content is 0.63% (as-received).

Table 3-14 Proximate and Ultimate Analysis of High-Sodium North Dakota Lignite Coal

Rank	High-Sodium Lignite	
Seam	Beulah-Zap	
Source	Freedom, ND	
Proximate Analysis (weight %)[1]		
	As Received	Dry
Moisture	36.08	0.00
Ash	9.86	15.43
Volatile Matter	26.52	41.48
Fixed Carbon	27.54	43.09
Total	100.00	100.00
Sulfur	0.63	0.98
HHV, kJ/kg (BTU/lb)	15,391 (6,617)	24,254 (10,427)
LHV, kJ/kg (BTU/lb)	14,804 (6,634)	23,335 (10,032)
Ultimate Analysis (weight %)		
	As Received	Dry
Moisture	36.08	0.00
Carbon	39.55	61.88
Hydrogen	2.74	4.29
Nitrogen	0.63	0.98
Chlorine	0.00	0.00
Sulfur	0.63	0.98
Ash	9.86	15.43
Oxygen	10.51	16.44
Total	100.00	100.00

1 The sulfur content of natural gas is primarily composed of added Mercaptan (methanethiol, CH4S) with trace levels of H2S. Note: Fuel composition is normalized and heating values are calculated.

The proximate and ultimate analysis of the high-sodium Beulah-Zap North Dakota lignite coal was used to identify coals in Microbeam's coal database that match, where detailed analyses of the fuel impurities are available. The compositional analysis of a sample from the Upper Beulah-Zap seam from the Fort Union Region was found to be a good match. The composition of the ash produced at 750°C (ASTM conditions) in the laboratory is summarized in Table 3-15. The main constituents of the ash consist of SiO_2, CaO, Al_2O_3, Fe_2O_3, and Na_2O, with minor amounts of MgO and K_2O.

Table 3-15 Composition of Ash (ASTM) Produced from High Sodium Beulah-Zap Lignite Coal (wt% of ash expressed as equivalent oxides)

Oxide	wt% of Ash
SiO_2	21.39
Al_2O_3	8.88
CaO	15.25
Fe_2O_3	13.12
MgO	4.05
K_2O	1.02
Na_2O	9.42
SO_3	23.88
TiO_2	0.43

The mineral size, composition, and abundance for the high-sodium North Dakota lignite coal is summarized in Table 3-15. The results show that the major minerals include quartz, pyrite, clay minerals (kaolinite, montmorillonite, aluminosilicate, and other Al-Silicates), and unclassified. A minor amount of pyrite was found. The chemical composition of the unclassified phases is known. The chemical formulas of the minerals are summarized in Appendix A.

Organically associated impurities in sub-bituminous and lignite coals

Some of the impurities or ash-forming components in the lignite are associated with the organic matrix of the coal. Table 3-16 shows organically associated elements of the performance coals.

Table 3-16 Performance Coals Organic Matrix

Analysis	Buelah-Zap Lignite		Wilcox Lignite		Rosebud Sub-bituminous	
	µg/g extrd	% extrd	µg/g extrd	% extrd	µg/g extrd	% extrd
Ba	239	38	53	28	57	30
Ca	9728	76	4420	62	2003	57
Cr	0	0	3	14	0	0
K	186	20	177	9	2	2
Mg	2241	90	1880	94	598	65
Mn	17	30	129	43	7	20
Na	3645	84	232	75	70	81
Sr	422	87	65	81	22	24

Fireside Performance Parameters and Boiler Design

Fuel performance is estimated in terms of slag flow behavior, abrasion and erosion wear, wall slagging, high-temperature silicate-based convective pass fouling, and low-temperature sulfate-based convective pass fouling.

The Coal Quality Management System (CQMS) indices provide information on the potential impacts of fuel impurities on the design and operation of power plants. For example, the sizing of the boilers depends on ash-related issues as illustrated in Figure 3-1.

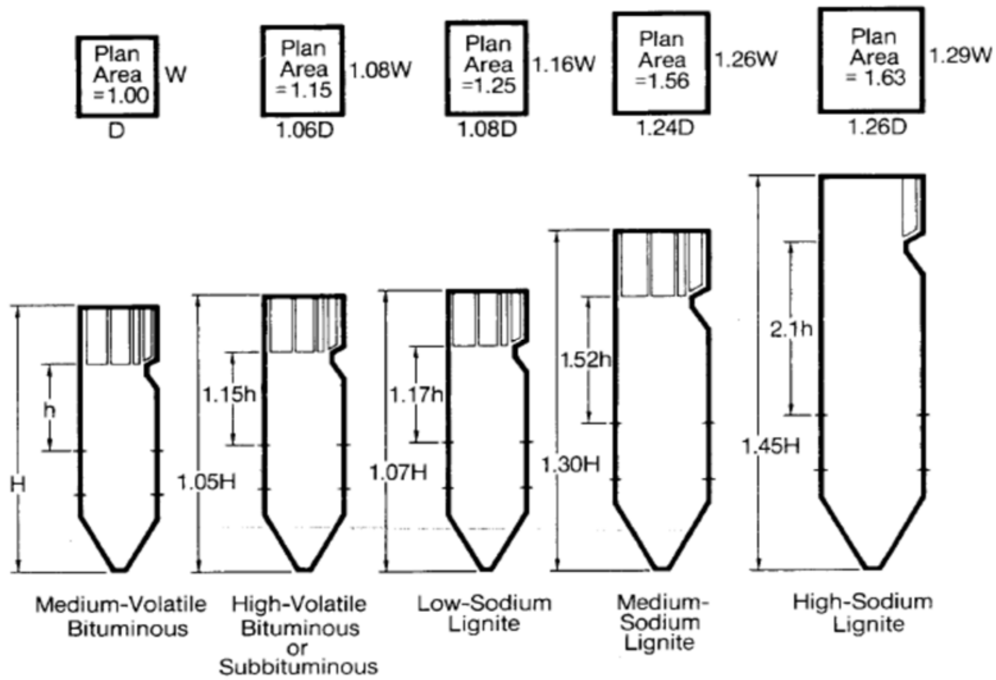

Figure 3-1 Impacts of Coal Properties on Boiler Sizing

The coal property data was used to calculate the indices for the base-case and performance coals.

Natural Gas (From Addendum 1 RFP)

The natural gas composition in Table 3-17 was used for the base case natural gas for the combustion turbine.

Table 3-17 Natural Gas Composition

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

3.2 Plant Performance Targets

3.2.1 General Plant Requirements

The proposed concept meets specific design criteria in the RFP as follows:

- Overall plant efficiency of 43% with ESS, 37% without ESS (RFP value 40%).
- Using a modular approach as much as possible.
- Near-zero emissions using a combination of advanced air-quality control systems (electrostatic precipitator (ESP), wet flue gas desulfurization system (FGD), selective catalytic reduction SCR for NO_x control) that make the flue gas ready for traditional post-combustion carbon-capture technology.
- Capable of high ramp rates (expected 6% versus RFP 4%) and minimum loads (expected better than the 5:1 target).
- Integrated energy storage system (ESS) with 50 MW Lithium Ion / Vanadium Redox Hybrid System.
- Minimized water consumption through the use of a cooling tower versus once-through cooling and internal recycling of water where possible.
- Design and commissioning schedules shortened by using state-of-the-art design technology, such as digital twin, 3D modeling, and dynamic simulation.
- Enhanced maintenance features to improve monitoring and diagnostics, such as coal-quality impact modeling and monitoring, advanced sensors, and controls.
- Integration with coal upgrading or other plant value streams (co-production). Potential for rare earth element extraction in the raw coal feed stage.

- Natural gas co-firing is an integral part of the design with the gas turbine responsible for nearly a quarter of direct power output. The gas turbine exhaust is used to assist with heating the coal-fired steam boiler.

Table 3-18 General Plant Requirements

Total Plant Output and Turndown with Full Environmental Compliance (From Addendum 1 RFP)		Proposed Plant Target
Target	>5:1	>5:1
Total Plant Ramp Rates (From Addendum 1 RFP)		**Proposed Plant Target**
Target	>4% max load/minute	>6% max load/minute
Time to Max Load	<2 hours	30 min Cold to Warm Start, 4-6 Hours to Full Load
Co-Firing Ability (From Addendum 1 RFP)		**Proposed Plant Target**
Target	<30% Natural Gas Heat Input	<30% Natural Gas Average Heat Input

3.2.2 Water Requirements

Table 3-19 Water Requirements

Target Plant Water Daily Average Suggested Target	
Raw Water Withdrawal	$\leq$14 (gpm)/MW_{net}
Raw Water Consumption	$\leq$10 (gpm)/MW_{net}

3.2.3 System Size Basis

Table 3-20 System Size Requirements

Plant Size Basis (From Addendum 1 RFP)		Proposed Plant Target
Key Component Modularized	As much as possible	As much as possible (includes factory and field modularization and skid-mounted and prefab piping/wiring as much as possible)
Maximum Power	50MWe – 350 MWe	350 MWe Net
Maximum Plant Efficiency (w/o CCS parasitic load)	>40%	>40% >35% with CCS parasitic load

3.2.4 Environmental Targets

The output-based emissions limits shown below are specified in the Coal FIRST RFP. While these are reasonable emission limits, case-specific air quality compliance requirements could drive limit adjustments. Ambient air quality attainment designations vary across the country; therefore, the ultimate siting of the project will determine the increment of negative air quality impact available for new emissions. The carbon capture aspect of the project implies a process that exhausts a cooler residual gas stream to the atmosphere from a stack that is likely at a lower height than a conventional coal plant stack. These stack parameters will be used as inputs to air dispersion modeling, which would be expected to show a dispersion profile different than experienced with a conventional coal-fired stack. Until siting and exhaust stream characteristics are established, it is possible that compliance with air quality standards could drive project design adjustments.

Table 3-21 Environmental Targets

Air Pollutant	Pulverized Coal (PC) (lb/MWh-gross) (From RFP Addendum 1)	Proposed Plant Target (lb/MWh-gross)
SO_2	1.00	1.00
NO_x	0.70	0.70
PM (Filterable)	0.09	0.09
Hg	$3x10^{-6}$	$3x10^{-6}$
HCl	0.010	0.010
CO_2	90% Capture	116 lb/MWh-gross (90% Capture)

Solid waste and liquid discharge requirements are listed in Table 3-22 and Table 3-23 below.

Table 3-22 Solid Waste Requirements

Solid Wastes (Less than Case B12B Equivalent - scaled to 350 MW)	
Bottom Ash Discharge	Saleable, 375 tons/day
Fly Ash Discharge	Saleable, 74 tons/day
FGD Gypsum Waste	Saleable, 64 tons/day
Wastewater Solid Waste	Minimized
ZLD Crystallized Waste	Minimized
CO_2 Capture Amine Waste	Saleable, 43 tons/day

Table 3-23 Liquid Discharge Requirements

Liquid Waste (From RFP Addendum 1)		Proposed Plant Target
Type	None, Zero Liquid Discharge	None, Zero Liquid Discharge

3.2.5 Plant Capacity Factor

Table 3-24 Plant Capacity Factor

Projected Plant Capacity Factor (Used to compare with Case B12B)	
Capacity Factor – based on cost for MWh basis to compare with B12B	85%

3.3 Selected Major Equipment Performance Criteria

Table 3-25 Boiler Design Basis Table

Boiler			
Type	Doosan Variable Pressure Once-through USC boiler		
USC PP Capacity	Coal feed rate (w' GT): 43.9 lb coal/sec (79 tons/hr) Coal feed rate (w/o GT): 49.9 lb coal/sec (90 tons/hr)[1] Air requirements: 480 lb/sec (from GT0 exhaust; 184 lb/sec (air to boiler)		
Details	Opposed wall-fired, once-through supercritical, 2-pass radiant-type boiler with drainable superheater		
Supercritical Steam Pressure	>242.33 bara		
Super Heat Steam Temp	603°C		
Reheat Steam Temperature (at Turbine inlet)	600°C		
Rating	BMCR (Coal + NG, VWO)	TMCR (Coal + NG, NR)	TMCR (Coal only)
SH outlet steam flow, kg/s	227.36	210.00	210.00
SH outlet steam temperature, °C	603	603	603
SH outlet steam pressure, bara	253	251 (3626 psig, 255kg/cm2 g)	251 (3626 psig, 255kg/cm2 g)
RH outlet steam flow, kg/s	193.99	179.99	179.99
RH outlet steam temperature, °C	603	603	603
RH outlet steam pressure, bara	55.4	51.5	51.5
RH inlet steam temperature, °C	378.1	365.1	365.1
RH inlet steam pressure, bara	57.2	53.3	53.3
Final feedwater temperature, °C	310.5	304.5	304.5
Ash / Reject System	Bottom ash handling with submerged flight conveyor with closed loop water circuit tied to pyrite wet-sluice system.		

1 When operating at 70% of full load, coal feed rate to boiler is higher
2 The above are indicative and may undergo changes during FEED stage

Table 3-26 Steam Turbine Design Basis Table

Steam Turbine			
Type	Doosan DST-S20		
Steam Turbine Capacity – USC PP	270 MW		
Details	Tandem compound two-flow machine with High Pressure and Intermediate Pressure		
Rating	BMCR (Coal + NG, VWO)	TMCR (Coal + NG, NR)	TMCR (Coal only)
SH outlet steam flow, kg/s	227.36	210	210
HP Turbine inlet steam temperature, °C	600	600	600
Main Steam at Turbine Main stop valve, bara	242.33	242.33 (3500psig, 246kg/cm2 g)	242.33 (3500psig, 246kg/cm2 g)
RH outlet steam flow, kg/s	193.99	179.99	179.99
Reheat steam temperature at Reheat stop valve outlet, ℃	600	600	600
Reheat steam pressure at Reheat stop valve outlet, bara	55.4	51.5	51.5
RH steam temperature at HP turbine outlet, °C	380.0	367.0	367.0
RH steam pressure at HP turbine outlet, bara	58.8	54.6	54.6
Steam flow for PCC from LP cross over pipe, kg/s	60.91	56.81	56.81
Steam temperature for PCC from LP cross over pipe, ℃	267.4	268.40	268.40
Steam pressure for PCC from LP cross over pipe, bara	5.37	5.01	5.01
Water return flow from PCC to Deaerator, kg/s	60.91	56.81	56.81
Water return temperature from PCC to Deaerator,℃	150.56	150.56	150.56
Water return pressure from PCC to Deaerator, bara	26.4	26.4	26.4
Condenser Pressure, bara	0.054	0.051	0.051

1 The above are indicative and may undergo changes during the FEED stage

Table 3-27 Gas Turbine Design Basis Table

Gas Turbine	
Type	GE 6F03 Model
Fuel Usage	11.1 lb natural gas/sec 471 lb air/sec
Gas Turbine Capacity	87 MW
Exhaust Gas Temp	620°C

Table 3-28 AQCS Design Basis Table

Air Quality Control System (AQCS) Equipment	
Selective Catalytic Reduction	
Inlet Gas temp	>300°C at min load
Inlet NO_x (bituminous/sub-bituminous / lignite)	150/147/141ppm
NO_x Outlet Concentration Target	10ppm at O_2 6% dry volume
Electrostatic Precipitator	
Type	Cold, Dry
Removal Rate	99% Dust reduction
Flue Gas Desulfurization	
Type	FGD with non-leakage gas-gas heater and Electrostatic Mist Eliminator with limestone reagent
SO_x inlet Concentration	40-50 ppm at O_2 6% dry volume
SO_x Outlet Concentration Target	4 ppm at O_2 6% dry volume
PM_{10} Reduction	90% (2 mg/m^3)
Chloride Purge	20,000 ppm
Carbon Capture System	
Type	Post Combustion amine
Efficiency	90% CO_2 capture efficiency
Reboiler Duty	2.5 MJ/kg CO_2
Inlet Gas Temp	<40°C

Table 3-29 ZLD Treatment System Design Basis

ZLD Treatment System	
Type	Softening/ultra-filtration pretreatment, reverse osmosis (RO) and mechanical vapor recompression crystallizer
Power requirement	1 MW / Startup Steam Utility

Table 3-30 CO_2 Compression

CO_2 Compression System	
Type	6 Stage Centrifugal Diffuser Guide Vane with Recirculation Loop
Power requirement	20 MW

Table 3-31 Energy Storage System Design Basis

Energy Storage System	
Type	Lithium Ion / Vanadium Redox Hybrid System
Storage Duration	1 hour
Power Contained	50 MW (460 kW Modular) 50 MWh
Efficiency	DC-DC 60%-80%
Life/Cycle	20/8,000 yr/cycles

Table 3-32 Advanced Controls Design Basis

Efficiency and Reliability Improvement Technologies – Illinois #6	
Type	Full stream elemental coal analysis combined (FSEA) combined with combustion system operational performance indices (CSPI) to optimize coal properties and plant operations- Note: all values are dependent upon fuel composition, system design, and operating parameters
Optimized fuel properties/selection blending – Wall slagging/Strength index temperature at 2250°F	2.27/0.29
Furnace exit gas temperature <less than	<2300°F
Initial Sintering Temperature, TIST	2100°F
Deposit build up rate (DBR – High Temperature fouling index)	14.21
Low Temperature fouling – Temperature	1540°F
DBR – Low temperature surfaces	0.02

3.4 Process Description

3.4.1 Proposed Concept Basic Operating Principles and How It's Unique and Innovative

The proposed plant combines a state-of-the-art ultra-supercritical (USC) coal power plant with a natural gas combustion turbine and energy storage system (ESS). The typical role of the heat recovery steam generator (HRSG) in a normal natural gas firing combined cycle (NGCC) power plant will be replaced by a coal boiler, resulting in a hot windbox repowering of the coal boiler. The proposed plant will consist of a 270-MW USC power plant, an 87-MW gas turbine, and 50-MW ESS battery storage system for a nominal output of 350 MW net.

The combined system will effectively handle variable power demand driven by the increased use of renewable power plants. The exhaust gas from the 87-MW gas turbine will feed the 270-MW USC coal boiler furnace. An economizer gas bypass system is adopted to increase the gas temperature over 300°C at low load for effective selective catalytic reduction (SCR) operation. Should power demand be lower than minimum load, the remaining electricity will be stored in an ESS.

Two unique combustion features of this power plant design will allow shorter startups and respond to load changes faster. The first is an indirect coal preparation and firing system. The system will allow pulverized coal to be prepared and stored independently from the boiler/steam turbine system. This will eliminate natural limitations in ramp rate caused by placing pulverizers into and out of service. The indirect firing design includes up to two hours of storage capacity to support shorter startups and faster load changes. The design will include an inerting system for the pulverized coal and a vibrating system to minimize plugging-related issues. The second unique combustion feature is using the traditional gas turbine, which has an inherently fast startup and ramp rate capability.

3.4.2 General System Description and Process Flow Diagram

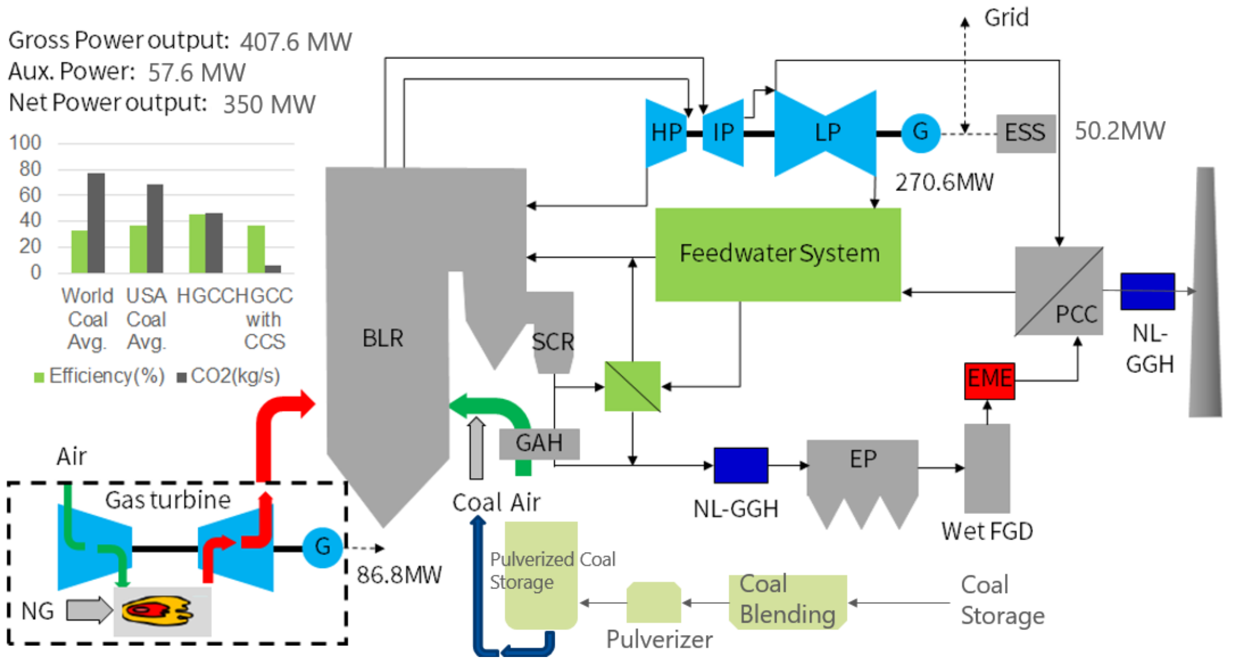

Figure 3-2 HGCC Concept Flow Diagram

A detailed process flow diagram can be found in Appendix B. Coal enters the coal preparation plant to be pulverized and collected prior to burning. The indirect coal firing system, as well as the exhaust from an 87-MW natural gas-fired turbine, will heat the USC steam boiler. Generated USC steam will power a 270-MW steam turbine. Power from this turbine will be transmitted either to the grid or to an ESS for use in intermittent or ramping power conditions. Flue gas from the boiler will be processed through several air-quality control systems. Finally, the flue gas will be processed through a traditional amine post-combustion carbon capture plant to remove the CO_2 generated from combustion.

All proposed components are commercially available; although, the performance and characteristics of coal burning under gas turbine exhaust need to be simulated and tested to develop safe and efficient operating limits.

The proposed power plant incorporates advanced design technology using a digital twin as well as 3D modeling and dynamic simulation by DHI to solve issues before the equipment is constructed.

3.4.3 Extent and Manner of Use of Other Fuels in Conjunction with Coal

Natural gas co-firing is an integral part of the design—the gas turbine is responsible for nearly a quarter of direct power output—as is the use of the gas turbine exhaust to assist with heating the coal-fired steam boiler.

3.4.4 System Description of Major Equipment

3.4.4.1 General Operation

The combustion turbine can operate independently from the USC boiler during startup as needed. From a cold start, the combustion turbine's full exhaust will be directed to a bypass stack. As the USC boiler warms, exhaust routing from the combustion turbine will gradually transition to the boiler until all exhaust is routed to the boiler and the bypass stack is closed. It is anticipated that the bypass will be used for approximately two hours during a warm start until the steam turbine synchronizes to the grid. The bypass stack will be used during a cold start for 6–8 hours until the steam turbine synchronizes to the grid. It is not necessary to start the combustion turbine in advance of firing the boiler. If output from the combustion turbine is not needed, the USC boiler can start independently. The air permit will include provisions to allow the combustion turbine to operate using the bypass stack for a specified period of time before the exhaust is routed into the USC boiler. The combustion turbine comes standard with burners that minimize CO and NO_x emissions.

The USC boiler is equipped with an indirect coal-firing system to decouple coal milling from boiler firing that is not found on current coal-fired boilers. The existing boiler configurations require pulverizers be placed into or taken out of service at certain load points, resulting in operating constraints. The indirect firing system allows for smooth ramp rates unencumbered by taking pulverizers in and out of service. In addition, the indirect firing system reduces the boiler minimum load by 20%.

When the plant begins operation from a cold start, the following startup order is expected:

- ESS: immediate
- Combustion turbine: 30 minutes to full load
- USC boiler steam cycle: 6–8 hours to full load from cold start, approximately 3 hours and 40 minutes from warm start

3.4.4.2 Coal, Activated Carbon, and Sorbent Receiving and Storage

Coal Receiving and Unloading

The coal receiving and storage system unloads, conveys, prepares, and stores the coal delivered to the plant. This scope outline is similar to the 2019 Case B12B performance cost report (2019). The scope of the system includes the trestle bottom dumper and coal receiving hoppers to the slide gate valves at the outlet of the coal storage silos.

The sorbent receiving and storage system scope includes truck roadways, turnarounds, unloading hoppers, conveyors, and day storage bins.

Coal is delivered to the site by 100-car unit trains containing 100-ton rail cars. A trestle-bottom dumper unloads the coal into two receiving hoppers. Coal from each hopper is fed directly into a vibratory feeder. The 8 cm x 0 (3" x 0) coal from the feeder is discharged onto a belt conveyor. Two conveyors with an intermediate transfer tower are assumed to convey the coal to the coal stacker, which transfers the coal to the long-term storage pile or to the reclaim area. The conveyor passes under a magnetic plate separator that removes tramp iron and then on to the reclaim pile.

Coal from the reclaim pile is fed onto a belt conveyor by two vibratory feeders, located under the pile. The belt conveyor transfers the coal to the coal surge bin in the crusher tower where the coal is reduced in size to 2.5 cm x 0 (1" x 0) by the coal crushers. The coal is then transferred by conveyor to the transfer tower.

Reagent Receiving and Unloading

Similar to Case B12B (2019), limestone is delivered to the site in 25-ton trucks. The trucks empty into a below-grade hopper where a feeder transfers the limestone to a conveyor for delivery to the storage pile. Limestone from the storage pile is transferred to a reclaim hopper and conveyed to a day bin.

Pulverized Coal Storage

The proposed pulverized coal storage is based on indirect firing systems currently deployed in the cement and smelting industries. Similar systems have been developed for lignite-fired boilers in Germany (Drosatos, et al., 2019). The proposed system will consist of a milling and drying system, a dust collection system, a coal bunker system, a CO_2 inerting system, a fire detection system (CO monitoring), and a fire suppression system. The coal bunker is designed for a coal firing supply capacity of 8-12 hours with 2 hours of storage capacity for the pulverized coal silo. Installing equipment that vibrates coal in the coalbunker will prevent silo plugging.

CO_2 Inerting/Suppression System

The indirect firing system proposed is a unique approach for providing load changing flexibility to the HGCC Concept proposed by Barr.

Many of the indirect firing system components are similar to components found in existing coal-fired facilities; however, the packaging and integration of this system is not commonly found in the current fleet of coal-fired facilities. Storage of pulverized coal in bins is unique to this system. It allows the pulverizer to operate semi-independently from the boiler providing increased operating flexibility. Along with this type of storage and handling of pulverized coal comes the need for increased levels of fire suppression and inerting for the indirect firing system when compared to conventional pulverized coal systems.

In response to the increased fire suppression and protection requirements, Barr requested and received a preliminary proposal from Electric Scientific Company of Minneapolis (based on Kidde Company technology) for the design and installation of a suitable fire suppression/inerting system. Electric Scientific's proposal is based on the following information:

- Process flow diagram – based on a concept design from Doosan
- Preliminary volume calculations for the various equipment
- Preliminary operating scenario for the Indirect Firing System

The proposal contains the following elements:

Suppression system

- Separate from inerting system due to the different flow requirements
- Four zones of protection
    - Zones 1-3 include the coal bunkers, coal feeders, pulverizer, cyclone separator, and interconnecting ducts
    - Zone 4 includes the pulverized coal bins and ducts
- Each zone has both suppression and inerting capabilities
    - Suppression flows are much higher than inerting flows
- Proposal includes valves, actuators, tanks, vaporizers, pumps, and nozzles

Fire Suppression Approach

- NFPA 12 compliant
- Floods spaces with sufficient CO_2
- Activated based on detection (heat, CO, etc.)
- Can be manually activated

Inerting Approach

- Bunkers – activated based on detection
- Coal pulverizers – activated based on detection
- Pulverized coal bin – activated based on pulverizer out of service
  - Either normal or emergency shut down
  - Inerting will continue for 8 hours – assumed that pulverizers will be shut down at night due to load electrical demand on the grid
- Can be manually activated

3.4.4.3 Fuel Monitoring and Plant Performance

Managing the behavior of ash produced during coal combustion is key to improving system efficiency, reducing cleaning outages and equipment failures, and optimizing emissions control. Detrimental effects of ash can manifest themselves in a boiler system in many ways, including fireside ash deposition on heat transfer surfaces, corrosion and erosion of boiler parts, poor slag flow, and production of fine particulates that are difficult to collect. Research, development, and demonstration programs have been conducted over the past several decades to develop a better understanding of the chemical and physical processes of ash formation, ash deposition, slag flow, and particulate control in combustion systems. This understanding is leading to the development of tools to predict and manage ash behavior.

The extent of ash-related problems depends on the quantity and association of inorganic constituents in the coal, boiler design, and combustion conditions. The inorganic constituents in coal take several forms, including organically associated inorganic elements and discrete minerals. The types of inorganic components present depend on the rank of the coal and the environment in which the coal formed. The inorganic components in high-rank coals are mainly mineral grains that include clay minerals (kaolinite, illite, and montmorillonite), carbonates, sulfides, oxides, and quartz. Lower-rank sub-bituminous and lignitic coals contain higher levels of organically associated cations such as sodium, calcium, magnesium, potassium, strontium, and barium in addition to the mineral grains that are found in bituminous coals.

During coal combustion, minerals and other inorganic components associated with the coal undergo a complex series of transformations that result in the formation of inorganic vapors, liquids, and solids in the flame. The inorganic vapors, liquids, and solids, referred to as "intermediates," cool when transported with the bulk gas flow through gas cooling and cleaning systems. The cooling process causes the vapor-phase inorganic components to condense and the liquid-phase components to solidify.

The physical and chemical characteristics of the intermediate materials that are transported through a combustion system dictate their ability to produce slag that will flow, water wall deposits, convective pass deposits, and vapor phase and fine ash that can cause corrosion. Ash deposition occurs when the intermediate ash species are transported to fireside surfaces (refractory and heat transfer) and accumulate, sinter, and develop strength. In a utility boiler, depending on gas velocity and geometry, particles greater than 5 to 10 µm will be transferred to a heat transfer surface by inertial impaction. Particles less than 5 µm and vapor-phase species are transported to heat transfer surfaces by diffusion and thermophoresis. The particle size of the deposited materials is important in the formation of strong deposits. Small particles will sinter (densify) and develop strength faster than larger particles. Vaporization and condensation of inorganic elements contribute to the formation of fine particulates when the vapors condense homogeneously. Additionally, these vapors can condense on surfaces of entrained ash particles and ash deposits, producing low-melting-point phases.

Illustrated in Figure 3-3, the Coal Quality Management System (CQMS) was developed in the 1990s as an internal software for use at Microbeam Technologies Inc. (MTI) to assess the impacts of fuel properties on plant performance. It has been used in hundreds of projects for clients worldwide. MTI has conducted over 1500 projects and has a database of over 12,000 samples of coal and ash-related materials (deposits, slag, and corrosion products). The CQMS system uses advanced indices that relate the coal characteristics as determined by computer controlled scanning electron microscopy (CCSEM) (Benson and Laumb, 2007)[xiv] and chemical fractionation (Benson and Holm, 1985)[xv] to ash behavior in a coal-fired utility boiler. MTI also developed simplified relationships for the indices described below that use ash composition and database information to predict the potential impacts of coal properties on plant performance (Benson, et al., 2004)[xvi]. Fuel performance is estimated in terms of slag flow behavior, abrasion and erosion wear, wall slagging, deposit strength, high-temperature silicate-based convective pass fouling, low-temperature sulfate-based convective pass fouling, peak impact pressure, low-temperature fouling, ash resistivity, and fine particle (aerosol).

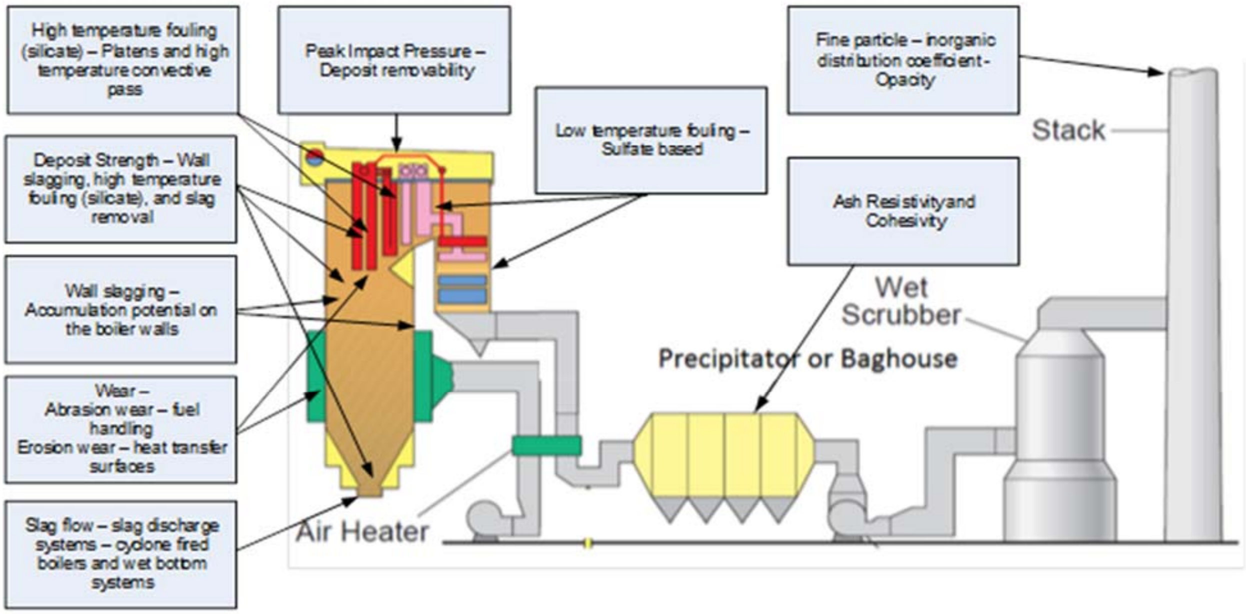

Figure 3-3 Description of CQMS Indices

3.4.4.4 Coal-Fired Boiler

The proposed coal-fired boiler will be a Doosan variable pressure once-through USC boiler. This boiler is an opposed wall-fired, once-through, ultra-supercritical boiler with supercritical steam parameters over 250 bar and 603°C at the outlet. It is a two-pass, radiant-type boiler capable of firing the coals specified in the RFP and Section 3.1 of this design basis report on condition that lignite coal is dried before it is supplied to the boiler. The boiler will be optimized for fast startup times and maximizing ramp rates. The boiler will incorporate advanced low NO_x axial swirl pulverized coal burners in the furnace's front and rear walls. The advanced low NO_x burners come complete with auxiliary fuel burners for startup and low-load combustion support.

The boiler design will be standardized to facilitate operation with different coal types. This is achievable by adopting a boiler design with 100% coal fuel input, which when modified to fit our concept results in a reduction in ash. The reduced ash loading coupled with lower furnace temperatures from the higher-moisture content (>10%) is expected to facilitate combustion of low-rank coals by reducing the occurrence and impact of slagging and fouling. By standardizing the size of the boiler, additional control systems (increased soot blowing, coal drying, ash removal, coal blending, lower coal feed rates) that are able to be demonstrated in an existing plant will be sufficient for handling low-rank coals.

During startup and low loads (below the minimum specified stable-operating load), two-phase flow is maintained in the furnace with the assistance of a recirculation pump. The pump increases economizer inlet water flow and maintains a sufficient water flow through the furnace tubes to provide adequate cooling. The recirculation pump is a standard design featuring suspended, in-line configuration with a wet stator motor. The pump extracts an amount of water from the separator and storage vessel system and recirculates it to the economizer inlet to combine with the feedwater such that the total water flow to the furnace tubes is at or above the minimum flow requirement. The recirculation pump system offers fast startup times, low firing rates, and low auxiliary fuel consumption. As limited hot water is dumped into flash tanks, system heat loss and feedwater inventory requirements are minimal. The heating surface arrangement is selected to maintain desired steam conditions throughout the required operating load range.

The steam generator includes the following, except where otherwise indicated:

- Variable pressure, once-through type steam generator
- Startup circuit, including integral separators
- Water-cooled furnace, dry bottom
- Superheater with water spray type attemperator
- Reheater with water spray type attemperator
- Economizer
- Sootblower system
- Gas air preheaters
- Steam air heaters
- Coal feeders and pulverizers
- Low NO_x coal burners and natural gas igniters/ warm-up system
- Overfire Air (OFA) system
- Forced draft (FD) fans
- Primary air (PA) fans
- Induced draft (ID) fans
- Air and gas duct with dampers, expansion joints
- GT exhaust bypass duct

Feedwater and Steam

High-pressure feedwater from the feedwater supply system is transferred to the economizer located in the boiler rear pass. The heated feedwater is supplied by the economizer to the furnace inlet header located at the furnace hopper bottom. Dry steam leaving separators is transferred to the primary superheater via the furnace roof and a steel-cooled cage wall.

The gas-tight furnace is of a welded wall construction. The lower furnace consists of continuous spiral wound tubes while the upper furnace is composed of vertical tubes. The furnace roof is a steam-cooled wall.

The superheater is arranged in three stages: primary, secondary (platen) and final, with additional steam-cooled surface provided by the furnace roof and the back-pass cage enclosures. The reheater surface consists of pendant section located in vestibule and horizontal section in the rear-pass cage. Crossover connection is supplied to minimize the effect of any gas side imbalances.

Air and Combustion Products

The boiler air and gas system composed of fans, air heaters, ducts, dampers, is necessary to perform the following:

- Provide and regulate the combustion air to the burners
- Bias the fuel gas between reheater and superheater sides of the boiler rear pass to control reheater steam temperatures
- Provide and regulate the air for transport of the pulverized coal to the burners
- Extract the gaseous products of combustion (flue gases) from the furnace
- Bypass gas turbine exhaust gas to stack

The boiler is designed to operate under a balanced draught condition. The flue gas system includes two identical circuits, each complete with a regenerative air preheater, ID fan, and all associated duct, dampers, and expansion joints.

Fuel Feed

The housing for the vertical-spindle mill will be designed in accordance with the pressure containment requirements of the National Fire Protection Association (NFPA) code. Raw coal is fed by chute through the top of the casing into the center of the grinding zone. Centrifugal force carries the coal outward and through the grinding elements, where it is pulverized to a fine powder. Hot primary air is then introduced to the mill periphery. Primary air is essential not only for the transportation of the pulverized fuel, but also to dry the coal during grinding.

Mills are operated independent of boiler loading and the pulverized coal is stored in the intermediate bunker. From the bunker, it is taken to the combustion chamber with the help of a primary air fan. Boiler loading is controlled by the amount of pulverized fuel fed to boiler. Cyclone type separators are used to separate the fine coal from the coal-air/gas mixture for storing in fine coal bunker.

This system offers the following advantages:

- Mill can be operated at full load, saving power and maintenance costs
- Startup time is reduced and load operation becomes more flexible (faster load changes)

Ash Removal

The furnace bottom includes several hoppers. A clinker grinder under each hopper breaks up any clinkers that may form. Accumulated bottom ash discharged from the hoppers passes through the clinker grinder, then to a submerged scraper conveyor, and finally to an outdoor silo before being transferred to trucks for sale to third parties. In a closed loop, water from the pyrite system will be used for the submerged flight conveyor system.

Burners

Each burner is designed as a low-NO_x configuration with staging of the coal combustion intended to minimize NO_x formation. The burner is also designed to be as robust and mechanically simple as possible, offering a long life and long periods of continuous operation as well as dramatically simplified commissioning and operating procedures. The following features are incorporated in the burner design:

- An initial oxygen-deficient zone to not only minimize NO_x formation, but also provide enough oxygen to maintain a stable flame.
- Optimization of both the residence time and the temperature under fuel-rich conditions to minimize NO_x formation.
- Maximization of the char residence time under fuel-rich conditions to reduce the potential for formation of char nitrogen oxide.

In addition, OFA nozzles further stage combustion to minimize NO_x formation.

Natural gas-fired burners, with a capacity of 30% BMCR, heat input for startup, warm-up, and flame stabilization at low loads. Natural gas is fired by a NG burner mounted in each pulverized fuel (PF) burner. High-energy arc will ignite natural gas.

Gas Air Preheater

The Ljungstrom Gas Air Heater (GAH) absorbs waste heat from flue gas and then transfers this heat to incoming cold air by continuously rotating the heat transfer elements of specially-formed metal plates. The housing surrounding the rotor has duct connections at both ends and is adequately sealed by seal frame and seal shoe to form a primary air passage, a secondary air passage, and a gas passage through the GAH.

The GAH rotor is driven by an electric motor through an enclosed speed reduction drive unit. A back-up air motor is supplied as well.

Sootblowers

Sootblowers for steam cleaning are included at the flue gas side, and an off-load water-washing device system is provided as well. A carefully selected number of sootblowers are strategically located in the furnace wall, superheater, reheater, and economizer of the boiler. The furnace walls have short, retractable rotary sootblowers above the top burner row elevation. The pendant and horizontal surfaces of superheater, reheater, and economizer include long retractable blowers arranged on both sides of the boiler.

