DESIGN BASIS REPORT

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

Rev. 1 – Final Public Version

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Acronyms

AI	Artificial Intelligence
ASU	Air Separation Unit
AQCS	Air Quality Control System
BDL	Blowdown Losses
BFW	Boiler Feedwater
CCSEM	computer-controlled scanning electron microscopy
CL	Closed loop
CWP	Circulating water pumps
CQMS	Coal Quality Management System
CSPI	Combustion System Operational Performance Indices
CWS	Cooling Water System
DCC	Direct Contact Cooler
ELG	Effluent Limitation Guideline
EME	Electrostatic Mist Eliminator
EPC	Engineering, Procurement, and Construction
ESP	Electrostatic Precipitator
ESS	Energy Storage System
FD	Forced Draft
FGD	Flue Gas Desulfurization
FSEA	Full Stream Elemental Coal Analysis
GAH	Gas Air Heater
GGH	Gas Heater
HHV	Higher Heating Value
HGCC	Hybrid Coal and Gas Boiler and Turbine Concept with Post Combustion Carbon Capture
HRSG	Heat Recovery Steam Generator
HSS	Heat Stable Salts
HX	Heat exchangers
ID	Induced Draft
LP	Low Pressure
MCCs	Motor Control Centers
ME	Mist Eliminator
NGCC	Natural Gas Firing Combined Cycle
NFPA	National Fire Protection Association
NL	Non Leakage
OEM	Original Equipment Manufacturer
OFA	Overfire air
PA	Primary Air

PAC	Powdered Activated Carbon
PCC	Post Combustion Carbon
PF	Pulverized Fuel
RAT	Reserve Auxiliary Transformer
RO	Reverse Osmosis
SAT	Station Auxiliary Transformer
SCR	Selective Catalytic Reduction
TRL	Technology Readiness Level
USC	Ultra-Supercritical
VFDs	Variable Frequency Drives
ZLD	Zero Liquid Discharge

1.0 Design Basis Input Criteria

1.1 Site Characteristics (From Addendum 1 RFP)

Table 1-1 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

1.2 Ambient Conditions (From Addendum 1 RFP)

Table 1-2 Ambient Conditions from DOE/NETL RFP Requirements

Parameter	Value
Elevation, (ft)	0
Barometric Pressure, MPa (psia)	0.101 (14.696)
Average Ambient Dry Bulb Temperature, °C (°F)	15 (59)
Average Ambient Wet Bulb Temperature, °C (°F)	10.8 (51.5)
Design Ambient Relative Humidity, %	60
Cooling Water Temperature, °C (°F)[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.

1.3 Water Type

1.3.1 Makeup Water

Table 1-3 Makeup Water Quality[1]

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

Parameter	Groundwater (Range)	POTW (Range)	Makeup Water (Design Basis – 50% Groundwater / 50% POTW
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

From Cost and Performance Baseline for Fossil Energy Power Plants Volume 1: Bituminous Coal and Natural Gas to Electricity, 2019

* Alkalinity is reported as $CaCO_3$ equivalent, rather than the concentration of HCO_3. The concentration of HCO_3 can be obtained by dividing the alkalinity by 0.82.

1.3.2 Boiler Feed Water Quality (based on USC 263 MW Unit)

Table 1-4 Required Feed Water Quality for Doosan Variable Pressure Once-through USC Boiler 263 MW Unit

Item	Unit	Design Value	
		Alkaline Water Treatment (AVT)	Combined Water Treatment (CWT)
pH at 25℃	-	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℃	㎲/cm	< 0.2	< 0.15
Sodium(Na)	ppb	< 3	

1.4 Fuel Type and Composition

1.4.1 Coal Specifications

1.4.1.1 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 1-5 (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 and 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) and is similar to reported average values for Herrin seam coals of 10.9% (Affolter and Hatch, 2010). The sulfur content of the Illinois #6 is 2.51% (as-received) and is slightly lower that average value of 3.0% reported by (Affolter and Hatch, 2010). The forms of sulfur are mainly in the form of pyrite and organic sulfur. The chlorine content of the Illinois coal is 0.29%. The free-swelling index for the Illinois #6 coals ranges from 3.5 to 4.5 (Riley, 2007).

Table 1-5 Proximate and Ultimate Analysis of Illinois #6 Bituminous Coal

Rank	Bituminous	
Seam	Illinois No. 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, CH_4S) with trace levels of H_2S. Note: Fuel composition is normalized and heating values are calculated.

The proximate and ultimate analysis of the Illinois #6 coal was utilized to identify coals in Microbeam's coal database that match where detailed analysis of the fuel impurities are available. The compositional analysis of the Illinois #6 Old Ben mine sample was found to be a good match. The 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 1-6. 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 1-6.