Condensate

Condensate will be recirculated back to the condenser. The clean condensate from the PCC system will be sent back to the deaerator.

Circulating Water System

It is assumed that the plant is serviced by a public water facility and has access to groundwater for use as makeup cooling water with minimal pretreatment. All filtration and treatment of the circulating water is to be conducted on site. A mechanical-draft, wood-frame, and counter-flow cooling tower is provided for the circulating water heat sink. Two 50% circulating water pumps (CWPs) are included. The cooling water system (CWS) provides cooling water to the condenser, the auxiliary cooling water system, and the PCC facility.

The HGCC concept recovers the heat of compression from the CO_2 compressors as part of the low-pressure feedwater heating system. This improves thermal efficiency and reduces the amount of heat rejected by the cooling tower, resulting in lower capital and operating costs for that system.

The auxiliary cooling water system is a closed-loop (CL) system. Plate and frame heat exchangers (HXs) with circulating water as the cooling medium are included. This system provides cooling water to the lube oil coolers, turbine generator, boiler feed pumps, etc. All pumps, vacuum breakers, air release valves, instruments, controls, etc., are included for a complete operable system.

The PCC and CO_2 compression systems in cases B11B and B12B require a substantial amount of cooling water provided by the PC plant CWS. The additional cooling loads imposed by the PCC and CO_2 compressors are reflected in the significantly larger CWPs and cooling tower in those cases. In the HGCC, only the PCC heat loads are removed by the CWS.

3.4.4.5 Ash Handling

The ash handling system provides the equipment required for conveying, preparing, storing, and disposing of the fly ash and bottom ash produced on a daily basis by the boiler.

The system's scope includes everything from the baghouse hoppers, air heater and economizer hopper collectors, and bottom ash hoppers to the separate bottom ash/fly ash storage silos and truck filling stations. The system is designed to support short-term operation at the 5% OP/VWO condition (16 hours) and long-term operation at the 100% guarantee point (90 days or more).

The fly ash collected in both the baghouse and the air heaters is conveyed to the fly ash storage silo. A pneumatic transport system that uses low pressure (LP) air from a blower provides the transport mechanism for the fly ash. Fly ash is discharged through a wet unloader, which conditions the fly ash and conveys it through a telescopic unloading chute into a truck for disposal.

The bottom ash from the boiler is fed into a series of dry storage hoppers, each equipped with a clinker grinder. The clinker grinder breaks up any clinkers that may form. Accumulated bottom ash discharged from the hoppers passes through the clinker grinder, then to a submerged scraper conveyor, and finally to an outdoor silo before being transferred to trucks for sale to third parties.

Ash from the economizer hoppers is pneumatically conveyed to the fly ash storage silos, and pyrites (rejected from the coal pulverizers) are conveyed using water on a periodic basis to the dewatering system (i.e., dewatering bins) for off-site removal by truck.

Wet sluicing for the pyrite system is being considered as a risk mitigation measure to avoid accidental ignition of combustible materials clinging to the mill rejects. The water from the submerged flight conveyor can be used in this system as a closed loop to reduce water usage. This can also come into effect when a mill trips and the contained solids need to be safely removed from the mills. This system will be further evaluated for the possibility of pneumatic conveying (dry handling).

3.4.4.6 Steam Turbine

The proposed steam turbine is a Doosan DST-S20 condensing steam turbine with reheat capabilities. The steam conditions are 3,500 psi and 1,112°F main steam/1,112°F reheat steam at steam turbine inlet. The steam turbine will be configured as a tandem compound two-flow machine featuring a combined HP-IP casing with a two-flow low-pressure turbine. The HP-IP casing has a horizontally split design with two shells. Steam entering into the HP inner casing is conducted into the circular duct or nozzle chambers, which are cast in the inner casing. The HP steam flows toward the front-bearing pedestal. The inlet connections are sealed in the inlet section of the nozzle chambers with special sealing rings. The reheat steam enters the IP inner casing via two inlet connections in the lower and upper halves of the outer casing. Steam entering into the IP inner casing is conducted into the circular duct. The IP steam flows toward the LP casing. The inlet connections are sealed in the inner casing in manner similar to the live steam inlet into the HP section of the turbine. The LP casing is a double-flow, double-shell design. The outer and inner casings are a welded design. Steam from the IP turbine is introduced through two crossover pipelines into the inlet that is equipped with the expansion joint and then into a circular duct in the inner LP casing. The walls of the outer LP casing form a rectangular exhaust hood. The LP casing’s lower half is welded on to the exhaust neck. Welded brackets on the periphery of the outer casing enable it to be setup on the foundation.

The extraction branches are situated in the lower half of the inner turbine casing, and they are led out through the condenser neck to regenerative heaters. The exhaust annulus is equipped with a spray cooling system, which is used when the quantity of steam passing through the rear section is low and the associated ventilation losses of the blades increase the temperature to about 194°F (typically during low-load or no-load operation).

3.4.4.7 Gas Turbine

The proposed gas turbine has an 87-MW power output capability and is configured as a single-shaft, bolted rotor with the generator connected to the gas turbine through a speed-reduction gear at the compressor or “cold” end. This feature allows for an axial exhaust path to optimize the plant arrangement for combined cycle. An 87-MW class GE 6F03 model is applied for the concept development and preFEED study. The major features of the gas turbine are described below.

The compressor is an 18-stage axial flow design with one row of modulating inlet guide vanes and a pressure ratio of 15.8:1 in ISO (Standard) conditions. Inter-stage extraction is used for cooling and sealing air (turbine nozzles, wheel spaces) and for compressor surge control during startup/shutdown.

A reverse-flow, six-chamber, second-generation dry low-NO_x (DLN-2.6) combustion system comes standard with six fuel nozzles per chamber. Two retractable spark plugs and four flame detectors are a standard part of the combustion system. Crossfire tubes connect each combustion chamber to adjacent chambers on both sides. Transition pieces are cooled by air impingement. Thermal barrier coatings are applied to the inner walls of the combustion liners and transition pieces for longer inspection intervals. Each chamber, liner, and transition piece can be individually replaced.

The turbine section has three stages with air cooling on all three nozzle stages and the first and second bucket stages. The first stage bucket has an advanced cooling system to withstand the higher firing temperature. It uses turbulated serpentine passages with cooling air discharging through the tip, leading, and trailing edges. The buckets are designed with long shanks to isolate the turbine wheel rim from the hot gas path, and integral tip shrouds are incorporated on the second and third stages to address bucket fatigue concerns and improve heat rate. The first stage has a separate, two-piece casing shroud that permits reduced tip clearances. The rotor is a single-shaft, two-bearing design with high-torque capability that incorporates internal air cooling for the turbine section.

3.4.4.8 Electrical Equipment with High Turndown

The proposed electrical equipment system can be broken down into three main parts: the station substation for interconnection to the electrical grid; the in-plant distribution system for powering the plant equipment; and the distribution system for powering the AQCS and CO_2 capture systems.

The station substation will consist of three step-up transformers: one for the combustion turbine generator, one for the steam turbine generator, and one for the energy storage system (ESS). The step-up transformers (GSU1, GSU2, and BSU) will convert the generator output voltages and the ESS output voltage to the grid voltage level of 345kV. The grid voltage level was referenced from the DOE pilot plant documentation and can be modified to the correct utility voltage level when the final plant site location is determined. During startup conditions, synchronizing relays will be used to close the generator circuit breakers to help ensure the generation sources are properly synced with the electrical grid.

The steam turbine generator will also power a station auxiliary transformer (SAT1) that will provide power for in-plant equipment loads. The SAT1 transformer will deliver 4160V power to the plant switchgear. The 4160V distribution system will provide power to multiple station auxiliary transformers and charging services to the ESS system. The auxiliary transformers will supply power to 480V motor control centers (MCCs) for distribution to the plant equipment.

Power for exceptionally large station loads, like the AQCS and CO_2 capture systems, will be provided from the electrical grid via a reserve auxiliary transformer (RAT1) and 13.8kV distribution switchgear. The 13.8kV distribution system will provide power to multiple reserve auxiliary Transformers that will deliver power to the AQCS 4160V switchgear and multiple 480V MCCs.

The distribution system will use the most current technology to minimize wiring and maximize control flexibility. Smart MCCs and variable frequency drives (VFD) will provide the most efficient use of distribution power. The use of VFDs on select electrical equipment will allow the plant to achieve a high turn-down ratio and effectively throttle the plant down to the limitations of the mechanical system.

3.4.4.9 Energy Storage System

The proposed energy storage system is a 50-MW modular Lithium Ion / Vanadium Redox Hybrid System that uses lithium and vanadium ions. The ESS will be designed to store energy from the nearby renewable power generation source as well as surplus power from HGCC plant. The ESS will also be designed to take care of the frequency control function for stabilization of the grid when renewable generation fluctuates. The Lithium Ion / Vanadium Redox Hybrid System has longer storage durations, a longer life cycle, and is easier to scale up than a lithium ion battery. The 50-MW ESS will have 50-MWh capacity with a 1-hour discharge and charge time. It will effectively cover the initial startup and load-following when renewable power is lost and before gas turbine ramp up is complete—a 30-minute duration. The ESS has an expected a 20-year life and operation capability of 8,000 cycles.

3.4.4.10 Environmental Controls

Bituminous coal serves as the base case for this study; however, the AQCS proposed method is applicable to each coal type listed in Section 1.0.

Hg Control

Hg control will be achieved using activated carbon injection upstream of the air preheater. Since the non-leakage gas-to-gas heater (GGH) cooler is located before the dry ESP, this is a cold ESP (flue gas temperature ranges from 194 to 212ºF) that has better mercury removal efficiency.

SO_x Control

To prepare the flue gas for amine-based carbon capture, the FGD/EME will be optimized to reduce SO_2 to less than 4 ppmv at the outlet of the EME. Preliminary performance results of the equipment show that this can be achieved without the need for an additional FGD polisher. A direct contact cooler will be installed downstream of the FGD to drop flue gas temperatures to optimal levels (~35°C) for PCC. This may eliminate the need for lime injection, which is known to lower fly ash resistivity.

SO_2 emissions will be controlled by a wet limestone FGD, and SO_3 will be controlled by both the EME and FGD. Additional $DeSO_x$ control, with a one-stage sieve tray and one-stage Vortex™ tray (newly developed by Doosan Lenjtes), will be added to meet the 4 ppm SO_2 target. The SO_2 to SO_3 conversion rate is expected to be less than 1%. The EME, which was developed by DHI, uses wet ESP technology. The EMEs are installed after a one-stage mist eliminator (ME) on top of the absorber. The EME is compact with a higher efficiency, a lower operating cost, and a greater than 90% reduction efficiency. More details are provided in Section 4.3.3.

NO_x Control

An SCR-deNO_x system, with >90% NO_x reduction efficiency, is installed before the GAH (Gas Air Heater) to reduce the NO_x flue gas concentration to less than 10 ppm. The optimum operating temperatures for SCR units using a base-metal oxide catalyst ranges from 600°F to 750°F. The inlet flue gas temperature to the SCR unit at the minimum load should be higher than 572°F.

PM Control

A dust reduction efficiency of more than 99% is targeted for the ESP. A non-leakage (NL)-GGH cooler is proposed to be placed before the dry ESP, since the ESP has the best efficiency at 194°F to 212°F.

PM_{10} will be controlled by an EME in combination with a wet limestone FGD absorber. The EME has a removal efficiency of 95% for PM greater than 0.7µm and 70% for PM of 0.3µm or less. The EME has the same performance as a bag house (99^+) for PM_{10} removal. PM_{10} and $PM_{2.5}$ can be effectively reduced to 0.5 mg/Nm^3.

CO_2 Control

The proposed concept for carbon capture will evaluate the amine-based Post Combustion Carbon (PCC) capture as the base case.

Carbon Capture Plant Requirements and Performance

Preliminary amine-based PCC plant requirements include an absorber with an inlet temperature of 95°F and outlet temperature of 113°F. The system also includes a 2.5 MJ/kg CO_2 reboiler with a steam requirement of 125.7 lb/s, an inlet temperature of 510.8°F, and outlet temperature of 303.8°F. The upstream ESP and FGD efficiencies are expected to be 99% and 90% respectively and the carbon capture rate is assumed to be 90%. To avoid solvent degradation, it is assumed that the maximum allowable SO_2 inlet is 4 ppmv. The resulting CO_2 product will be greater than 99.9% vol. CO_2 and 0.1% vol. H_2O at a flow rate of 119 lb/s, a temperature of 104°F, and a pressure of 2,200 psi. One key aspect of flexible operation for post-combustion capture plants is steam availability and the conditions necessary to regenerate the solvent.

Uncontrolled steam extraction (floating pressure) to supply the reboiler is preferred over controlled extraction by throttling the low pressure turbine inlet, since it improves full- and part-load performance. There are limitations for regeneration at partial load, since the floating pressure integration leads to steam pressures that are too low for additional solvent regeneration. The insertion of a butterfly valve in the IP-LP crossover downstream of the steam extraction point allows steam throttling at reduced loads, which provides steam with enough energy to continue capture operations at full capacity. This increases the operational flexibility of the power plant by allowing it to respond to load demand changes but has a negative impact on overall system efficiency. This design technology is adopted for the HGCC concept.

The required reboiler steam flow at 30% load is 62.9 lb/s with an inlet temperature of 501.7°F, which is about 50% of design flow and 100% of design temperature. This unbalanced load steam requirement can be met in the current proposed boiler and turbine concept design.

The vapor phase amine concentration at the outlet of the absorber is controlled with two wash sections. The washing sections are located immediately above the CO_2 absorber section. A chimney tray to cool the treated flue gas to recover entrained solvent and remove solvent degradation components separates the sections. Wash water is introduced at the top of a single metal packed bed. The rising treated flue gas comes into contact with recirculating wash water flowing in a counter-current direction. Due to the large interfacial surface area associated with structured packing, both gas cooling and recovery of solvent carryover from the absorption section are maximized. As the treated flue gas is cooled within the washing section of the column, solvent carryover and flue gas moisture are condensed out of the vapor phase. Most of the evaporated solvent is recovered in the first wash section (>99% recovery). The cooled CO_2 –lean off-gas exits the top of the absorber water wash section and is directed to the second wash section. The second wash section behaves in much the same way as the first and its primary function is reduction of ammonia. Following the second wash section the final treated off-gas leaves the absorber column through a wire mesh type demister.

Requirement for AQCS to PCC Connection

The PCC plant requires some flue-gas upstream processing in coal-fired applications due to the detrimental impact of acid gas components on the solvent life. These components in the flue gas, such as SO_2, SO_3, NO_2, and halides, react with the solvents to produce unreactive heat stable salts (HSS), which have to be removed or converted back to amine. It is normally recommended that the inlet SO_2 concentration of the PCC plant must be less than 4 ppmv. NO_x reduction technologies are anticipated to be sufficient to minimize the impact of nitrate salt formation. Optimal PCC performance is achieved at relatively low flue-gas temperature (i.e., 86°F to 104°F), with a typical operating temperature of 95°F. A direct contact cooler (DCC) is installed downstream of the FGD to cool the flue gas from the typical main FGD outlet temperature to achieve the required PCC inlet temperature.

Carbon Capture Integration and Technology Options

Among the various carbon capture technologies, amine base absorption technology is the most proven technology, but it requires a significant amount of heat for absorbent regeneration. Calcium/sorbent looping adsorption technologies such as CACHYS™ have some technological benefit, such as lower energy penalties, because it includes an exothermic carbonation reaction. But, it has much lower technology readiness level (TRL) than amine base PCC. Cryogenic distillation technology requires CO_2 concentration and high cooling energy.

The preFEED design includes an advanced amine base absorption PCC technology with reduced energy consumption will be applied for HGCC plant. The reboiler energy consumption is reduced to 2.5 MJ/kg CO_2 level by applying the Doosan Babcock internal integration technologies. Steam for the reboiler is extracted from the LP cross-over pipe. Unused energy from the reboiler will be recovered at the deaerator. CO_2 compression heat will be recovered by heating feed water to increase plant efficiency. Alternative integration options to reduce the performance decrease by the PCC process will be investigated.

Carbon Compression and Utilization

The boundary limits of this concept and the preFEED study end with the compressed CO_2. The compressor under consideration uses a 6-stage variable diffuser-guide vane technology with high turndown capability. A recirculation loop is also being considered to aid in higher turndown and flexibility for the plant. The compressors (3 x 50%) will be modularized to be shipped on a skid with components prewired and installed. This unit will compress approximately 50 kg/s carbon dioxide from 29 psia to 2200 psia for carbon dioxide storage and pipeline transportation.

ZLD System

Wastewater from the flue gas cleanup will be sent to a zero liquid discharge system or ZLD. The concentrated water chemistry of the purge stream poses a challenge for the reverse osmosis (RO) system. The design case for this system uses a pretreatment and a straight evaporation system. The thermal system will have two steps: a brine concentration and a crystallizer. Due to the flow and chemistry, it is much more convenient to run the brine crystallizer with electricity and the crystallizer with steam. The distillate from the crystallizer is sent back as part of the condensate return. Softening solids from a filter press and concentrated solids from the crystallizer are sent to a landfill. The pretreatment includes pretreatment for hardness removal to eliminate scaling concerns due to high sulfates.

The ZLD system is divided into softening/ultra-filtration pretreatment, RO for brine concentrating, and a mechanical vapor recompression crystallizer requiring a small amount of startup steam initially. The RO permeate and distillate from the crystallizer are sent back as part of condensate return. Softening solids from a filter press and concentrated solids from the crystallizer are landfilled. The RO system will include pretreatment for hardness removal eliminating scaling concerns due to high sulfates.

3.4.4.11 Water Use

Water consumption is estimated at 2 million gallons per day. Most of the consumptive use is for cooling tower make up, with blowdown routed to treatment discussed in the next section. Water consumption is minimized by the use of a cooling tower versus once-through cooling and internal recycling of water where possible.

- Boiler feedwater (BFW) blowdown and air separation unit (ASU) knockout were assumed to be treated and recycled to the cooling tower.
- Water from the flight scraper conveyor will be circulated with the pyrite removal system in a closed loop to reduce water consumption.
- The cooling tower blowdown is sent to the FGD system. The purge on the FGD is sent to wastewater treatment and zero liquid discharge processing. The distillate and treated water from the treatment system will be reused back to the system.
- PCCC Plant Cooling - Areas of the plant that have the potential to contain solvent (through heat exchanger leakage for example) are served by a dedicated closed loop cooling system. The closed loop acts as a barrier to prevent the potential of solvent leakage into the wider power plant cooling systems. The closed loop system is monitored for traces of solvent so that water can be drained and disposed of if a lead is detected. The CO_2 compression and dehydration island cooling is integrated with the wider power plant system.

In the PCC, the direct contact cooling (DCC) water system is a closed-loop direct cooling configuration with a heat exchanger used to reject heat to the capture plant system closed circuit cooling water. Although the DCC re-circulating water will be initially charged using demineralized water, the cooling of flue gas condenses a portion of the water vapor present in the saturated inlet flue gas. This condensate must therefore be removed to prevent accumulation. The water level in the sump at the base of the column is maintained by discharging water to the make-up systems for the PCCC plant make-up. The DCC contributes mostly towards maintaining the water balance in the PCCC plant by utilizing the water condensed during the flue gas cooling process. A portion of this water (which is 10,000-50,000 kg/hr) is discharged from the PCC and sent to the makeup water system to be treated and reused.

- The cooling tower load includes the condenser, capture process heat rejected to cooling water, the CO_2 compressor intercooler load, and other miscellaneous cooling loads.

- The largest consumer of raw water in all cases is cooling tower makeup. The HGCC concept uses a mechanical draft, evaporative cooling tower. The design ambient wet bulb temperature of 11°C (51.5°F) was used to achieve a cooling water temperature of 16°C (60°F) using an approach of 5°C (8.5°F). The cooling water range was assumed to be 11°C (20°F). The cooling tower makeup rate was determined using the following information obtained from vendors:
    - Evaporative losses 2000 gpm
    - Drift losses of 0.001% of the circulating water flow rate
    - Blowdown losses (BDL) were calculated assuming eight (8) cycles of concentration

3.4.4.12 Liquid Discharge

The final effluent limitation guideline (ELG) rule established new wastewater categories and discharge limits and updated discharge requirements for existing wastewater categories. The following are the new or updated categories in the rule:

- Flue gas desulfurization (FGD) wastewater
- Fly ash transport water
- Bottom ash transport water
- Landfill leachate
- Flue gas mercury control wastewater
- Non-chemical metal cleaning wastewater

Both fly ash and bottom ash handling systems are considered dry and do not result in a water stream requiring treatment under ELG. Similarly, the flue gas mercury control approach by carbon injection does not generate a water stream for treatment. Runoff or drainage from solid piles (coal, limestone, ash, gypsum) and unloading will be captured and treated in the wastewater treatment and ZLD systems. Saleability of the CO_2 system precoat waste, crystallized brine, and wastewater sludge will be reviewed with further engineering, but currently they are considered waste to be landfilled. Bottom ash, gypsum, and fly ash are considered saleable.

3.4.4.13 Solid Waste

Solid waste includes fly ash and gypsum, which are saleable. Precoat (amine system) waste from flue gas clean up and solids from the wastewater treatment and ZLD are collected and landfilled.

The salt cake from the ZLD system is anticipated to be sent to an industrial landfill. This would not be considered a hazardous waste. We used the cost in O&M to reflect this from the Case B12B 2019 report as $38/ton. The leachate from this cake would be considered corrosive but we have not evaluated how the landfill would handle this waste. This product has the potential for beneficial reuse such as de-icing and commercialization as salt as well as chloro-alkali processes. However, this value engineering was not considered for this project based on the progress in technology and current economic considerations.

3.5 Project Execution

A project execution presentation is provided in Appendix G. The host utility for the FEED study has been identified as City, Water, Light, and Power with the City of Springfield. It describes the project timeline from the end of the preFEED study phase through the FEED study and design / procurement / construction of a greenfield commercialized plant by 2030. The following necessary steps are also discussed within the presentation:

- Non-commercial component development
- Site selection
- Permitting
- Commercialization
- Detailed design

3.5.1 List of Components Not Commercially Available

Equipment Item	preFEED Preliminary Development for FEED Study Completion
GT gas combustion coal burner	Coal burner development for NO_x 150 ppm and maximum O_2 level of 3.5% at boiler exit with 30% gas turbine exhaust combustion co-firing. DHI will supply the burners with design considerations identified during the FEED study.
Fast startup USC boiler model	Advanced boiler model to minimize full load startup time after weekly shutdown. Drainable superheater with advanced control system/logic would be required.
Low-load operation USC steam turbine model with PCC	Steam turbine can run down to 20% and provide steam for PCC.
Low energy and low cost PCC	Amine base PCC with reboiler heat duty level of 2.0 MJ/kg CO_2 and 30% cost down by modularization.
ESS Battery	Reductions in capital cost and O&M costs. Improvements to efficiency, improvements to longevity.
USC boiler indirect firing system	Integrating the Indirect Firing System into a new burner system.
USC boiler/combustion turbine	Integrating the combustion turbine exhaust into the boiler proper and overfired air system.
Flue gas heat recovery	Integrating two additional heat exchangers to recover heat from the flue gas for use in the condensate/feedwater heater cycle.

3.5.2 Sparing Philosophy

Because our concept uses advanced process controls, has the ability to provide high ramp rates and turndown, and will not be expected to run at full load continuously, the sparing philosophy of this plant is based on including full redundancy at 50%, but at 100% there is no redundancy.

Single trains are used throughout the design, except where equipment capacity requires an additional train. There is no redundancy other than normal sparing of rotating equipment. Certain critical systems, such as coal milling equipment, are included to provide 100% redundancy at full load. The plant design consists of the following major subsystems:

- Three (3x50%) coal milling systems/pulverizers
- One dry-bottom, Variable Pressure Once-through USC boiler (1 x 100%) with burners
- One SCR reactors (1 x 100%)
- One ACI system (1 x 100%)
- One Electrostatic Precipitator (1 x 100%)
- One wet limestone forced oxidation positive pressure absorber (1 x 100%)
- One steam turbine (1 x 100%)
- One CO_2 absorption system, consisting of an absorber, stripper, and ancillary equipment (1 x 100%) and three CO_2 compression systems (3 x 50%)

3.5.3 Techniques to Reduce Design, Construction, and Commissioning Schedules

State-of-the-art design technology, such as digital twin and 3D modeling and dynamic simulation, at the design stage will be applied to improve power plant reliability and reduce construction time. The field welding points of high pressure components will be reduced as much as possible, and a standard-size boiler will be applied to reduce construction cost. Additionally, a modularization approach will be used as much as possible during the FEED study stage to reduce the construction time. The energy storage system batteries are a modular concept to reduce installation costs and easily increase storage capacity.

Many existing power plants or prospective plant sites are on or near major waterways. Using barges, where possible, will allow large pieces of equipment such as vessels, boiler components, etc. to be fabricated off-site and shipped in large pieces.

Tactics to reduce design, construction, and commissioning schedules from conventional norms include:

- Complete boiler modularization characteristics (e.g., shop fabrication of equipment or subsystems, or laydown area pre-assembly, in whole or part)
    - Combustion turbine – ships as a complete unit
    - Boiler and accessories
- Environmental control systems – each system is composed of modules
- ESS Battery system – ships as a complete unit for assembly in the field
- Factory modularization of CO_2 compressors
- Field modularization of cooling tower has been considered but due to significant reduction in size a field erected tower is included in the basis
- Skid-mounted assemblies with piping and control wiring and junction boxes whenever possible
- Pre-assembly of major piping components
- Prefabricated electrical building with major equipment wired and preassembled
- CFD and 3D modeling
- Advanced process engineering such as using heat balances to optimize the thermal efficiency

- Demonstrate in existing power plants and repurpose existing infrastructure, such as coal handling and cooling water systems

- Continuous analysis of coal delivered to the plant using a full stream elemental analyzer to blend coals based on projected impacts on plant performance

- One equipment manufacturer to streamline commissioning

- Achieve loads that correlate with the renewable market in the year 2050

- Demonstration pathway to completion of pilot-scale testing by 2030 with potential market penetration in the 2030-timeframe

3.5.3.1 EPC Approach

Discussions with engineering, procurement, and construction companies (EPC) have been completed and final selection was completed during the preFEED study. Kiewit has been selected to be in the role of EPC for this plant and a letter of commitment has been submitted by the EPC. A memo of understanding has been prepared detailing the role of the selected EPC during the remainder of the preFEED study and, if awarded, their role within the FEED study. In addition to preparing the memo of understanding, the EPC will facilitate host site investigations and selection for the HGCC concept. The following is a preliminary summary of the EPC scope (subject to change):

- Partner with DOE Coal FIRST initiative for engineering, procurement, and construction

- Provide engineering input as part of the FEED study

- Coordinate with Doosan as original equipment manufacturer (OEM)

- Provide FEED-level engineering design and construction fee estimating of the HGCC concept

- Provide commercialization plan at the end of the FEED study

- Host site selection support

3.5.4 Reliability and Capital Cost Criteria

Coal FIRST plants of the future should exhibit approaches to increase reliability and lower capital costs when compared to current alternatives.

3.5.4.1 Reliability

Most current coal plants use two scheduled outages (spring and fall) to reduce the number of forced outages during the winter and summer peak electrical use times. The Coal FIRST design will have a target design of one scheduled outage per year. The design will incorporate robust equipment designs combined with an artificial intelligence (AI) capability to allow for longer run times than are currently possible. This AI capability would include coal-quality monitoring along with specific equipment monitoring to allow plant operators to know the up-to-date condition of the equipment (using the DOE Cross Cutting Research Program) and to minimize fouling.

4.0 Performance Results Report and Technology Gap Discussion

4.1 Plant Performance Targets

4.1.1 General Plant Requirements

The proposed concept meets specific design criteria in the RFP as follows:

- Overall plant efficiency of 43% with ESS, 37% without ESS (RFP value 40% without carbon capture).
- Using a modular approach as much as possible.
- Near-zero emissions using a combination of advanced air quality control systems (electrostatic precipitator (ESP), wet flue gas desulfurization system (FGD), selective catalytic reduction (SCR) for NO_x control) that make the flue gas ready for traditional post-combustion carbon-capture technology.
- Capable of high ramp rates (expected 6% versus RFP 4%) and minimum loads (expected better than 5:1 target).
- Integrated energy storage system (ESS) with 50 MW Lithium Ion / Vanadium Redox Hybrid System.
- Minimized water consumption by the use of a cooling tower versus once-through cooling, and internal recycling of water where possible.
- Design and commissioning schedules shortened by using state-of-the-art design technology, such as digital twin, 3D modeling, and dynamic simulation.
- Enhanced maintenance features to improve monitoring and diagnostics such as coal-quality impact modeling and monitoring, advanced sensors, and controls.
- Integration with coal upgrading or other plant value streams (co-production). Potential for rare earth element extraction in the raw coal feed stage.
- Natural gas co-firing is an integral part of the design with the gas turbine responsible for nearly a quarter of direct power output. The gas turbine exhaust is used to assist with heating the coal-fired steam boiler.

Table 4-1 General Plant Requirements

Total Plant Output and Turndown with Full Environmental Compliance (From Addendum 1 RFP)		Proposed Plant Target
Target	>5:1	>5:1
Total Plant Ramp Rates (From Addendum 1 RFP)		**Proposed Plant Target**
Target	>4% max load/minute	>6% max load/minute
Time to Max Load	<2 hours	ESS 50 MW immediate, combustion turbine 86 MW in 30 min, full load from cold 6-9 hours Warm start 3-4 hours to full load.
Co-Firing Ability (From Addendum 1 RFP)		**Proposed Plant Target**
Target	<30% Natural Gas Heat Input	<30% Natural Gas Average Heat Input

4.1.2 Water Requirements

Table 4-2 Water Requirements

Target Plant Water Daily Average Suggested Target		Proposed Plant Target
Raw Water Withdrawal	<14 (gpm)/MWnet	<9 (gpm)/MWnet <13 (gpm)/MWnet (w/o ESS)
Raw Water Consumption	<10 (gpm)/MWnet	<8 (gpm)/MWnet <10 (gpm)/MWnet (w/o ESS)

4.1.3 System Size Basis

Table 4-3 System Size Requirements

Plant Size Basis (From Addendum 1 RFP)		Proposed Plant Target
Key Component Modularized	As much as possible	As much as possible (includes factory and field modularization, skid-mounted and prefab piping/wiring as much as possible)
Maximum Power	50MWe–350 MWe	350 MWe Net
Maximum Plant Efficiency (w/o CCS parasitic load)	>40%	>40% w/o CCS parasitic load >35% with CCS parasitic load

4.1.4 Environmental Targets

Table 4-4 Environmental Targets

Air Pollutant	PC (lb/MWh-gross) (From Addendum 1 RFP)	Proposed Plant Target (lb/MWh-gross)
SO_2	1.00	1.00
NO_x	0.70	0.70
PM (Filterable)	0.09	0.09
Hg	$3x10^{-6}$	$3x10^{-6}$
HCl	0.010	0.010
CO_2	90% Capture	116 lb/MWh-gross (90% Capture)

The output-based emissions limits shown above are specified in the Coal FIRST RFP. While these are reasonable emission limits, case-specific air-quality compliance requirements could drive limit adjustments. Ambient air-quality attainment designations vary across the country; therefore, the ultimate siting of the project will determine the increment of negative air quality impact that is available for new emissions. The carbon capture aspect of the project implies a process that exhausts a cooler residual gas stream to the atmosphere from a stack that is likely lower than a conventional coal plant stack. These stack parameters will be used as inputs to air dispersion modeling, which would be expected to show a dispersion profile different than experienced with a conventional coal-fired stack. Until siting and exhaust stream characteristics are established, it is possible that compliance with air quality standards could drive project design adjustments.

Table 4-5 Solid Waste Requirements

Solid Wastes (Less than Case B12B Equivalent (scaled to 350 MW)		Proposed Plant Target
Bottom Ash Discharge	Saleable, 40 tons/day	Saleable, 40 tons/day
Fly Ash Discharge	Saleable, 170 tons/day	Saleable, 151 tons/day
FGD Gypsum Waste	Saleable, 274 tons/day	Saleable, 230 tons/day
Wastewater Solid Waste	Minimized	20 tons/day
ZLD Crystallized Waste	Minimized	40 tons/day
CO_2 Capture Amine Waste	Saleable, 43 tons/day	1 ton/day

Table 4-6 Liquid Discharge Requirements

<table>
<tr><th colspan="2">Liquid Waste (From Addendum 1 RFP)</th><th>Proposed Plant Target</th></tr>
<tr><td>Wastewater</td><td>None, Zero Liquid Discharge</td><td>None, Zero Liquid Discharge</td></tr>
<tr><td>SCR Catalyst</td><td>None, Zero Liquid Discharge</td><td>None, Zero Liquid Discharge</td></tr>
<tr><td>PCC</td><td>None, Zero Liquid Discharge</td><td>170 tpd (30 gpm) sent to Wastewater Treatment / ZLD
<table>
<tr><td></td><td>PCC Effluent</td></tr>
<tr><td></td><td>lb/hr</td></tr>
<tr><td>H_2O</td><td>15,800</td></tr>
<tr><td>$(NH4)_2SO_4$</td><td>1100</td></tr>
<tr><td>Na_2SO_4</td><td>179</td></tr>
</table>
</td></tr>
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4.1.5 Plant Capacity Factor

Table 4-7 Plant Capacity Factor

Projected Plant Capacity Factor (Used to compare with Case B12B)	
Capacity Factor—based on cost for MWh basis to compare with B12B	85%

4.2 Performance Results Summary

4.2.1 Plant Performance Summary

Table 4-8 Overall Plant Performance Summary

	Overall Performance Summary				
Fuel Type	Bituminous 100% (Base)	Bituminous 50%	Bituminous 30%	Sub-Bituminous	Lignite
Total Gross Power Output, MWe	407.6	135.3	81.1	408.2	354.2
CO_2 Capture/Removal auxiliaries, kWe	5,128	2,763	1,696	5,420	4,979
CO_2 Compression, kWe	17,622	11,339	6,960	19.067	17,123
ZLD System, kWe	1,850	997	612	1,955	1,796
Balance of Plant, kWe	32,974	15,609	9,070	35,109	30,347
Total Auxiliaries, MWe	57.6	30.7	18.3	61.6	54.2
Net Power, MWe	350.0	104.6	62.8	346.6	300.0
HHV Net Plant Efficiency, % with ESS	43.2	29.7	29.1	41.8	40.1
HHV Net Plant Heat Rate with ESS, kJ/kWh (BTU/kWh)	8,342 (7,907)	12,109 (11,477)	12,385 (11,739)	8,620 (8,170)	8,983 (8,515)
LHV Net Plant Efficiency, %	45.7	30.8	30.1	44.3	42.6
LHV Net Plant Heat Rate, kJ/kWh (BTU/kWh)	7,877 (7,466)	11,680 (11,070)	11,945 (11,322)	8,125 (7,701)	8,452 (8,011)

Fuel Type	Overall Performance Summary				
	Bituminous 100% (Base)	Bituminous 50%	Bituminous 30%	Sub-Bituminous	Lignite
HHV Net Plant Efficiency without ESS, %	37.0	29.7	29.1	35.7	34.6
HHV Net Plant Heat Rate without ESS, kJ/kWh (Btu/kWh)	9,739 (9,231)	12,109 (11,477)	12,385 (11,739)	10,080 (9,554)	10,404 (9,861)
HHV Net Plant Efficiency, % w/o CO_2 capture, w/o ESS	43.6%				
HHV Net Plant Heat Rate w/o CO2 capture & w/o ESS kJ/kWh (BTU/kWh)	8,267 (7,835)				
HHV Boiler Efficiency, %	89.7	88.4	91.7	87.6	85.6
LHV Boiler Efficiency, %	92.3	91.6	95.0	90.4	88.1
Steam Turbine Cycle Efficiency, %	56.5	52.2	49.0	56.8	56.4
Steam Turbine Heat Rate, kJ/kWh (BTU/kWh)	6,366 (6,034)	6,892 (6,532)	7,350 (6,967)	6,335 (6,004)	6,382 (6,049)
Condenser Duty (Except PCC), GJ/hr (MMBTU/hr)	896 (849)	439 (416)	295 (280)	902 (855)	762 (722)
As-Received Coal Feed, kg/hr (lb/hr)	72,504 (159,844)	46,732 (103,025)	28,685 (63,239)	102,096 (225,083)	113,119 (249,385)
NG fuel Feed, kg/hr (lb/hr)	18,144 (40,001)	0	0	18,144 (40,001)	18,144 (40,001)
Limestone Sorbent Feed, kg/hr (lb/hr)	7,300 (16,094)				
HHV Thermal Input, kWt (MMBTU/hr)	811,064 (2767)	351,954 (1201)	216,036 (737)	829,939 (2832)	748,624 (2554)
LHV Thermal Input, kWt (MMBTU/hr)	765,849 (2614)	339,466 (1158)	208,371 (711)	782,262 (2669)	704,339 (2403)

Table 4-9 Plant Power Summary

Power Summary					
Coal Type	**Bituminous 100% (Base)**	**Bituminous 50%**	**Bituminous 30%**	**Sub-Bituminous 100%**	**Lignite 100%**
Steam Turbine Power, MWe	270.6	135.3	81.1	271.2	226.5
Gas Turbine Power, MWe	86.8	-	-	86.8	86.8
Battery, MWe	50.2	-	-	50.2	40.9
Total Gross Power, MWe	407.6	135.3	81.1	408.2	354.2
Total Gross Power w/o battery, MWe	357.4			358	313.3
Auxiliary Load Summary					
Ash Handling	700	451	277	986	1,092
Boiler Feed Water Pump	9,168	2,810	1,088	9,169	7,195
Circulating Water Pumps	3,110	1,848	1,242	3,126	2,642
CO2 Capture/Removal Auxiliaries	5,128	2,763	1,696	5,420	4,979
CO2 Capture and Compression	17,622	11,339	6,960	19,067	17,123
Coal Handling and Conveying	201	129	79	283	313
Condensate Pumps	436	137	57	439	359
Cooling Tower Fans	1,788	875	588	1,797	1,519
Dry ESP	3,000	1,617	992	3,171	2,913
Flue Gas Desulfurization/Ox Air Reagent Prep. Gypsum	4700	4703	4704	4705	4706
Forced Draft Fans	567	306	188	574	551
Ground and Service Water Pumps	228	123	75	241	221
GT Auxiliary	420	-	-	420	420
Induced Draft Fans	3,949	2,128	1,306	4,600	3,834
Miscellaneous Balance of Plant[A]	804	471	303	847	776
Primary Air Fans	1,044	563	345	1,488	1,014
Pulverizers	1,411	909	558	1,519	1,635
Reboiler Condensate Pump	184	61	24	193	183
SCR	200	108	66	211	194
Steam Turbine Auxiliaries	233	126	77	246	226
Transformer Losses	830	415	249	832	695
Wastewater Pre-Treatment/ZLD System	1,850	997	612	1,955	1,796
Total Auxiliaries, MWe	57.6	30.7	18.3	61.6	54.2
Net Power, MWe	350.0	104.6	62.8	346.6	300.0
Net Power w/o battery, MWe	300.0			296.4	259.1

A Includes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

4.3 Performance Results Details

4.3.1 Performance Model/Material and Energy Balance

The mass and energy balances around the power block of the system for the steam, flue gas emissions (including boiler and gas turbine), and feedwater systems were modeled in an integrated plant performance calculation tool—UniPlant from Doosan Heavy Industries. The results from the model are included in Appendix D. The full-load carbon capture system mass and energy balance was modeled in Doosan Babcock process simulation software. Doosan Heavy Industries has modeled low-load operation of the power block and steam and flue gas emissions, and the University of North Dakota/Envergex has performed low-load operation modeling of the carbon capture system.

Barr evaluated water, carbon, and other balance-of-plant systems by doing an overall mass balance in Excel, based on vendor-provided information. The environmental systems were specified based on the power block simulations, and vendor information was gathered and integrated into the overall mass balance.

The Hybrid Gas/Coal Concept (HGCC) power plant has a high predicted plant efficiency of 37.0% with PCC. This efficiency can be increased up to 43.2% during peak time by using ESS power charged with surplus power during low demand time and near area renewable power.

The HGCC power plant can use various kind of coals as well as natural gas. This feature can help energy security and flexibility during future fuel market fluctuation. Bituminous and sub-bituminous coal can be burned in a same boiler design with a well proven coal blending technology. In case of the High-Sodium lignite coal firing, a larger boiler is required for the same power output with bituminous. But, the same HGCC boiler can be used if the steam power output is reduced from 270MW to 227MW. The slagging and fouling can be controlled with the reduced heat release rate by this reduced power output and proper selection of boiler tube transverse pitch. The burner system can operate without significant issues using the High-Sodium Lignite coal moisture up to 40% moisture. Plant efficiency using the High-Sodium lignite coals is expected to be approximately 3.1% lower than a bituminous firing. The lignite coal power plant efficiency can be increased if the steam turbine is modified for 227MW power output. Additional coal drying system with waste heat can also increase efficiency.

The HGCC power plant can be applied and have optimum efficiency to all kinds of U.S. coals with small modification of steam turbine and an addition of coal drying system for the High-Sodium lignite coal. Standardization of power output with the same hardware design is a realization of the “Transformative” concept of Coal FIRST which is fundamentally redesigned to change how coal technologies are manufactured. For the power plant construction, it can be more focused on the performance optimization and selection of optimum power output combination selection of modular product. DHI has been putting a great effort on the hardware design for each power plant construction in the past. HGCC power plants with various power generation units of gas turbine and ESS are appropriate to cover the whole U.S. power plant owner needs. The HGCC power plant efficiency can be increased by increasing the main steam and reheat steam temperature more than 600°C. But, the steam temperature of 600°C would be very appropriate for the wide application of the HGCC in the U.S. because some coals may cause issues such as coal ash corrosion at higher steam temperatures.

4.3.2 Water Balance

A water balance was developed as part of the HGCC performance evaluation. Clean water is reused in the system as much as possible. Recycling considerations include:

- A portion of the cooling tower blowdown is used for the limestone slurry makeup that goes to the flue gas desulphurization scrubber and other FGD makeup water.
- The filtrate from dewatering is recirculated back into the scrubber as makeup.
- The carbon capture system produces a clean effluent at the cooler. This effluent is used as makeup to the PCC system, but about 50 gpm can be recirculated back into the overall plant makeup.
- About 24 gpm of condensate from the CO_2 compressors is recirculated back into the overall plant makeup.
- The distillate from the wastewater and ZLD system is recirculated back to the overall plant makeup.

The cooling tower makeup is considered greater than 95% of the overall plant makeup. The cooling tower evaporative losses are the most significant losses of water. The blowdown, which considers eight (8) cycles when using pretreatment addition for cooling tower make-up, is the largest stream that goes to wastewater. Because of the back-pressure requirements of the HGCC system, air-cooled condensers have not been considered as a viable cooling option.

Because the scrubber outlet temperature is expected to range from 50-55°C, the evaporative losses at the FGD system are not significant, and the makeup water requirement is enough for the reclaim recycle and limestone slurry feed. If the outlet temperature of the scrubber unit is higher, more cooling tower blowdown can be fed into the scrubber system as makeup water, while the remaining cooling tower blowdown is sent to the wastewater and ZLD system.

Separate systems for potable water (1 gpm), oil-water separator (3 gpm), and sanitary treatment were considered. These systems were not included in the system water balance and would operate independently of the plant. The stormwater system (estimated at 110 gpm rate) is also considered, but not included in the system water balance. The cost and site layouts for these systems have been considered and are included in Section 5.0 and Appendix E, respectively.

Table 4-10 Water Balance

System	In (GPM)		Out (GPM)		
	Makeup	Recycle from other systems	Emission / Waste	Discharge to Wastewater	Recycle to other Systems
Combustion	400-From Combustion	0	0	0	400 - FGD water vapor
Water System - Cooling Tower, Service Water, Boiler Feedwater	2310	70 (From PCC)	2000 - cooling tower evaporative and drift losses	10 - cooling tower blowdown, & 100 water treatment backwash, pile runoff, drainage	270 - cooling tower blowdown to FGD
FGD Scrubber	0	670	20 - gypsum moisture and bonded water	70-FGD purge	580 - to PCC water vapor
PCC System	0	580	480- stack water vapor, PCC effluent	30 (Liquid Effluent)	70 - to HGCC makeup water
Total Before WW	**2710-400=2310**	**1320**	**2500**	**210**	**1320**
Wastewater Treatment / ZLD	0	210	42		168 - to HGCC makeup water
Overall Plant Water	**2142**	**168**	**2542**		

4.3.3 Steady State Emissions Data

The environmental targets for emissions of Hg, NO_x, SO_2, and PM were presented in Section 4.1.4. A summary of plant air emissions is presented in Table 4-11. SO_2 emissions are used as a surrogate for HCl emissions; therefore, HCl is not reported.

Table 4-11 Air Emissions

Pollutant	Bituminous TMCR at 85% Capacity Factor Kg/GJ (lb/MMBTU) (gross output)	Bituminous TMCR at 85% Capacity Factor Tonne/year (ton/year at 85% capacity factor)	Bituminous TMCR at 85% Capacity Factor Kg/MWh (lb/MWh) (gross output-unless specified other)	Subbituminous TMCR at 85% Capacity Factor Kg/MWh (lb/MWh) (gross output-unless specified other)	Lignite TMCR at 85% Capacity Factor Kg/MWh (lb/MWh) (gross output-unless specified other)	Bituminous TMCR at 85% Capacity Factor PPMDV (6% O_2)
SO_2	0.000 (0.000)	0.000 (0.000)	0.000 (0.000)	0	0	0
NO_x	0.007 (0.015)	148.6 (163.8)	0.056 (0.123)	0.059 (0.129)	0.062 (0.137)	10
SO_3	0.000 (0.000)	0.000 (0.000)	0.000 (0.000)	0	0	0
Particulate	0.0003 (0.0007)	6 (6.6)	0.002 (0.005)	0	0	0
Hg		0.0034 (0.0037)	$9.2x10^{-7}$ ($2.0x10^{-6}$)	0	0	0
CO_2 (gross output)	7(16)	167,616 (184,765)	63 (139)	67 (149)	69 (153)	13,970
CO_2 (net output)	-	-	75 (166)			13,970
Pollutant	**mg/Nm³**					
Particulate Concentration	<2 (after FGD at 32°F and 14.696 psia)					

NO_x emissions from the boiler are anticipated to be below 150 ppm for bituminous coal firing using low NO_x burners and overfire air (OFA). It is further reduced to less than 10 ppm with the SCR system.

The temperature of the flue gas leading up to the gas-gas cooler (GGC) will be maintained higher than the acid dew point (~130-140°C), maintaining SO_3 in the gas phase. We, therefore, do not expect corrosion or fouling issues in the air-preheater or the feed-water heater HX.

Within the GGC, the flue gas is cooled to ~95°C, condensing a significant portion of the SO_3. Considering the bituminous coal composition, there is sufficient fly ash loading in the flue gas, where most of condensed SO_3 will be deposited. The SO_3 will adhere to the ash particles predominantly, and not on the tube surface, because of the much higher surface area of the fly ash. Some of the ash (with the condensed SO_3) will find its way to the heat exchange surfaces of the GGC. The GGC is also equipped with aggressive soot-blowing functionality and complete soot-blowing coverage, to periodically clean the heat exchange surfaces in an effective fashion, allowing the HX to perform per design.

The GGC is installed ahead of the low temperature dry ESP, which is also designed with ash collection and discharge that can handle the SO_3-coated ash. While earlier design guidelines may have been conservative with respect to acid dew points and heat exchanger operation, recent experiences in both Korea and China, provide sufficient data and details for the GGC design in the context of a low-temperature ESP (< 100oC),[xvii xviii]and provide the confidence that the GGC component can be operated reliably and meet performance targets (i.e., achieve low exit flue gas temperatures of ~90-100°C). Such operation is necessary to achieve the ultra-low emissions of particulate (<5 mg/Nm3) and acid gases. Additionally, materials of construction of the GGC (NL GGH Cooler) include sulfuric acid resistant material and a phenolic coating to combat any potential corrosion issues.

SO_2 and Hg will be reduced to near zero by the wet FGD and new two-stage electrostatic mist eliminator (EME) technology. At the exit of the FGD, SO_2 concentration will be less than 15 ppm. The EME technology targets high-efficiency removal of pollutants via two steps: first, via the application of a micro spraying system that provides a very large number of reactive droplets and, consequently, a high surface area (10x versus the standard) to counteract the challenge of low SO_2 concentrations at the exit of the FGD; and second, by incorporating a two-stage wet ESP (EME) for collection of the fine droplets with very high efficiency.

The EME is also very effective for particulate matter (PM), SO_3, and Hg reduction. It has >99% removal efficiency for PM bigger than 0.7 µm and >70% for 0.3 µm or less. Therefore, EME has the same performance characteristics as a baghouse for PM10 removal.

In our AQCS system, a non-leakage gas-gas heat exchanger (GGH) is located before the dry ESP. Thus, this system includes a cold ESP, which has better removal efficiency of mercury. In addition, the majority of mercury in bituminous-fired boilers exists as Hg^{2+}, which is soluble. Most Hg^{2+} that is not removed in the ESP is captured by the wet FGD and additionally by the EME, which uses wet ESP technology to remove Hg^{2+} and Hg-PM. In the case of a sub-bituminous coal firing, Hg^0 exists in gaseous form. The SCR catalyst will oxidize a portion of the Hg^0 to Hg^{2+}. This can be further supplemented with a trace bromide/iodide addition to the coal-fired boiler, as necessary, to completely oxidize the mercury. The EME will also remove condensable PM such as SO_3 and HCl to a very high efficiency.

This AQCS system eliminates the need for activated carbon injection and additional sulfur oxide removal additives, which reduce CAPEX investment and OPEX cost.

Table 4-12 Carbon Balance

Carbon In		Carbon Out	
	Kg/hr (lb/hr)		Kg/hr (lb/hr)
Coal	46,200 (101,900)	Stack Gas	6,000 (13,300)
Air (CO_2)	50 (110)	FGD Product	50 (110)
PAC	0 (0)	Fly Ash	120 (270)
FGD Reagent	800 (1,800)	Bottom Ash	20 (50)
Natural Gas	12,500 (27,500)	CO_2 Product	53,300 (117,500)
		CO_2 Dryer Vent	5 (11)
		CO_2 Knockout	28 (62)
Total	59,500 (131,000)	Total	59,500 (131,000)

Table 4-13 Sulfur Balance

	Sulfur In Kg/hr (lb/hr)		Sulfur Out Kg/hr (lb/hr)
Coal	1,800 (4,000)	FGD Product	1540 (3,400)
		Ash / WWT/ZLD	250 (550)
		Stack Gas (SO_2)	5 (10)
Total	1,800 (4,000)	**Total**	1,800 (4,000)

Table 4-14 Solid Waste

Solid Waste	
Bottom Ash Discharge	Saleable, 40 tons/day
Fly Ash Discharge	Saleable, 151 tons/day
FGD Gypsum Waste	Saleable, 230 tons/day
Wastewater Solid Waste	20 tons/day (Sludge)
ZLD Crystallized Waste	40 tons/day
CO_2 Capture Amine Waste	1 ton/day (Reclaimer Waste and Spent Activated Carbon)

Table 4-15 Removal Performance

Pollutant	Technology	Removal Performance
SO_2	Wet Limestone Forced Oxidation Scrubber	99%, 15 ppmv
	Electrostatic Mist Eliminator (EME)	4 ppmv outlet target
	Amine Base CC	<4 ppmv outlet
NO_x	LNBs and OFA	0.09 kg/GJ (0.19 lb/MMBTU)
	SCR	93.3% 0.007 kg/GJ (0.015 lb/MMBTU)
Particulate	Dry ESP	99.9%
Hg	SCR, Wet FGD, EME	97%
CO_2	Amine Base Carbon Capture	90%

4.4 Equipment Summary

Description	Type	Design Condition	Operating Qty.	Spares
PFD-010 COAL DELIVERY, STOCKPILE, AND CRUSHING				
Rail Car Delivery/Rail Dump Pocket	Rail car dump	3000 tph	1	0
Feeders (rail dump pocket)	Vibrating	750 tph each	4	0
Conveyors	Belt	3000 tph each	2	0
Surge Bin with Stacker Boom	Cone bottom	3000 tph	1	0
Feeder (stockpile)	Apron	250 tph	1	0
Conveyor	Belt	250 tph	1	
Surge Bin (crusher feed)	Cone bottom		1	0
Feeder (crusher)	Belt	250 tph	1	0
Crusher	Roll	250 tph	1	0
Feeder (crusher)	Apron	250 tph	1	0
Conveyor w/tramp metal magnet and sampler	Belt	250 tph	1	0
Surge Bin (Full Spectrum Elemental Analyzer feed)	Cone bottom		1	0
Feeder (Full Spectrum Elemental Analyzer feed)	Apron	250 tph	1	0
Conveyor with Full Spectrum Elemental Analyzer	Belt	250 tph	1	0
PFD-011 COAL STORAGE AND PULVERIZATION				
Tripper Conveyor	Belt	250 tph	1	0
Storage Silos	Cone bottom	800 tons total, 40,000 cubic feet total	5	0
Feeders	Vibrating	25 tph each	5	0
Conveyor	Belt	125 tph	1	0
Conveyor with Full Spectrum Elemental Analyzer	Belt	125 tph	1	0

Description	Type	Design Condition	Operating Qty.	Spares
Tripper Conveyor	Belt	125 tph	1	0
Storage for CO_2			1	0
Indirect Firing System				
Coal Bunkers	Cone bottom	400 ton each	2	1
Coal Feeder (bunker discharge)			2	1
Pulverizers	Vertical spindle mill		2	1
Cyclones			2	1
Dust collectors	Baghouse		2	1
Drag Chain Feeder (Pulverized Coal)		90 tph	1	0
Primary air fans	Centrifugal		2	1
Airlock (PCB Inlet)	Rotary		1	1
Feeder (pulverized coal)	Screw	25 tph each	3	1
Airlocks (PCB Outlet)	Rotary	25 tph each	3	5
Pulverized Coal Bin	Cone bottom	200 ton each	1	1
Airlocks	Rotary		3	5
Pulverized Coal Pipe (feed to burners)	Pipe		2	1
Hot Gas Generator			2	1
Fresh Air Fan	Centrifugal		2	1
Combustion Air Fan	Centrifugal		2	1
Seal Air Fan	Centrifugal		2	1
Pulverizer Air Re-Circulation Duct			2	1
Pulverizer Air By-Pass Duct(Vent Line)			2	1
Pulverized Coal Duct			2	1
Multi-gamma Analyzer			3	1
Pyrite reject system (dewatering tank and pump)	Sluice system	10 TPH capacity; includes pyrites hoppers, water supply pumps, JETPULSION pumps, and conveyor piping	1	0

Description	Type	Design Condition	Operating Qty.	Spares
PFD-012 COMBUSTION				
Boiler including SCR System	Opposed wall-fired, USC, Two-pass radiant-type	210 kg/s superheated steam flow, 251bar/603°C/603°C NO_x reduction at SCR from 150 ppm to 10ppm; 1ppm NH3 slip allowance; Inlet Gas Conditions: 2,197,600 m3/hr gas volume flow, 387 °C temperature, and 750 mmHg pressure	1	0
Forced draft fan	Axial	7,690Am3/min, 5.3kPa	2	0
ID fans (Combined)	Axial	13,700 Am3/min, 11.0kPa (inlet Temp : 90°C)	2	0
Primary Air Fan	Centrifugal	1,800 Am3/min, 14.5kPa	2	0
PC Transport Fan	Centrifugal	1,150 Am3/min, 13.0kPa	3	1
Gas Air Heater	Regenerative	Air flow 120 kg/s, gas flow 130 kg/s(Coal only)	2	0
Bottom Ash Scraper Conveyor (ash handling)	UCC Model 1019 MAX® SFC	Up to 8 hours storage capacity at 1.6 TPH ash generation rate	1	0
Ammonia Storage Injection System	Horizontal tank	220 lb/hr injection rate	1	0
Gas Turbine with bypass stack	GE 6F03 Model	87 MW, natural gas fired, 620°F exhaust temp	1	0
Gas Air Heater			1	0
PFD-013 STEAM TURBINE AND FEEDWATER HEATING				
Steam Turbine	USC, Tandem compound	270 MWe, 242 bar/600ºC/600ºC	1	0
Steam Turbine Generator	Hydrogen cooled, static type excitation	320 MVA, 0.9PF, 18kV, 60Hz, 3-Phase	1	0
Boiler Feed Pump - Electric Driven	Centrifugal	230 kg/s flow; 11.71 Bar(a) pressure; 187 °C temperature; max turndown to 20% of flow (42 kg/s)	2-50% (2 operating at 50% of full load)	0
Condensate Pumps	Centrifugal	1870 gpm flow rate; 380 psi pressure; 94°F condensate max temp	2-50%	

Description	Type	Design Condition	Operating Qty.	Spares
Condenser	Steam driven; bottom steam turbine exhaust interface; two pass; divided waterbox; self-cleaning	830 MbTU/hr heat duty; 83,000 gpm cooling water volume; 888,900 lb/hr steam flow rate; 60°F inlet temp, 80°F outlet temp; 1.5" Hg back pressure	1	0
Condenser Auxiliaries	Stainless Steel Expansion Joint; Basket Tips; Sacrificial Anodes; Tube Installation/Removal Kit (Less Driver); Slide Plates; Startup/Commissioning Spares		1	0
Deaerator w/Storage Tank		4 kg/s, 360°C, 11.5 Bar(a) IPT steam to 210 kg/s, 180°C,10.91 Bar(a) H_2O	1	0
Slipstream Feedwater Heaters - Flue gas		Heater 1: 65 kg/s, 305 bar(a), 190 °C; Heater 2: 111.47kg/s, 26.4 bar(a), 114°C	2	0
Gland Steam Condenser		120 kg/s	1	0
High Pressure Feedwater Heater	Shell and Tube	210 kg/s, 320 bar	4	0
Low Pressure Feedwater Heater	Shell and Tube	160 kg/s, 26 bar	4	0
Energy Storage System	Lithium Ion / Vanadium Redox Hybrid System	50 MWe, 50 MWh	1	0
PFD-014 WATER SYSTEM				
Ground Water Pumps	Centrifugal	220 gpm, 75 ft tdh	2x50%	1x50%
Raw Water Pump	Centrifugal	220 gpm, 75 ft tdh	2x50%	1x50%
Makeup Water Tank			1x100%	NA
Makeup Water Transfer Pump	Centrifugal	917 gpm, 35 ft tdh	2x50%	1x100%
Circulating Water Pump	Vertical Turbine Pump	45,000 gpm, 100 ft tdh	6x33%	3x33%
Circulating Water Booster Pump	Centrifugal	25,000gpm, 100 ft tdh	4x50%	2x50%
Closed Cycle Water (CCW) Cooling Heat Exchangers	Shell and Tube	5,000 gpm Circulating Water, 80F Inlet 60F Outlet	4x100%	4x100%
Closed Cycle Cooling Water Pumps	Centrifugal	5,000 gpm, 105 ft tdh	4x100%	4x100%
Cooling Tower	Counter Flow Mechanical Draft			
Cooling Tower Blowdown Pumps		215 gpm, 35 ft tdh	10x10%	1x10
Sodium Hypochlorite Feed Skid			1x100%	NA

Description	Type	Design Condition	Operating Qty.	Spares
Coagulant Feed Skid			1x100%	NA
Mixed Media Filters		80 GPM, 35 tdh	1x100%	1x100%
Fire/Service Water Tank			1x100%	NA
Service Water Pump	Centrifugal	80 gpm, 35 tdh	2x50%	1x50%
Activated carbon filtration		30 gpm	1x100%	1x100%
Cartridge filters		30 gpm	1x100%	1x100%
Anti-Scalant Feed Skid			1x100%	NA
Acid Feed Skid			1x100%	NA
Caustic Feed Skid			1x100%	NA
Reverse Osmosis	1st & 2nd Pass	30 gpm	1x100%	1x100%
Fractional Electro-de-ionization (FEDI)		30 gpm	1x100%	1x100%
PFD-015 AIR QUALITY CONTROL SYSTEMS				
Gas-to-Gas Cooler		330 kg/s, 1200 tph	1-100%	0
Dry Electro Static Precipitator (Dry ESP for fly ash handling)		330 kg/s, 1200 tph	2-50%	0
Fly Ash System	UCC Vacuum System with (2) Model 65-W-72 Filter/Separators, (2) mechanical exhausters, bin vent filter, field-welded 20ft diameter fly ash storage silo, Model 1535 Paddle Mixer/Unloader, and telescopic spout dry unloader	Conveying capacity: 13 TPH up to 500ft		
ID Booster Fan	Axial	330 kg/s, 1200 tph	1-50%	1-50%
Wet FGD System				
Non-leakage type GGH		330 kg/s, 1200 tph	1-100%	0
Limestone feed system (rail dump, bin, day silo)		20 tph	1-100%	0
Limestone Feeders	Weigh Belt-Gravimetric	18,000 lb/hr	1-100%	1-100%
Ball mill with mill classifier	Horizontal Ball Mill with Lube Oil System	18,000 lb/hr	1-100%	1-100%
Mill product tank with agitator	Field-Erected or Pre-Fabricated	55% Slurry, 2,500 GAL	1-100%	1-100%
Slurry tank with agitator	Field-Erected	30% Slurry, 24,000 GAL	1-100%	0
Limestone slurry pumps	Horizontal, Centrifugal	150 GPM	1-100%	1-100%
FGD w/EME	Counter Current, Spray Tower, Trays, EME	330 kg/s, 1188tph	1-100%	0
Absorber Recycle Pumps	Horizontal, Centrifugal	27,000 GPM	3-33%	1-33%
Absorber Bleed Pumps	Horizontal, Centrifugal	300 GPM	1-100%	1-100%

Description	Type	Design Condition	Operating Qty.	Spares
Absorber Agitators	Side Entry		3	0
Oxidation Air Compressors and Lances	Centrifugal or Roots	7,300 cfm, normal, dry	1-100%	1-100%
Primary hydroclone (gypsum) / Launder Box		250 GPM	1 Unit - 6 cyclones	2 cyclones
Secondary hydroclone (gypsum) / Launder Box		80 GPM	1 Unit - 4 cyclones	2 cyclones
Vacuum filter with filtrate receiver and vacuum pump	Horizontal Belt	12 tph	1-100%	1-100%
Filtrate pump	Horizontal, Centrifugal	70 GPM	1-100%	1-100%
Gypsum conveyor	Belt	20 tph	1-100%	1-100%
Purge Tank and Agitator	Field-Erected	13,000 GAL	1-100%	0
Purge Pumps	Horizontal, Centrifugal	70 gpm	1-100%	1-100%
Reclaim water tank and agitator	Field-Erected	48,000 GAL	1-100%	0
Reclaim Water Pumps	Horizontal, Centrifugal	200 GPM	1-100%	1-100%
Makeup Water tank	Field-Erected	56,000 GAL	1-100%	0
Makeup Water Pumps	Horizontal, Centrifugal	250 GPM	6-100%	3-100%
PFD-016 ZERO LIQUID DISCHARGE				
WW Pre-Treatment Lime silo	Equipped with Dust Collector, Vibrating Bin Bottoms		1x100%	NA
WW Pre-Treatment Lime Conveyor	Screw Conveyor		1x100%	NA
WW Pre-Treatment Lime Sluicing Tank			1x100%	NA
WW Pre-Treatment Lime Sluicing Tank Agitator			1x100%	NA
WW Pre-Treatment Lime Sluicing Tank Heater			1x100%	NA
WW Pre-Treatment Lime Slurry Pump		60 gpm	1x100%	1x100%
WW Pre-Treatment Clarifier			1x100%	NA
WW Pre-Treatment Caustic Feed Skid			1x100%	NA
WW Pre-Treatment Sulfuric Feed Acid Skid			1x100%	NA
WW Pre-Treatment Polymer Feed Skid			1x100%	NA
WW Pre-Treatment Clarifier		11 ft Diameter	1x100%	NA
WW Pre-Treatment Filter Press		.75 tph	1x100%	NA
WW Pre-Treatment Feed Pumps		100 gpm Feed	1x100%	1x100%
ZLD Seeded Brine concentrator	Electric Driven Mechanical Vapor Recompression	90 gpm Feed	1x100%	NA
ZLD Forced Circulation Crystallizer	Steam Driven	13 gpm Feed	1x100%	NA

Description	Type	Design Condition	Operating Qty.	Spares
Centrifuge and waste handling		1.4 tph	1x100%	NA
PFD-017 CARBON CAPTURE				
CO_2 Amine System				
Booster Fan	Centrifugal with VFD and Inlet Guide Vane	650 tph	1-50%	1-50%
Flue Gas Cooler / Heat Exchanger	Direct Contact Packed-Bed Column with Counter-current Cooling Water Circuit	1300 tph	1-100%	0
DCC Recirc Cooler			1-100%	0
DCC Cooling water pump	Centrifugal	1300 tph	1-100%	1-100%
Absorber	Doosan Proprietary Solvent , Metal packing, Counter-current column	1260 tph	1-100%	0
Rich Solvent Pump	Centrifugal	2780 tph	1-100%	1-100%
Lean Solvent Pump	Centrifugal	2480 tph	1-100%	1-100%
Lean Solvent Heat Exchanger	Water Cooled	Hot: 2250 tph	20	0
Rich Amine Heat Exchanger	Water Cooled	Cold: 2520 tph		0
Reclaimer		4.6 tph Steam	1-100%	0
Stripper	Packed-bed	2480 tph	1-100%	0
Reboiler	A plate and frame type thermosyphon reboiler/ LP steam	3890 tph	1-100%	0
Wash Pumps (1st stage)	Centrifugal	2470 tph	1-100%	1-100%
Wash Pumps (2nd stage)	Centrifugal	1190 tph	1-100%	1-100%
Wash Water Cooler	Water Cooled		1-100%	0
Precoat Waste Solids and Handling		40 tph	1-100%	1-100%
Gas-to-Gas Heater	Water Transport	1050 tph	1-100%	0
Stack		1050 tph	1-100%	0
CO_2 Product Reflux Vessel		290 tph	1-100%	0
CO_2 Compressor (from 1^{st} stage to 5^{th} stage, each)		110 tph	2-50%	1-50%
CO_2 DEHY System (from 1^{st} stage to 2^{nd} stage, each)	No triethylene glycol	110 tph	2-50%	1-50%
CO_2 Interstage Coolers	Cooling water, 7 stages	110 tph	1-100%	1-100%
CO_2 Compressor Condensate Pump	Centrifugal	70 tph		

Description	Type	Design Condition	Operating Qty.	Spares
CO_2 Purge System	Low pressure "Cardox" System	4 hr CO_2 storage; 150 tons pulverized coal storage; 20 kg/s coal feed rate to burner; 1000-ft storage silo to source		

4.5 Technology Assessment

4.5.1 Technology Summary

The HGCC utilizes state-of-the-art power plant equipment and systems, including:

- USC pulverized coal boiler
- USC steam turbine
- AQCS consisting of SCR, ESP, Wet FGD, and EME
- PCC system and CO_2 compression
- Process controls
- ESS with storing capability from HGCC and nearby renewable source
- Advanced coal property monitoring and management system

The major engineering challenge will be integrating the following six systems into commercially-available hardware.

- *Indirect Coal Firing System.* This system effectively decouples coal mill operation from boiler operation. The advantage of this system is that the boiler turndown and ramp rate are dramatically improved when compared to a traditional pulverized coal boiler. This system mills the coal and stores it in bins, employing a CO_2 gas inerting system to prevent auto-ignition. Similar CO_2 gas inerting systems are deployed in the cement/lime industry and for lignite-fired boilers in Germany. From the bins, the coal is fed into the boiler as load changes. Kidde Fire Systems is currently developing the preliminary CO_2 gas inerting system design for the HGCC concept. Specific details about the Kidde system are discussed in Section 3.4.4.2. DHI will supply the burners with design considerations identified during the FEED study.

  In markets with increasing requirements for the flexible operation of the hard coal and lignite power plants, modifying an existing boiler and installing an indirect firing system in parallel with the conventional direct firing system will allow a reduction of the boiler’s minimum load lower than 30%. In this way, a kind of “idle” operation can be achieved, where the plant stays on the grid at a very low load, providing primary and secondary control services with the ability to ramp up again whenever required by the system operator.

For fuels with high moisture contents, such as a lignite, the indirect firing concept requires heat energy for coal drying during pulverization and handling of the off-gas (vapors) from the dryer/pulverizer system. The process scheme of the steam-heated fluidized-bed drying and its integration in a hybrid firing system is shown in Figure 4-1. The vapor resulting from coal water evaporation is cleaned and partially used for fluidization and heat recovery in the low-pressure preheaters of the power plant. A system similar to that shown has operated for more than 10 years in the Niederaußem K power station (Germany), including a prototype fluidized-bed dryer.

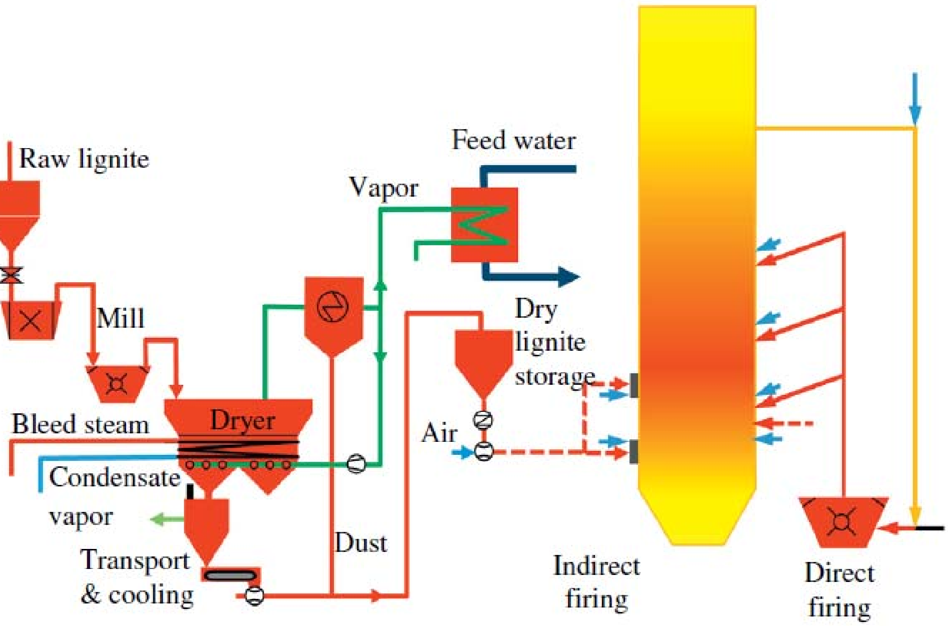

Figure 4-1 External Pre-drying System based on Fluidized Bed Drying Technology for Lignite Firing

- *Gas Turbine (GT) Integration*. The exhaust from the GT will be introduced into the boiler via the windbox and the overfire air system. The lower O_2 content and higher temperature of the flue gas requires that CFD modeling be performed to optimize the performance of the burner/OFA system for NO_x emission, combustion completion, and heat transfer rates for the various sections of the boiler (waterwalls, superheater, reheater, etc.).

- *Flue Gas/Air Heater Heat Recovery*. The high flowrate and temperature of the gas turbine flue gas (which, in part, is used to supply oxygen for combustion) minimizes boiler air preheating requirements. To accomplish the required heat recovery from the combustor flue gas, two additional heat exchangers are included to preheat the condensate and the feedwater system. The equipment used to achieve this integration is standard commercial systems; however, its integration with the boiler/feedwater cycle is novel.

- *ESS (batteries).* The ESS (Lithium Ion / Vanadium Redox Hybrid System) is undergoing commercial deployment. Discussions are ongoing with ESS suppliers to integrate their systems with this concept.

- *Advanced coal property monitoring and management system.* This component is designed to minimize impact on performance and reliability. Variability of coal properties is managed using on-line analyzers, fireside performance indices, and condition-based monitoring.

- *Cooling water circuit.* Due to the carbon capture system demands, we anticipate that the cooling tower cell footprint, power usage, and water usage will be significant compared to the rest of the plant. While we plan to further investigate how to optimize pretreatment to consider more cycles, reducing the amount of blowdown required for wastewater treatment, the evaporative losses and the makeup water necessary to recover those losses is great. In an effort to reduce the water consumption and wastewater, air-cooling was considered but disregarded due to backpressure requirements. We had also considered a modularized cooling system of cells, but due to their size, the modules would still require a significant amount of labor for installation. Further evaluation of how to reduce evaporative losses and water usage, the cooling tower footprint, and increased cooling efficiency could be beneficial.

4.5.2 Technical Challenges & Critical Components

4.5.2.1 Technical Gaps

The HGCC key technical gaps and risks as well as the proposed approaches to address them are discussed in the following subsections.

Boiler Combustion Gaps

Boiler Size: The USC technologies are well proven—up to 1,000 MW—and have demonstrated high reliability. However, a typical USC power plant is normally configured with a capacity of over 400 MW to take advantage of economies of scale. The 270 MW-class USC coal power plant, featuring rapid start and low-load operation, will require a thorough design study and analysis.

Coupled Indirect System Design and Optimization: Pulverized coal combustion systems are divided according to how they are connected to the boiler. In the preFEED phase, indirect coal firing system was applied to improve plant flexibility. To optimize the efficiency of the plant, it was upgraded to a system that combines boiler and pulverizer air. In the FEED study, coupled indirect system will be further developed through detailed design and system risk assessment.

	Advantages
Direct Firing System	• Considerably smaller investment costs • Lower operating and maintenance costs • Less complex safety devices required • Minimize loss of boiler efficiency
In Direct Firing System	• High flexibility of the firing system (Ramp Rate) • Minimum load reduction and Start-up time • Separation of fuel preparation and combustion

Use of the turbine exhaust gas in the OFA ports is beneficial because the lower oxygen concentration and higher gas flow provides higher momentum for mixing with the main boiler flue gas (always a challenge for OFA injection). It also provides reduced O_2 levels throughout the furnace volume, reducing the formation of NO_x along with improved burnout.

Mixing the GT flue gas with the combustion air does not significantly affect flame stability. However, the draft loss of the burner air register increases when the oxygen partial pressure decreases, delaying combustion. This could result in increased unburned carbon content. This risk is mitigated by multiple strategies in our design.

Through the HGCC preFEED study, it is analyzed in terms of both the qualitative effects and the quantitative effects applying actual boiler design in both the GT exhaust gas and pure-air modes by combustion CFD. Investigated parameters include gas temperature, flow distribution, species concentration, and char burnout. CFD results show that NO_x concentration at the furnace outlet is 99 ppm (at 6% O2) in GT exhaust mode and 113 ppm in pure-air mode, which are less than the NO_x emission target of 150 ppm. Carbon in ash at the outlet of the furnace is 4.5% in the GT exhaust-gas mode and 2.7% in the pure air mode. These results indicate no serious problems in terms of combustion. These combustion performances will be verified in further by a pilot-scale test in the FEED study. However, the OFA system should be considered further to enhance flow penetration, such as by introducing two-stage OFA. In addition, it is assumed that GT exhaust gas and air are completely mixed, so suitable a mixer and duct should be designed to match this assumption.

<u>Boiler Heat Transfer Surfaces:</u> USC heat transfer surfaces operate at higher temperatures than subcritical boilers. The proposed concept has a lower adiabatic flame temperature than pure air combustion. The addition of the GT exhaust gas in the OFA could result in changing the furnace exit gas temperature, which would shift the heat absorption duty from the furnace body to the convective section. All of these could result in boiler heat absorption changes. Such changes require an optimization study of the configuration and design parameters of the boiler to maximize the benefits (heat extraction) and minimize the risks (fouling and slagging in convective section) for boiler design and the RFP requirements.

4.5.2.2 Risks

The key technical risk associated with the HGCC is the integration of the combustion turbine into the boiler. Introduction of turbine exhaust into the boiler requires that the following areas be redesigned compared to a traditional pulverized coal boiler (refer to Section 4.5.1):

- Coal preparations, handling, storage, and fire suppression systems
- Furnace windbox and burners
- Overfired air system
- Flue gas/air heater and external heat exchangers

The design issues are anticipated to cover:

- CO_2 inerting system
- Heat transfer for the various boiler sections
- Expected tube metal temperatures and their variation as load changes
- NO_x emissions reductions from the overfire air system
- Flue gas temperature entering the SCR system at all boiler loads
- Efficiency at risk during high ramp rates
- Minimum load considerations

4.5.3 Development Pathway

4.5.3.1 Research & Development

To address the gaps identified above, we recommend:

- Burner evaluation to identify the optimal operating parameters for hotter transport air
- Demonstration testing at the MW_{th} scale to verify and confirm the CFD model and burner evaluation
- Burner performance test
- Optimizing OFA design

Analysis of the boiler furnaces using GT exhaust gas as an oxidant showed no serious problems in terms of combustion. This analysis result is performed under the premise that the GT exhaust gas supplied to the burner is well mixed with pure air and the mixed oxygen concentration is constant. Therefore, there is room for change, depending on actual GT and boiler operation. It is considered necessary to review this in the future and further study is needed.

It is proposed to carry out a combustion performance test by applying a pilot scale model (3MW) of actual burner. The burner combustion test facility owned by Doosan Heavy Industries & Construction is designed to recycle exhaust gas and supply pure air to the burner. It also has an indirect type pulverizer, which can be used to check the burner's combustion performance against the actual combustion conditions, which can be operated in the boiler by controlling the concentration of oxygen supplied to the burner by load. It is possible to obtain flame characteristic data according to the burner outlet speed which is different between the pure air operation mode and the GT exhaust gas operation mode.

Optimizing OFA Design

As confirmed by the analysis results, the penetration depth was different because the flow rate difference between the GT exhaust gas and the pure-air operation mode is very large. In order to optimize the performance, it is necessary to review the design that satisfies both modes of operation, such as adopting a two-stage OFA.

Mixer and Mixing Duct Design and Optimization

In the preFEED phase, the GT exhaust gas and the air were assumed to be completely mixed in the GT exhaust gas operation mode. However, this kind of mixing requires a suitable mixer and duct design for it.

Coupled Indirect System Design and Optimization

Pulverized coal combustion systems are divided according to how they are connected to the boiler. In the preFEED stage, indirect coal firing system was applied to improve plant flexibility. To optimize the efficiency of the plant, it was upgraded to a system that combines boiler and pulverizer air and injects it. This will further be developed in the FEED study.

The proposed development is essential to identifying the optimal method of adding GT flue gas into the boiler system without adversely affecting boiler design. A two-year timeline is proposed for the evaluations with a completion date of 2022. A FEED study can be performed concurrently with the evaluations. Subsequently, a demonstration of the concept to reduce investment and risk can be implemented in the 2024-2027 timeframe and the FEED updated to include results from the demonstration.

Table 4-16 illustrates items to be addressed during the FEED stages of the project

Table 4-16 Technical Pathway

Technical pathway	Technical agendas	Key activities	Target
Research & Development	Optimize heat absorption profile	CFD modeling of boiler; burner tuning for GT flue gas; pilot demonstration to validate CFD modeling and identify fouling/slagging issues.	Identify optimal integration of GT flue injection to boiler
FEED	Demonstration and new build project feasibility	Basic design and critical component detail design for the targeted plant demonstration and new build power plant.	Confirm the technical and economic feasibility of demonstration and new project
	Flexibility improvement- Startup time	Advanced boiler model design with drainable superheater and advanced control system/logic.	2 hours full load for warm start
Potential 2030 Status	Full Scale Commercial Greenfield Construction	Commercial demonstration by applying the FEED study result and plant demonstration experience developed technology. The project will be conducted by commercial contract except for developed components.	350MW Scale commercial

A project schedule has been developed as part of the project execution plan provided in Appendix G. Items in the technology gap review will be addressed during the FEED study.

4.5.4 Technology Original Equipment Manufacturers

4.5.4.1 Commercial Equipment

The equipment required to execute the HGCC project is available on the market. Examples of the major components are listed in Table 4-17. To the greatest extent practicable, all equipment and products purchased will be made in The United States of America, shop assembled and shipped. This will be further defined in our FEED proposal.

Table 4-17 Commercially Available Equipment

Equipment Item	Manufacturer
Gas turbine	GE
Steam turbine	DHI, GE, Siemens
USC steam boiler	DHI
Gas air heater	DHI
Heat exchangers	Yuba
Boilers	DHI, Alstom, B&W
Boiler Fans	Barron
SCR	DHI
Dry ESP	DHI
Wet FGD with EME	DHI
Non leakage gas heater and cooler	DHI
PCC	Doosan Babcock
Condenser	DHI
Cooling tower	Marley, SPX

Equipment Requiring Research & Development

The main R&D challenge for the HGCC is the new and emerging hardware in the ESS Battery storage system. The concept envisions a 50-MW storage system integrated into the basic USC pulverized coal steam cycle. Items of concern are the capital cost, O&M cost, efficiency, and longevity.

The remainder of the concerns involve integrating the indirect firing system and the combustion turbine into the USC boiler design.

The R&D items listed in Table 4-18 will be developed during the preFEED stage and conducted and completed in the FEED stage.