Table 1-6 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 for the Illinois #6 coal is summarized in Table 1-7. The results show that the major minerals include quartz, pyrite, clay minerals (kaolinite, K-AlSilicate (Illite), and other Al-Silicates), and unclassified. The chemical composition of the unclassified phases are 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 1-7 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

1.4.1.2 Sub-Bituminous (From Addendum 1 RFP)

The subbituminous coal used as a performance coal in the design basis is the Montana Rosebud coal. The Rosebud coal is from the northern Powder River Basin. The proximate and ultimate analysis is summarized in Table 1-8 (Addendum 1 of the Coal FIRST RFP). The coal is a subbituminous 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 1-8 Proximate and Ultimate Analysis of Montana Rosebud Subbituminous 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 utilized to identify coals in Microbeam's coal database that match where detailed analysis of the fuel impurities are available. The compositional analysis of a Rosebud seam coal sample from the Absolaka 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 1-9. 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 1-9.

Table 1-9 Composition of Ash (ASTM) Produced from Montana Rosebud Subbituminous 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. (deg F)	2,220
S.T. (deg F)	2,250
H.T. (deg F)	2,260
F.T. (deg F)	2,430

The mineral size, composition, and abundance for the Montana Rosebud subbituminous coal is summarized in Table 1-10. The results show that the 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 are known. The chemical formulas of the minerals are summarized in Appendix A.

Table 1-10 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

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

The low-sodium lignite coal used as a performance coal in the design basis is the Wilcox formation in Texas. The proximate and ultimate analysis is summarized in Table 1-11 (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 1-11 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, CH_4S) 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 utilized to identify coals in Microbeam's coal database that match where detailed analysis 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 1-12. 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 1-12 Composition of Ash (ASTM) Produced from Texas Lignite Coal (wt% of ash expressed as equivalent oxides)

Oxide	Wt% of Ash
SiO2	52.65
Al2O3	15.22
TiO2	1.02
Fe2O3	5.27
CaO	8.27
MgO	1.64
K2O	0.70
Na2O	0.37
SO3	10.80
P2O5	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 for the low-sodium Texas lignite coal is summarized in Table 1-13. 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 are known. The chemical formulas of the minerals are summarized in Appendix A.

Table 1-13 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

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

The high-sodium lignite coal used as a performance coal in the design basis is the Beulah-Zap seam from the Fort Union Region in North Dakota. The proximate and ultimate analysis is summarized in Table 1-14 (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 1-14 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, CH_4S) 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 ND lignite coal was utilized to identify coals in Microbeam's coal database that match where detailed analysis 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 1-15. 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 1-15 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 ND lignite coal is summarized in Table 1-15. 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 are known. The chemical formulas of the minerals are summarized in Appendix A. Organically associated impurities in subbituminous and lignite coals

Some of the impurities or ash-forming components in the lignite are associated with the organic matrix of the coal. Table 1-16 will be used for discussion of organically associate elements for the performance coals.

Table 1-16 Performance Coals Organic Matrix

Analysis	Buelah-Zap Lignite		Wilcox Lignite		Rosebud Subbituminous	
	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

1.4.1.5 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 are dependent upon ash-related issues as illustrated in Figure 1-1. Table 1-17 presents the assumed basis around these indices for the base and performance coals.

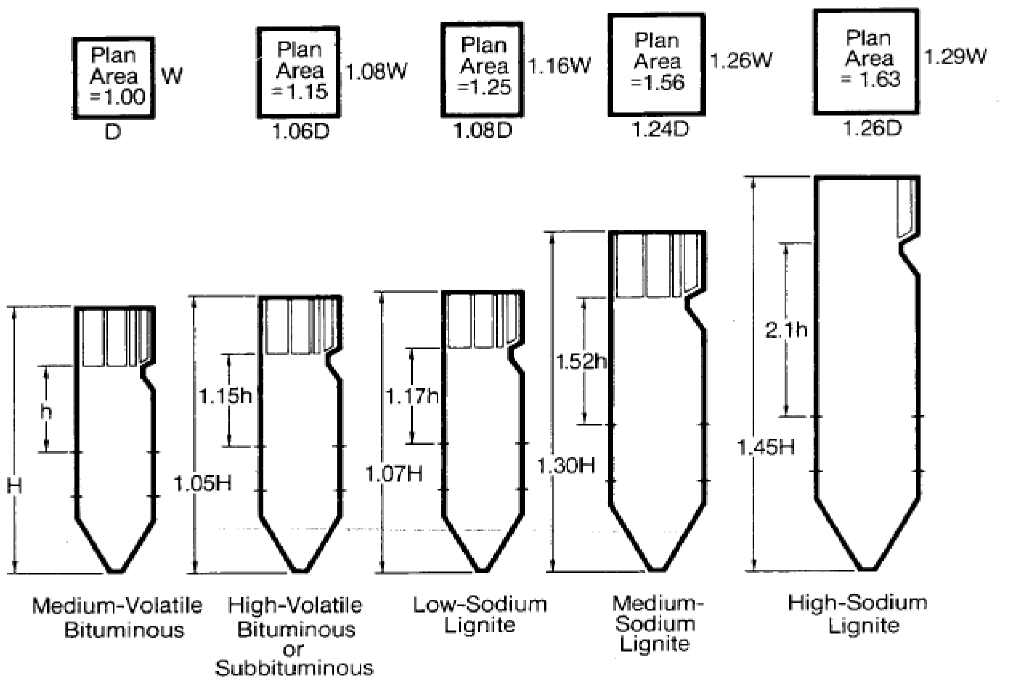

Figure 1-1 Impacts of Coal Properties on Boiler Sizing

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

1.4.1.6 Natural Gas (From Addendum 1 RFP)

Table 1-17 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)

2.0 Plant Performance Targets

2.1 General Plant Requirements

The proposed concept meets the specific design criteria in the RFP per the following details:

- Overall plant efficiency of 43.5% (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 - wet flue gas desulfurization (FGD), selective catalytic reduction for NOx control - SCR) that make the flue gas ready for traditional post combustion carbon capture technology.
- Capable of high ramp rates (expected 6% vs. RFP 4%) and minimum loads (expected better than. 5:1 target).
- Integrated energy storage system (ESS) with 51 MW vanadium redox flow batteries.
- Minimized water consumption by the use of a cooling tower vs. once-through cooling, and internal recycle of water where possible.
- Reduced design and commissioning schedules from conventional norms by utilizing state-of-the-art design technology, such as digital twin, and 3D modeling and dynamic simulation.
- Enhanced maintenance features to improve monitoring and diagnostics such as coal quality impact modeling/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, as well as utilizing the gas turbine exhaust to assist with heating the coal-fired steam boiler.

Table 2-1 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	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

2.2 Water Requirements

Table 2-2 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}

2.3 System Size Basis

Table 2-3 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% >35% with CCS parasitic load

2.4 Environmental Targets

Table 2-4 Environmental Targets

Air Pollutant[1]	PC (lb/MWh-gross) (From Addendum 1 RFP)	Proposed Plant Target
SO_2	1.00	1.00
NOx	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)

1 The sulfur control technologies are used to remove H2S formed in the gasifier to ultimately limit SO_2 emissions after the syngas is combusted in the CT.

The output-based emissions limits above are specified by 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 dispersion profile that is different than experienced with a conventional coal-fired stack. Until siting and exhaust stream characteristics are established, a possibility exists that compliance with air quality standards could drive some project design adjustments.

Table 2-5 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 2-6 Liquid Discharge Requirements

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

2.5 Plant Capacity Factor

Table 2-7 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%

3.0 Selected Major Equipment Performance Criteria

Table 3-1 Boiler Design Basis Table

Boiler			
Type	Doosan Variable Pressure Once-through USC boiler		
USC PP Capacity	Coal Feedrate (w' GT): 43.9 lb coal/sec (79 tons/hr) Coal Feedrate (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	227.361	210.000	210.000
SH outlet steam temperature, ℃	603	603	603
SH outlet steam pressure, bara	252.6	251 (3626 psig, 255kg/cm2 g)	251 (3626 psig, 255kg/cm2 g)
RH outlet steam flow, kg/s	180.556	179.320	179.320
RH outlet steam temperature, ℃	603	603	603
RH outlet steam pressure, bara	55.0	53.7	53.7
RH inlet steam temperature, ℃	379.3	372.1	372.1
RH inlet steam pressure, bara	56.8	55.5	55.5
Final feedwater temperature, ℃	308.9	308.5	297.3
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 PreFEED and FEED stage

Table 3-2 Steam Turbine Design Basis Table

Steam Turbine			
Type	Doosan DST-S20		
Steam Turbine Capacity – USC PP	263 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	180.556	179.320	179.320
Reheat steam temperature at Reheat stop valve outlet, °C	600	600	600
Reheat steam pressure at Reheat stop valve outlet, bara	53.9	53.1	53.1
RH steam temperature at HP turbine outlet, °C	381.5	375.1	375.1
RH steam pressure at HP turbine outlet, bara	58.6	57.1	57.1
Steam flow for PCC from LP cross over pipe, kg/s	61.35	56.81	56.81
Steam temperature for PCC from LP cross over pipe, °C		(266.420)	(266.420)
Steam pressure for PCC from LP cross over pipe, bara		(5.209)	(5.209)
Water return flow from PCC to Deaerator, kg/s	61.35	56.81	56.81
Water return temperature from PCC to Deaerator,°C		(150.583)	(150.583)
Water return pressure from PCC to Deaerator, bara		(26.4)	(26.4)
Condenser Pressure, bara		0.051	0.051