Table 4-18 Equipment Not Commercially Available

Equipment features / Concept	R&D Entity/Manufacturer
Construction and operation of integration of the GT exhaust gas with coal combustion burner	DHI
Fast startup USC boiler model control system	DHI
Low-load operation USC steam turbine model with PCC control system	DHI/Doosan Babcock/PCC Manufacturer
ESS battery (limited commercial installations)	DHI/ESS Vendor
USC boiler indirect firing system – Integration with boiler/combustion turbine	DHI
Battery storage/USC boiler/combustion turbine control system	DHI/ESS Vendor

5.0 Cost Results Report

5.1 Overview

The total project cost, including equipment costs based on factoring and vendor quotations for an HGCC power plant, are presented in this report. The team used previously developed documents from the preFEED study such as the Design Basis Report[xix], Performance Report with Energy & Mass Balances[xx], and latest vendor quotations as references to develop the costs. The total project cost estimate, divided into 17 code of accounts similar to Case B12B in 2019 revision of "NETL Cost and Performance Baseline for Fossil Energy Plant Volume 1: Bituminous Coal and Natural Gas to Electricity, corresponds to a Class 4 estimate (AACE International Recommended Practice No. 18R-97)[xxi] for the process industries and the range of accuracy for the HGCC plant is -15 - +30% accuracy.

This section discusses the Methodology and Approach (Section 5.2), Capital Cost Estimate (Section 5.2.8), Owner's Cost (Section 5.3) Operating and Maintenance Cost (Section 5.4), Cost of Electricity (Section 5.5), Risk and Sensitivity Cost Discussion (Sections 5.6 and 5.7, respectively), and Value Engineering Discussions (Section 5.7.9). Table 5-1 provides a summary of cost results and highlights some key results from the sensitivity evaluation.

Table 5-1 Cost Results Summary

Description for HGCC Plant	Greenfield-Bituminous (Base Case)	Demonstration at Existing Facility - Bituminous (Base Case)	Greenfield- Sub-bituminous	Greenfield-Lignite with Coal Drying
Total Project Cost ($/MW$_{net}$-w/ ESS, $/MW$_{net}$-w/o ESS)	$1.86 Billion ($5,300, $6,200)	$1.26 Billion ($3,600, $4,200)	$1.86 Billion ($5,300, $6,200)	$1.86 Billion ($5,300, $6,200)
Total Overnight Cost ($/MW$_{net}$-w/ ESS, $/MW$_{net}$-w/o ESS)	$2.25 Billion ($6,400, $7,500)	$1.53 Billion ($4,400, $5,100)	$2.25 Billion ($6,400, $7,500)	$2.25 Billion ($6,400, $7,500)
Total As Spent Cost ($/MW$_{net}$-w/ ESS, $/MW$_{net}$-w/o ESS)	$2.80 Billion ($8,000, $9,300)	$1.90 Billion ($5,400, $6,300)	$2.80 Billion ($8,000, $9,300)	$2.80 Billion ($8,000, $9,300)
Total Annual O&M	$111,500,000		$91,700,000	$96,900,000
Cost of Electricity (COE, $/MW$_{net}$h-w/o ESS)	$160	$126	$154	$178
Cost of Electricity (COE, $/MW$_{net}$h-w/ ESS) 1 hour per day	$138	$108	$132	$153
Cost of Electricity (COE, $/MW$_{net}$h-w/o ESS) 47% Load	$303	$233		
Cost of Electricity (COE, $/MW$_{net}$h-w/o ESS) $7/MMBTU N.G.	$173	$138		
Cost of Electricity (COE, $/MW$_{net}$h-w/o ESS) $35/ton CO_2 Credit	$154	$118		
Cost of Electricity (COE, $/MW$_{net}$h-w/o ESS) $50/ton CO_2 Credit	$151	$115		

5.2 Methodology and Approach

5.2.1 Cost Estimation Qualifications

The Class 4 constructed cost estimate provided in this report is based on our experience and qualifications and represents our best judgment as experienced and qualified professionals familiar with the project. This opinion is based on project-related information available to team at this time, current information about probable future costs, and a concept-level design of the project. The construction cost opinion will likely change as more information becomes available and more of the design is completed. In addition, because we have no control over the eventual cost of labor, materials, equipment, or services furnished by others; the contractor's methods of determining prices; competitive bidding; or market conditions, we cannot and do not guarantee that proposals, bids, or actual construction costs will not vary from the opinion of probable construction cost presented in this report. Greater assurance as to the probable construction cost can be achieved through additional design to provide a more complete project definition. Qualifying assumptions and exclusions on which the estimate is based are included in Section 5.2.5.

The following guidelines were used in evaluation and preparation of this cost report:

- Quality Guidelines for Energy Systems Studies (QGESS) https://www.netl.doe.gov/research/energy-analysis/search-publications/vuedetails?id=1022)
- The capital and O&M costs have been reported at a level of detail similar to that found in DOE/NETL Baseline studies (see e.g. https://www.netl.doe.gov/energy-analyses/temp/CostandPerformanceBaselineforFossilEnergyPlantsVolume1aBitCoalPCandNaturalGastoElectRev3_070615.pdf, pp. 132-136)
    - The costs estimate were compared with the capital cost estimate provided in case B12B. However, since the proposed plant design is not identical to the plant design in case B12B, the costs vary. It is important to note differences between the two plant designs being compared. Some examples of these differences are:
        - The proposed plant design produces a net power of 350MW, while the B12B plant produces 650MW, requiring different equipment capacities and sizes
        - The proposed plant design contains capital costs for a battery ESS and B12B does not contain an ESS
        - The proposed plant design contains pulverized coal storage whereas the B12B plant does not
        - The B12B plant design contains a Cansolv Carbon Dioxide (CO_2) Removal system that differs from the proposed plant's PCC system (amine-based system provided by Doosan Babcock).

5.2.2 Estimate Type

The cost estimate corresponds to a Class 4 estimate (AACE International Recommended Practice No. 18R-97) for the process industries. This estimate classification is characterized by limited project definition and the wide-scale use of scaling and power industry experience to calculate costs. A Class 4 has an end use for concept screening, with a lower bound accuracy range of -15% to -30% and an upper bound accuracy range of +20% to +50%. These parameters for a Class 4 estimate are shown in the table below.

Table 5-2 AACE Generic Cost Estimate Classification Matrix[xxii]

		Primary Characteristic	Secondary Characteristics			
		Level of Project Definition	End Usage	Methodology	Low Range Expected Cost	High Range Expected Cost
Estimate Class	ANSI Classification	Expressed as % of complete project definition	Typical purpose of estimate	Typical estimating method	Typical +/- range relative to best range index of	Typical degree of effort relative to least cost index
Class 4	Order of Magnitude	1% to 15%	Study or Feasibility	Feasibility, Top-down screening, Pre-design	-30%- -15%	+20% - +50%

Similar to PC technologies in the 2019 revision of "NETL Cost and Performance Baseline for Fossil Energy Plant Volume 1: Bituminous Coal and Natural Gas to Electricity," cost values in this report reflect an AACE Class 4 estimate, and the uncertainty for these estimates ranges from **-15% to +30%**. These uncertainty values have been taken into consideration during the contingencies application process.

5.2.3 Cost Estimate Scope

The scope of the cost estimate is completed for a theoretical 350MW coal-fired power plant with integrated carbon capture and combustion turbine located on a generic greenfield site in moderate climates in the midwestern United States. Databases for costs were provided by ACM.

The capital cost estimate provided is considered an order of magnitude, or parametric type, estimate with historical/actual cost curves based on historical data from other projects.

The operating and maintenance costs were evaluated using the mass balance calculations in the performance report. Costs of labor, consumables, and waste disposal were estimated from Case B12B, vendor quotes, and estimates from similar projects. The proprietary solvent annual cost used in the carbon capture system was provided by Doosan Babcock. Bottom ash and fly ash were not included in disposal costs as these streams are considered saleable. Gypsum and ash sales cost was not considered in the total operating and maintenance.

5.2.4 System Code-of-Accounts

The costs are grouped in a manner similar to the processes/system-oriented code of accounts as defined and structured in the 2019 revision of NETL's "Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity."

Table 5-3 includes a description of the HGCC code of accounts used to break down the cost evaluation.

Table 5-3 Description of HGCC Code of Accounts

Item	Description
1	Coal & Sorbent Handling
2	Coal & Sorbent Preparation and Feed
3	Feedwater & Misc. BOP Equipment & Systems
4	Boiler and Accessories
5	Flue Gas Cleanup
6	Carbon Capture & Compression
7	Ductwork & Stack
8	Steam Turbine Generator
9	Cooling Water System
10	Ash & Gypsum Handling Systems
11	Accessory Electric Plant
12	Instrumentation & Control
13	Improvements to Site
14	Buildings & Structures
15	Gas Turbine
16	Energy Storage System (ESS)
17	Water Treatment / Zero Liquid Discharge (ZLD) System

5.2.4.1 Code of Accounts Detailed Breakdown

Class 4 cost estimates are presented for the following construction features required for the project:

1. Coal and Sorbent Handling
    A. Prepare site, concrete foundations, slabs, and equipment to install; coal unload station, coal storage yard, push walls, coal stackers, conveyors and towers
    B. Concrete foundations, support steel, equipment to install; limestone unload, limestone conveyors, and feeder
    C. Concrete foundations, support steel, piping, and equipment to install
    D. Concrete foundations, support steel, piping, and equipment to install; activated carbon unload and storage silo and feeder

2. Coal and Sorbent Preparation and Feed
   A. Prepare site, concrete foundations, slabs, duct, and equipment to install; coal pulverizer and feeder
   B. Concrete foundations, support steel, piping, and equipment to install; limestone mill, slurry tanks, feed pumps, piping, slurry storage tanks, and limestone slurry injectors
   C. Full stream elemental analyzer (FSEA), belt weighing system, structure to house data acquisition system

3. Feedwater and Misc. BOP Systems
   A. Concrete foundations, piping, and equipment to install; makeup water, water pretreatment, low pressure feedwater heaters, high pressure feedwater heaters, feedwater pumps, deaerator and storage tank
   B. Piping and valves for service water system
   C. Service air compressor, piping, and outlets
   D. Ground water pumps and piping to pretreatment
   E. Natural gas piping to feed gas turbine
   F. Natural gas piping boiler for startup
   G. Fire sprinklers pumps and piping
   H. Wastewater piping to ZLD
   I. Concrete foundation, support steel, runway rail, and equipment to install; canes and hoist

4. Boiler and Accessories
   A. Concrete foundations, support steel, duct, piping, and equipment to install; ultra-supercritical coal-fired boiler, primary air fans, and induced draft fans
   B. Concrete foundations, support steel, duct, storage, piping, and equipment to install; SCR reactor vessel, dilution blower, ammonia feed storage, ammonia piping, and injectors

5. Gas Cleanup
   A. Concrete foundations, support steel, ductwork, piping, and equipment to install; electrostatic precipitator
   B. Support steel, ductwork, piping, and equipment to install; flue gas desulfurization wet scrubber
   C. Ductwork for ESP and scrubber

6. CO_2 Removal and Compression
   A. Concrete foundations, support steel, piping, ductwork, and equipment to install; carbon capture absorber vessel, compression and drying systems, and regeneration equipment

7. Ductwork/Piping/Support/Insulation
   A. Exhaust flue; concrete foundations
   B. Continuous emissions monitoring system (CEMS) in stack
   C. Duct from FGD scrubber to PCC

8. Steam Turbine and Auxiliaries
   A. Concrete foundations, support steel, piping, and equipment to install; steam turbine/generator
   B. Concrete foundations, support steel, piping, and equipment to install; steam condenser and condensate pumps

9. Cooling Water System
   A. Concrete foundations, support steel, piping, and equipment to install; cooling tower and circulating pumps

10. Ash and Spent Sorbent Handing System
    A. Concrete foundations, support steel, ductwork, piping, and equipment to install

11. Accessory Electric Plant
    A. Concrete foundations, support steel, conduit, cable tray, and equipment to install; main power transformers, STG isolated phase bus duct, and tap bus
    B. Medium and low voltage switchgear
    C. Concrete foundations, piping, conduit, wire, and equipment to install; emergency diesel generator

12. Instrumentation and Control
    A. Operator station, panels and microprocessors for DCS Main Control
    B. Control instruments and fiber optic cabling to complete the DCS system
    C. Data acquisition system for condition based monitoring (CBM) computers

13. Improvements to Site
    A. Temporary erosion and sediment controls
    B. Preliminary earthwork and grading
    C. Ground water wells and piping for 50% plant makeup and cooling water
    D. Concrete foundations, covered concrete utility trenches, surface stone, conduit, MCM cable, and cathodic protection/ grounding for electric distribution yard/ substation
    E. Mechanical site utilities and storm drainage
    F. Site improvements: roads, drives, parking, site signage, flagpoles, fences and gates, and site furnishings

14. Buildings and Structures

    A. Foundations, slabs, superstructure, enclosure, roofing, finishes, plumbing, HVAC, electric, and lighting for: boiler building, turbine building, administration building, pumphouse, water treatment buildings, machine shop, warehouse, and waste treatment buildings

15. Gas Turbine

    A. Concrete foundations, support steel, piping, flue duct, and equipment to install; 6F.03 gas turbine generator
    B. Flue duct to USC Boiler and external heaters

16. Battery ESS

    A. Concrete foundations, support steel, conduit, cable tray, wire, and equipment to install; battery storage system

17. Water Treatment / Zero Liquid Discharge System

    A. Concrete foundations, support steel, piping, and equipment to install; zero liquid discharge system.

5.2.5 Assumptions and Exclusions

The basis of design is included in the design basis report provided previously for the HGCC project in Section 3.0. Key assumptions are included below and also summarized in Appendix F.

5.2.5.1 Base Case Assumptions

1. Bituminous coal per DOE requirements.
2. 85% capacity factor (O&M Base Case), redundancy based on 50% capacity factor for low risk equipment. Capacity of this plant is anticipated to range from 30-85%.
3. Greenfield site / Midwest U.S.
4. 300-acre site.
5. The plant includes a substation bus that can be connected to the grid and the railroad siding with a coal receiving area, equipment and facilities.
6. The natural gas supply is assumed to be available at the site boundary at a pressure of between 400-600 psig and with hydrocarbon dewpoint lower than -20ºF; water from the municipality is assumed to be at pressure between 100-150 psig and available flow rate of >3000 gpm; electricity tie-in is assumed to be at a 345kV dead-end structure near the switchyard; revenue metering will be at a single point on the 345kV interconnect.
7. CO_2 off-take will be by pipeline at the plant boundary and 1000 psig interface pressure; pipeline and booster compressors (if needed) are by others.

8. Prices may fluctuate due to the varying costs of material and equipment that are driven by multiple market variables. Vendor quotes were provided in 2019 and 2020 dollars, except the battery estimates, which are based on 2030 equipment cost that is projected to be reduced by Doosan between now and that time. The quotes provided by the vendor may vary over time and as the scope and design becomes more defined.

Table 5-4 Updated Energy Storage System Specifications

System	ESS Energy Capacity	50 MWh
	PCS Power	50 MW
	System Efficiency	AC Round Trip 85-90%
	Life Span	> 4,000 cycle at DoD 80%
Battery	Battery Type	Hybrid Battery (Lithium-ion + Vanadium Redox flow)
	Door	Indoor, Battery 1.5MWh in 40ft Container
	Container	40ft Container 34 EA
	C-rate	0.5~1.5C
	Battery Voltage Range	DC 750~1000 V
	Operation Mode	CC, CV, CP
	Cooling	Air Cooling, HVAC
	Protection	Passive Cell Balancing, System/Rack/Module BMS, Rack Switch Gear
	Communication	Ethernet (TCP/IP), CAN, RS232/485
PCS	UNIT	20 SET (2.5 MW)
	Door	Indoor, PCS 2 set in 40-ft Container
	Container	40-ft Container 10 EA
	Efficiency	Max. 99%, Min. 92%
	Power Factor	> 0.99
	Input Voltage	DC 750~1000 V
	Input Current	3500 Adc
	Output Voltage	AC 440~480V
	Output Frequency	50Hz/60Hz
	Cooling	Air Cooling, HVAC
	Protection	DC Switch, DC Fuse, ACB, AC Fuse, GFD
	Standard	SGSF-04-2012-07, EMC CISPR11 : 2011, EN61000-4-2, 4, 6, 11 / IEEE1547, MESA
	Communication	Ethernet(TCP/IP), CAN, RS232/485
TR	Main TR	50MVA, 22.9kV, 6.9kV
	Sub TR	6MVA, 6.9kV, 440V

5.2.5.2 Base Case Exclusions

The following items are excluded from the project cost estimate:

1. Hazardous, contaminated materials and remediation
    a. Asbestos
    b. Lead abatement
    c. PCBs
    d. Contaminated soils
        i. Contaminated ground water
    e. Site conditions
        i. Piles or caissons
        ii. Rock removal
        iii. Excessive dewatering
        iv. Expansive soil considerations
        v. Excessive seismic considerations
        vi. Extreme temperature considerations
        vii. Demolition or relocation of existing structures
        viii. Unforeseen conditions
        ix. Sub-surface conditions
        x. Existing unknown conditions
    f. Fees and Permits
        i. State licenses
        ii. Local license
        iii. Environmental permits
        iv. Building permits
        v. Third party, professional fees, material testing, and inspections
    g. Leasing of off-site land for parking or laydown
    h. Busing of craft to site
    i. Costs of off-site storage
    j. Furnishings and special items
        i. Any furniture, window treatments, or other furnishings
    k. Transportation and storage (T&S) is not considered in the capital cost, owner's costs, O&M, or COE results. T&S includes items such as:
        i. New access roads and railroad tracks
        ii. Upgrades to existing roads to accommodate increased traffic
        iii. Makeup water pipe outside the "fence line"
        iv. Landfill for onsite waste (slag) disposal
        v. Backup fuel provisions
        vi. Plant switchyard
        vii. Electrical transmission lines outside of plant boundary
        viii. Carbon unloading, sequestration, or transport pipeline

5.2.6 Cost of Mature Technologies and Designs

The cost estimates of mature technologies and designs are based on vendor quotes procured for this cost estimate. These quotes were used in a capital cost estimate conducted by Barr and ACM. Original equipment manufacturer (OEM) Quotes for the major equipment listed in Table 5-5.

Table 5-5 List of Major Equipment and Vendors

Equipment	Vendor
SCR	Doosan Heavy Industries
ID Fan	Howden
Gas Cleanup Equipment, including: • Flue-Gas Desulfurization (FGD) • Electrostatic Mist Eliminator (EME) • Non-Leakage Gas-Gas Heat Exchanger (NL GGH) • Dry Electro Static Precipitator (Dry ESP)	Doosan Heavy Industries
Steam Turbine (with auxiliaries) / Integrated Heat Exchangers	Doosan Heavy Industries
Natural Gas Turbine	GE
Cooling Tower	Marley
Condenser	Maarky Thermal Systems
Circulating Water Pumps / Feedwater Pumps	Flowserve
Ash Handling Systems	UCC
Water Treatment System and ZLD	WesTech or Aquatech
Electric System	Siemens
Control System	Rockwell Automation / Allen Bradley

For these readily-available systems, a process contingency of 0% was considered in the cost estimate. These systems have been proven in full-scale commercial applications. The electrical, controls, fuel feed system, and some piping and ductwork around the indirect firing system was considered for a slight contingency based on the emerging technologies that were associated with the components.

5.2.7 Costs of Emerging Technologies, Designs, and Trends

There are some areas where the technology is not common or commercially available. Table 5-6 lists these areas. The cost was obtained from the OEM for each of these areas. A process contingency is included to account for the emerging technology status.

Table 5-6 List of Emerging Technologies

Equipment	Vendor	Proposed Process Contingency
Boiler (with auxiliaries) controls with Indirect Firing Systems	DHI	5% (Burner Parts and Air Systems)
Lithium Ion / Vanadium Redox Hybrid System ESS	Toshiba, Samsung & Avalon / DHI	3%

While the equipment listed is available on the market, additional engineering costs will be required to integrate the equipment into the proposed concept. These costs are taken into consideration in the TPC. The potential factors which may affect the capital cost of each of these technologies follow:

- *Indirect Firing System.* The indirect firing system itself is a straightforward concept that poses little uncertainty. Factors that are undefined are the flowability of the pulverized coal, its proclivity toward spontaneous combustion, as well as control of this plant to accommodate the high ramp rates and turndowns. These factors will influence the design of the fluidizing nozzles, the blanketing gas quantity, and any special features required to prevent caking, bridging, or channeling.

- *Energy Storage System.* A battery storage system of this technology and size has not been constructed to date. While battery storage systems should be easily scalable, there is always some potential for unforeseen challenges.

5.2.7.1 Project Contingency

Project contingency compensates for cost uncertainties and construction risk associated with final design and construction of the project until the project is completed. Uncertainty in early stages of project planning and design, especially during the feasibility study phase, are greater due to factors such as limited project definition, design and analysis assumptions, unforeseen constraints and constructability issues, construction schedule, and other construction risk factors. In general, uncertainty will decrease as greater definition is developed and more detailed information becomes available.

At this stage in the project, the design is less than 2% complete and constructability has not been evaluated due to insufficient design detail. Therefore, the range of uncertainty of total project cost is considered to be high. AACE 16R-90 states that project contingency for a “budget-type” estimate (AACE Class 4 or 5) should be 15% to 30% of the sum of BEC, EPC fees, and process contingency.

The project contingency was determined by taking various percentages of the bare erected costs plus the costs up through process contingency. The project contingency will be reduced as engineering progresses in later phases and potential further cost reduction with value engineering, standardization, and modularization strategies.

5.2.8 Capital Cost Results

The TPC cost for the HGCC system is summarized in Table 5-7.

Table 5-7 HGCC Capital Cost Summary

Item	Category	Bare Erected Cost (BEC) ($)	Engineering, Procurement & Construction ($)	Process Contingency ($)	Project Contingency ($)	% Process / % Project Contingency	Total Project Cost (TPC) ($)	$/kW (w/ESS)
1	Coal & Sorbent Handling	70,000,000	10,500,000	0	12,100,000	0%/15%	92,600,000	260
2	Coal & Sorbent Preparation and Feed	20,000,000	3,000,000	0	3,500,000	0%/15%	26,500,000	80
3	Feedwater & Misc. BOP Systems	140,000,000	21,000,000	0	24,200,000	0%/15%	185,200,000	530
4	Boiler & Accessories	250,000,000	37,500,000	0	43,100,000	0%/15%	330,600,000	940
5	Gas Cleanup	130,000,000	19,500,000	0	22,400,000	0%/15%	171,900,000	490
6	CO_2 Removal & Compression	185,000,000	27,800,000	0	31,900,000	0%/15%	244,700,000	680
7	Ductwork/Piping/ Support / Insulation	23,000,000	3,500,000	0	4,000,000	0%/15%	30,400,000	90
8	Steam Turbine and Auxiliaries	130,000,000	19,500,000	0	22,400,000	0%/15%	171,900,000	490
9	Cooling Water System	66,000,000	9,900,000	0	11,400,000	0%/15%	87,300,000	250
10	Ash & Spent Sorbent Handling System	21,000,000	3,200,000	0	3,600,000	0%/15%	27,800,000	80
11	Accessory Electric Plant	96,000,000	14,400,000	0	16,600,000	0%/15%	127,000,000	360
12	Instrumentation and Control	33,000,000	5,000,000	1,900,000	6,000,000	5%/15%	45,800,000	130
13	Improvements to Site	57,000,000	8,600,000	0	9,800,000	0%/15%	75,400,000	220
14	Buildings and Structures	65,600,000	9,800,000	0	11,300,000	0%/15%	86,700,000	250
15	Gas Turbine	44,800,000	6,700,000	0	7,700,000	0%/15%	59,300,000	170
16	Lithium Ion - Vanadium Battery ESS	53,700,000	8,100,000	1,800,000	9,500,000	3%/15%	73,000,000	210
17	Water Treatment / ZLD	17,800,000	2,700,000	500,000	3,100,000	2%/15%	24,100,000	70
	Total Plant Cost						**$1,860,000,000**	**5,300**

5.3 Owner's Costs

The owner's costs were estimated by factoring the values provided in the B12B case in the NETL report. This report estimated the costs based on the 2019 revision of the QGESS document "Cost Estimation Methodology for NETL Assessment of Power Plant Performance." In this document, the total owner's costs consist of preproduction (startup) costs, inventory capital, land, financing cost, and other owner's costs. Prepaid royalties and working capital are not included in the owner's costs.

The preproduction costs include six months of operating labor, one month maintenance materials at full capacity, one month non-fuel consumables at full capacity, one month waste disposal, 25% of one month's fuel cost at full capacity, and 2% of TPC. The six months of operating labor includes the cost of training the plant operators, participation in startup, and occasionally involving them in the design and construction of the power plant.

The inventory capital includes 0.5% of the TPC for spare parts, a 60-day supply (at full capacity) of fuel, and a 60-day supply (at full capacity) of non-fuel consumables (e.g., chemicals and catalysts) that are stored on site. The cost for a 60-day supply (at full capacity) of fuel is not applicable for natural gas. The 60-day supply (at full capacity) of non-fuel consumables does not include catalysts and adsorbents that are batch replacements (such as selective catalytic reduction catalysts).

The cost of land includes a 300-acre site with a $3000/acre price (based on the site being located in a rural area).

The financing cost is based on 2.7% of the TPC and covers the cost of securing financing, fees, and closing costs. It does not include interest during construction (or AFUDC).

Other owner's costs are estimated using 15% of the TPC. This includes:

1. Preliminary feasibility studies (including a Front-End Engineering Design (FEED) study)
2. Economic development (costs for incentivizing local collaboration and support)
3. Construction and/or improvement of roads and/or railroad spurs outside of site boundary
4. Legal fees
5. Permitting costs
6. Owner's engineering (staff paid by owner to give third-party advice and to help the owner oversee/evaluate the work of the EPC contractor and other contractors)
7. Owner's contingency (sometimes called "management reserve"—these are funds to cover costs relating to delayed startup, fluctuations in equipment costs, unplanned labor incentives in excess of a five-day/ten-hour-per-day work week; owner's contingency is not a part of project contingency)

The owner's costs do not include:

1. EPC risk premiums (costs estimates are based on an EPCM approach utilizing multiple subcontracts, in which the owner assumes project risks for performance, schedule, and cost)
2. Transmission interconnection: the cost of interconnecting with power transmission infrastructure beyond the plant busbar

3. Taxes on capital costs: all capital costs are assumed to be exempt from state and local taxes
4. Unusual site improvements: normal costs associated with improvements to the plant site are included in the BEC, assuming that the site is level and requires no environmental remediation; unusual costs associated with the following design parameters are excluded: flood plain considerations, existing soil/site conditions, water discharges and reuse, rainfall/snowfall criteria, seismic design, buildings/enclosures, fire protection, local code height requirements, noise regulations

The factors used to adjust the B12B costs were taken from the 2019 revision of the QGESS document "Capital Cost Scaling Methodology: Revision 4 Report."

5.3.1 Owner's Cost Results

The Owner's costs for the HGCC are summarized in Table 5-8.

Table 5-8 Owner's Costs

Owner's Costs			
Description	**$**	**$/kW$_{net}$ (w/o ESS)**	**$/kW$_{net}$ (w/ ESS)**
Pre-Production Costs			
6 Months All Labor	9,710,000	32	28
1 Month Maintenance Materials	460,000	2	1
1 Month Non-fuel Consumables	633,000	2	2
1 Month Waste Disposal	70,000	0	0
25% of 1 Month's Fuel Cost at 100% CF	1,060,000	4	3
2% of TPC	37,200,000	124	106
Total	**49,100,000**	164	140
Inventory Capital			
0.5% of TPC (Spare Parts)	9,300,000	31	27
60 day Supply of fuel at 100% CF	5,076,000	17	15
60 day Supply of consumables at 100% CF	1,250,000	4	4
Total	**15,626,000**	52	45
Land			
Cost (Based on 300 Acres)	900,000	3	3
Total	**900,000**	**3**	3
Financing Cost			
2.7% of TPC	50,220,000	168	143
Total	**50,220,000**	**168**	143
Other Costs			
15% of TPC	279,000,000	931	797
Total	**279,000,000**	**931**	797
Total Owner's Cost	**394,850,000**	**1,317**	**1,128**
Total Overnight Costs (TOC)	2,254,850,000	7,521	6,442
TASC/TOC Multiplier (IOU, high-risk, 3 year)	1.242		
Total As-Spent Cost (TASC)	2,800,520,000	9,341	8,001

5.4 Operation and Maintenance Costs

The yearly operating and maintenance costs associated with the proposed power plant were calculated. The main components of the yearly operating cost are:

- Operating labor
- Maintenance material and labor
- Administrative and support labor
- Consumables
- Waste handling

- Co-products and saleable by-products
- Fuel

The operating and maintenance labor was estimated using methods similar to those contained in the 2019 revision of the QGESS document “Cost Estimation Methodology for NETL Assessment of Power Plant Performance.” Since the NETL study did not contain an energy storage system, the 2019 “Energy Storage Technology and Cost Characterization Report” authorized by the DOE was used to estimate the operations and maintenance costs of the energy storage system proposed in this concept.

5.4.1 Auxiliary Power Consumption

When operating under the base case scenario, the plant generates a total gross power of 408 MWe including the ESS. The plant’s net power generation is calculated by subtracting auxiliary power consumption from gross power. Auxiliary power is estimated to be 58 MWe and subtracting this from the gross power results in a net output of 350 MWe.

Auxiliary power consumption does not represent a financial cost to the project, except where it impacts the net output and net heat rate. Impacts to net output could be mitigated by increasing the firing rate to maintain the dispatched load. Consequently, variations in auxiliary power consumption are manifested in variations to the net heat rate.

5.4.1.1 Operating Labor

The HGCC system will require highly-skilled operating and maintenance personnel. Personnel will be required to understand the requirements for:

- Coal boiler with integrated natural gas turbine and steam turbine
- Carbon capture system
- CO_2 compression and purge
- Battery ESS
- Water treatment and ZLD

It is assumed that the number of personnel at this power plant will be similar to power plants of similar size and complexity. For this plant, the personnel include: one plant manager, one operations manager, one maintenance engineer, one senior engineer, one junior engineer, one engineering technician, two financial accountants, two procurement and warehouse managers, two control room operators per shift, five outside operators per shift, two coal reclaimer operators per shift, two train unloading operators at two shifts per weekday, three maintenance mechanics, one I&C technician, two maintenance electricians, four general laborers, and one full-time security person. The fully burdened rates are based on estimated costs associated with an employee. This includes salary, benefits, overhead, and other costs.

5.4.1.2 Maintenance Material and Labor

Maintenance materials were also estimated using similarly sized projects. The maintenance required throughout the plant involves:

- Annual outages to service the natural gas turbine's hot gas path, combustor, rotors, and other major components
- Outages to inspect and maintain the steam turbine and generator
- Maintenance of the boiler and boiler tubes
- Maintenance of the coal and limestone handling equipment, such as conveyers, crushers, mills, and dust collectors
- Occasional maintenance of the ZLD and water treatment system components, including vapor compressors, centrifuge, and demisting pads
- Maintenance of the FGD, including seal and nozzle replacements
- Maintenance of the pumps, heaters, and BOP
- Maintenance of the ESS and periodic cell replacement
- Improvements to the buildings, pavement, and railing system
- Spares

5.4.1.3 Consumables

Consumable rates were provided by equipment vendors or calculated from the heat, water, and mass balances. The estimated cost of these consumables was derived from various chemical suppliers such as Airgas Inc., USP Technologies, Spectrum Chemical, Andy McCabe, and CQConcepts, as well as factoring based on costs of consumables provided in the 2019 revision of the QGESS document "Cost Estimation Methodology for NETL Assessment of Power Plant Performance."

5.4.1.4 Waste Disposal

Waste production rates were provided by equipment vendors or calculated from the heat, water, and mass balances. The cost estimate for removing or disposing of waste was derived from factoring based on costs of consumables provided in the 2019 revision of the QGESS document "Cost Estimation Methodology for NETL Assessment of Power Plant Performance."

5.4.1.5 Co-Products and Saleable By-Products

Co-products and by-products production rates were either provided by equipment vendors or calculated from the heat, water, and mass balances. However, to remain conservative and comparable to cost estimate for Case B12B, it is assumed that no profit is received from selling or using these products.

The salt cake from the ZLD has the potential for beneficial reuse such as de-icing and commercialization as salt as well as chloro-alkali processes. However, this value engineering was not considered for this project based on the progress in technology and current economic considerations.

5.4.1.6 Fuels

The consumption of coal and natural gas is based on the base-case heat balance and heat rates as well as input from boiler and natural gas turbine vendors. The price of coal is assumed to be \$1.6/MMBTU based on an average Midwest price of coal from Table 4.10A in the January 2020 Electric Power Monthly from the U.S. Energy Information Administration. The price of natural gas is assumed to be \$3.00 based on an average high price of natural gas in 2019 from the Henry Hub's Historical Prices records. A sensitivity analysis on how the cost of coal and natural gas influences COE is outlined in Section 5.7.4.

5.4.2 O&M Cost Results

The operating and maintenance costs for the HGCC system are summarized in Table 5-9. The O&M was calculated based on the methods described in Section 5.4. The resulting O&M costs are approximately \$111,500,000 per year or around \$50/MWhr. Fuel is the highest contributor of the O&M costs at approximately \$51,000,000. The O&M cost is used to calculate the COE in Section 5.5. The sensitivity analysis in Section 5.7.4 was performed to determine how fuel cost affects the COE.

Table 5-9 O&M Cost Summary

Operations and Maintenance Costs			
Plant Operation			
Steam Turbine Power, MWe	271	HHV Net Plant HR, kJ/kWh	8,340
Gas Turbine Power, MWe	87	HHV Net Plant Heat Rate without ESS, kJ/kWh	9700
Battery, MWe	50		
Total Gross Power, MWe	406		
Total Auxiliaries, MWe	56	Cost Base:	Sep-19
Net Power, MWe	350	Capacity Factor (%):	85
Net Power without Battery, Mwe	300	Days per year:	365
Net ST Power, Mwe	215	Operating Hours:	7451

Operating & Maintenance Labor						
Position	**Required**	**Labor Rate (\$/hour)**	**Weekly Coverage (hr)**	**Weekly Costs (\$)**	**Monthly Costs (\$)**	**Annual Costs (\$)**
Plant Manager	1	150	40	6,000	26,000	313,000
Operations Manager	1	135	40	5,400	23,000	282,000
Maintenance Manager	1	135	40	5,400	23,000	282,000
Senior Engineer	1	140	40	5,600	24,000	292,000
Junior Engineer	1	120	40	4,800	21,000	250,000
Engineering Technician	1	90	40	3,600	16,000	188,000
Financial Accountant	2	75	40	6,000	26,000	313,000

Operations and Maintenance Costs						
Procurement & Warehouse Manager	2	70	40	5,600	24,000	292,000
Control Room Operator	2	120	168	40,320	175,000	2,104,000
Outside Operator	5	100	168	84,000	365,000	4,383,000
Coal Reclaim Operator	2	110	168	36,960	161,000	1,928,000
Train Unloading Operator	2	110	84	18,480	80,000	964,000
Maintenance Mechanic	3	100	40	12,000	52,000	626,000
I&C Technician	1	120	40	4,800	21,000	250,000
Maintenance Electrician	2	110	40	8,800	38,000	459,000
General Laborer	4	70	40	11,200	49,000	584,000
Security	1	40	168	6,720	29,000	351,000
Subtotal:				**$265,680**	$1,153,000	**$13,860,000**
Fixed Operating Costs						
Description					**Cost ($)**	**$/kWnet (Without ESS)**
Annual Operating Labor:					13,860,000	6
Maintenance Labor:					5,560,000	2
Property Taxes and Insurance:					26,970,000	12
Subtotal:					$46,390,000	21
Variable Operating Costs						
Description					**Cost($)**	**$/MWh$_{net}$ (Without ESS)**
Maintenance Material:					5,560,000	2
Subtotal:					**$5,560,000**	**2**
Consumables						
	Consumption/ Production		**Cost**			
	Initial Fill	**Per Day**	**Cost Per Unit ($)**	**Initial Fill**	**Cost ($)**	**$/MWh$_{net}$ (Without ESS)**
Ammonia, lb		5280	0.417		684,000	0
Water,/1000 gal		2,570	1.927		1,538,000	1
Limestone, ton (FGD Reagent)		193	22.317		1,338,000	1
CO_2 Capture System Solvent, lb	Proprietary	6,085	0.000		3,030,000	1
Caustic Soda (50% wt.), lb		7,408	0.500		4,000	0
Sulphuric Acid (98% wt.), lb		4,762	0.100		0	0
Nitrogen (GAS), lb		18,519	2.280		42,000	0
Water Systems Chemicals					964,000	0
Subtotal:				-	**$7,600,000**	**3**

Operations and Maintenance Costs						
Waste Disposal						
	Consumption/ Production		**Cost**			
	Initial Fill	**Per Day**	**Cost Per Unit ($)**	**Initial Fill**	**Cost ($)**	**$/MWh$_{net}$ (Without ESS)**
Wastewater Solid Waste, ton		20	38.00		236,000	2
ZLD Crystallized Waste, ton		40	38.00		472,000	0
Amine Purification Unit Waste, ton		0.23	596.00		43,000	0
Thermal Reclaimer Unit Waste, ton		1	280.00		64,000	0
Subtotal:					**$ 820,000**	**2**
Saleable By-Products						
Bottom Ash, ton	-	40			0	
Fly Ash, ton	-	151			**0**	
FGD Gypsum Waste, ton		230			0	
CO_2 Capture Amine Waste, ton		1,410			0	
Subtotal:	**-**				**$0**	
Variable Operating Costs Total:				**$-**	**$14,000,000**	**$6**
Fuel Cost						
As-Received Coal Feed, ton	-	1,918	$-	$-	$30,900,000	$14
Natural Gas, ton	-	480	$-	$-	$20,200,000	$9
Subtotal:				**$-**	**$51,100,000**	**$23**
				Total O&M:	**$111,500,000**	**$50**

5.5 Cost of Electricity (COE)

The method for calculating the cost of electricity (COE) is based on the methods described in the 2019 revision of the QGESS document "Cost Estimation Methodology for NETL Assessment of Power Plant Performance." This report makes assumptions provided in Section 5.5.1. This is used to develop the finance structure in Section 5.5.2. Both are used to calculate the cost of electricity (COE) in Section 5.5.3.

5.5.1 Global Economic Assumptions

The 2019 revision of the QGESS document "Cost Estimation Methodology for NETL makes the following assumptions:

1. Taxes
    a. The Federal Income Tax Rate is 21%, the State Income Tax Rate is 6%, and the Effective Tax Rate (ETR) is 25.74%
    b. Capital depreciation over 20 years is 150% (declining balance)
    c. There is no Investment Tax Credit
    d. There is no Tax Holiday
2. Contracting and Financing Terms
    a. The Contracting Strategy consists of Engineering Procurement Construction Management (owner assumes project risks for performance, schedule, and cost)
    b. Debt Financing is Non-recourse (collateral that secures debt is limited to the real assets of the project)
    c. The Repayment Term of Debt is equal to operational period in formula method
    d. There is no grace period on debt repayment
    e. There is no debt reserve fund
3. Analysis Time Periods
    a. The capital expenditure period is 3 years for natural gas plants and 5 years for coal plants
    b. The operational period is 30 years
    c. The economic analysis period is 33 years for natural gas plants or 35 years for coal plants (capital expenditure period plus operational period)
4. Treatment of Capital Costs
    a. The capital cost escalation during the capital expenditure period is 0% real (or 3% nominal)
    b. The distribution of Total Overnight Capital over the capital expenditure (before escalation) is 10%, 60%, 30% for a 3-year period and 10%, 30%, 25%, 20%, 15% for a 5-year period.
    c. There is no working capital
    d. 100% of the Total Overnight Capital depreciates (actual amounts are likely lower and do not influence results significantly)
5. Escalation of Operating Costs and Revenues
    a. Escalation of COE (revenue), O&M Costs is 0% real (3% nominal)
    b. Fuel costs are based on the Quality Guidelines for Energy Systems Studies Fuel Prices for Selected Feedstock in NETL Studies

5.5.2 Finance Structure

In order to evaluate the economic feasibility of the project, a financial structure is established based on market and ownership risks. The cost analysis is developed for both commercial technology in 2020 and advancing technology projected to become commercial in 15 years or more. It can be assumed that they are commercially ready and that there are no risks or tax subsidies associated with any of the technology. The same structure should use real dollars and be applied to all scenarios in order to compare the technologies. Nominal dollars should be used to evaluate the technologies in various cash flow analyses. The structure will assume a large, financially stable, investor-owned utility (IOU) or merchant plant.

5.5.3 COE Calculation

The following calculations from the 2019 revision of the QGESS document "Cost Estimation Methodology for NETL Assessment of Power Plant Performance" were used to calculate the COE of the proposed power plant. COE is the revenue required to be received by the generator ($/MWh, equivalent to mills/kWh) during the power plant's first year of operation in order to satisfy the finance structure assumptions.

$$COE = \frac{\begin{array}{c}\text{first year}\\ \text{capital charge}\end{array} + \begin{array}{c}\text{first year}\\ \text{fixed operating}\\ \text{costs}\end{array} + \begin{array}{c}\text{first year}\\ \text{variable operating}\\ \text{costs}\end{array}}{\begin{array}{c}\text{annual net megawatt hours}\\ \text{of power generated}\end{array}}$$

$$COE = \frac{(FCR)(TASC) + OC_{FIX} + (CF)(OC_{VAR})}{(CF)(MWH)}$$

OC_{FIX} is the sum of all fixed annual operating costs during the first year of operation. OC_{VAR} is the sum of all variable annual operating costs during the first year of operation at 100% capacity factor, including fuel and other feedstock costs. This is offset by any byproduct revenues. CF is the plant capacity factor expressed as a fraction of the total electricity that would be generated if the plant operated at full load without interruption. It is assumed that this factor be constant or levelized over the operational period. The fixed charge rate (FCR) is based on capital recovery factors (CRF) that match the finance structure and capital expenditure period. The CRF includes an after-tax weighted average cost of capital (ATWACC) appropriately to address the actual cost of repaying the interest on debt accrued during construction and included in the total as spent capital (TASC) factor. The FCR is provided by the 2019 revision of the QGESS document "Cost Estimation Methodology for NETL Assessment of Power Plant Performance" and shown in Table 5-10. The rate chosen for this study was a nominal three-year FCR.