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

Table 3-3 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	88 MW
Exhaust Gas Temp	620°C

Table 3-4 AQCS Design Basis Table

Air Quality Control System (AQCS) Equipment	
Selective Catalytic Reduction	
Inlet Gas temp	>300°C @ min load
Inlet NO_x (bituminous/sub-bituminous / lignite)	150/147/141ppm
NO_x Outlet Concentration Target	10ppm @ 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 @ O_2 6% dry volume
SO_x Outlet Concentration Target	4 ppm @ 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
Sorbent Injection	
Sorbent (Target pollutant)	hydrated lime (SO_2), Activated Carbon (Hg)
Injection Location	Upstream of the Air Heater
Outlet concentration target	0.5ppm SO3, 3 X 10^-6 lb/MWh Gross Hg

Table 3-5 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 3-6 CO_2 Compression

CO2 Compression System	
Type	6 Stage Centrifugal Diffuser Guide Vane with Recirculation Loop
Power requirement	20 MW

Table 3-7 Energy Storage System Design Basis

Energy Storage System	
Type	Vanadium Redox Flow Batteries
Storage Duration	1 hour
Power Contained	51 MW (460 kW Modular) 51 MWh
Efficiency	DC-DC 60%-80%
Life/Cycle	20/8,000 yr/cycles

Table 3-8 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

4.0 Process Description

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 263-MW USC power plant, an 88-MW gas turbine, and 51-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 88-MW gas turbine will feed the 263-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 enable shorter startups and respond faster to 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 eliminate natural limitations in ramp rate caused by placing pulverizers into and out of service. The indirect firing design includes up to hours of storage capacity to support shorter startup and faster load change achievement. 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 utilizing the traditional gas turbine, which has an inherently fast startup and ramp rate capability.

4.2 General System Description and Process Flow Diagram

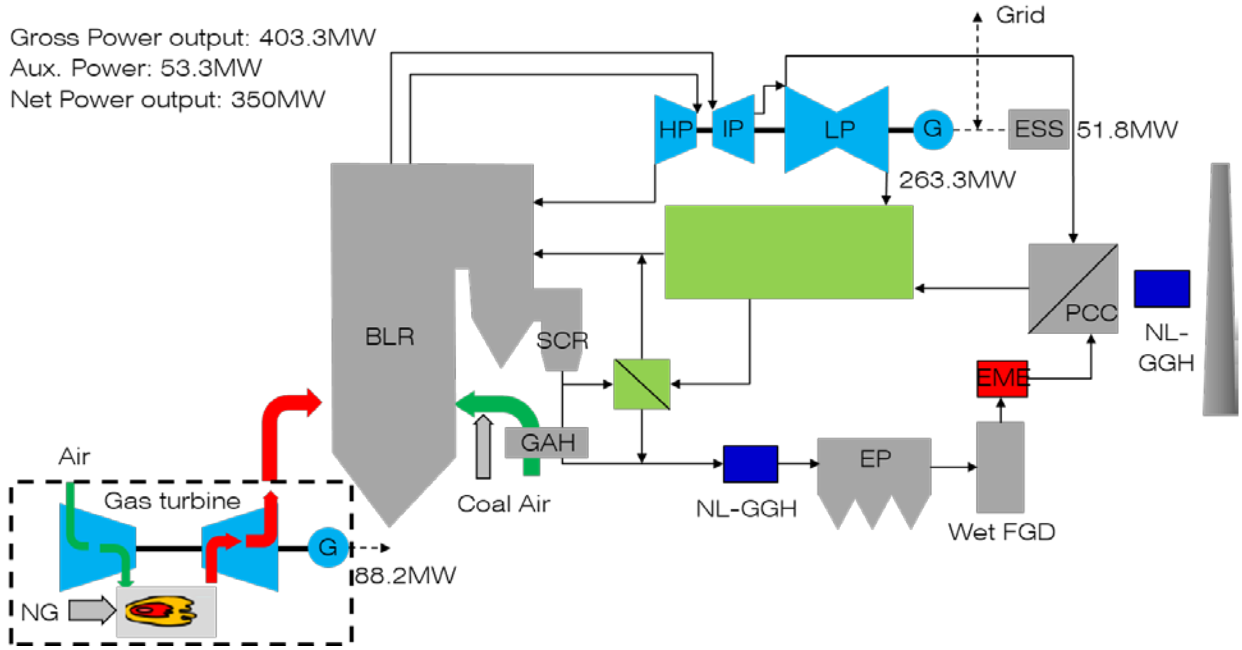

Figure 4-1 HGCC Concept Flow Diagram

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 88-MW natural gas-fired turbine will heat the USC steam boiler. Generated USC steam will power a 263-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 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 technology in design utilizing a digital twin as well as 3D modeling and dynamic simulation to solve issues before equipment is constructed.

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 with the gas turbine responsible for nearly a quarter of direct power output, as well as use of the gas turbine exhaust to assist with heating the coal-fired steam boiler.

4.4 System Description of Major Equipment

4.4.1 General Operation

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 to the stack is closed. It is anticipated that the bypass will be utilized for approximately 2 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 up 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 independently. Provisions will be included in the air permit, which 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, not found on current 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 allows the boiler minimum load to be reduced 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

4.4.2 Coal, Activated Carbon, and Sorbent Receiving and Storage

4.4.2.1 Coal Receiving and Unloading

The function of the Coal Receiving and Storage system is to unload, convey, prepare, and store the coal delivered to the plant. This scope is outlined similarly to the 2019 Case B12B performance cost report (2019). The scope of the system is from the trestle bottom dumper and coal receiving hoppers up to and including the slide gate valves at the outlet of the coal storage silos.

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

The coal is delivered to the site by 100-car unit trains comprising 100-ton rail cars. The unloading is done by a trestle bottom dumper, which 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 transfer the coal to either the long-term storage pile or to the reclaim area. The conveyor passes under a magnetic plate separator to remove tramp iron and then to the reclaim pile.

Coal from the reclaim pile is fed by two vibratory feeders, located under the pile, onto a belt conveyor, which transfers the coal to the coal surge bin located in the crusher tower. 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.

4.4.2.2 Reagent Receiving and Unloading

Similarly to Case B12B (2019), limestone is delivered to the site using 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.

Brominated powdered activated carbon (PAC) is delivered to the site in 10-ton batches by self-unloading pneumatic trucks. The carbon is unloaded from the truck via an on-board compressor into the dry, welded-steel storage silo where the displaced air is vented through a silo vent filter. The carbon level in the silo is measured by system instrumentation.

Hydrated lime is delivered and distributed in a manner very similar to that of the PAC. The hydrated lime is delivered in 10-ton batches.

4.4.2.3 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 currently designed for a coal firing supply capacity of 8-12 hours with 2 hours of storage capacity for the pulverized coal silo. Silo plugging will be prevented by installing equipment that vibrates coal in the coalbunker.

4.4.2.3.1 CO_2 Inerting/Suppression System

The Indirect Firing System proposed is a unique approach to providing load changing flexibility to the HGCC Concept proposed by the Barr Team.

Many of the Indirect Firing System components are similar to the 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. One unique aspect is the storage of pulverized coal in bins, which allows the pulverizer to operate semi-independently from the boiler allowing for increased operating flexibility. Along with this flexibility, 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 suppression/fire protection requirements, Barr requested and received a preliminary proposal from Electric Scientific Company of Minneapolis (based upon 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 provided by Barr:

- Process Flow Diagram – based upon a concept design from Doosan
- Preliminary volume calculations for the various equipment
- Preliminary operating scenario for the Indirect Firing System

The proposal received has the following basic elements:

<u>Suppression system</u>

- Separate from inerting system due to the different flow requirements
- Four zones of protection
  - Zones 1-3 includes 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

<u>Fire Suppression Approach</u>

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

<u>Inerting Approach</u>

- Bunkers – activated based upon detection
- Coal Pulverizers – Activated based upon detection
- Pulverized Coal Bin – Activated based upon 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

4.4.3 Coal Drying (Lignite Only)

The Coal Drying concept will be based upon the Great River Energy Dryfining^{tm} process. A hot water loop will extract heat from one of the Slip Stream Feedwater Heaters shown on PFD 001. Final selection of the exact Slip Stream Heater is under evaluation. The hot water loop will provide the necessary heat to operate the Dryfining^{tm} system. Initial moisture removal is targeted at producing a lignite with 29% moisture content.

Great River Energy has been contacted regarding the design aspects of this system and will provide an estimate of the heat required to dry the lignite.

4.4.4 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. The many ways in which the detrimental effects of ash manifest themselves in a boiler system include 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 upon the quantity and association of inorganic constituents in the coal, boiler design, and combustion conditions. The inorganic constituents in coal are in several forms, including organically associated inorganic elements and discrete minerals. The types of inorganic components present depend upon the rank of the coal and the environment in which the coal was 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 subbituminous 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," are cooled when transported with the bulk gas flow through the body of the gasifier and 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 being transported through the combustion system dictate their ability to produce slag that will flow, produce water wall deposits and convective pass deposits, and produce 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 upon 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. In addition, these vapors can condense on surfaces of entrained ash particles and ash deposits, producing low-melting-point phases.