Table 5-10 Fixed Charge Rate for COE

Finance Structure	IOU – 30 Years	
Capital Recovery Periods	Three Years	Five Years
FCR Nominal	0.0886	0.0886
FCR Real	0.0707	0.0707

The TASC is expressed in mixed-year, current or real dollars over the entire capital expenditure period. It is calculated from the total overnight cost (TOC) by using the following factors taken from the 2019 revision of the QGESS document "Cost Estimation Methodology for NETL Assessment of Power Plant Performance" shown in Table 5-11. The TASC/TOC chosen for this study was a nominal three-year ratio.

Table 5-11 TASC/TOC Factors

Finance Structure	BBB+[3] or Higher Company	
Capital Expenditure Period	Three Years	Five Years
$TASC/TOC_{nominal}$	1.242	1.289
$TASC/TOC_{real}$	1.093	1.154

The TOC includes "overnight" depreciable and non-depreciable capital expenses that are incurred during the capital expenditure period. This does not include escalation and interest during construction. The factor of TASC to TOC is calculated by adding the cost of escalation to the cost of funding.

5.5.4 Cost of Electricity (COE) Results

The results of the cost of electricity, with and without the energy storage system, calculations are shown in Table 5-12.

Table 5-12 Cost of Electricity

Cost of Electricity	
Plant Capacity, %	85
Total Annual Operation, hrs	8,766
Total As Spent Cost (TASC), $	2,800,520,000
Fixed Rate Charge (FRC), $	0.0886
First Year Capital Charge, $	248,126,000
First Year Fixed Operating Costs, $	46,538,000
First Year Variable Operating Costs, $	14,000,000
First Year Fuel Costs, $	51,100,000
Total Annual Cost, $	359,764,000
Annual Net Power Production, MWh	2,234,000
Cost Of Electricity $/MWhr$_{net}$ (without ESS)	160

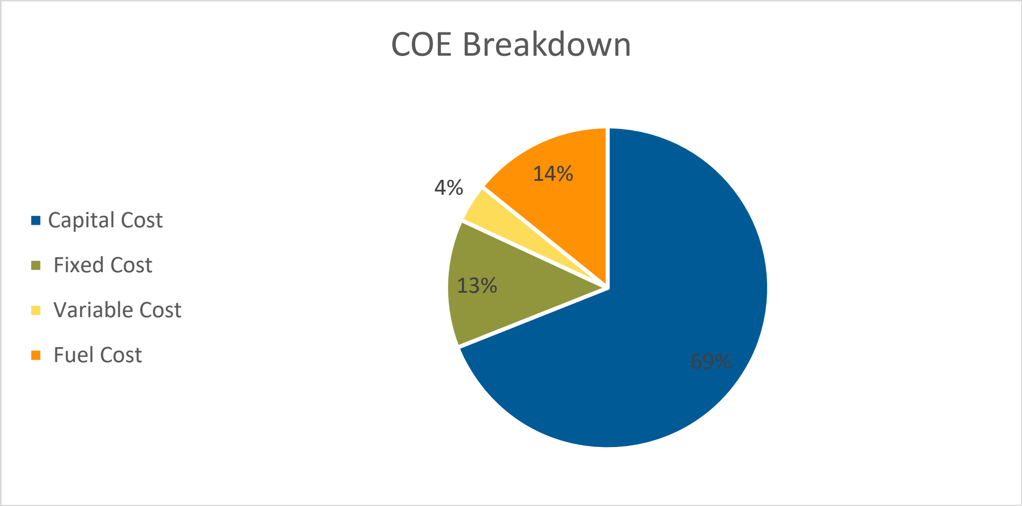

Figure 5-1 Cost of Electricity Breakdown for Base Case

5.6 Risk Factors

5.6.1 Risk Factors

As discussed in Section 4.0 of this report, the contingencies of areas that are considered emerging technologies include higher-process contingencies and, in some areas, engineering compared to the common commercialized technologies. We also included cost for several systems noted in the risk management discussions. The following list describes a summary of cost considerations based on risk management:

- A bypass stack was considered so the plant could operate if the CO_2 compressor or carbon capture system was not functioning as expected. A stub stack was considered in the original cost, but additional cost for a bypass stack was added for bypass functionality.

- Cost of the LTO/NCM lithium ion battery system includes a real-time temperature monitoring system and a fire suppression system based on NFPA 855.The redox flow battery considers a real-time monitoring system for liquid pressure, flow rate, liquid level, temperature and automated valve system. A drain tank is included to prepare for an accidents like earthquake a dike or emergency.

- A redundant line for the CO_2 purge was considered in case the CO_2 compressors or the purge line was not functioning properly. No added cost was included under the assumption an existing pipeline is near the plant.

- There is an efficiency at risk when considering this plant will need to ramp up and ramp down quickly. During these situations we are considering this power plant will have greater instrumentation and controls complexity over traditional power plants to smooth out the charges during ramp changes. The ability to maintain efficiency during these swings will need to be investigated further in the FEED study.

- Added steam capacity from the auxiliary steam plant may be required during low-load scenarios for the carbon capture and ZLD system operation.

- Contingency was added around the electrical and process controls.

5.7 Sensitivity Analysis

5.7.1 Total Plant Cost Sensitivity for Existing Coal-Fired Power Plant Demonstration

The capital cost sensitivity for a demonstrating coal plant was conducted by assuming an existing coal-fired power plant similar in size to the 350MW proposed power plant with a subcritical or ultra-super critical boiler. The plant is assumed to have a coal yard and handing equipment. It is assumed to have most flue gas cleanup with a wet scrubber for the FGD. It is also assumed to have most water systems, such as the cooling water tower, the circulating water equipment, feedwater heaters, wastewater treatment system, and other miscellaneous BOP.

The seventeen cost categories were assigned a percent reduction based on potentially existing equipment at the coal-fired power plant. This is illustrated in Table 5-13. As a result, it can be estimated that demonstrating at an existing coal-fired power plant can save approximately \$600M or ~32% of the total capital cost.

Table 5-13 Percent Reduction of Cost for Demonstration at an Existing Coal-Fired Power Plant

#	Item	Cost Reduction ($)	Anticipated TPC ($)	Anticipated Reduction ($)
1 & 2	Coal Handling & Coal Preparation and Feed	80	119,025,000	95,000,000
3	Feedwater & Misc. BOP Systems	0	185,150,000	0
4	Boiler & Accessories	25	330,625,000	83,000,000
5	Gas Cleanup	60	171,925,000	103,000,000
6	CO_2 Removal & Compression	0	244,662,500	0
7	Ductwork/Piping/Support/Insulation	10	30,417,500	3,000,000
8	Steam Turbine and Auxiliaries	50	171,925,000	86,000,000
9	Cooling Water System	30	87,285,000	26,000,000
10	Ash & Spent Sorbent Handing System	75	27,772,500	21,000,000
11	Accessory Electric Plant	65	126,960,000	83,000,000
12	Instrumentation and Control	10	45,824,625	5,000,000
13	Improvements to Site	40	75,382,500	30,000,000
14	Buildings and Structures	70	86,710,355	61,000,000
15	Gas Turbine	0	59,254,000	0
16	Lithium Ion / Vanadium Redox Battery ESS	0	72,986,000	0
17	Water Treatment System/ ZLD	15	24,095,000	4,000,000
	Total	**32**	**1,860,000,000**	**600,000,000**

5.7.2 Effect of COE by Varying TPC

Capital cost varies with a range of accuracy. The capital cost also varies depending on a plant's ability to use some demonstration options or the variable battery cost changes. Visual representations of the COE and TPC relationship can be found in Figure 5-2. This figure illustrates that the anticipated COE is estimated to vary between $100 and $250 depending on the TPC.

The COE will be reduced by minimizing the project contingency as the design progresses during the FEED study. Furthermore, the capital cost can be reduced in later phases with value engineering, standardization, and modularization strategies.

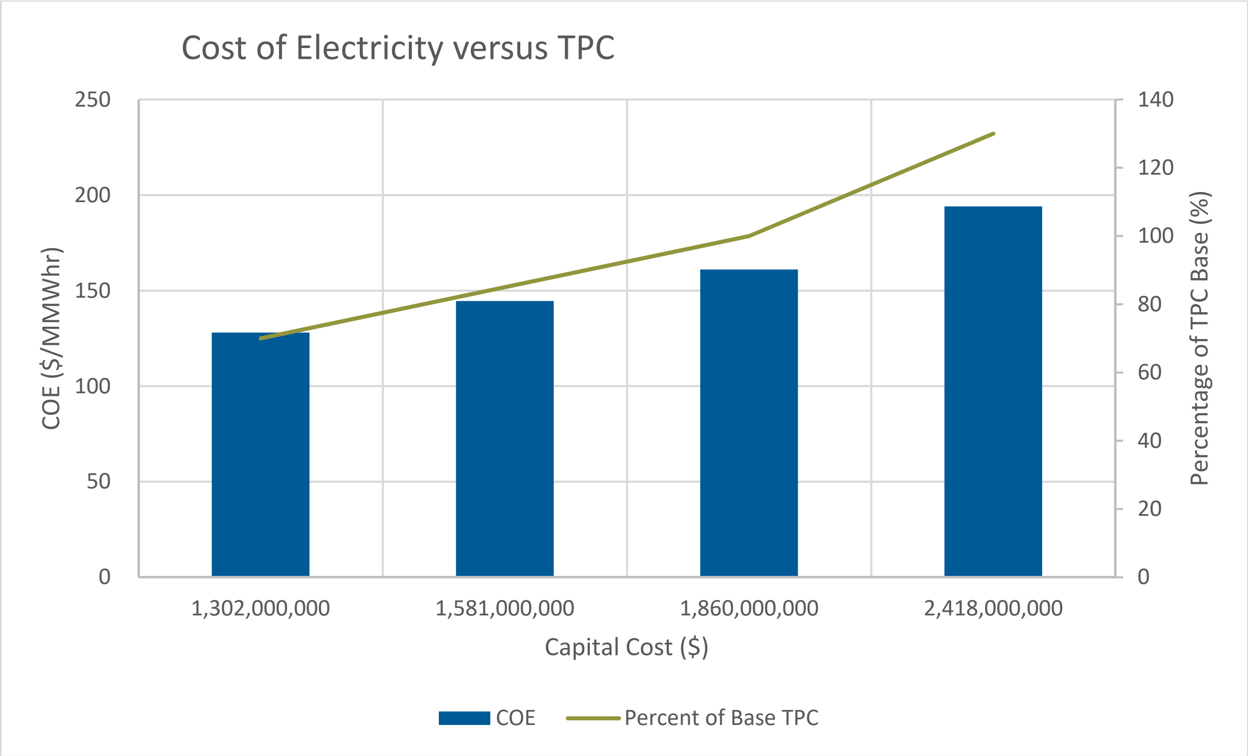

Figure 5-2 Cost of Electricity versus Capital Cost

5.7.3 Plant Loading Sensitivity

Due to the proposed plant's probable variance in operating load, a sensitivity analysis was conducted to compare the COE to different loading scenarios.

For this study, there are five different loading scenarios.

- 20% Plant Load: This consists of the gas turbine load being at 0% and the coal power load being at 30%
- 33% Plant Load: This consists of the gas turbine load being at 0% and the coal power load being at 50%
- 47% Plant Load: This consists of the gas turbine load being at 0% and the coal power load being at 70%
- 66% Plant Load: This consists of the gas turbine load being at 75% and the coal power load being at 75%
- 100% Plant Load (or Base Case): This consists of the gas turbine load being 100% and the coal power load being at Maximum Continuous Rating (MCR)

Table 5-14 and Figure 5-3 calculate COE based on these different loading scenarios. The variable operating costs are expected to decrease as load decreases with water and chemical consumption and waste disposal. This reduction is not linear as the number of starts on the gas engine and maintenance outage work is anticipated to increase as the operating capacity for this plant is reduced. The values in the table below show fixed labor operating cost, which includes plant personnel, would not change as the load would decrease. Table 5-14 and Figure 5-3 display the COE compared to the plant load and illustrate how the cost decreases as the load increases.

Table 5-14 Effect of Cost of Electricity with Reduction in Loading

Cost of Electricity					
Loading, %	**20**	**33**	**47**	**66**	**100**
Net Output, MW	**63**	**106**	**151**	**225**	**300**
First Year Capital Charge, $	248,126,000	248,126,000	248,126,000	248,126,000	248,126,000
First Year Fixed Operating Costs, $	46,390,000	46,390,000	46,390,000	46,390,000	46,390,000
First Year Variable Operating Costs, $	5,460,000	8,400,000	10,780,000	10,500,000	14,000,000
First Year Fuel Costs, $	18,333,000	27,885,200	35,720,100	46,736,400	51,100,000
Annual Net Power Production, MWh	469,000	787,000	1,125,000	1,679,000	2,237,000
Cost Of Electricity, $	**679**	**420**	**303**	**210**	**160**

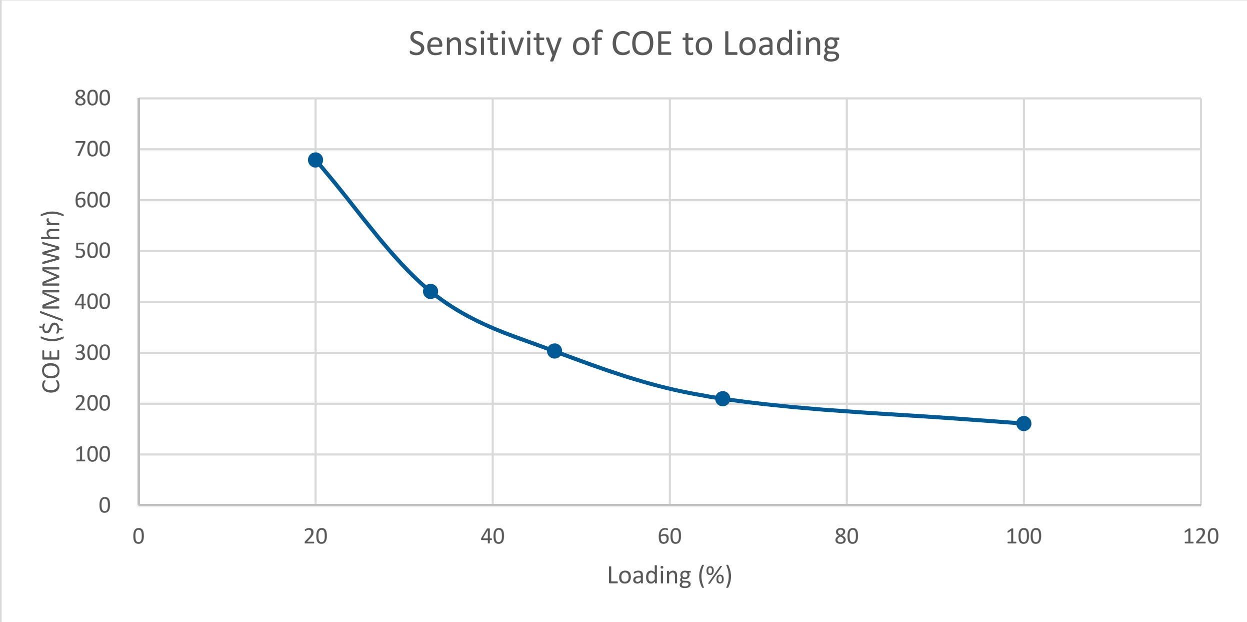

Figure 5-3 Sensitivity of Cost of Electricity based on Plant Loading

5.7.4 COE with Varying Fuel Prices

5.7.4.1 Coal Pricing

The cost of coal used to develop the operations and maintenance cost estimate was $1.6/MMBTU. Since the price of coal varies based on other factors such as type, plant location, and transport, the cost of coal can affect the cost of electricity. This cost was calculated based on a cost of coal from $0.5/MMBTU to $5/MMBTU. These results are represented visually in

Figure 5-4 which demonstrates the COE will be between approximately $150 and $190 without ESS, based on an 85% capacity factor.

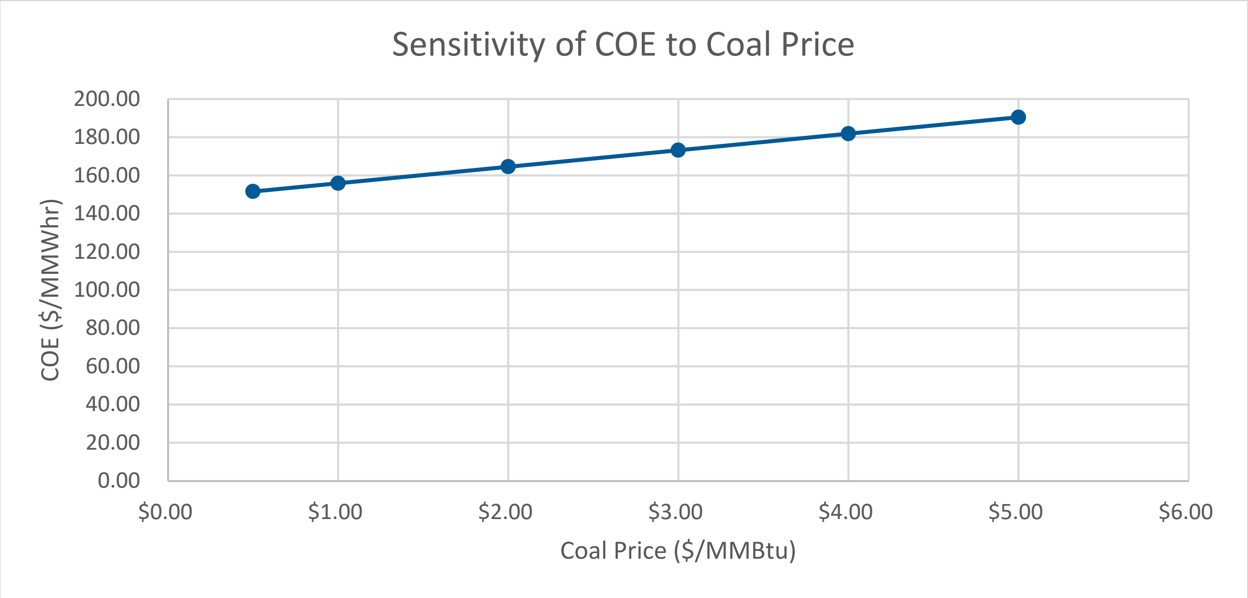

Figure 5-4 COE versus the Price of Coal

5.7.4.2 Natural Gas Pricing

Much like the price of coal, the price of natural gas varies. The cost of fuel gas used to develop the operations and maintenance cost estimate was $3.0/MMBTU. The cost was calculated based on a cost of natural gas from $0.5/MMBTU to $10/MMBTU as shown in Figure 5-5. This chart demonstrates the COE will be between $150 and $185 without ESS, based on an 85% capacity factor.

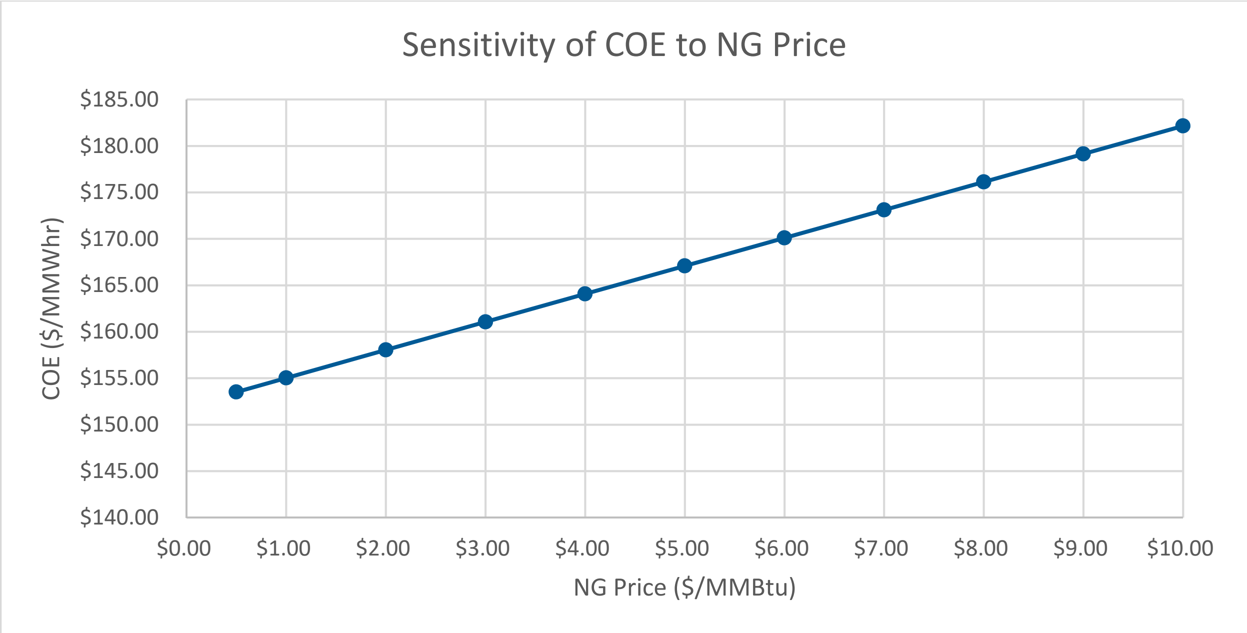

Figure 5-5 COE versus the Price of Natural Gas

5.7.5 The Effect of COE with Variations in Heat Rate

Variations in heat rate effect the COE in the same way as variations in fuel pricing. For example, a 1% increase in heat rate results in a 1% increase in annual fuel cost—just as a 1% increase in fuel pricing does. Consequently, any variation in heat rate between the calculated value and the as- built value will look the same as a variation in fuel pricing between the pro forma value and the actual value. Therefore, we have not graphed it independently. The economic value of variations in heat rate is important to the topic of value engineering later described in Section 5.7.9.

5.7.6 The Effect of COE with Different Fuel Qualities

The base case for the capital cost of the HGCC plant and the performance modeling was based on the bituminous coal specification provided by the Department of Energy[xxiii]. Currently, performance modeling is being evaluated to determine the effect of efficiency on the existing plant, assuming the same size boiler and turbines. Coal with high moisture or alkalinity would need additional coal conditioning and drying systems, which add capital cost. There would also be an increase in operating and maintenance cost for those systems in parasitic load and chemical additives for variable O&M. The maintenance and labor cost as well as environmental reagents and waste disposal is also anticipated to increase. This could be minimized by adding a coal conditioning system that would reduce the alkalinity or other contaminants in the coal prior to combustion. Figure 5-6 illustrates the effect these different types have on the cost of electricity due to its coal heating input value.

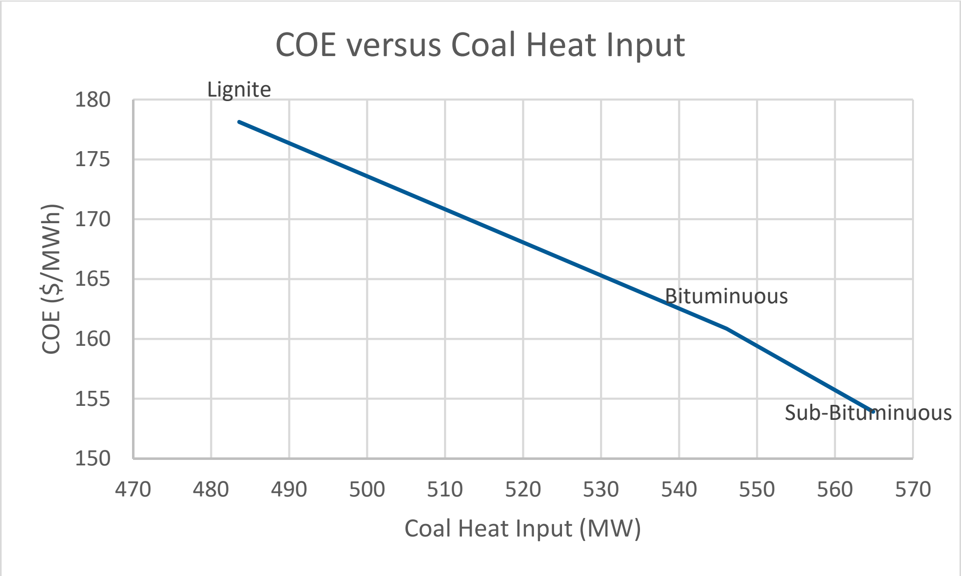

Figure 5-6 Effect of Coal Type on Cost of Electricity

5.7.7 The Effect of COE with Carbon Tax

Since one of the main objectives of this concept is to lower the amount of CO_2 being released into the atmosphere, it is important to note how this is beneficial from a cost perspective. The COE was originally estimated without a CO_{2e} tax for the sake of simplicity. However, Figure 5-7 shows how the COE increases very slightly with a greater CO_{2e} tax rate. Based on tax rates being considered throughout the world, a tax range of $0–$50/ton CO_2 emitted was considered[xxiv]. Table 5-15 below shows how the cost of electricity would be effected assuming our base case, which considered 147,000 tons CO_2 emitted per year.

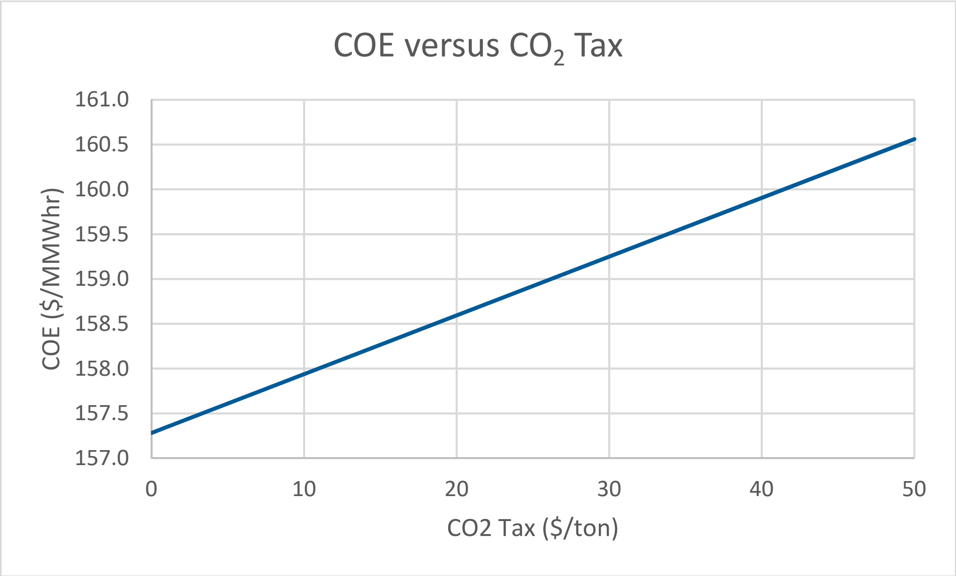

Figure 5-7 COE Increase versus Carbon Tax Base Case

5.7.8 The Effect of COE with Varying Carbon Capture Credits

For this calculation, it was assumed that the CO_2 production would be approximately 1410 tons/day and that the carbon capture system would be 90% effective.

26 USC 45Q: Credit for Carbon Oxide Sequestration provides the tax credit for geologic storage at $50/ton at 2026 (which increases based on inflation) and for commercial use at $35/ton at 2060 (which increases based on inflation). [xxv]

Table 5-15 Effect of Cost of Electricity with Varying Carbon Capture Credits

Cost of Electricity with Different Tax Credits					
Tax Credit	**Base (none), $**	**Storage, $**	**EOR – Min, $**	**EOR – Average, $**	**EOR – Max, $**
Credit, $/ton	0	50	35	66	97
Total As Spent Cost (TASC), $	2,800,520,000	2,800,520,000	2,800,520,000	2,800,520,000	2,800,520,000
Fixed Rate Charge (FRC)	0.0886	0.0886	0.0886	0.0886	0.0886
First Year Capital Charge	248,126,072	248,126,072	248,126,072	248,126,072	248,126,072
First Year Fixed Operating Costs, $	46,539,000	46,539,000	46,539,000	46,539,000	46,539,000
Total Credit, $	0	23,174,000	16,222,000	30,590,000	44,958,000
First Year Variable Operating Costs, $	14,000,000	14,000,000	14,000,000	14,000,000	14,000,000
First Year Fuel Costs, $	51,100,000	51,100,000	51,100,000	51,100,000	51,100,000
Annual Net Power Production, MWh	2,234,000	2,234,000	2,234,000	2,234,000	2,234,000
Cost Of Electricity $/MWh	$160	$151	$154	$147	$141

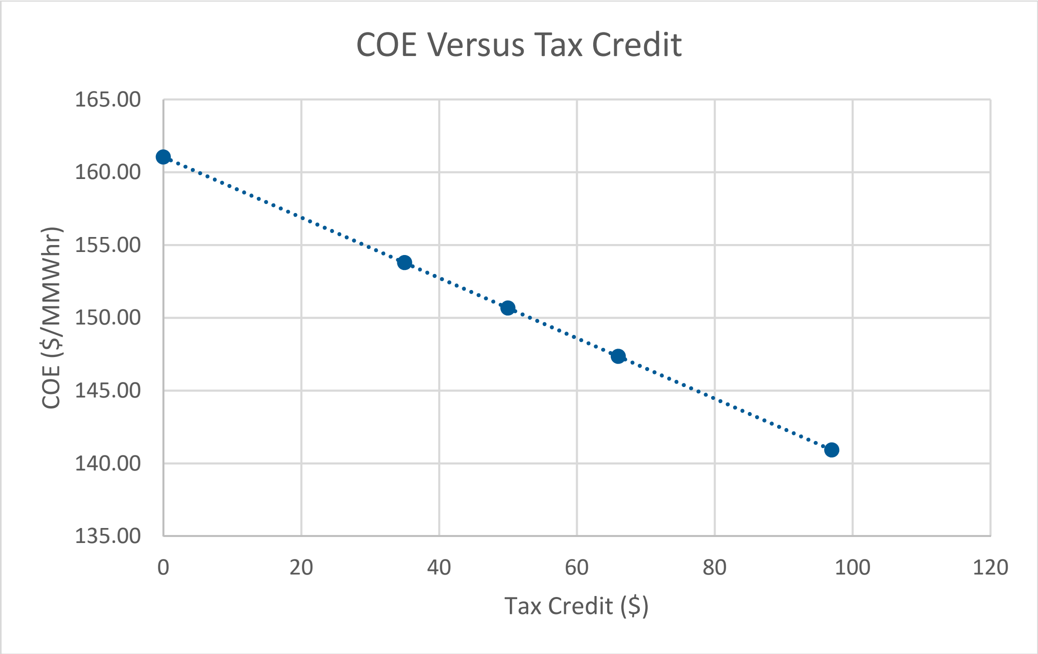

Figure 5-8 COE versus Tax Credits

5.7.9 US Financing

Electric Cooperatives have the ability to secure RUS financing for their power infrastructure projects. These loans once obtained provide for significant reductions in the COE when compared the financing alternatives available to IOUs. This can be observed in Figure 5-9.

RUS interest rates are nearly equivalent to 30 year United States Treasury Rates. Currently those rates are at historical lows in the range of 1-1.5%. A couple of years ago those rates were in the 3%. Range. Market conditions at the time of financing will determine the ultimate interest rate for the load. The curve below shows how the much the COE would be lowered for different interest rate scenarios when compared to the base case in the report.

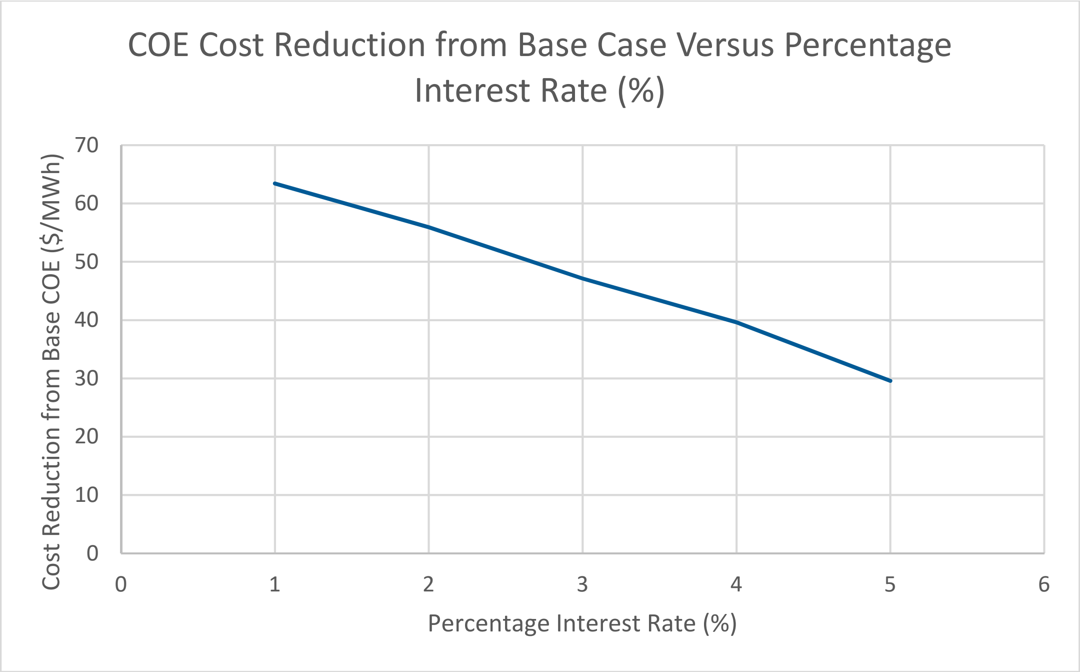

Figure 5-9 COE versus Interest Rate

5.8 Value Engineering

As the team reviewed this approach, opportunities for conducting further engineering evaluations (in the FEED study) to explore reduction in cost and improvements in performance are expected. These are identified in the table below along with an indication of whether they are expected to result in a savings of capital cost or an improvement to heat rate. There are some items listed that have neither a capital cost benefit nor a heat rate benefit but may have different advantages such as ability to use lower cost fuel, reduction in maintenance costs, or an added revenue stream.

Table 5-16 Summary of Value Engineering Considerations

Value Engineering Option	Heat Rate Impact	Capital Cost Impact
Heat CTG fuel gas to 365F	decrease	increase
Apply evaporative cooling to the CTG with 85% effectiveness	decrease	increase
Eliminate top two heaters and slip stream heaters and use LTE	decrease	decrease
Use shaft driven feed pump with Vorecon fluid coupling	decrease	increase
Design cooling tower for 5F approach	decrease	increase
Use hybrid SJAE / LRVP system	none	decrease
Use two-shell condenser, 10F rise, 5F TTD, and 20 ft water side pressure drop	decrease	increase
Arrange gland steam condenser in parallel with FWH#1	none	decrease
Send ZLD distillate to MUF tank through EDI; delete demineralizer	none	decrease
Delete CCW booster pumps, design CCW HX for same dP as condenser	decrease	decrease
Use WSAC for CO_2 compressors inter & after coolers	decrease	decrease
Use circulating water directly in flue gas cooler instead of CCW	decrease	decrease
Use flue gas in mills for coal pre-drying & heating	decrease	unknown
Use hot CO_2 for coal bin blanketing, fluidizing & final heating / drying	decrease	unknown
Locate cooling tower closer to condenser	none	decrease
Pump FWH drains forward	decrease	increase
Send ZLD sludge to same filter press as FGD sludge	none	decrease
Use 7EA instead of 6F	unknown	decrease
Eliminate electrostatic mist eliminator	none	decrease
Optimize water treatment / ZLD to eliminate unnecessary items	none	decrease
Modularization or containerization of equipment	none	decrease
Utilization of battery ESS capacity	none	none
Utilization of available site acreage	none	none
Condition Based Monitoring	none	increase
Pulverized Coal Mixing System	none	increase
Use closed cooling water for CTG in lieu of air coolers	none	decrease

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Appendix A Minerals Chemical Formulas

Table A1. Silicate and Oxide Minerals Found in Coals

Species	Chemical Formula
Silica and Silicates – Common Occurrence	
Quartz	SiO_2
Kaolinite	$Al_2O_3 \cdot 2SiO_2 \cdot 2H_2O$
Muscovite	$K_2O \cdot 3Al_2O_3 \cdot 6SiO_2 \cdot 2H_2O$
Illite	As Muscovite with Mg, Ca and Fe
Montmorillonite	$(1-x)Al_2O_3 \cdot x(MgO, Na_2O) \cdot 4SiO_2 \cdot H_2O$
Chlorite	$Al_2O_3 \cdot 5(FeO, MgO)\ 3.5SiO_2 \cdot 7 \cdot 5H_2O$
Orthoclase	$K_2O \cdot 3Al_2O_3 \cdot 6SiO_2$
Plagioclase	$Na_2O \cdot Al_2O_3 \cdot 6SiO_2$ – Albite $CaO \cdot Al_2O_3 \cdot 2SiO_2$ – Anorthite
Silicates – Rare	
Augite	$Al_2O_3 \cdot Ca(Mg, Fe, Al, Ti) \cdot O \cdot 2SiO_2$
Biotite	$Al_2O_3 \cdot 6(MgO \cdot FeO) \cdot 6SiO_2 \cdot 4H_2O$
Sanadine	$K_2O \cdot Al_2O_3 \cdot 6SiO_2$
Zeolite	$Na_2O \cdot Al_2O_3 \cdot 4SiO_2 \cdot 2H_2O$ – Analcime $CaO \cdot Al_2O_3 \cdot 7SiO_2 \cdot 6H_2O$ – Heulandite
Zircon	$ZrO_2 \cdot SiO_2$
Oxides and Hydrated Oxides	
Rutile	TiO_2
Magnetite	Fe_3O_4
Hematite	Fe_2O_3
Limonite	$Fe_2O_3 \cdot H_2O$
Diaspore	$Al_2O_3 \cdot H_2O$

Table A2. Carbonate, Sulfide, Sulfate, and Phosphate Minerals Coals

Species	Chemical Formula
Carbonates	
Calcite	$CaCO_3$
Dolomite	$CaCO_3 \cdot MgCO_3$
Ankerite	$CaCO_3 \cdot FeCO_3$
Siderite	$FeCO_3$
Sulfides	
Pyrite	FeS_2
Marcasite	FeS_2
Chalcopyrite	CuFeS
Galena	Pbs
Sphalerite	ZnS
Sulfates	
Barite	$BaSO_4$
Gypsun	$CaSO_4 \cdot 2H_2O$
Jarosite	$K_2SO_4 \cdot xFe_2(SO_4)_3$
Phosphates	
Apatite	$Ca_5F\ (PO_4)_3$
Monazite	(Ce, La, Y, Th) PO_4

Appendix B Process Flow Diagrams PFD-001 & 002, Feedwater

PERFORMANCE SUMMARY				
TOTAL PLANT LOAD				MCR
COAL POWER PLANT LOAD				MCR
COAL TYPE	BITUMINOUS	SUB-BITUMINOUS	LIGNITE	
AMBIENT DRY BULB TEMPERATURE	15.0	15.0	15.0	°F
AMBIENT RELATIVE HUMIDITY	60.0	60.0	60.0	%
BAROMETRIC PRESSURE	1.0	1.0	1.0	bara
GAS TURBINE LOAD	100	100	100	%
GAS TURBINE POWER OUTPUT	86.8	86.8	86.8	MW
STEAM TURBINE POWER OUTPUT	270.6	271.2	226.5	MW
ENERGY STORAGE SYSTEM POWER OUTPUT	50.2	50.2	40.9	MW
PLANT GROSS POWER OUTPUT	407.6	408.2	354.2	MW
AUXILIARY POWER CONSUMPTION	57.6	61.6	54.2	MW
PLANT NET POWER OUTPUT	350.0	346.0	300.0	MW
NATURAL GAS HEAT INPUT	265.0	265.0	265.0	MW
COAL HEAT INPUT	546.1	564.9	483.6	MW
PLANT GROSS EFFICIENCY (HHV)	50.3	49.2	47.3	%
PLANT NET EFFICIENCY (HHV)	43.2	41.8	40.1	%
PLANT NET EFFICIENCY WITHOUT ENERGY STORAGE SYSTEM (HHV)	37.0	35.7	34.6	%