Coal Quality Management System (CQMS) was initially developed in the 1990s as an internal software for use at MTI and is illustrated in Figure 4-2 to assess the impacts of fuel properties on plant performance. It has been used in hundreds of projects for clients world-wide. MTI has conducted over 1500 projects and has a database of coal and ash-related materials (deposits, slag, and corrosion products) of over 12,000 samples. The CQMS system utilizes advanced indices that relate the coal characteristics as determined computer controlled scanning electron microscopy (CCSEM) (Benson and Laumb, 2007) and chemical fractionation (Benson and Holm, 1985) to ash behavior in a coal-fired utility boiler. MTI has 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). 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).

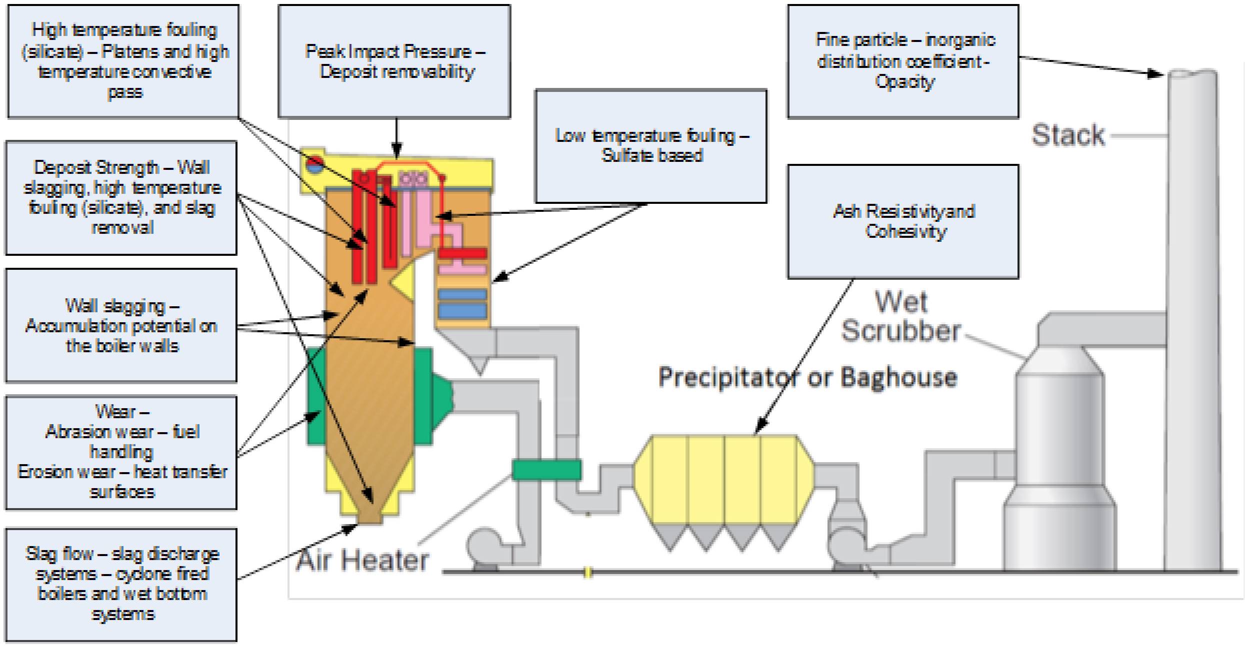

Figure 4-2 Description of CQMS Indices

4.4.5 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 1.0 of this design basis report on condition that Lignite coal is dried before supplied to the boiler. The boiler will be optimized for fast start-up 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 start-up and low-load combustion support.

The boiler design will be standardized to facilitate operation with different coal types. This will be achieved by adopting a boiler design with 100% coal fuel input, which when modified to fit our concept results in a reduction in ash. This 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 retro-fitable for demonstration 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 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. For startup, the recirculation pump system offers fast startup times, low firing rates, and low auxiliary fuel consumption. As limited hot water is dumped to 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.

Lime and activated carbon is injected upstream of the air heater for SO_3 and Hg reduction before it goes to flue gas heat exchangers to minimize corrosion potential. This is important to the heat transfer surface integrity. If after further review of the performance results, arsenic poisoning is likely, the location of lime injection will be re-evaluated to be upstream of the SCR. The flue gas desulphurization scrubber unit is also being optimized to reduce the need for both activated carbon and lime at the power block. This optimization will be finalized in the performance report.