ISSUED FOR FINAL PRE-FEED STUDY NOT FOR CONSTRUCTION

NO.	BY	CHK.	APP.	DATE	REVISION DESCRIPTION
G	CAH	CAH	-	3/27/2020	ISSUED FINAL FOR PRE-FEED STUDY
F	CAH	CAH	-	3/15/2020	ISSUED FOR REVIEW
E	CAH	CAH	-	2/15/2020	ISSUED FOR REVIEW
D	CAH	CAH	-	1/24/2020	ISSUED FOR REVIEW
C	CAH	CAH	-	1/6/2020	ISSUED FOR REVIEW - PERFORMANCE REPORT
B	KDS	-	-	11/22/19	ISSUED FOR CLIENT REVIEW

RELEASED TO/FOR	6/19/19	11/22/19	1/6/2020	1/24/2020	2/15/2020	3/15/2020	3/27/2020
CLIENT							
BID							
CONSTRUCTION							
	A	B	C	D	E	F	G
	DATE RELEASED						

BARR
Corporate Headquarters: Minneapolis, Minnesota Ph: 1-800-632-2277
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Scale	NO SCALE
Date	6/12/19
Drawn	DAK
Checked	CAH
Designed	CAH
Approved	

NETL/DOE COAL FIRST - HGCC
PRE-FEED STUDY

HGCC

HGCC FUEL PREP, COMBUSTION, WATER SYSTEM OVERALL PROCESS FLOW DIAGRAM

BARR PROJECT No. 48/31-1001.01
CLIENT PROJECT No.
DWG. No. PFD-001
REV. No. G

ISSUED FOR FINAL
PRE-FEED STUDY
NOT FOR CONSTRUCTION

NO.	BY	CHK.	APP.	DATE	REVISION DESCRIPTION
F	CAH	CAH	-	3/27/2020	ISSUED FINAL FOR PRE-FEED STUDY
E	CAH	CAH	-	3/15/2020	ISSUED FOR REVIEW
D	CAH	CAH	-	1/24/2020	ISSUED FOR REVIEW
C	CAH	CAH	-	1/6/2020	ISSUED FOR REVIEW - PERFORMANCE REPORT
B	KDS	-	-	11/22/19	ISSUED FOR CLIENT REVIEW

RELEASED TO/FOR	A	B	C	D	E	F	0
CLIENT	6/19/19	11/22/19	1/6/2020	1/24/2020	3/15/2020	3/27/2020	
BID							
CONSTRUCTION							

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Scale	NO SCALE
Date	6/12/19
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Checked	CAH
Designed	CAH
Approved	

NETL/DOE COAL FIRST - HGCC
PRE-FEED STUDY

HGCC

HGCC AIR QUALITY CONTROL SYSTEM AND WASTEWATER
OVERALL PROCESS FLOW DIAGRAM

BARR PROJECT No. 48/31-1001.01
CLIENT PROJECT No.
DWG. No. PFD-002
REV. No. F

ISSUED FOR FINAL
PRE-FEED STUDY
NOT FOR CONSTRUCTION

NO.	BY	CHK.	APP.	DATE	REVISION DESCRIPTION
D	KAS2	KAS2	-	3/27/2020	ISSUED FINAL FOR PRE-FEED STUDY
C	KAS2	KAS2	-	3/15/2020	ISSUED FOR REVIEW
B	KAS2	KAS2	-	1/24/2020	ISSUED FOR REVIEW
A	KAS2	KAS2	-	1/6/2020	ISSUED FOR REVIEW - PERFORMANCE REPORT

RELEASED TO/FOR	A	B	C	D	0	1	2
CLIENT	1/6/2020	1/24/2020	3/15/2020	3/27/2020			
BID							
CONSTRUCTION							

DATE RELEASED

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Scale	NO SCALE
Date	11/25/19
Drawn	DAK
Checked	KAS2
Designed	KAS2
Approved	

NETL/DOE COAL FIRST - HGCC
PRE-FEED STUDY

HGCC

STEAM TURBINE AND FEEDWATER HEATING PROCESS FLOW DIAGRAM

BARR PROJECT No. 48/31-1001.01
CLIENT PROJECT No.
DWG. No. PFD-013
REV. No. D

Appendix C Capital Cost Estimate

Breakdown of Costs

Class IV Estimate of Capital Costs, Coal First PreFEED Study

Barr Engineering

For the U. S. Department of Energy

Item No.	Description	Plant Equipment Costs	Bulk Materials Cost	Direct Labor	Indirect Labor	Bare Erected Cost	Eng'g CM H.O. & Fee 15%	Process Contingencies, varies	Process Contingencies, %	Project Contingencies, varies	Project Contingencies, %	Total Plant Costs	S/ kW
1	**Coal & Sorbent Handling**												
1.01	Coal Receiving/ Unload Station: Foundations & Slabs	$ -	$ 470,000	$ 430,000	$ -	$ 900,000	$ 135,000	$ -	0%	$ 155,250	15%	$ 1,190,250	$ 3.40
1.02	Coal Bunker/ Storage Yard: Sitework & Conc. Push Walls	$ -	$ 900,000	$ 1,100,000	$ -	$ 2,000,000	$ 300,000	$ -	0%	$ 345,000	15%	$ 2,645,000	$ 7.56
1.03	Coal Stacker & Declaimer: Foundations	$ -	$ 200,000	$ 300,000	$ -	$ 500,000	$ 75,000	$ -	0%	$ 86,250	15%	$ 661,250	$ 1.89
1.04	Coal Conveyors: Foundations	$ -	$ 550,000	$ 650,000	$ -	$ 1,200,000	$ 180,000	$ -	0%	$ 207,000	15%	$ 1,587,000	$ 4.53
1.05	Coal Hoppers & Feeders for Unload: Equipment	$ 854,000	$ 180,000	$ 466,000	$ -	$ 1,500,000	$ 225,000	$ -	0%	$ 258,750	15%	$ 1,983,750	$ 5.67
1.06	Coal Stacker & Declaimer: Equipment	$ 2,744,000	$ 475,000	$ 781,000	$ -	$ 4,000,000	$ 600,000	$ -	0%	$ 690,000	15%	$ 5,290,000	$ 15.11
1.07	Coal Conveyors: Structure, Conveyor Equip., & Belts	$ 22,895,000	$ 6,245,000	$ 9,860,000	$ -	$ 39,000,000	$ 5,850,000	$ -	0%	$ 6,727,500	15%	$ 51,577,500	$ 147.36
1.08	Coal Dust/ CO2 Purge Fire Suppression	$ 950,000	$ 750,000	$ 1,200,000	$ -	$ 2,900,000	$ 435,000	$ -	0%	$ 500,250	15%	$ 3,835,250	$ 10.96
1.09	Hydrated Lime (Sorbent) Unload & Storage Silo: Foundations	$ -	$ 85,000	$ 115,000	$ -	$ 200,000	$ 30,000	$ -	0%	$ 34,500	15%	$ 264,500	$ 0.76
1.10	Hydrated Lime (Sorbent) Unload & Storage Silo: Equipment	$ 280,000	$ 50,000	$ 170,000	$ -	$ 500,000	$ 75,000	$ -	0%	$ 86,250	15%	$ 661,250	$ 1.89
1.11	Limestone, Truck Receive & Unload: Foundations	$ -	$ 95,000	$ 205,000	$ -	$ 300,000	$ 45,000	$ -	0%	$ 51,750	15%	$ 396,750	$ 1.13
1.12	Limestone, Stack out & Reclaim: Foundations	$ -	$ 230,000	$ 270,000	$ -	$ 500,000	$ 75,000	$ -	0%	$ 86,250	15%	$ 661,250	$ 1.89
1.13	Limestone, Conveyors to Reclaim & Feeder: Foundations	$ -	$ 380,000	$ 420,000	$ -	$ 800,000	$ 120,000	$ -	0%	$ 138,000	15%	$ 1,058,000	$ 3.02
1.14	Limestone, Truck Receive & Unload: Equipment	$ 2,335,000	$ 380,000	$ 1,085,000	$ -	$ 3,800,000	$ 570,000	$ -	0%	$ 655,500	15%	$ 5,025,500	$ 14.36
1.15	Limestone, Stack out & Reclaim: Equipment	$ 1,381,000	$ 331,000	$ 588,000	$ -	$ 2,300,000	$ 345,000	$ -	0%	$ 396,750	15%	$ 3,041,750	$ 8.69
1.16	Limestone, Conveyors: Structure, Conveyor Equip., & Belts	$ 5,092,000	$ 801,000	$ 2,507,000	$ -	$ 8,400,000	$ 1,260,000	$ -	0%	$ 1,449,000	15%	$ 11,109,000	$ 31.74
1.17	Condition Base Monitoring, CMB, MGA, & FESA	$ 598,000	$ 172,000	$ 430,000		$ 1,200,000	$ 180,000	$ -	0%	$ 207,000	15%	$ 1,587,000	$ 4.53
	Subtotal	**$ 37,129,000**	**$ 12,294,000**	**$ 20,577,000**	**$ -**	**$ 70,000,000**	**$ 10,500,000**	**$ -**	**0%**	**$ 12,075,000**	**15%**	**$ 92,575,000**	**$ 264.50**
2	**Coal & Sorbent, Prep & Feed**												
2.01	Coal Pulverizer & Feeder: Foundations	$ -	$ 430,000	$ 470,000	$ -	$ 900,000	$ 135,000	$ -	0%	$ 155,250	15%	$ 1,190,250	$ 3.40
2.02	Coal Pulverizer & Feeder: Equipment	$ 2,110,000	$ 250,000	$ 740,000	$ -	$ 3,100,000	$ 465,000	$ -	0%	$ 534,750	15%	$ 4,099,750	$ 11.71
2.03	Coal Feed to Boiler: Duct	$ 7,103,000	$ -	$ 2,597,000	$ -	$ 9,700,000	$ 1,455,000	$ -	0%	$ 1,673,250	15%	$ 12,828,250	$ 36.65
2.04	Hydrated Lime Injectors at Flue: Equipment	$ 35,000	$ 20,000	$ 45,000	$ -	$ 100,000	$ 15,000	$ -	0%	$ 17,250	15%	$ 132,250	$ 0.38
2.05	Limestone Mill, Slurry Tank, & Pumps: Foundations	$ -	$ 175,000	$ 225,000	$ -	$ 400,000	$ 60,000	$ -	0%	$ 69,000	15%	$ 529,000	$ 1.51
2.06	Limestone Mill, Equipment	$ 1,629,000	$ 273,000	$ 698,000	$ -	$ 2,600,000	$ 390,000	$ -	0%	$ 448,500	15%	$ 3,438,500	$ 9.82
2.07	Limestone Slurry Tank & Pumps	$ 1,317,000	$ 280,000	$ 603,000	$ -	$ 2,200,000	$ 330,000	$ -	0%	$ 379,500	15%	$ 2,909,500	$ 8.31
2.08	Limestone Slurry to Injectors: Piping & Valves	$ -	$ 235,000	$ 265,000	$ -	$ 500,000	$ 75,000	$ -	0%	$ 86,250	15%	$ 661,250	$ 1.89
2.09	Limestone Slurry Injectors at Flue: Equipment	$ 300,000	$ 60,000	$ 140,000	$ -	$ 500,000	$ 75,000	$ -	0%	$ 86,250	15%	$ 661,250	$ 1.89
	Subtotal	**$ 12,494,000**	**$ 1,723,000**	**$ 5,783,000**	**$ -**	**$ 20,000,000**	**$ 3,000,000**	**$ -**	**0%**	**$ 3,450,000**	**15%**	**$ 26,450,000**	**$ 75.57**
3	**Feedwater & Misc. BOP Equipment & Systems**												
3.01	Groundwater Wells	$ -	$ 830,000	$ 870,000	$ -	$ 1,700,000	$ 255,000	$ -	0%	$ 293,250	15%	$ 2,248,250	$ 6.42
3.02	Ground Water Pumps : Equipment	$ 565,000	$ -	$ 435,000	$ -	$ 1,000,000	$ 150,000	$ -	0%	$ 172,500	15%	$ 1,322,500	$ 3.78
3.03	Ground Water to Pretreatment: Piping & Valves	$ -	$ 470,000	$ 530,000	$ -	$ 1,000,000	$ 150,000	$ -	0%	$ 172,500	15%	$ 1,322,500	$ 3.78
3.04	Makeup Water Supply & Water Pre-treatment: Piping	$ -	$ 1,440,000	$ 1,560,000	$ -	$ 3,000,000	$ 450,000	$ -	0%	$ 517,500	15%	$ 3,967,500	$ 11.34
3.05	Feed Water NAOH Pre-Treatment: Equipment	$ 2,530,000	$ 650,000	$ 1,820,000	$ -	$ 5,000,000	$ 750,000	$ -	0%	$ 862,500	15%	$ 6,612,500	$ 18.89
3.06	Feedwater Pumps: Equipment	$ 472,000	$ 150,000	$ 378,000	$ -	$ 1,000,000	$ 150,000	$ -	0%	$ 172,500	15%	$ 1,322,500	$ 3.78
3.07	Boiler High Pressure Feedwater Heater: Equipment	$ 2,240,000	$ 500,000	$ 1,260,000	$ -	$ 4,000,000	$ 600,000	$ -	0%	$ 690,000	15%	$ 5,290,000	$ 15.11
3.08	Low Pressure Feed Water Heater: Equipment	$ 964,000	$ 150,000	$ 686,000	$ -	$ 1,800,000	$ 270,000	$ -	0%	$ 310,500	15%	$ 2,380,500	$ 6.80
3.09	Auxiliary Boilers: Equipment	$ 2,370,000	$ 500,000	$ 1,130,000	$ -	$ 4,000,000	$ 600,000	$ -	0%	$ 690,000	15%	$ 5,290,000	$ 15.11
3.10	Deaerator & Storage Tank	$ 2,068,000	$ 718,000	$ 1,214,000	$ -	$ 4,000,000	$ 600,000	$ -	0%	$ 690,000	15%	$ 5,290,000	$ 15.11
3.11	External Feedwater Heaters - Flue Gas	$ 2,200,000	$ 480,000	$ 1,020,000	$ -	$ 3,700,000	$ 555,000	$ -	0%	$ 638,250	15%	$ 4,893,250	$ 13.98
3.11	Feedwater, Condenser to Boiler: Piping	$ -	$ 6,400,000	$ 5,600,000	$ -	$ 12,000,000	$ 1,800,000	$ -	0%	$ 2,070,000	15%	$ 15,870,000	$ 45.34
3.12	Steam Piping	$ -	$ 8,525,000	$ 9,175,000		$ 17,700,000	$ 2,655,000	$ -	0%	$ 3,053,250	15%	$ 23,408,250	$ 66.88
3.13	Makeup Water & Condensate, Feed to Heat Recovery @ Carbon Capture: Piping	$ -	$ 5,160,000	$ 6,840,000	$ -	$ 12,000,000	$ 1,800,000	$ -	0%	$ 2,070,000	15%	$ 15,870,000	$ 45.34
3.14	Other Boiler Plant Systems	$ 1,800,000	$ 600,000	$ 1,600,000	$ -	$ 4,000,000	$ 600,000	$ -	0%	$ 690,000	15%	$ 5,290,000	$ 15.11
3.15	Natural Gas Feed to Gas Turbine: Piping & Valves	$ -	$ 2,612,000	$ 2,388,000	$ -	$ 5,000,000	$ 750,000	$ -	0%	$ 862,500	15%	$ 6,612,500	$ 18.89
3.16	Natural Gas Feed to Coal Boiler for Startup: Piping & Valves	$ -	$ 490,000	$ 510,000	$ -	$ 1,000,000	$ 150,000	$ -	0%	$ 172,500	15%	$ 1,322,500	$ 3.78
3.17	Wastewater Treatment ; Equipment	$ 6,303,000	$ 2,100,000	$ 5,597,000		$ 14,000,000	$ 2,100,000	$ -	0%	$ 2,415,000	15%	$ 18,515,000	$ 52.90
3.18	Wastewater & ZLD: Piping	$ -	$ 3,815,000	$ 4,185,000	$ -	$ 8,000,000	$ 1,200,000	$ -	0%	$ 1,380,000	15%	$ 10,580,000	$ 30.23
3.19	Fire Service Pumps: Equipment	$ 68,000	$ -	$ 32,000	$ -	$ 100,000	$ 15,000	$ -	0%	$ 17,250	15%	$ 132,250	$ 0.38
3.20	Fire Sprinklers: Piping & Valves	$ -	$ 5,158,000	$ 5,842,000	$ -	$ 11,000,000	$ 1,650,000	$ -	0%	$ 1,897,500	15%	$ 14,547,500	$ 41.56

Item No.	Description	Plant Equipment Costs	Bulk Materials Cost	Direct Labor	Indirect Labor	Bare Erected Cost	Eng'g CM H.O. & Fee 15%	Process Contingencies, varies	Process Contingencies, %	Project Contingencies, varies	Project Contingencies, %	Total Plant Costs	S/ kW
3.21	Service Water Systems: Piping	$ 2,500,000	$ 6,275,000	$ 8,225,000	$ -	$ 17,000,000	$ 2,550,000	$ -	0%	$ 2,932,500	15%	$ 22,482,500	$ 64.24
3.22	Service Air Compressors: Equipment	$ 832,000	$ 450,000	$ 718,000	$ -	$ 2,000,000	$ 300,000	$ -	0%	$ 345,000	15%	$ 2,645,000	$ 7.56
3.23	Service Air: Piping , Valves, & Outlets	$ -	$ 1,900,000	$ 2,100,000	$ -	$ 4,000,000	$ 600,000	$ -	0%	$ 690,000	15%	$ 5,290,000	$ 15.11
3.24	Misc. Equipment: Cranes, Compressors, & Circulation Pumps	$ 900,000	$ 450,000	$ 650,000	$ -	$ 2,000,000	$ 300,000	$ -	0%	$ 345,000	15%	$ 2,645,000	$ 7.56
	Subtotal	**$ 25,812,000**	**$ 49,823,000**	**$ 64,365,000**	**$ -**	**$ 140,000,000**	**$ 21,000,000**	**$ -**	**0%**	**$ 24,150,000**	**15%**	**$ 185,150,000**	**$ 529.00**
4	**Boiler & Accessories**												
4.01	PC Boiler: Conc. Foundations	$ -	$ 1,350,000	$ 1,450,000	$ -	$ 2,800,000	$ 420,000	$ -	0%	$ 483,000	15%	$ 3,703,000	$ 10.58
4.02	SCR Conc. Foundations	$ -	$ 390,000	$ 510,000	$ -	$ 900,000	$ 135,000	$ -	0%	$ 155,250	15%	$ 1,190,250	$ 3.40
4.03	PC Boiler: Equipment	$ 112,252,212	$ 1,000,000	$ 66,747,788	$ -	$ 180,000,000	$ 27,000,000	$ -	0%	$ 31,050,000	15%	$ 238,050,000	$ 680.14
4.04	Indirect Firing System	$ 15,318,584	$ 2,000,000	$ 12,281,416		$ 29,600,000	$ 4,440,000	$ -	0%	$ 5,106,000	15%	$ 39,146,000	$ 111.85
4.04	Solid Catalytic Reduction: Equipment	$ 7,938,053	$ 1,000,000	$ 6,061,947	$ -	$ 15,000,000	$ 2,250,000	$ -	0%	$ 2,587,500	15%	$ 19,837,500	$ 56.68
4.05	Combustion Air, Induced Draft Fan: Equipment	$ 4,573,000	$ 1,500,000	$ 3,427,000	$ -	$ 9,500,000	$ 1,425,000	$ -	0%	$ 1,638,750	15%	$ 12,563,750	$ 35.90
4.06	Primary Air Fan: Equipment	$ 1,416,000	$ 200,000	$ 884,000	$ -	$ 2,500,000	$ 375,000	$ -	0%	$ 431,250	15%	$ 3,306,250	$ 9.45
4.07	Forced Draft Fan: Equipment	$ 1,314,000	$ 170,000	$ 1,516,000	$ -	$ 3,000,000	$ 450,000	$ -	0%	$ 517,500	15%	$ 3,967,500	$ 11.34
4.08	Combustion Air Induction: Duct	$ -	$ 2,782,000	$ 3,218,000	$ -	$ 6,000,000	$ 900,000	$ -	0%	$ 1,035,000	15%	$ 7,935,000	$ 22.67
4.09	Combustion Air, Tie In to Gas Turbine Exhaust Flue: Duct	$ -	$ 365,000	$ 335,000	$ -	$ 700,000	$ 105,000	$ -	0%	$ 120,750	15%	$ 925,750	$ 2.65
	Subtotal	**$ 142,811,849**	**$ 10,757,000**	**$ 96,431,151**	**$ -**	**$ 250,000,000**	**$ 37,500,000**	**$ -**	**0%**	**$ 43,125,000**	**15%**	**$ 330,625,000**	**$ 944.64**
5	**Flue Gas Cleanup**												
5.01	Electrostatic Precipitator: Concrete Foundations	$ -	$ 560,000	$ 640,000	$ -	$ 1,200,000	$ 180,000	$ -	0%	$ 207,000	15%	$ 1,587,000	$ 4.53
5.02	FGD Scrubber Foundations	$ -	$ 1,437,000	$ 2,463,000	$ -	$ 3,900,000	$ 585,000	$ -	0%	$ 672,750	15%	$ 5,157,750	$ 14.74
5.03	Electrostatic Precipitator: Equipment & Steel Structure.	$ 8,752,212	$ 1,833,000	$ 4,414,788	$ -	$ 15,000,000	$ 2,250,000	$ -	0%	$ 2,587,500	15%	$ 19,837,500	$ 56.68
5.04	Flue Gas Desulfurization Wet Scrubber: Equipment	$ 46,915,929	$ 11,000,000	$ 38,084,071	$ -	$ 96,000,000	$ 14,400,000	$ -	0%	$ 16,560,000	15%	$ 126,960,000	$ 362.74
5.05	Gypsum Dewatering System	$ 6,638,000	$ 2,800,000	$ 4,462,000	$ -	$ 13,900,000	$ 2,085,000	$ -	0%	$ 2,397,750	15%	$ 18,382,750	$ 52.52
	Subtotal	**$ 62,306,141**	**$ 17,630,000**	**$ 50,063,859**	**$ -**	**$ 130,000,000**	**$ 19,500,000**	**$ -**	**0%**	**$ 22,425,000**	**15%**	**$ 171,925,000**	**$ 491.21**
6	**Carbon Capture & Compression**												
6.01	Carbon Capture, Absorb & Compression: Conc. Foundations	$ -	$ 2,417,000	$ 2,583,000	$ -	$ 5,000,000	$ 750,000	$ -	0%	$ 862,500	15%	$ 6,612,500	$ 18.47
6.02	Carbon Capture, Cansolv CO2 Removal System	$ 97,198,304	$ 12,820,000	$ 26,981,696	$ -	$ 137,000,000	$ 20,550,000	$ -	0%	$ 23,632,500	15%	$ 181,182,500	$ 506.10
6.04	Carbon Capture: Compression & Drying Equipment	$ 20,655,989	$ 3,800,000	$ 13,544,011	$ -	$ 38,000,000	$ 5,700,000	$ -	0%	$ 6,555,000	15%	$ 50,255,000	$ 140.38
6.05	Carbon Capture Piping/ Duct	$ 380,000	$ 1,645,000	$ 2,975,000	$ -	$ 5,000,000	$ 750,000	$ -	0%	$ 862,500	15%	$ 6,612,500	$ 18.47
	Subtotal	**$ 118,234,293**	**$ 20,682,000**	**$ 46,083,707**	**$ -**	**$ 185,000,000**	**$ 27,750,000**	**$ -**	**0%**	**$ 31,912,500**	**15%**	**$ 244,662,500**	**$ 683.41**
7	**Ductwork & Stack**												
7.01	Stack & Flue Duct : Conc. Foundations	$ -	$ 950,000	$ 1,050,000	$ -	$ 2,000,000	$ 300,000	$ -	0%	$ 345,000	15%	$ 2,645,000	$ 7.56
7.02	Stack: Steel Structure	$ -	$ 4,025,000	$ 4,375,000	$ -	$ 8,400,000	$ 1,260,000	$ -	0%	$ 1,449,000	15%	$ 11,109,000	$ 31.74
7.03	Stack, Epoxy Flue Liner:	$ -	$ 2,509,000	$ 2,791,000	$ -	$ 5,300,000	$ 795,000	$ -	0%	$ 914,250	15%	$ 7,009,250	$ 20.03
7.04	Ductwork, Boiler to Scrubber & Stack	$ -	$ 2,632,000	$ 2,368,000	$ -	$ 5,000,000	$ 750,000	$ -	0%	$ 862,500	15%	$ 6,612,500	$ 18.89
7.05	Continuous Emissions Monitoring System in Stack	$ 930,000	$ 500,000	$ 870,000	$ -	$ 2,300,000	$ 345,000	$ -	0%	$ 396,750	15%	$ 3,041,750	$ 8.69
	Subtotal	**$ 930,000**	**$ 10,616,000**	**$ 11,454,000**	**$ -**	**$ 23,000,000**	**$ 3,450,000**	**$ -**	**0%**	**$ 3,967,500**	**15%**	**$ 30,417,500**	**$ 86.91**
8	**Steam Turbine Generator**												
8.01	Turbine/ Generator & Condenser: Concrete Foundations	$ -	$ 727,000	$ 773,000	$ -	$ 1,500,000	$ 225,000	$ -	0%	$ 258,750	15%	$ 1,983,750	$ 5.67
8.02	Steam Turbine/ Generator: Equipment	$ 41,654,643	$ -	$ 8,345,357	$ -	$ 50,000,000	$ 7,500,000	$ -	0%	$ 8,625,000	15%	$ 66,125,000	$ 188.93
8.03	Steam Condenser : Equipment	$ 6,110,000	$ -	$ 1,890,000	$ -	$ 8,000,000	$ 1,200,000	$ -	0%	$ 1,380,000	15%	$ 10,580,000	$ 30.23
8.04	Condensate Pumps : Equipment	$ 1,546,000	$ -	$ 454,000	$ -	$ 2,000,000	$ 300,000	$ -	0%	$ 345,000	15%	$ 2,645,000	$ 7.56
8.05	Steam & Condensate Piping	$ 1,900,000	$ 35,000,000	$ 31,600,000	$ -	$ 68,500,000	$ 10,275,000	$ -	0%	$ 11,816,250	15%	$ 90,591,250	$ 258.83
	Subtotal	**$ 51,210,643**	**$ 35,727,000**	**$ 43,062,357**	**$ -**	**$ 130,000,000**	**$ 19,500,000**	**$ -**	**0%**	**$ 22,425,000**	**15%**	**$ 171,925,000**	**$ 491.21**
9	**Cooling Water System**												
9.01	Cooling Tower & Circulating Pumps: Conc. Foundations	$ -	$ 1,340,000	$ 1,660,000	$ -	$ 3,000,000	$ 450,000	$ -	0%	$ 517,500	15%	$ 3,967,500	$ 11.34
9.02	Cooling Tower, 13 Cell, Build in Place Equipment	$ 8,665,000	$ 839,000	$ 12,496,000	$ -	$ 22,000,000	$ 3,300,000	$ -	0%	$ 3,795,000	15%	$ 29,095,000	$ 83.13
9.03	Cooling System Auxiliaries: Equipment	$ 12,324,000	$ 2,000,000	$ 5,676,000	$ -	$ 20,000,000	$ 3,000,000	$ -	0%	$ 3,450,000	15%	$ 26,450,000	$ 75.57
9.04	Circulating Pumps: Equipment	$ 1,050,000	$ 172,000	$ 778,000	$ -	$ 2,000,000	$ 300,000	$ -	0%	$ 345,000	15%	$ 2,645,000	$ 7.56
9.05	Circulating & Cooling Water: Piping & Valves	$ -	$ 9,140,000	$ 9,860,000	$ -	$ 19,000,000	$ 2,850,000	$ -	0%	$ 3,277,500	15%	$ 25,127,500	$ 71.79
	Subtotal	**$ 22,039,000**	**$ 13,491,000**	**$ 30,470,000**	**$ -**	**$ 66,000,000**	**$ 9,900,000**	**$ -**	**0%**	**$ 11,385,000**	**15%**	**$ 87,285,000**	**$ 249.39**
10	**Ash & Spent Sorbent Handling Systems**												
10.01	Bag Filter, Ash Conveyor, & Storage Silos: Conc. Foundations	$ -	$ 1,280,000	$ 1,220,000	$ -	$ 2,500,000	$ 375,000	$ -	0%	$ 431,250	15%	$ 3,306,250	$ 9.45
10.02	Ash Transfer, Bottom & Fly Ash to Silos: Conveyor Equipment	$ 5,200,000	$ 500,000	$ 3,800,000	$ -	$ 9,500,000	$ 1,425,000	$ -	0%	$ 1,638,750	15%	$ 12,563,750	$ 35.90
10.03	Ash Storage: Steel Support Structure & Silos: Equipment	$ 1,255,000	$ 320,000	$ 1,425,000	$ -	$ 3,000,000	$ 450,000	$ -	0%	$ 517,500	15%	$ 3,967,500	$ 11.34
10.04	Ash Storage & Loading: Equipment	$ 950,000	$ -	$ 550,000	$ -	$ 1,500,000	$ 225,000	$ -	0%	$ 258,750	15%	$ 1,983,750	$ 5.67
10.05	Gypsum Processing; Equipment	$ 1,650,000	$ -	$ 1,350,000	$ -	$ 3,000,000	$ 450,000	$ -	0%	$ 517,500	15%	$ 3,967,500	$ 11.34
10.06	Gypsum Silo/ Load-out: Equipment	$ 514,000	$ 286,000	$ 700,000	$ -	$ 1,500,000	$ 225,000	$ -	0%	$ 258,750	15%	$ 1,983,750	$ 5.67
	Subtotal	**$ 9,569,000**	**$ 2,386,000**	**$ 9,045,000**	**$ -**	**$ 21,000,000**	**$ 3,150,000**	**$ -**	**0%**	**$ 3,622,500**	**15%**	**$ 27,772,500**	**$ 79.35**

Item No.	Description	Plant Equipment Costs	Bulk Materials Cost	Direct Labor	Indirect Labor	Bare Erected Cost	Eng'g CM H.O. & Fee 15%	Process Contingencies, varies	Process Contingencies, %	Project Contingencies, varies	Project Contingencies, %	Total Plant Costs	S/ kW
11	**Accessory Electric Plant**												
11.01	Switchgear & Transformers: Conc. Foundations	$ -	$ 712,800	$ 787,200	$ -	$ 1,500,000	$ 225,000	$ -	0%	$ 258,750	15%	$ 1,983,750	$ 5.67
11.02	Emergency Diesel Generator: Conc. Foundations	$ -	$ 220,000	$ 180,000	$ -	$ 400,000	$ 60,000	$ -	0%	$ 69,000	15%	$ 529,000	$ 1.51
11.03	Main Power Transformers: Equipment	$ 12,460,000	$ -	$ 4,540,000	$ -	$ 17,000,000	$ 2,550,000	$ -	0%	$ 2,932,500	15%	$ 22,482,500	$ 64.24
11.04	STG Isolated Phase Bus Duct & Tap Bus: Equipment	$ 8,400,000	$ -	$ 3,600,000	$ -	$ 12,000,000	$ 1,800,000	$ -	0%	$ 2,070,000	15%	$ 15,870,000	$ 45.34
11.05	Switchgear: Equipment	$ 10,490,000	$ -	$ 5,510,000	$ -	$ 16,000,000	$ 2,400,000	$ -	0%	$ 2,760,000	15%	$ 21,160,000	$ 60.46
11.06	Emergency Diesel Generator: Equipment	$ 5,730,000	$ -	$ 3,270,000	$ -	$ 9,000,000	$ 1,350,000	$ -	0%	$ 1,552,500	15%	$ 11,902,500	$ 34.01
11.07	Raceways, Conduit & Cable Trays	$ -	$ 8,830,000	$ 9,770,000	$ -	$ 18,600,000	$ 2,790,000	$ -	0%	$ 3,208,500	15%	$ 24,598,500	$ 70.28
11.09	High Voltage Conductors: Wire & Cable	$ -	$ 6,250,000	$ 3,750,000	$ -	$ 10,000,000	$ 1,500,000	$ -	0%	$ 1,725,000	15%	$ 13,225,000	$ 37.79
11.10	MCM Cable & Wire	$ -	$ 6,640,000	$ 3,360,000	$ -	$ 10,000,000	$ 1,500,000	$ -	0%	$ 1,725,000	15%	$ 13,225,000	$ 37.79
11.11	Cathodic Protection/ Grounding	$ -	$ 635,900	$ 864,100	$ -	$ 1,500,000	$ 225,000	$ -	0%	$ 258,750	15%	$ 1,983,750	$ 5.67
	Subtotal	**$ 37,080,000**	**$ 23,288,700**	**$ 35,631,300**	**$ -**	**$ 96,000,000**	**$ 14,400,000**	**$ -**	**0%**	**$ 16,560,000**	**15%**	**$ 126,960,000**	**$ 362.74**
12	**Instrumentation & Control**												
12.01	Coal Boiler Control, Equipment	$ 720,000	$ -	$ 380,000	$ -	$ 1,100,000	$ 165,000	$ 63,250	5%	$ 199,238	15%	$ 1,527,488	$ 4.36
12.02	Steam Turbine Control Equipment	$ 650,000	$ -	$ 350,000	$ -	$ 1,000,000	$ 150,000	$ 57,500	5%	$ 181,125	15%	$ 1,388,625	$ 3.97
12.03	Control Room: Control Panels, Boards, & Racks	$ 815,000	$ -	$ 485,000	$ -	$ 1,300,000	$ 195,000	$ 74,750	5%	$ 235,463	15%	$ 1,805,213	$ 5.16
12.04	Control Room & Remote Operator Stations	$ 382,000	$ -	$ 218,000	$ -	$ 600,000	$ 90,000	$ 34,500	5%	$ 108,675	15%	$ 833,175	$ 2.38
12.05	DCS -Processor & Main Control : Equipment	$ 9,500,000	$ -	$ 1,500,000	$ -	$ 11,000,000	$ 1,650,000	$ 632,500	5%	$ 1,992,375	15%	$ 15,274,875	$ 43.64
12.06	Control Instruments at Process Equipment	$ 2,365,000	$ -	$ 635,000	$ -	$ 3,000,000	$ 450,000	$ 172,500	5%	$ 543,375	15%	$ 4,165,875	$ 11.90
12.07	Fiber Optic Cabling & Control Wiring	$ 4,560,000	$ 857,000	$ 3,583,000	$ -	$ 9,000,000	$ 1,350,000	$ 517,500	5%	$ 1,630,125	15%	$ 12,497,625	$ 35.71
12.08	Other I & C Equipment	$ 2,500,000	$ 500,000	$ 3,000,000	$ -	$ 6,000,000	$ 900,000	$ 345,000	5%	$ 1,086,750	15%	$ 8,331,750	$ 23.81
	Subtotal	**$ 21,492,000**	**$ 1,357,000**	**$ 10,151,000**	**$ -**	**$ 33,000,000**	**$ 4,950,000**	**$ 1,897,500**	**5%**	**$ 5,977,125**	**15%**	**$ 45,824,625**	**$ 130.93**
13	**Improvements to Site**												
13.01	Erosion/ Sediment Controls	$ -	$ 375,000	$ 525,000	$ -	$ 900,000	$ 135,000	$ -	0%	$ 155,250	15%	$ 1,190,250	$ 3.40
13.02	Preliminary Earthwork	$ -	$ 600,000	$ 7,400,000	$ -	$ 8,000,000	$ 1,200,000	$ -	0%	$ 1,380,000	15%	$ 10,580,000	$ 30.23
13.03	Rail Bed and Track	$ -	$ 3,800,000	$ 3,200,000	$ -	$ 7,000,000	$ 1,050,000	$ -	0%	$ 1,207,500	15%	$ 9,257,500	$ 26.45
13.04	Roads, Drives, & Parking	$ -	$ 5,740,000	$ 2,260,000	$ -	$ 8,000,000	$ 1,200,000	$ -	0%	$ 1,380,000	15%	$ 10,580,000	$ 30.23
13.05	Fences & Gates	$ -	$ 450,000	$ 550,000	$ -	$ 1,000,000	$ 150,000	$ -	0%	$ 172,500	15%	$ 1,322,500	$ 3.78
13.06	Signage & Traffic Control	$ -	$ 270,000	$ 230,000	$ -	$ 500,000	$ 75,000	$ -	0%	$ 86,250	15%	$ 661,250	$ 1.89
13.07	Site Furnishings & Improvements	$ -	$ 1,300,000	$ 700,000	$ -	$ 2,000,000	$ 300,000	$ -	0%	$ 345,000	15%	$ 2,645,000	$ 7.56
13.08	Site Drainage	$ -	$ 3,700,000	$ 3,300,000	$ -	$ 7,000,000	$ 1,050,000	$ -	0%	$ 1,207,500	15%	$ 9,257,500	$ 26.45
13.09	Fire Water Loop & Hydrants: Piping	$ -	$ 3,296,000	$ 3,704,000	$ -	$ 7,000,000	$ 1,050,000	$ -	0%	$ 1,207,500	15%	$ 9,257,500	$ 26.45
13.10	Municipal Water & Sewer, On Site	$ -	$ 1,775,000	$ 2,225,000	$ -	$ 4,000,000	$ 600,000	$ -	0%	$ 690,000	15%	$ 5,290,000	$ 15.11
13.11	Municipal Water & Sewer Tie In, Off Site	$ -	$ 750,000	$ 850,000	$ -	$ 1,600,000	$ 240,000	$ -	0%	$ 276,000	15%	$ 2,116,000	$ 6.05
13.12	Electric Distribution Substation	$ 750,000	$ 500,000	$ 750,000	$ -	$ 2,000,000	$ 300,000	$ -	0%	$ 345,000	15%	$ 2,645,000	$ 7.56
13.13	Switch Yard Civil Work	$ -	$ 1,260,000	$ 1,740,000	$ -	$ 3,000,000	$ 450,000	$ -	0%	$ 517,500	15%	$ 3,967,500	$ 11.34
13.14	Site Lighting	$ -	$ 2,853,000	$ 2,147,000	$ -	$ 5,000,000	$ 750,000	$ -	0%	$ 862,500	15%	$ 6,612,500	$ 18.89
	Subtotal	**$ 750,000**	**$ 26,669,000**	**$ 29,581,000**	**$ -**	**$ 57,000,000**	**$ 8,550,000**	**$ -**	**0%**	**$ 9,832,500**	**15%**	**$ 75,382,500**	**$ 215.38**