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
- Soot blower 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 & gas duct with dampers, expansion joints
- GT exhaust bypass duct

4.4.5.1 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 by economizer is supplied 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 steal cooled cage wall.

The furnace is of a gas tight 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.

4.4.5.2 Air and Combustion Products

The boiler air and gas system comprises of fans, air heaters, ducts, dampers, 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 the 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 comprises of two identical circuits each complete with regenerative air preheater, ID fan, and all associated duct, dampers, and expansion joints.

4.4.5.3 Fuel Feed

The mill will be the vertical spindle type with the housing designed in accordance with the pressure containment requirements of 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 outwards and through the grinding elements where it is pulverized to a fine powder. Hot primary air is 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 pulverized coal is stored in the intermediate bunker. From the bunker it is taken to combustion chamber with the help of 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 coal, air/gas mixture for storing in fine coal bunker.

This system favors the following advantages:

- Mill can be operated always at full load, thus saving in power, maintenance cost.
- Reduction of start-up time and flexibilization of load operation (Faster load changes)

4.4.5.4 Ash Removal

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

4.4.5.5 Burners

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

- Provide an initial oxygen-deficient zone to minimize NO_x formation, but also provide enough oxygen to maintain a stable flame
- Optimize both the residence time and the temperature under fuel-rich conditions, to minimize NO_x formation.
- Maximize the char residence time under fuel-rich conditions, to reduce the potential for formation of char nitrogen oxide.

In addition, OFA nozzles are provided to further stage combustion and thereby minimize NO_x formation.

Natural gas-fired burners are provided with a capacity of 30% BMCR heat input for start-up, warm-up and flame stabilization at low loads. Natural gas is fired by NG burner mounted in each PF (Pulverized Fuel) Burner. High energy ark are provided to ignite natural gas.

4.4.5.6 Gas Air Preheater

The Ljungstrom Gas Air Heater (GAH) absorbs waste heat from flue gas, then transfers this heat to incoming cold air by means of continuously rotating heat transfer elements of specially formed metal plates. The housing surrounding the rotor is provided with duct connections at both ends and is adequately sealed by seal frame and seal shoe forming 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 a totally enclosed speed reduction drive unit and a back-up air motor is supplied.

Soot Blowers

Sootblowers for steam cleaning is provided at flue gas side and an off-load water washing device system is provided.

A carefully selected number of soot blowers are strategically located in the furnace wall, superheater, reheater, and economizer of the boiler.

The furnace walls are provided with short retractable rotary soot blowers above top burner row elevation.

The pendant and horizontal surfaces of superheater, reheater, and economizer are provided with long retractable blowers arranged on both sides of the boiler.

4.4.5.7 Condensate

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

4.4.5.8 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 conducted on site. A mechanical draft, wood frame, counter-flow cooling tower is provided for the circulating water heat sink. Two 50% circulating water pumps (CWPs) are provided. 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 the thermal efficiency and reduces the amount of heat rejected by the cooling tower resulting in lowered 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 provided. 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 that is 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.

4.4.6 Ash Handling

The function of the ash handling system is to provide the equipment required for conveying, preparing, storing, and disposing of the fly ash and bottom ash produced on a daily basis by the boiler, along with the hydrated lime and activated carbon injected for mercury control.

The scope of the system is 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 the baghouse and the air heaters is conveyed to the fly ash storage silo. A pneumatic transport system using 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 is provided to break up any clinkers that may form. Accumulated bottom ash discharged from the hoppers passes through the clinker grinder, and 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(s) and pyrites (rejected from the coal pulverizers) are conveyed using water on a periodic basis to the dewatering system (i.e., dewatering bins) for offsite removal by truck.

The wet sluicing for the pyrite system is 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 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 possibility of pneumatic conveying dry handling.

4.4.7 Steam Turbine

The proposed steam turbine will be a Doosan DST-S20 condensing steam turbine with reheat. 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 in the upper half of the outer casing. Steam entering into the IP inner casing is conducted into the circular duct. The IP steam flows toward the low pressure (LP) casing. The inlet connections are sealed in the inner casing in a similar way as 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 of welded design. Steam from the IP turbine is introduced through two cross-over pipelines into the inlet equipped with the expansion joint and into a circular duct in the inner LP casing. The walls of the outer LP casing form a rectangular exhaust hood. The LP casing lower half is welded on to the exhaust neck. Welded brackets are on the periphery of the outer casing and enable the casing to be set up 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).

4.4.8 Gas Turbine

The proposed gas turbine has an 88-MW power output capability with the configuration of 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 provides for an axial exhaust to optimize the plant arrangement for combined cycle. An 88-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 is 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 replaced individually.