Item No.	Description	Plant Equipment Costs	Bulk Materials Cost	Direct Labor	Indirect Labor	Bare Erected Cost	Eng'g CM H.O. & Fee 15%	Process Contingencies, varies	Process Contingencies, %	Project Contingencies, varies	Project Contingencies, %	Total Plant Costs	S/ kW
14	**Buildings & Structures**												
14.01	Boiler Building: Foundations & Slab	$ -	$ 2,930,000	$ 2,311,000	$ -	$ 5,241,000	$ 786,150	$ -	0%	$ 904,073	15%	$ 6,931,223	$ 19.80
14.02	Boiler Building: Structure & Enclosure	$ -	$ 12,495,717	$ 11,881,000	$ -	$ 24,376,717	$ 3,656,508	$ -	0%	$ 4,205,340	15%	$ 32,238,564	$ 92.11
14.03	Steam Turbine Building: Foundations & Slab	$ -	$ 2,442,600	$ 2,654,000	$ -	$ 5,096,600	$ 764,490	$ -	0%	$ 879,164	15%	$ 6,740,254	$ 19.26
14.04	Steam Turbine Building: Structure & Enclosure	$ -	$ 11,413,450	$ 8,644,950	$ -	$ 20,058,400	$ 3,008,760	$ -	0%	$ 3,460,074	15%	$ 26,527,234	$ 75.79
14.05	Administration Building	$ -	$ 1,616,050	$ 1,279,950	$ -	$ 2,896,000	$ 434,400	$ -	0%	$ 499,560	15%	$ 3,829,960	$ 10.94
14.06	Circulation/ Cooling Water Pumphouse	$ -	$ 166,000	$ 120,000	$ -	$ 286,000	$ 42,900	$ -	0%	$ 49,335	15%	$ 378,235	$ 1.08
14.07	Water Treatment Buildings	$ -	$ 696,000	$ 672,000	$ -	$ 1,368,000	$ 205,200	$ -	0%	$ 235,980	15%	$ 1,809,180	$ 5.17
14.08	Machine Shop	$ -	$ 483,000	$ 360,000	$ -	$ 843,000	$ 126,450	$ -	0%	$ 145,418	15%	$ 1,114,868	$ 3.19
14.09	Warehouse	$ -	$ 589,000	$ 443,000	$ -	$ 1,032,000	$ 154,800	$ -	0%	$ 178,020	15%	$ 1,364,820	$ 3.90
14.1	Waste Water Treatment Structures	$ -	$ 1,737,500	$ 2,080,000	$ -	$ 3,817,500	$ 572,625	$ -	0%	$ 658,519	15%	$ 5,048,644	$ 14.42
14.11	Other Buildings & Structures	$ -	$ 500,000	$ 50,000	$ -	$ 550,000	$ 82,500	$ -	0%	$ 94,875	15%	$ 727,375	$ 2.08
	Subtotal	**$ -**	**$ 35,069,317**	**$ 30,495,900**	**$ -**	**$ 65,565,217**	**$ 9,834,783**	**$ -**	**0%**	**$ 11,310,356**	**15%**	**$ 86,710,355**	**$ 247.74**
15	**Co-Firing, Gas Turbine**												
15.01	Simple Cycle Gas Turbine GE 6F.03	$ 27,500,000	$ -	$ 2,547,000	$ -	$ 30,047,000	$ 4,507,050	$ -	0%	$ 5,183,345	15%	$ 39,737,395	$ 113.54
15.02	Flue Gas Booster Fan: Equipment	$ 337,000	$ -	$ 105,000	$ -	$ 442,000	$ 66,300	$ -	0%	$ 76,245	15%	$ 584,545	$ 1.67
15.03	Gas Turbine Foundations & Building	$ -	$ 2,147,000	$ 1,950,000	$ -	$ 4,097,000	$ 614,550	$ -	0%	$ 706,733	15%	$ 5,418,283	$ 15.48
15.04	Gas Turbine, Flue Duct to Coal Induction Air & By-Pass Stack	$ -	$ 1,858,000	$ 2,640,131	$ -	$ 4,498,131	$ 674,720	$ -	0%	$ 775,928	15%	$ 5,948,778	$ 17.00
15.04	Gas Turbine, Balance of Plant	$ -	$ 2,450,000	$ 3,270,000	$ -	$ 5,720,000	$ 858,000	$ -	0%	$ 986,700	15%	$ 7,565,000	$ 21.61
	Subtotal	**$ 27,837,000**	**$ 6,455,000**	**$ 10,512,131**	**$ -**	**$ 44,804,131**	**$ 6,720,620**	**$ -**	**0%**	**$ 7,728,950**	**15%**	**$ 59,254,000**	**$ 169.30**
16	**Vanadium Battery ESS**												
16.01	Foundations for Battery Containers		$ 1,378,308	$ 1,250,000		$ 2,628,308	$ 394,246	$ -	0%	$ 453,383	15%	$ 3,475,937	$ 9.93
16.02	Vanadium Battery System: Equipment	$ 40,039,436	$ -	$ 6,761,000	$ -	$ 46,800,436	$ 7,020,065	$ 1,614,615	3%	$ 8,239,805	15%	$ 63,674,922	$ 181.93
16.03	ESS Storage, Instrumentation & Balance of Plant	$ -	$ 2,196,000	$ 2,087,693	$ -	$ 4,283,693	$ 642,554	$ 147,787	3%	$ 761,105	15%	$ 5,835,141	$ 16.67
	Subtotal	**$ 40,039,436**	**$ 3,574,308**	**$ 10,098,693**	**$ -**	**$ 53,712,437**	**$ 8,056,866**	**$ 1,762,402**	**3%**	**$ 9,454,294**	**15%**	**$ 72,986,000**	**208.53**
17	**Project Specific Technology, Zero Liquid Discharge**												
17.01	ZLD, Pretreat & Clarify Equipment	$ 430,000	$ -	$ -	$ -	$ 430,000	$ 64,500	$ 24,725	5%	$ 77,884	15%	$ 597,109	$ 1.71
17.02	ZLD, RO Filters, Pumps, & Backwash Tank	$ 680,000	$ -	$ -	$ -	$ 680,000	$ 102,000	$ 39,100	5%	$ 123,165	15%	$ 944,265	$ 2.70
17.03	ZLD, Evaporation & Crystallization Equipment	$ 5,077,500	$ -	$ -	$ -	$ 5,077,500	$ 761,625	$ 291,956	5%	$ 919,662	15%	$ 7,050,743	$ 20.14
17.04	ZLD, Solids Buildup Equipment	$ 1,910,000	$ -	$ -	$ -	$ 1,910,000	$ 286,500	$ 109,825	5%	$ 345,949	15%	$ 2,652,274	$ 7.58
17.05	ZLD, Foundations, Sumps, Instrumentation, & Balance of Plant	$ -	$ 4,178,000	$ 5,539,000	$ -	$ 9,717,000	$ 1,457,550	$ -	0%	$ 1,676,060	15%	$ 12,850,610	$ 36.72
	Subtotal	**$ 8,097,500**	**$ 4,178,000**	**$ 5,539,000**	**$ -**	**$ 17,814,500**	**$ 2,672,175**	**$ 465,606**	**2%**	**$ 3,142,719**	**15%**	**$ 24,095,000**	**$ 68.84**
	Project Totals												
	Total of Capital Cost in 2020	**$ 555,525,721**	**$ 258,090,325**	**$ 459,280,239**	**$ -**	**$ 1,402,896,285**	**$ 210,434,443**	**$ 4,125,509**	**0.26%**	**$ 242,543,443**	**15%**	**$ 1,860,000,000**	**$ 5,298.66**

Appendix D Power Plant of the Future Overall and Feedwater Stream Mass & Energy Balances

	Combustion Air	Coal Feed + Pulverizer Air	Natural Gas Feed to Combustion Turbine	Natural Gas Turbine Combustion Air	Heated Natural Gas Turbine Exhaust to Boiler	CO2 Inerting Gas	Ammonia Injection to SCR	Boiler Feedwater	Flue Gas from Boiler	HPT Steam to Boiler	HPT Steam from Boiler to IPT	Boiler Steam to HPT	Bottom Ash Discharge	Flue Gas from Gas Air Heater with SlipStream
	1	**6A**	**8**	**9**	**11A**	**12**	**14**	**15**	**16**	**17A**	**17B**	**18**	**20**	**22**
V-L Mass Fraction														
Ar	0.013	0.013	0.000	0.013	0.013	0.000	0.000	0.000	0.012	0.000	0.000	0.000	0.000	0.012
CO_2	0.001	0.001	0.025	0.001	0.044	0.973	0.000	0.000	0.186	0.000	0.000	0.000	0.000	0.183
H_2O	0.006	0.006	0.000	0.006	0.041	0.027	0.810	1.000	0.070	1.000	1.000	1.000	1.000	0.069
N_2	0.750	0.750	0.026	0.750	0.738	0.000	0.000	0.000	0.698	0.000	0.000	0.000	0.000	0.699
NOX	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
O_2	0.230	0.230	0.000	0.230	0.164	0.000	0.000	0.000	0.030	0.000	0.000	0.000	0.000	0.034
SO_2	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.003	0.000	0.000	0.000	0.000	0.003
CH4	0.000	0.000	0.862	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other Organics	0.000	0.000	0.087	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
NH3	0.000	0.000	0.000	0.000	0.000	0.000	0.190	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
V-L Flowrate (kg/hr)	337518.2	146439.6	18144.0	769644.0	1092996.0	1815.0	101.0	521644.7	1165205.0	647969.9	647969.9	756006.9	145.0	1188396.0
Solids Flowrate (kg/hr)	0.0	72504.0	0.0	0.0	0.0	0.0	0.0	0.0	5800.3	0.0	0.0	0.0	1450.1	5800.3
Temperature (°C)	15.00	77.00	27.00	29.00	530.13	45.00	29.00	304.54	387.26	366.99	600.00	600.00	65.00	133.58
Pressure (MPa, abs)	0.10	0.11	3.04	0.10	0.11	0.15	0.20	31.77	0.10	5.46	5.15	24.23	0.10	0.10
Steam Table Enthalpy (kJ/kg)[A]					549.69	0.00		1351.00	398.93	3103.51	3665.65	3500.76		114.79
V-L Flowrate (lb/hr)	744092.7	322840.7	40000.3	1696757.2	2409640.8	4001.3	222.7	1150018.0	2568810.9	1428514.4	1428514.4	1666692.7	319.7	2619937.8
Solids Flowrate (lb/hr)	0.0	159842.3	0.0	0.0	0.0	0.0	0.0	0.0	12787.4	0.0	0.0	0.0	3196.8	12787.4
Temperature (°F)	59.00	170.60	80.60	84.20	986.23	113.00	84.20	580.17	729.07	692.58	1112.00	1112.00	149.00	272.44
Pressure (psia)	14.65	15.23	435.00	14.50	15.23	22.19	29.01	4607.86	14.07	791.62	746.37	3514.71	14.50	14.07
Steam Table Enthalpy (Btu/lb)[A]					236.32	0.00		580.83	171.51	1334.27	1575.95	1505.06		49.35

[A] Steam table reference conditions are 32.02°F and 0.089 psia

[B] Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

	Service Water to Boiler Treatment	Treated Boiler Water	Steam to PCC and ZLD	LPT Steam to Condenser	Circulating Water Pump to Condenser	Condenser to Closed Loop Circulating Water	Feedwater Heater to Condenser	Low Pressure Steam Crossover Reboiler Condensate	Gland Steam Condensate to Condenser	Condenser to Gland Steam / Feedwater System	Cooling Tower to Circulating Water Pump	Cooling Tower Blowdown to FGD Makeup	Cooling Tower Evaporative + Drift Losses	Cooling Tower Water Makeup	Total Service Water
	23	24	25D	26	27	28	29	29I	30	31	32	33	34	35	37
V-L Mass Fraction															
Ar	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
CO_2	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
H_2O	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
N_2	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
NOX	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
O_2	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
SO_2	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
CH4	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other Organics	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
NH3	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
V-L Flowrate (kg/hr)	7496.1	7496.1	213499.1	401943.6	18850459.0	18850459.0	13608.1	204517.9	2124.0	422679.8	18850459.0	64892.7	454249.0	519141.7	18352.8
Solids Flowrate (kg/hr)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temperature (°C)	25.00	25.00	268.40	33.16	15.55	26.67	101.40	169.43	69.97	33.16	15.55	26.67	26.67	26.67	25.00
Pressure (MPa, abs)	0.20	0.20	0.50	0.01	0.45	0.45	0.18	2.64	0.03	0.01	0.45	0.10	0.10	0.10	0.20
Steam Table Enthalpy (kJ/kg)[A]			2999.25	2326.30			425.08	717.74	292.91	138.94					
V-L Flowrate (lb/hr)	16526.0	16526.0	470680.1	886125.0	41557721.9	41557721.9	30000.5	450880.1	4682.6	931840.0	41557721.9	143062.5	1001437.3	1144499.8	40460.6
Solids Flowrate (lb/hr)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temperature (°F)	77.00	77.00	515.12	91.69	59.99	80.00	214.52	336.97	157.95	91.69	59.99	80.00	80.00	80.00	77.00
Pressure (psia)	29.01	29.01	72.66	0.73	65.00	65.00	25.96	382.90	4.50	0.73	65.84	30.00	14.50	14.50	29.01
Steam Table Enthalpy (Btu/lb)[A]			1289.45	1000.13			182.75	308.57	125.93	59.73					

[A] Steam table reference conditions are 32.02°F and 0.089 psia

[B] Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

	Total Makeup Water	Flue Gas from GGC	ESP Flyash Unloading	Flue Gas from Dry ESP	Flue Gas from ID Fan	Limestone Slurry to FGD	Gypsum Product Discharge from FGD	FGD Purge Stream + Surplus Water to Water Treatment	Flue Gas from FGD	Water Treatment Product to ZLD	Wastewater Sludge Loadout	ZLD Crystallized Solids Waste	ZLD Treated Distillate to Makeup	Flue Gas from Cooler to Amine Scrubber
	38	39	40	41	42	43	44	45	46	47	48	49	50	51
V-L Mass Fraction														
Ar	0.000	0.012	0.000	0.012	0.012	0.000	0.000	0.000	0.011	0.000	0.000	0.000	0.000	0.012
CO_2	0.000	0.183	0.000	0.183	0.183	0.000	0.000	0.000	0.182	0.000	0.000	0.000	0.000	0.196
H_2O	1.000	0.069	1.000	0.069	0.069	1.000	1.000	1.000	0.102	1.000	1.000	0.000	1.000	0.033
N_2	0.000	0.699	0.000	0.699	0.699	0.000	0.000	0.000	0.673	0.000	0.000	0.000	0.000	0.725
NOX	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
O_2	0.000	0.034	0.000	0.034	0.034	0.000	0.000	0.000	0.031	0.000	0.000	0.000	0.000	0.034
SO_2	0.000	0.003	0.000	0.003	0.003	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
CH4	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other Organics	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
NH3	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	0.000	1.000	1.000
V-L Flowrate (kg/hr)	574142.4	1188496.8	574.2	1188496.8	1188496.8	26490.1	1551.3	15968.0	1234538.3	32368.4	143.7	0.0	25894.7	1146587.3
Solids Flowrate (kg/hr)	0.0	5800.3	5742.3	58.0	58.0	6622.5	8790.7	958.1	0.0	958.1	958.1	1270.1	0.0	0.0
Temperature (°C)	25.00	90.02	90.02	90.02	95.02	25.00	25.00	45.02	45.02	25.00	25.00	25.00	25.00	35.00
Pressure (MPa, abs)	0.20	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.11
Steam Table Enthalpy (kJ/kg)[A]		68.23	90.02	68.23	50.02				20.85					
V-L Flowrate (lb/hr)	1265754.3	2620160.0	1266.0	2620160.0	2620160.0	58400.0	3420.0	35203.1	2721663.1	71359.4	316.8	0.0	57087.5	2527766.4
Solids Flowrate (lb/hr)	0.0	12787.4	12659.5	127.9	127.9	14600.0	19380.0	2112.2	0.0	2112.2	2112.2	2800.0	0.0	0.0
Temperature (°F)	77.00	194.04	194.04	194.04	203.04	77.00	77.00	113.04	113.04	77.00	77.00	77.00	77.00	95.00
Pressure (psia)	29.01	14.07	14.07	14.07	14.79	14.79	14.79	14.50	14.79	14.79	14.79	14.79	14.79	15.23
Steam Table Enthalpy (Btu/lb)[A]		29.33		29.33	21.50				8.96					0.00

[A] Steam table reference conditions are 32.02°F and 0.089 psia

[B] Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

	CO2 Spent Carbon and Reclaimer Waste to Loadout	Captured CO2 to Compressors	Flue Gas from GGH to Stack	Pure CO2 for Storage or Utilization	CO2 Compressor Condensate
	53	54	56	57	58
V-L Mass Fraction					
Ar	0.000	0.000	0.015	0.000	0.000
CO_2	0.000	0.973	0.023	1.000	0.000
H_2O	0.000	0.027	0.060	0.000	1.000
N_2	0.000	0.000	0.862	0.000	0.000
NOX	0.000	0.000	0.000	0.000	0.000
O_2	0.000	0.000	0.040	0.000	0.000
SO_2	0.000	0.000	0.000	0.000	0.000
CH4	0.000	0.000	0.000	0.000	0.000
Other Organics	1.000	0.000	0.000	0.000	0.000
NH3	0.000	0.000	0.000	0.000	0.000
Total	1.000	1.000	1.000	1.000	1.000
V-L Flowrate (kg/hr)	0.0	208174.0	965322.0	199114.0	5573.0
Solids Flowrate (kg/hr)	40064.3	0.0	0.0	0.0	0.0
Temperature (°C)	25.00	45.00	99.37	40.00	40.0
Pressure (MPa, abs)	0.10	0.15	0.10	15.70	0.2
Steam Table Enthalpy (kJ/kg)^A			78.17	293.23	
V-L Flowrate (lb/hr)	0.0	458940.4	2128148.9	438966.7	12286.2
Solids Flowrate (lb/hr)	88325.8	0.0	0.0	0.0	0.0
Temperature (°F)	77.00	113.00	210.87	104.00	104.00
Pressure (psia)	14.79	22.19	14.79	2277.10	21.76
Steam Table Enthalpy (Btu/lb)^A			33.61	126.07	

Notes:

[1] Stream table data from the "HBD_BLR" & "HBD_TBN" tab of Doosan's conceptual heat and mass balance spreadsheet: DOE_HGCC_Pre-FEED_Final_TMCR_Release_rev0.2.xlsx

[2] Stream data design based off Exhibit 3-54 Case B12B stream table, supercritical unit with capture on page 139 of the NETL report: \\barr.com\projects\Mpls\48 WV\31\48311001 Coal FIRST_01 Coal and NG Concept\Deliverables\20190731 CoalFIRST CombustionConcept 17_FINAL.docx

[3] The following Streams are no flow streams for the full load base case and would only have flow during certain situations such as startup or shutdown: 3A, 21A

^A Steam table reference conditions are 32.02°F and 0.089 psia

^B Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

	Boiler Feedwater (excludes slipstream)	CR Steam to Boiler	HR Steam from Boiler to IPT	Boiler Steam to HPT	Main Steam to FWH	HPT Steam to FWH	Steam to LPT	IPT Steam to LPT and Auxiliaries	Steam to PCC and ZLD	IPT Steam to FWH	IPT Steam to Deaerator	IPT Steam to FWH	LPT Steam to Condenser	LPT Steam to Gland Steam Condenser	LPT Steam to FWH
	15	17A	17B	18	18B	18C	25	25A	25D	25F	25G	25H	26	26B	26C
V-L Mass Fraction															
Ar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CO_2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
H_2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
H_2O	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
N_2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
O_2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SO_2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CH4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Organics	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
V-L Flowrate (kg_{mole}/hr)															
V-L Flowrate (kg/hr)	521,645	647,970	647,970	756,007	40,752	50,112	419,584	624,102	213,499	0	13,680	24,516	401,944	2,124	13,608
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	304.54	366.99	600.00	600.00	450.91	364.67	268.40	268.40	268.40	-	360.92	472.80	33.16	186.07	166.34
Pressure (MPa, abs)	31.77	5.46	5.15	24.23	8.57	5.19	0.50	0.50	0.50	0.00	1.09	2.23	0.01	0.03	0.18
Steam Table Enthalpy (kJ/kg)[A]	1351.00	3103.51	3665.65	3500.76	3266.92	3103.51	2999.25	2999.25	2999.25	-	3179.61	3405.39	2326.30	2851.50	2803.96
Density (kg/m^3)															
V-L Molecular Weight															
V-L Flowrate (lb_{mole}/hr)															
V-L Flowrate (lb/hr)	1150017.977	1428514.394	1428514.394	1666692.72	89842.67424	110477.9174	925014.5	1375894.524	470,680	0	30159.2016	54048.46	886124.9628	4682.61288	30000.47
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	580.17	692.58	1112.00	1112.00	843.64	688.41	515.12	515.12	515.12	0.00	681.66	883.04	91.69	366.93	331.41
Pressure (psia)	4607.86	791.62	746.37	3514.71	1243.27	752.60	72.66	72.66	72.66	0.00	158.24	323.29	0.73	4.50	25.96
Steam Table Enthalpy (Btu/lb)[A]	580.8254514	1334.269132	1575.94583	1505.05589	1404.522786	1334.269132	1289.445	1289.4454	1289.445	0	1366.986242	1464.054	1000.128977	1225.924334	1205.486
Density (lb/ft^3)															

[A] Steam table reference conditions are 32.02°F and 0.089 psia

[B] Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

	LPT Steam to FWH	LPT Steam to FWH	Circulating Water Pump to Condenser	Condenser to Closed Loop Circulating Water	FWH to FWH	FWH to FWH	CO2 Compressor to FWH	FWH to FWH	Low Pressure Steam Crossover Reboiler Condensate	FWH to Deaerator	Deaerator to Boiler Feed Pump	FWH to Deaerator	Boiler Feed Pump to Slipstream FWH	FWH to FWH	FWH to FWH
	26D	**26E**	**27**	**28**	**29B**	**29C**	**29D**	**29H**	**29I**	**29K**	**29L**	**29M**	**29P**	**29S**	**29U**
V-L Mass Fraction			0												
Ar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CO_2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
H_2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
H_2O	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
N_2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
O_2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SO_2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CH4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Organics	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
V-L Flowrate (kg_{mole}/hr)															
V-L Flowrate (kg/hr)	0	0	18,850,459	18,850,459	29,556	422,428	392,872	21,132	204,518	626,946	756,007	115,381	521,645	521,645	521,645
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	-	-	15.55	26.67	36.49	95.80	95.80	113.98	169.43	169.43	183.72	195.33	189.73	218.84	268.07
Pressure (MPa, abs)	0.00	0.00	0.45	0.45	2.64	2.64	2.64	2.64	2.64	2.64	1.09	2.23	31.77	31.77	31.77
Steam Table Enthalpy (kJ/kg)[A]	-	-			155.23	403.35	403.35	480.00	717.74	717.74	779.66	831.74	821.51	948.55	1172.57
Density (kg/m^3)															
V-L Molecular Weight															
V-L Flowrate (lb_{mole}/hr)															
V-L Flowrate (lb/hr)	0	0	41557721.91	41557721.91	65159.75	931284.4	866124.6502	46588.03	450880.0639	1382164.463	1666692.72	254369.0556	1150017.977	1150018	1150018
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	0.00	0.00	59.99	80.00	97.68	204.44	204.44	237.16	336.97	336.97	362.70	383.59	373.51	425.91	514.53
Pressure (psia)	0.00	0.00	65.84	65.84	382.90	382.90	382.90	382.90	382.90	382.90	158.24	323.29	4607.86	4607.86	4607.86
Steam Table Enthalpy (Btu/lb)[A]	0	0	0	0	66.73689	173.4093	173.4092863	206.3629	308.5726569	308.5726569	335.1934652	357.5838349	353.1857266	407.8031	504.1144
Density (lb/ft^3)															

[A] Steam table reference conditions are 32.02°F and 0.089 psia

[B] Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

	FWH to FWH	Slipstream FWH to Boiler FW	Condenser to Condensate Pump	Gland Steam Condenser to CO2 Compressor Heat Exchanger	Gland Steam Condenser to FWH
	29V	29W	31	31C	31D
V-L Mass Fraction					
Ar	0	0	0	0	0
CO_2	0	0	0	0	0
H_2	0	0	0	0	0
H_2O	1	1	1	1	1
N_2	0	0	0	0	0
O_2	0	0	0	0	0
SO_2	0	0	0	0	0
CH4	0	0	0	0	0
Other Organics	0	0	0	0	0
Total	1	1	1	1	1
V-L Flowrate (kg_{mole}/hr)					
V-L Flowrate (kg/hr)	521,645	234,362	422,680	392,872	29,556
Solids Flowrate (kg/hr)	0	0	0	0	0
Temperature (°C)	301.17	305.92	33.16	36.49	36.49
Pressure (MPa, abs)	31.77	30.50	0.01	2.64	2.64
Steam Table Enthalpy (kJ/kg)^A	1333.88	1358.73	138.94	155.23	155.23
Density (kg/m^3)					
V-L Molecular Weight					
V-L Flowrate (lb_{mole}/hr)					
V-L Flowrate (lb/hr)	1150018	516674.743	931839.9631	866124.6502	65159.74872
Solids Flowrate (lb/hr)	0	0	0	0	0
Temperature (°F)	574.11	582.66	91.69	97.68	97.68
Pressure (psia)	4607.86	4423.51	0.73	382.90	382.90
Steam Table Enthalpy (Btu/lb)^A	573.4652	584.148753	59.73344798	66.73688736	66.73688736
Density (lb/ft^3)					

Notes:

[1] Stream table data from the "HBD_BLR" & "HBD_TBN" tab of Doosan's conceptual heat and mass balance spreadsheet: DOE_HGCC_Pre-FEED_Final_TMCR_Release_rev0.2.xlsx

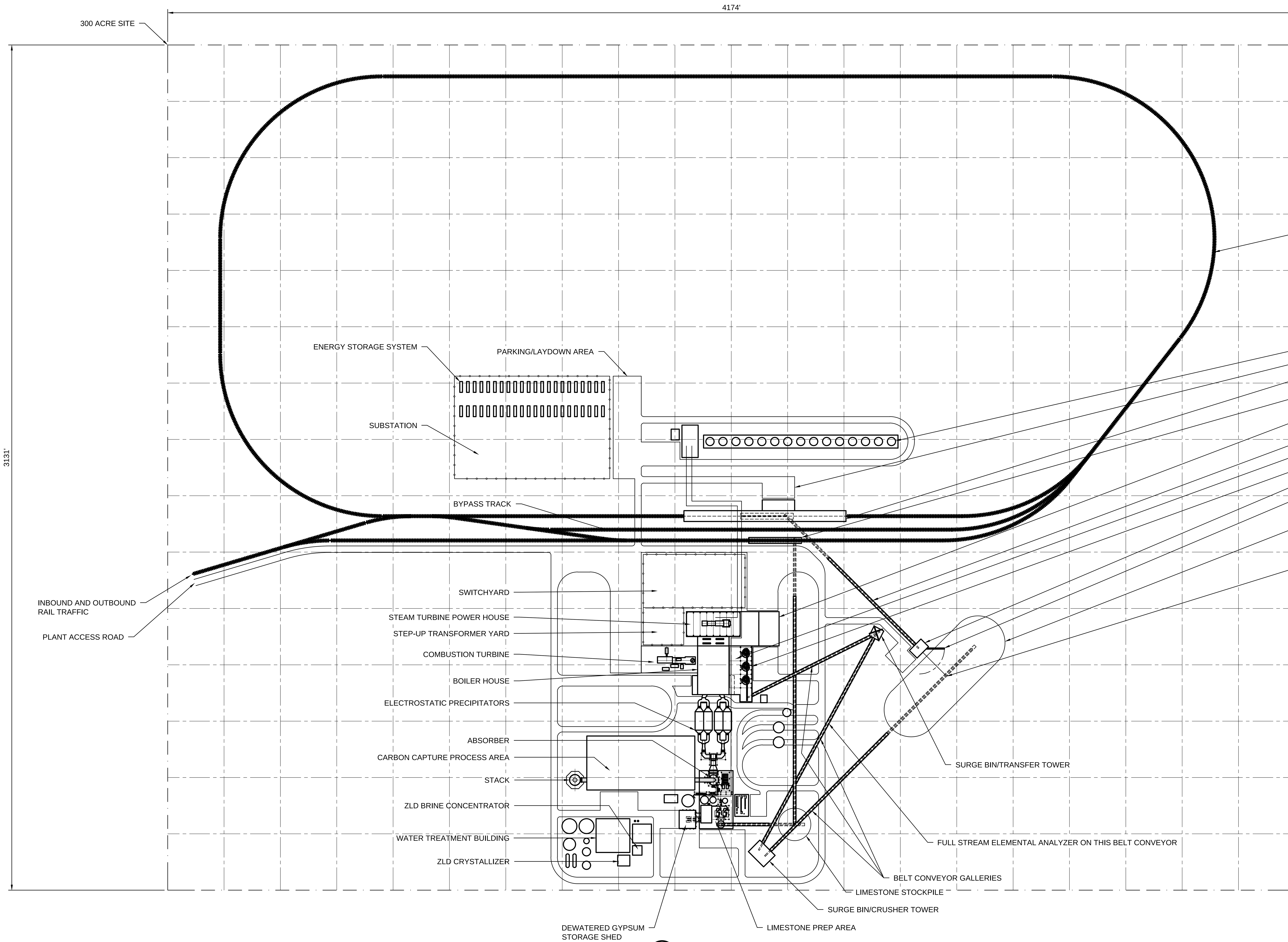
[2] Stream data design based off Exhibit 3-54 Case B12B stream table, supercritical unit with capture on page 139 of the NETL report: \\barr.com\projects\Mpls\48 WV\31\48311001 Coal FIRST_01 Coal and NG Concept\Deliverables\20190731 CoalFIRST CombustionConcept 17_FINAL.docx

[3] The following Streams are no flow streams for the full load base case and would only have flow during certain situations such as startup or shutdown: 3A, 21A

[A] Steam table reference conditions are 32.02°F and 0.089 psia

[B] Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

Appendix E Power Plant of the Future Site Layouts



1 PLAN: OVERALL SITE
1"=200'

0 200 400
SCALE IN FEET

ISSUED FOR FINAL
PRE-FEED STUDY
NOT FOR CONSTRUCTION

NO.	BY	CHK.	APP.	DATE	REVISION DESCRIPTION
C	NLN	NLN	-	3/27/2020	ISSUED FINAL FOR PRE-FEED STUDY
B	DAK	NLN	-	3/15/2020	ISSUED FOR REVIEW
A	DAK	NLN	-	1/6/2020	ISSUED FOR REVIEW

RELEASED TO/FOR	A	B	C	0	1	2	3
CLIENT	1/6/2020	3/15/2020	3/27/2020	—	—	—	—
BID	—	—	—	—	—	—	—
CONSTRUCTION	—	—	—	—	—	—	—

DATE RELEASED

BARR

Corporate Headquarters:
Minneapolis, Minnesota
Ph: 1-800-632-2277

Project Office:
BARR ENGINEERING CO.
3128 14TH AVENUE EAST
HIBBING, MN 55746

Ph: 1-800-225-1966
Fax: (218) 262-3460
www.barr.com

Scale	AS SHOWN
Date	12/4/19
Drawn	DAK
Checked	
Designed	CAH/DAK
Approved	

NETL/DOE COAL FIRST - HGCC
PRE-FEED STUDY

HGCC

GENERAL ARRANGEMENT
OVERALL SITE PLAN

BARR PROJECT No. 48/31-1001.01
CLIENT PROJECT No.
DWG. No. GA-001
REV. No. C

CADD USER: Hibpwuser FILE: \\HIB-PW\HIB_PW_IN\6F4089CC-EE24-48C7-B9CB-2CF121BCF236\B2422135-87FE-438E-8D20-7EC8DBB8A6A4\4831100101_GA-001 PUBLIC.DWG PLOT SCALE: 1:1 PLOT DATE: 3/31/2020 7:39 AM
BAR M:\AutoCAD 2011\AutoCAD 2011 Support\enu\Template\Barr_2011_Template.dwt Plot at 1 10/05/2010 14:03:50

Appendix F Power Plant of the Future List of Assumptions

Appendix F Assumption List

I. Site Characteristics and Ambient Conditions (Based on Design Basis Report)

II. Water Balance

1. Condenser backpressure is 1.5” Hg
2. The hot circulating water temperature is 80oF, and is cooled down to 60oF
3. The cooling tower will be run at at least eight (8) cycles of concentration to meet the cooling tower circulating water quality limits
4. Boiler feedwater is 33.4gpm
5. 15.4gpm of the treatment water backwash is sent to the wastewater treatment to maintain water balance.
6. Scrubber Evaporative Losses are based on 55oC.
7. 12.3 m3/hr of chloride is purged from the FGD
8. Gypsum moisture is 0.15%
9. The Gypsum bonded water is 21% of the total Gypsum capacity.
10. FGD Makeup water / Limestone Slurry Feed can be taken from the cooling tower blowdown
11. Limestone slurry feed is based on an 80/20 Water/Limestone mixture.
12. 10,000 kg/hr of Flue Gas PCC condensate can be used in the remainder of the plant.
13. PCC Effluent is based on Doosan’s PCC Performance Results Rev F03.
14. Wastewater Distillate can be reused in the plant makeup water system.
15. Wastewater sludge is based on Doosan’s PCC Performance Results Rev F03.
16. Wastewater Effluent losses are 20%
17. Flows are representative of average daily flows for annual average conditions
18. Equipment shall not be designed to handle peak flows.
19. Sanitary wastewater will be discharged to the POTW
20. Coal pile area is 5 acres
21. Paved area is 20 acres
22. Non-Contact Stormwater will be discharged from the facility as direct discharge without treatment
23. Oily wastewater will be treated to remove oil/grease and the effluent routed to the local POTW. The effluent stream will contain less than 10 mg/L of oil/grease.
24. Potable water demand is 20 gallons per day per person
25. Average daily precipitation is assumed 0.5 inches
26. Steam/Condensate/Feedwater cycle makeup is 1% of main steam flow

III. Carbon-Sulfur Balance

1. 90% of FGD Limestone Slurry is $CaCO_3$.
2. FGD Gypsum flowrate is based on 90% Gypsum.

IV. Civil Assumptions

No.	Assumption	Reference Doc.
1	Civil Quantities provided to truth check percentage multiplier	
2	"The site is considered to be Seismic Zone 1, relatively level, and free from hazardous materials, archeological artifacts, or excessive rock. Soil conditions are considered adequate for spread footing foundations. The soil bearing capability is assumed adequate such that piling is not needed to support the foundation loads."	Cost and Performance Baseline For Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity: NETL-PUB-22638, 2019-09-24
3	Installation at a greenfield site	Cost and Performance Baseline For Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity: NETL-PUB-22638, 2019-09-24
4	No Wetlands/soft soils	
5	Granular Fill for concrete slabs is available on site and covered under excavation and placement	
6	Topsoil covered under excavation and placement	
7	Groundwater not encountered during civil construction	
8	Capital costs for roads/access stops at edge of GA (incurred by municipalities beyond what is shown)	
9	Capital costs for rail stops at edge of GA (incurred by railroad)	
10	Concrete Pavement assumed to be 8" concrete thickness over 6" aggregate subbase	

V. Structural Assumptions

No.	Assumption
1	5 FT FROST DEPTH
2	• The site is considered to be Seismic Zone 1, relatively level, and free from hazardous materials, archeological artifacts, or excessive rock. Soil conditions are considered adequate for spread footing foundations. The soil bearing capability is assumed adequate such that piling is not needed to support the foundation loads.

VI. Mechanical Assumptions

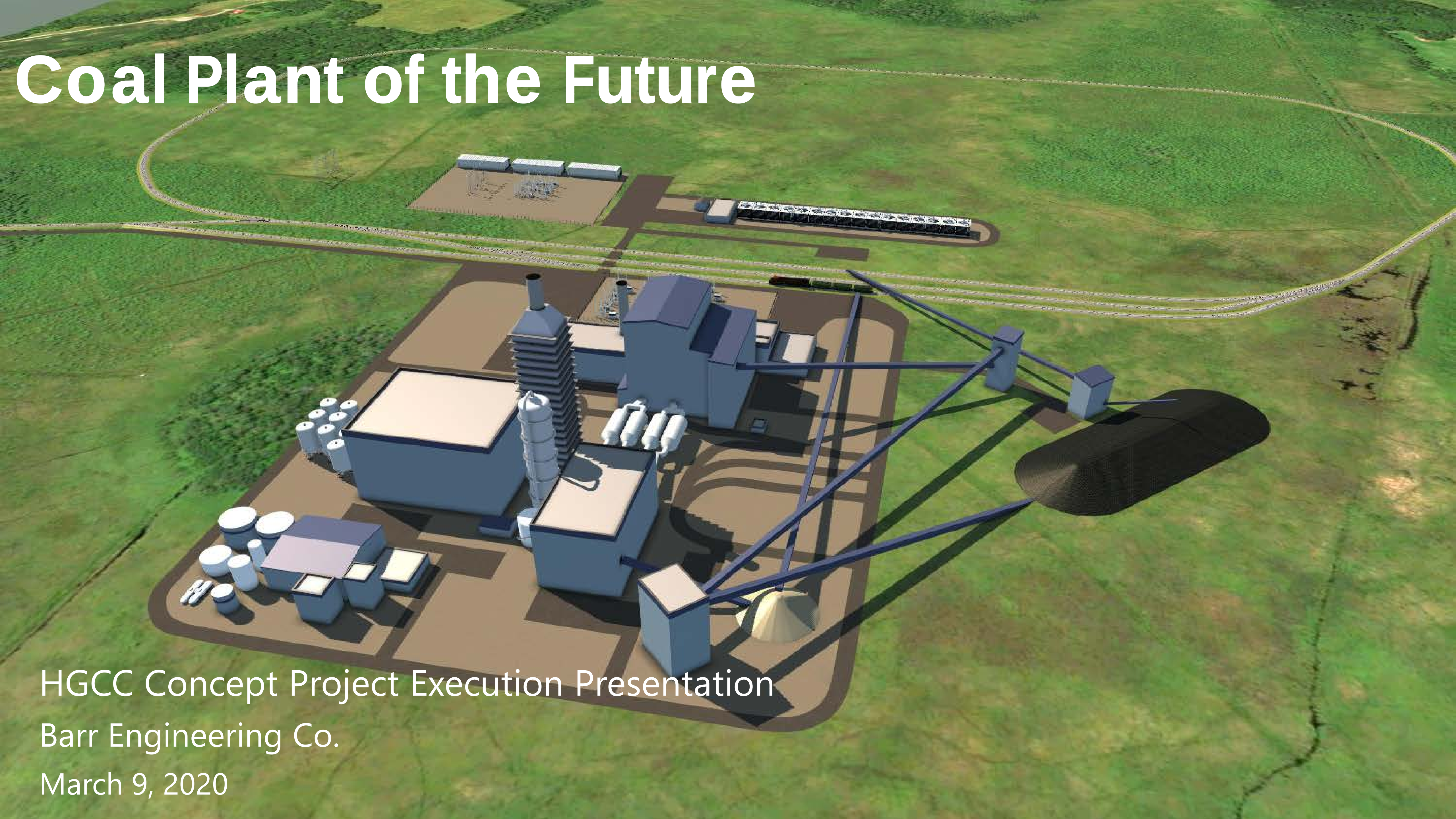
No.	Assumption	Reference Doc.
1	Density and ACFM calculated using air properties at actual temperature and pressure.	
2	Duct design velocities of 4000 fpm.	
3	Insulation thicknesses estimated assuming 120F skin temperature of lagging required (JM 1230 MinWool - 1200 flexible batt).	
4	Low carbon steel (ASTM A635/ ASTM A35) ductwork for 650F or less before boilers.	SMACNA
5	Low alloy steel (ASTM A387-22) ductwork for temperatures from 650F-1000F.	2004 ASME Boiler and Pressure Vessel Code, Part II, pg. 30.
6	Additional 20% of steel weight added to account for flanges, stiffeners, etc.	
7	HA/CA flowrates to pulverizers based on providing 30ft^3 of air per pound of coal at 150F mill outlet temperature and 450F mill inlet temperature.	B and W Steam Book, pg. 13-7, Figure 11, 41st Ed.
8	All ductwork has a square cross section.	
9	Corten steel (ASTM A606-4) ductwork downstream of airheaters to carbon capture area.	
10	Makeup water tank was scaled from Mesquite Power LLC 1200 MW (Combined cycle plant). Makeup water tank is similar in function to Mesquite's 1M Gallon raw water tank. Scaling by net energy production results in 225,000 gallon makeup water tank. See Drawing 065162-CWSB-M2662.	
11	Fire water/service water tank was scaled from Mesquite Power LLC 1200 MW (combined cycle plant) fire water storage tank (300,000 gallons) resulting in 70,000 gallon tank.	
12	Demineralized water storage tank was scaled from Mesquite Power LLC 1200 MW (combined cycle plant) fire water storage tank (155,000 gallons) resulting in 35,000 gallon tank.	
13	HGCC Closed circuit cooling water pumps flowrate were scaled from case B12B net power (650 MW). PCCC System closed cooling derived from Doosan Babcock Performance information.	

VII. EI&C Assumptions

No.	Assumption	Comment
1	**Controls Estimate includes:**	provided by (BARR)
	Processor rack w/ 2 processors for load sharing (non-redundant)	
	10 Remote I/O panels (20 I/O racks) with 20%+ spare based on I/O count	
	Stratus redundant server. Virtualized system.	
	Historian SE server	
	HMI server	
	Engineering workstation	
	Domain Controller (may not be needed)	
	10 HMI client licenses	
	PLC Programming (Barr)	
	HMI Programming (Barr)	
	Redundant processors	
	Redundant network	
	HMI client PC hardware	
	Estimate does not include:	
	Start-up/Commissioning	
	Project Management	
	Redundant I/O	
	I/O devices	
	Budget for Drawings	
	Etc.	

Appendix G Project Execution Presentation

Coal Plant of the Future



HGCC Concept Project Execution Presentation

Barr Engineering Co.

March 9, 2020

Presentation Overview

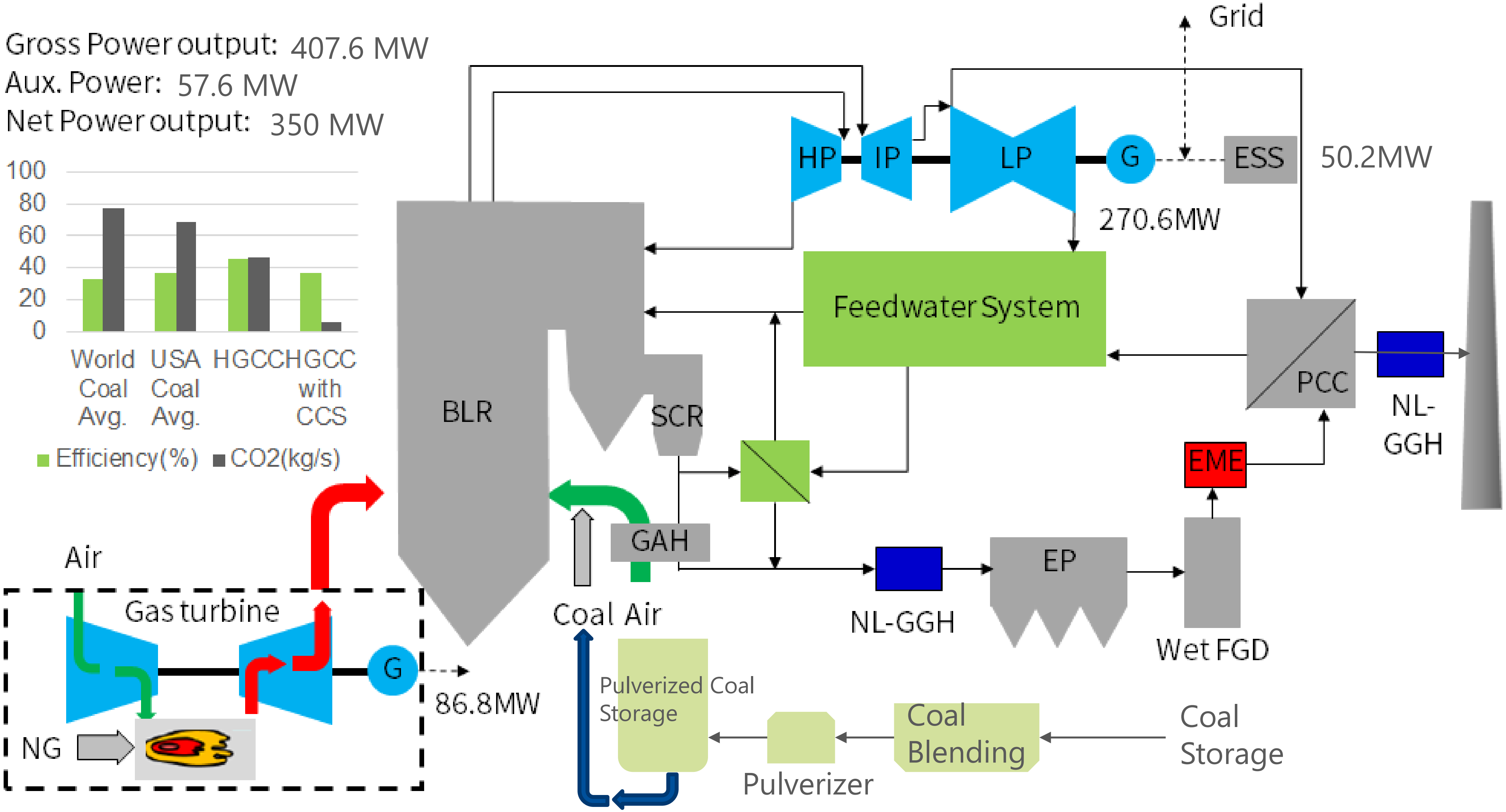
- PreFEED design summary
- Overall HGCC Project Execution Plan
- Overall HGCC Schedule
- Prime Contractor
- DOE FEED Study Proposal
- Host utility
- Project Financing Plan
- FEED Study
  - Schedule
  - Division of Responsibility
- FEED Study (continued)
  - Non-commercial component development
  - Site Selection
  - Prospective Permitting Plan
  - Commercialization Plan
- Detailed Engineering, Procurement and Construction

PreFEED Design Summary

- Boiler/burner size for base case
- Indirect system concept
- Steam and gas turbine
- CO_2 purging for pulverized coal
- Air quality control systems
- CO_2 capture
- Plant water balance and balance of plant
- Class 4 cost estimate
- ESS

PreFEED Design Summary

Gross Power output: 407.6 MW
Aux. Power: 57.6 MW
Net Power output: 350 MW

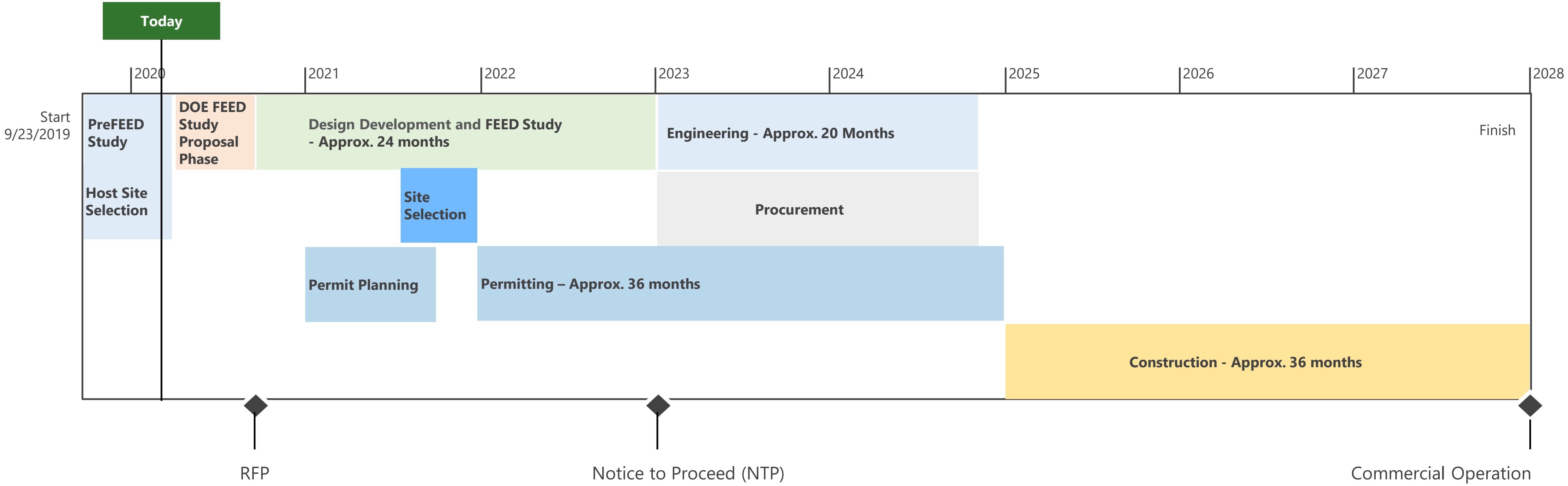


BARR

Overall HGCC Project Execution Plan

	PreFEED (Complete)	FEED/Site Selection (Approx. 2 years)	Detailed Engineering, Procurement & Construction Mgmt (Approx. 4-years)
University of IL		Project Manager	Support for state and local funding and permitting
Kiewit		30% Design	Project Management/Detailed Engineering Procurement → Construction
Barr	PM/Concept Design	30% Design	Detailed Engineering
Doosan	Boiler Concept/AQCS/ESS	Boiler/Turbine/ AQCS/ESS Design	Detailed Engineering/OEM
University of North Dakota	Concept Model		
Envergex	R&D/Non Commercial Component Development		
Microbeam	R&D/Non Commercial Component Development		

Overall HGCC Schedule



Prime Contractor – University of Illinois……….

Prairie Research Institute

Illinois-focused Resource Research and Service

ILLINOIS

↓

ILLINOIS
Prairie Research Institute

↓

ILLINOIS
Illinois Natural History Survey
PRAIRIE RESEARCH INSTITUTE

ILLINOIS
Illinois State Water Survey
PRAIRIE RESEARCH INSTITUTE

ILLINOIS
Illinois State Geological Survey
PRAIRIE RESEARCH INSTITUTE

ILLINOIS
Illinois State Archaeological Survey
PRAIRIE RESEARCH INSTITUTE

ILLINOIS
Illinois Sustainable Technology Center
PRAIRIE RESEARCH INSTITUTE

Existing DOE Capture Related Projects in Illinois

Prairie Research Institute engaged in all projects and awardee in almost all

Abbott Power Plant : UIUC campus

- *Aerosol reduction technologies*
- *Bi-Phasic solvent for carbon capture*
- *CO_2 utilization: Algae cultivation for animal feed*

City, Water, Light, and Power (CWLP): Springfield

- *10 MW Large Capture Pilot*
- *Water recycle and reuse*

Prairie State Generating Company (PSGC): Marissa

- *Large FEED – 816 MW*

DOE FEED Study Proposal

- March-September 2020

Committed Prime: University of Illinois – project management

ILLINOIS

- Kiewit - EPC
- Doosan – OEM Technology Partner
  - Barr Engineering – Engineering
  - Microbeam – R&D/ Non-commercial component development
  - Envergex – R&D/Non-commercial component development
  - University of North Dakota – R&D/Non-commercial component development
- Committed Host Utility: CWLP City of Springfield

Technology Partners

Doosan Heavy Industries	Doosan Babcock	Doosan Gridtech	Microbeam
• Boiler and turbines • Air quality control systems	• CO_2 capture • Solvent technology	• Energy storage system	• Condition-based monitoring

Bituminous

Sub-bituminous

Lignite

Host utility………

City, Water, Light, & Power (CWLP)

Supplies electricity and water to Springfield, IL

- Currently four coal-fired steam turbine-generators with a total nameplate capacity of 578 MW (Units 31 & 32, Unit 33, Dallman #4)
- Three of the four units to be retired as part of Integrated Resource Planning (Unit 31& 32 by 12/31/2020 commissioned in 1968 & 1972)) and (Unit 33 by 9/15/2023 commissioned in 1978))
- Only one unit, Dallman #4 will remain (207 MW commissioned in 2009)
- Dallman #4 is site for 10 MW Large Capture Pilot (DOE funded Phase II FEED ongoing and will be proposed for DOE funded Phase III build/operate)

Why CWLP is an Excellent Host Site

Need for generation and physical space will be available

Total space available for project by 2023

- Proposed Coal FIRST technology could fill “gap” in generating capacity lost due to shut down of older units
- Between shut down on Units 31, 32, and 33 and demolition of Lakeside Power Station sufficient space would be available
- Existing relationship with UIUC on DOE projects
- CWLP has history of interest in new generation and environmentally sound generation technologies
- Strong support by the City of Springfield for technologies such as carbon capture (i.e., City ratified 10 MW large capture pilot for Dallman #4)
- Site details and commitment already in hand

BARR

Proven Means to Select Host Site

Used in previous DOE projects

Site Selection Criteria	
Technical	Flue gas availability
	Flue gas CO_2 concentration
	Aerosol concentration in flue gas
	Steam and utility availability for ISBL
	Design costs for OSBL
	Available plot size for ISBL
	Use of domestic coal
	Existing abatement equipment (FGD, ESP, SCR, etc.)
	Logistics of transportation and lifting
Regulatory and Environmental	Permitting requirements
	Permitting timelines
	Supports NEPA
	Safety culture
Financial and Business Agreements	Cost share commitment
	Contractual terms and conditions
	Site interest
	Sign-off requirements
	Potential for capture system to permanently remain
	Interest in serving as future training site
	Personnel support and responsiveness

CWLP meets all these criteria for the Coal FIRST project

BARR

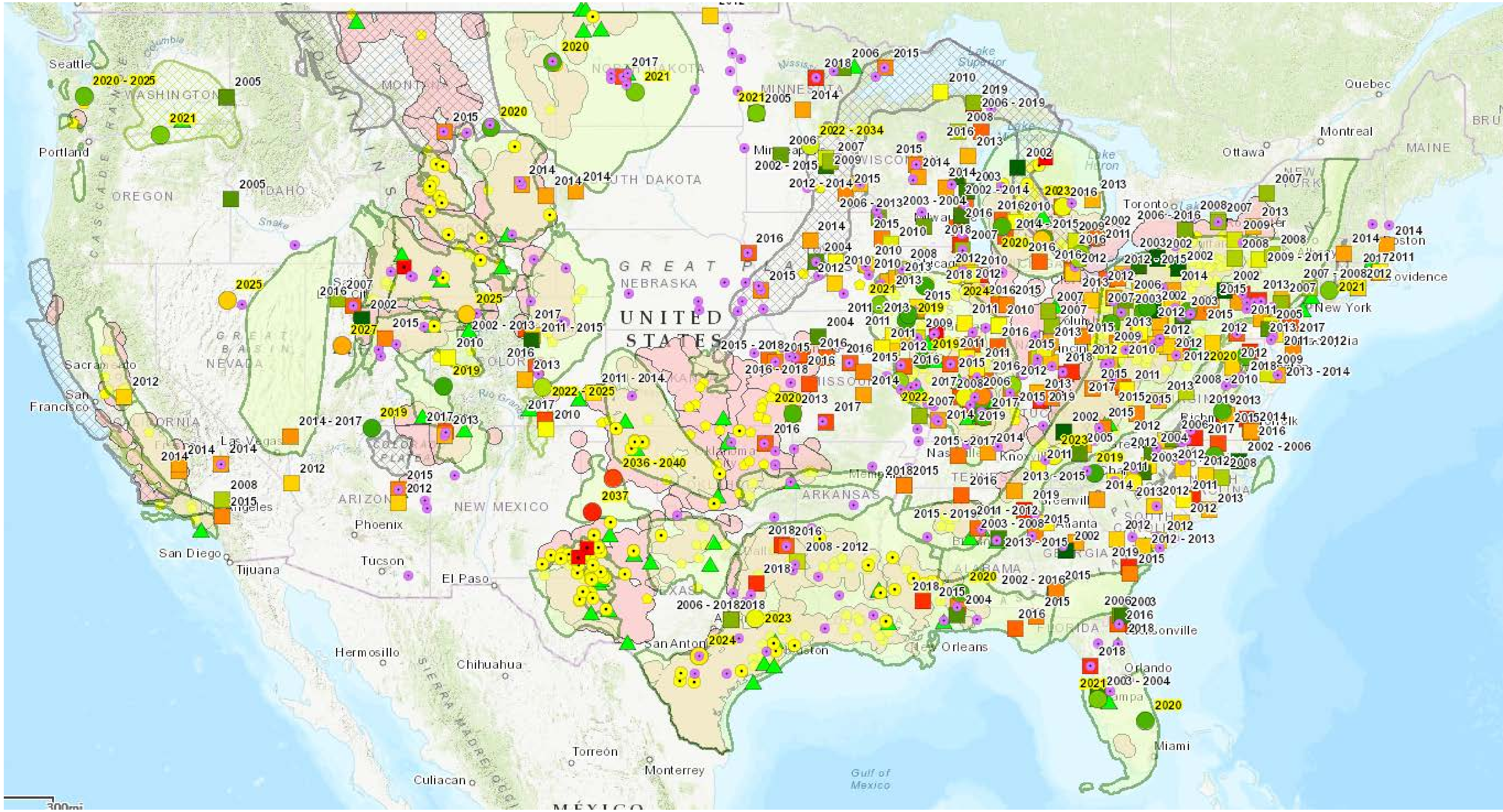
Steam Coal Plants (EIA)

Operating Conventional Steam Coal Plants (EIA860M August 2019)

- 2019
- 2020
- 2020 - 2025
- 2021
- 2022
- 2022 - 2025
- 2022 - 2034
- 2023
- 2024
- 2025
- 2027
- 2028
- 2029 - 2030
- 2036 - 2040
- 2037
- Not Provided

Retired Conventional Steam Coal Plants (EIA860M August 2019)

- 2002
- 2002 - 2006
- 2002 - 2013
- 2002 - 2014
- 2002 - 2015
- 2002 - 2016
- 2003
- 2003 - 2004
- 2003 - 2008
- 2003 - 2015
- 2004
- 2005



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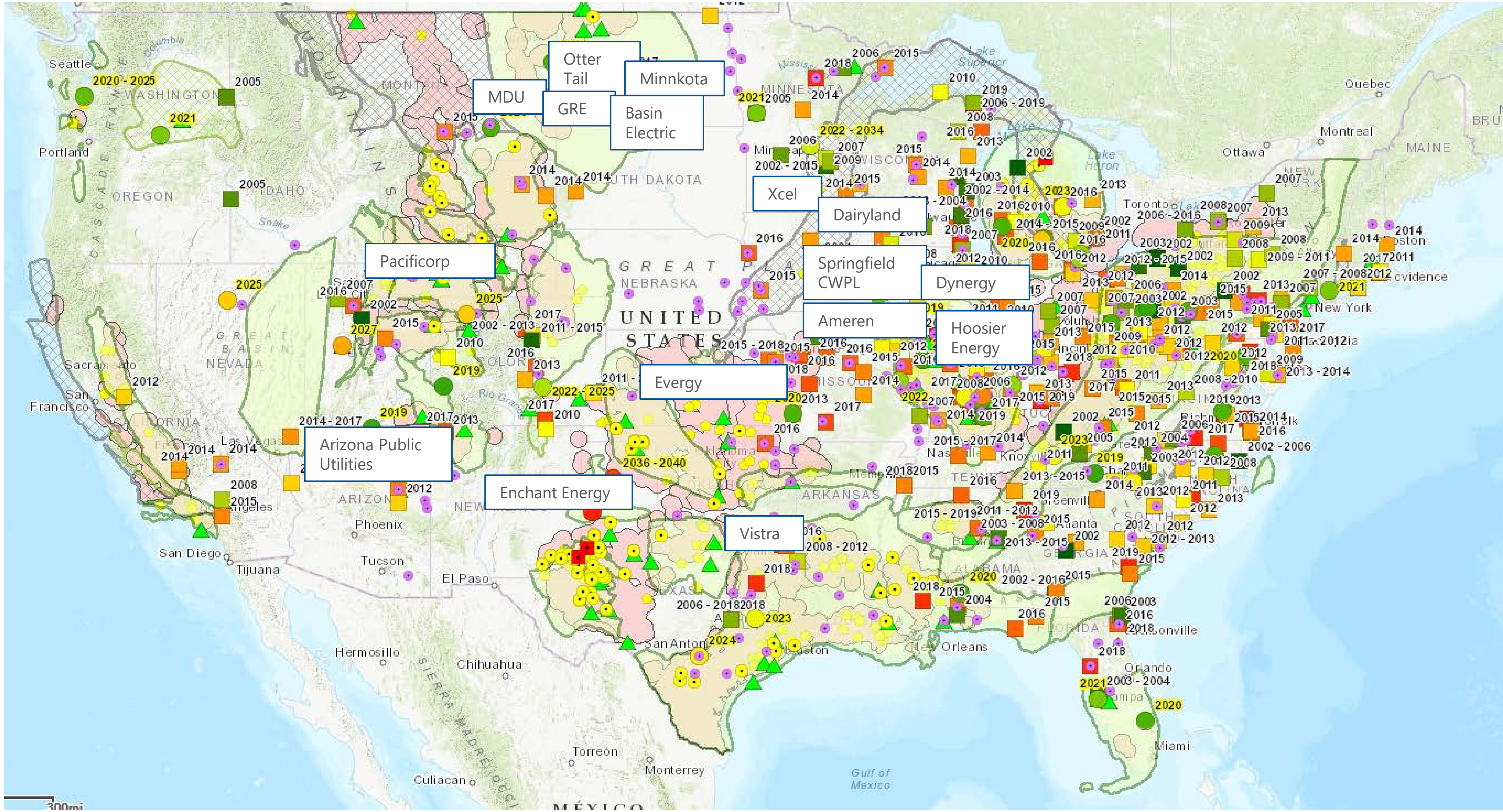

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Operating Conventional Steam Coal Plants (EIA860M August 2019)

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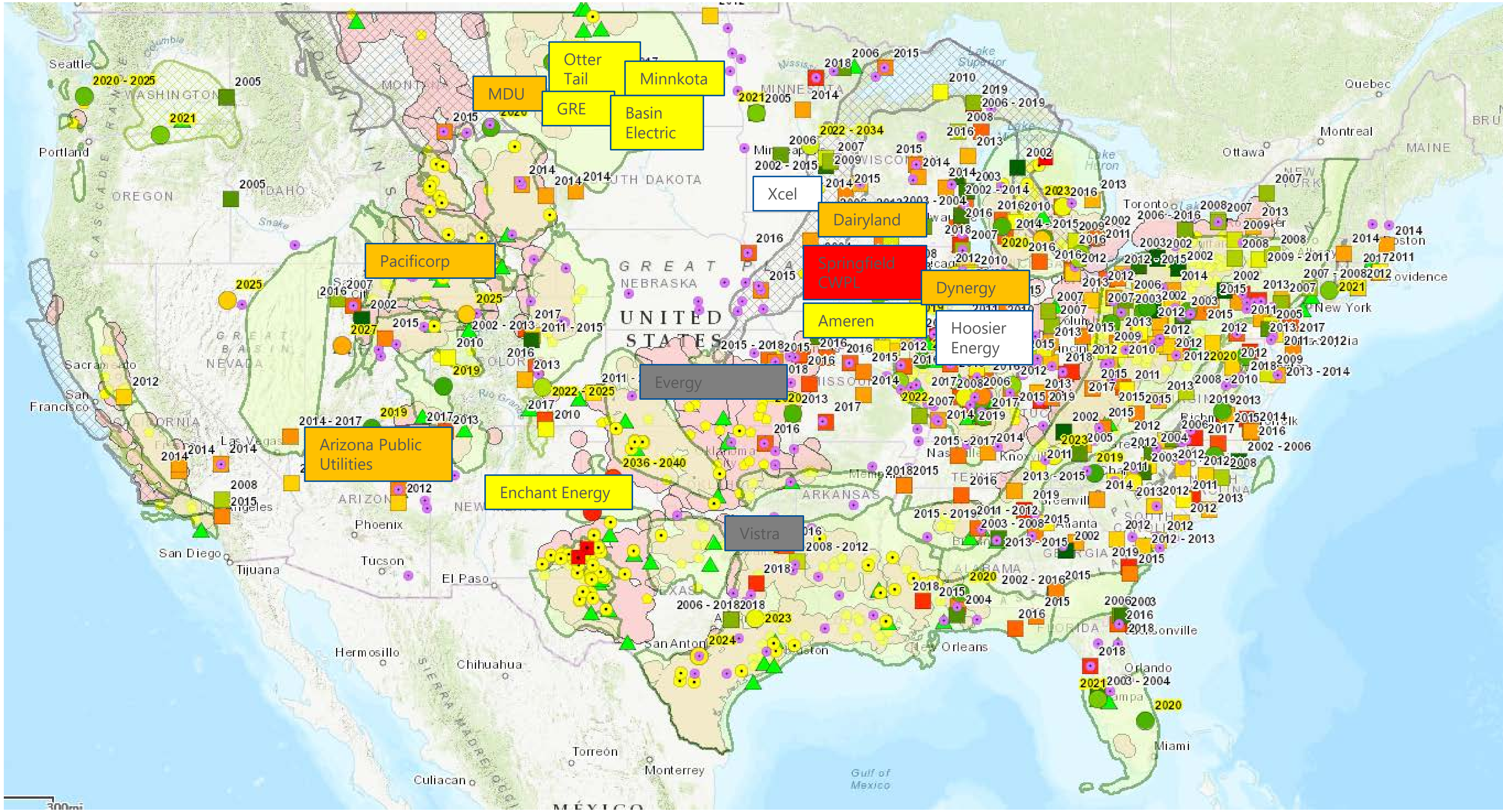


Project Financing Plan

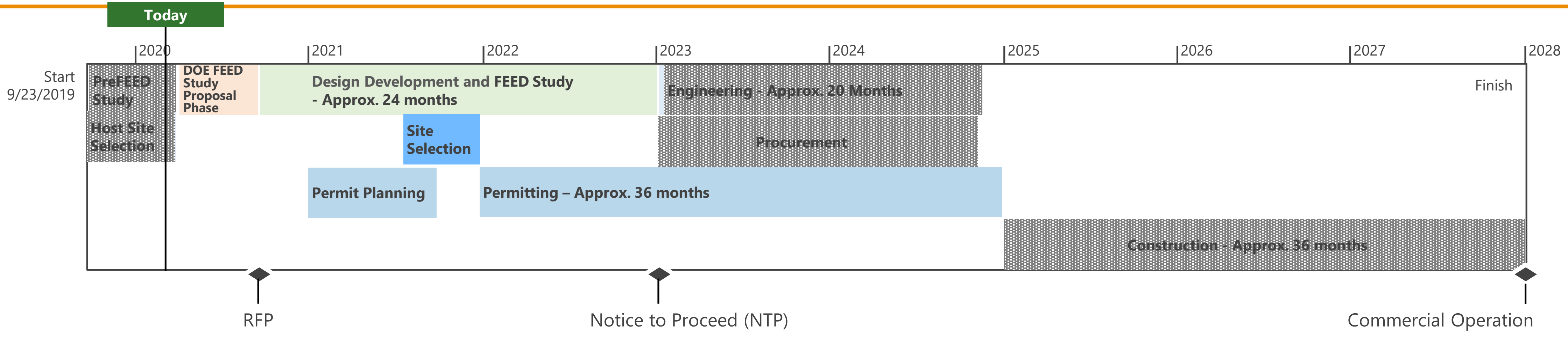
- FEED funding
  - DOE funds
  - 20% cost share
    - Kiewit and Doosan
    - In-kind cost share from utility
- Establish steering committee
  - Created to carry out specific objectives for financing
- Commercialized Project financing
  - RUS loans (if applicable) and DOE/State/Federal grants

Project Financing Plan – Benefits to Utility

- Establishing utility investment
  - Develop financial pro forma plan for HGCC concept
    - Energy storage for peak capacity revenue generation
    - Fuel flexibility using lower cost fuel
  - Monetize revenue streams
    - Power sales
    - CO_2 45Q credits or sales for EOR
    - Fly ash/bottom ash
    - Gypsum

BARR

FEED Study - Schedule



- September 2020 – December 2023
- HGCC design development
  - 30% Engineering
  - Environmental permitting review
  - Develop financing plan
  - CAPEX/OPEX updates
- Non-commercial development

FEED Study - Division of Responsibility

University of IL	• Project management • FEED study design basis • Final FEED study package
Kiewit	• Mechanical, structural, and electrical/I&C design • Balance of plant • Combustion turbine package • Cost assessment
Doosan	• Boiler, steam turbine, combustion turbine, AQCS, carbon capture package • ESS system package • Cost assessment • Non-commercial development
Barr	• Water treatment and coal handling package • Permitting review • Site civil and electrical • Cost assessment
Envergex/UND/Microbeam	• Non-commercial development/Modeling support

BARR

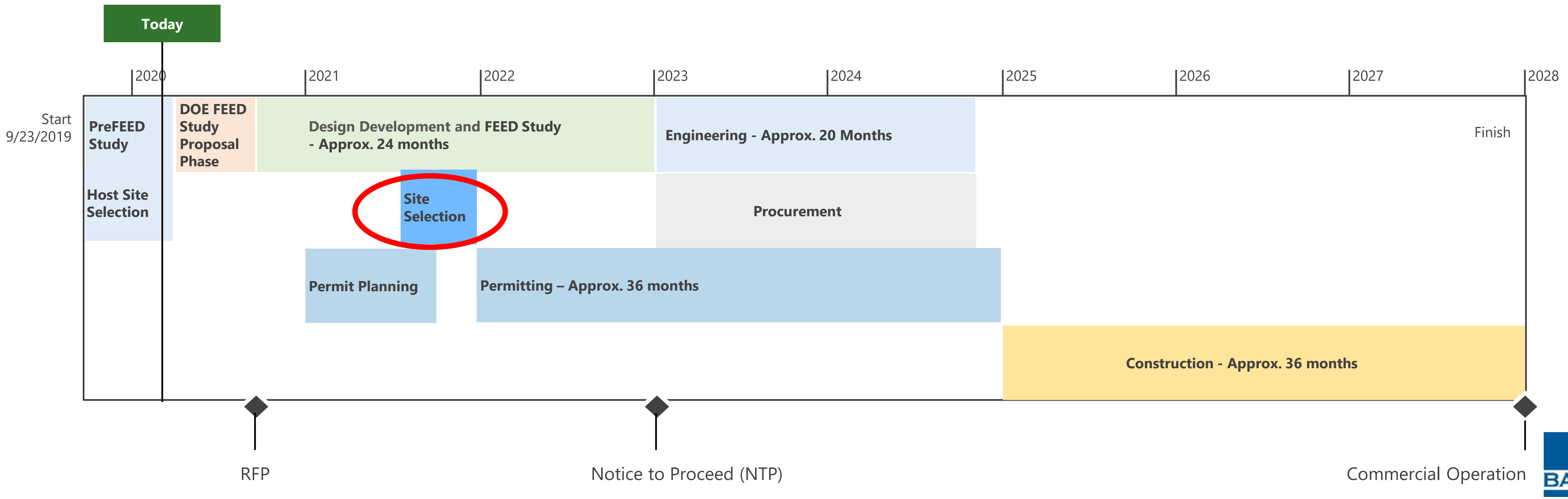
FEED Study - Non-Commercial Component Development

HGCC System	Indirect Firing	ESS Integration	Environmental
• Burner optimization with GT flue gas • CFD Modeling • Unit flexibility • Modularization • Efficiency optimizing	• Efficiency optimizing • Pulverized coal storage CO_2 purging	• Cost reviews • Load following optimization	• Emissions profile • Water minimization • CO_2 capture energy/ cost reduction

BARR

Feed Study - Site Selection

- Anticipate 6 months during FEED study for final site for commercialization



Steam Coal Plants (EIA)

Operating Conventional Steam Coal Plants (EIA860M August 2019)

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- 2020
- 2020 - 2025
- 2021
- 2022
- 2022 - 2025
- 2022 - 2034
- 2023
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- 2025
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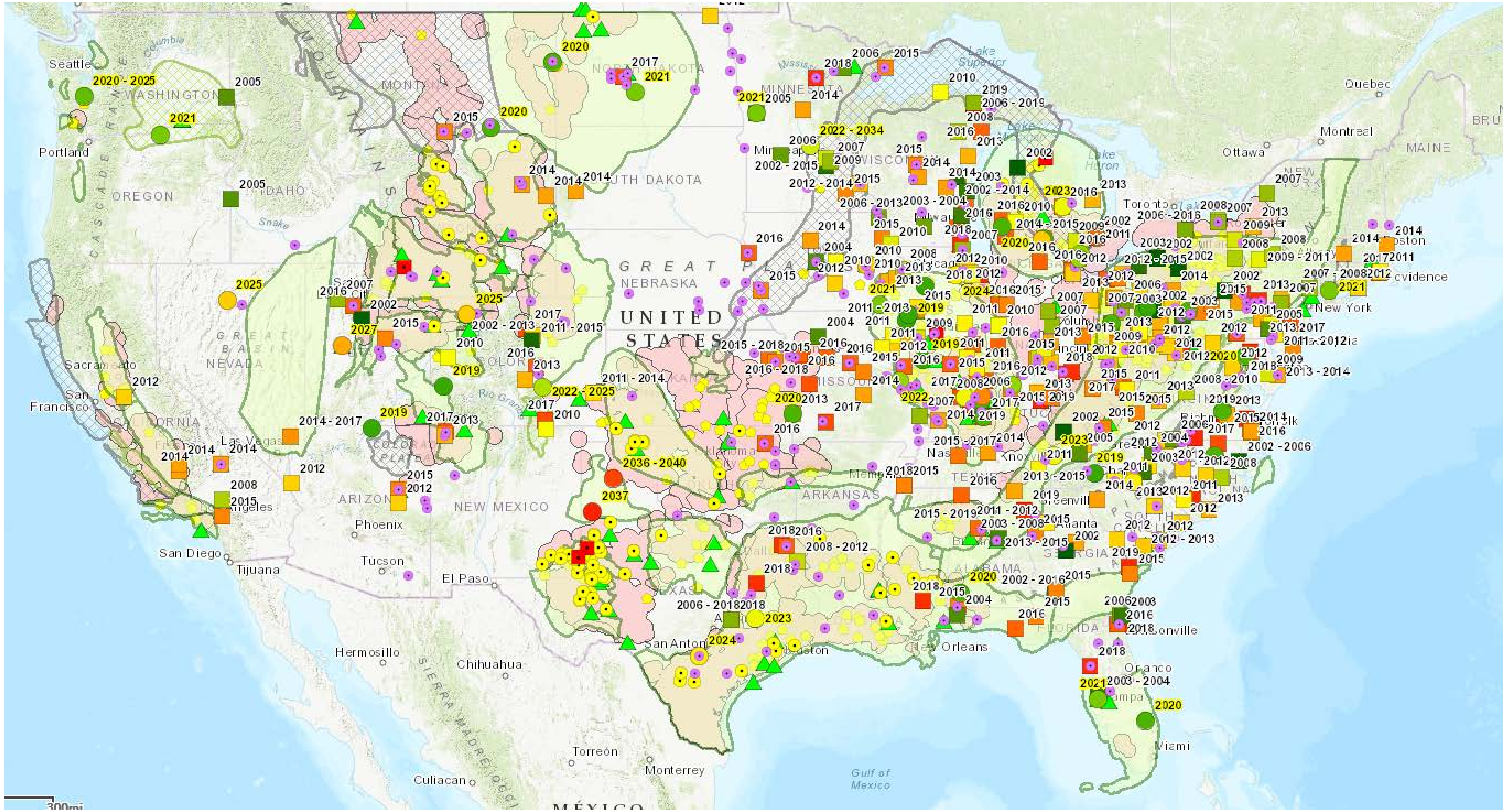
- 2003 - 2015
- 2004
- 2005



FEED Study - Commercialization Plan

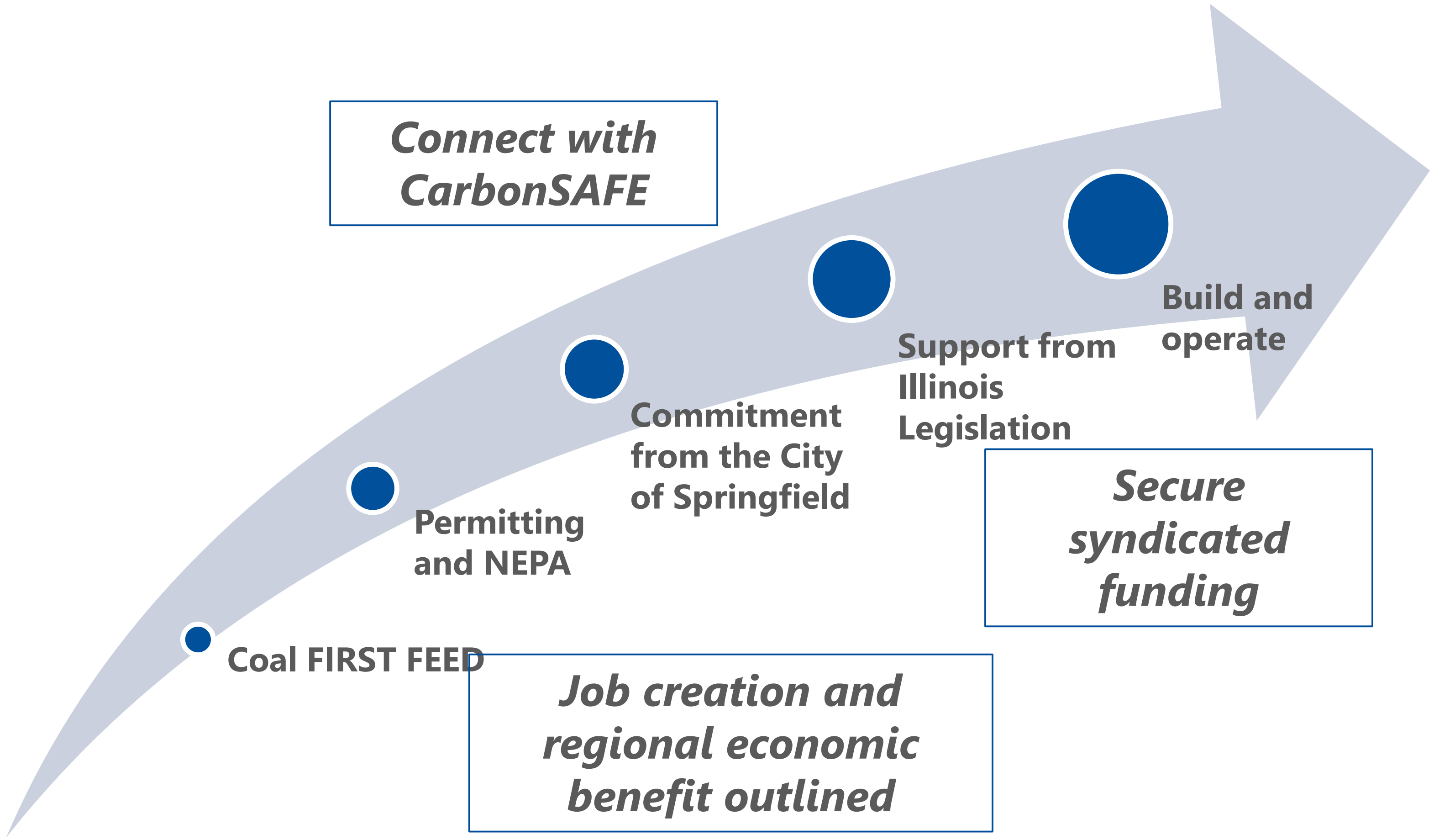
- Site selection for commercialization
- Commercial guarantees
- Letters of intent (equipment & material procurement)

Responsibilities and Capabilities of Prairie Research / University of Illinois Urbana-Champaign (UIUC)

- Overall project management
  - History of experience with DOE projects
  - Accounting systems in place
  - Proven ability to deliver on time and on budget
  - Proven ability to provide required deliverables
- Permitting agencies and timelines
  - Strong relationships with permitting authorities for this project – Illinois EPA and Sangamon Waste Reclamation District
  - Same groups for existing DOE 10 MW large capture pilot at CWLP
- Interaction with NEPA contractor
  - Existing relationship with NEPA contractor being used for 10 MW Large Capture Pilot at CWLP
  - NEPA considerations well understood at site
- Existing relationships with City of Springfield (owner of CWLP) and state legislators
  - Known pathway for approval – previous obtained for 10 MW Large Pilot
  - Known pathways to legislative support - previous obtained for 10 MW Large Pilot
- Link with CarbonSAFE and utilization activities to assure pathway to sequester or utilize CO_2 for Coal FIRST project
- Legislation at the State Level has stimulated the formation of a CO_2 value chain

Pathways to Commercialization

Known pathway with milestones well understood



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FEED Study - Prospective Permitting Plan

- Permitting will commence post FEED
- Likely Approvals and Permits
  - NEPA review: for federally funded projects, includes EIS
  - State Utility Commission: e.g., siting permit, certificate of need
  - Interconnection studies: independent system operator agreement
  - PDS air permit: state-administered federal permit
  - USFWS approval: federal protected species impacts
  - EPA SDWA or delegated states: Underground Injection Control (UIC)permit
  - Water allocation: state permit
  - NPDES water discharge: assume zero liquid discharge for HGCC
  - Ash disposal: assume beneficial use
  - Local permits: land use, noise, road access, zoning

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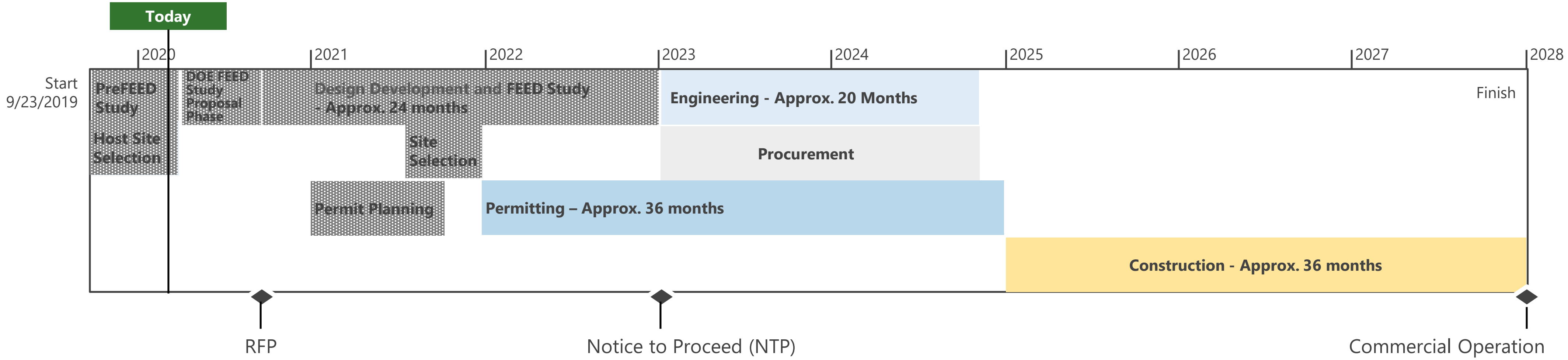
Detailed Engineering through Commercial Operation



- December 2023 – February 2028
- Engineering
- Procurement
- Construction
- Permitting
- Startup
- Commercial operation

Engineering, Procurement, Construction

- December 2023 – October 2025
- Detailed engineering from 30% to 100%
  - 60% review
  - 90% review
  - 100% final
- Equipment procurement
  - Leverage FEED study equipment lists
  - Finalize equipment specs and complete procurement
- DOR will remain similar to FEED study

Construction & Startup

- Early 2025 – 2028
- Kiewit to complete construction as EPC
- Utility lead to complete startup
- Support from vendors and engineering team

THANK YOU!

DOOSAN

Kiewit

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Envergex
Sparking Innovations

MLJ Consulting

UND INSTITUTE FOR ENERGY STUDIES
THE UNIVERSITY OF NORTH DAKOTA

MICROBEAM
TECHNOLOGIES, INC.

CITY WATER LIGHT AND POWER
SPRINGFIELD, IL

ILLINOIS

ACM
Project and Program Managers

QUESTIONS?