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 utilizes 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 incorporating internal air cooling for the turbine section.

4.4.9 Electrical Equipment with High Turndown

The proposed electrical equipment system can be broke 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 (3) 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 utilized to close the generator circuit breakers to 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 utilize the most current technology to minimize wiring and maximize control flexibility. The use of 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.

4.4.10 Energy Storage System

The proposed energy storage system is a 51-MW modular redox flow battery system using a vanadium ion. 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 vanadium redox flow battery has longer storage durations and longer life cycle and is easier to scale up than a lithium ion battery. The 51-MW ESS will have 51-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 is expected to have a 20-year life and the operation capability is expected to be 8,000 cycles.

4.4.11 Environmental Controls

Bituminous coal is the base case for this study, however, the AQCS proposed method is applicable to each coal type listed in Section 1.

4.4.11.1 Hg Control

Hg control will be achieved using activated carbon injection upstream of the air preheater. Co-benefit capture is also expected from the hydrated lime injection for SO_2/SO_3 control, electrostatic precipitation (ESP) and EME (Electrostatic Mist Eliminator). Since the non-leakage gas gas heater (GGH) cooler is located before the dry ESP, this is a cold ESP (flue gas temperature ranges from 194 to 212^{o}F), which has better mercury removal efficiency. °

4.4.11.2 SO_x Control

To prepare the flue gas for amine-based carbon capture, the FGD will be optimized to reduce SO_2 to less than 4 ppmv. Preliminary performance results of the equipment show that this can be achieved without the need of 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 that 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 is developed by DHI, uses wet ESP technology. The EMEs are installed after a one-stage ME (Mist Eliminator) on top of the absorber. EME is compact with higher efficiency, lower operating cost, and greater than 90% reduction efficiency.

SO_2 concentration will be less than 15 ppm at the exit of the FGD. SO_2 and Hg will be reduced to near zero by the wet FGD and new two-stage electrostatic mist eliminator (EME) technology. The EME technology targets high efficiency removal of pollutants via two steps: first via application of a micro spraying system providing a very large number of reactive droplets and consequently a high surface area (10x versus 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.

A GGH (gas-gas heat exchanger) 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. Hence, 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 particulate-bound Hg. In the case of a sub-bituminous coal firing, elemental mercury (Hg^0) exists in gaseous form. The SCR catalyst will oxidize a portion of the Hg^0 to Hg^{2+}. Trace bromide/iodide addition to the flue gas, as necessary, can increase Hg^0 oxidation. 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 reduces CAPEX investment and OPEX cost.

4.4.11.3 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 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.

4.4.11.4 PM Control

Greater than 99% dust reduction efficiency is targeted for the ESP. A NL (Non Leakage)-GGH (Gas Gas Heater) 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 95% removal efficiency for PM greater than 0.7μm and 70% for PM of 0.3μm or less. Therefore, the EME has the same performance as a bag house for PM_{10} removal. PM_{10} and $PM_{2.5}$ can be effectively reduced to 0.5 mg/Nm^3.

4.4.11.5 CO_2 Control

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

4.4.11.5.1 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. A key aspect of the flexible operation of post-combustion capture plants is steam availability and 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. However, there are limitations for regeneration at partial load, since the floating pressure integration leads to steam pressures at partial load 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 enables 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.

4.4.11.5.2 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 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.

4.4.11.5.3 Carbon capture integration & technology options

Among the various carbon capture technologies, the 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^{TM} have some technological benefit, such as low 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. At this moment, 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.

4.4.11.5.4 Carbon compression and utilization

The boundary limits of this concept ends at the compressed CO_2. The compressor being considered uses a 6-stage variable diffuser-guide vane technology that has 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.

4.4.11.6 ZLD System

Wastewater from the flue gas cleanup sent to a zero liquid discharge system or ZLD. The concentrated water chemistry of the purge stream poses a challenge for the RO system. The design case for this system uses a pretreatment and a straight evaporation system. The thermal system is will have two steps: a brine concentration + a crystallizer. Due to the flow and the chemistry, it is much more convenient running 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 landfilled. The pretreatment include pretreatment for hardness removal eliminating scaling concerns due to high sulfates.

The ZLD system is divided into softening / ultra-filtration pretreatment, reverse osmosis (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.

4.4.12 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 vs. once-through cooling and internal recycle 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.

- Discharge water from the PCC system will be treated if needed and used back into the overall system either as FGD or cooling water makeup. The discharge quality will determine how the stream is 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 utilizes 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 1300 gpm
    - Drift losses of 0.001% of the circulating water flow rate
    - Blowdown losses (BDL) were calculated assuming four cycles of concentration

4.4.13 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 of combined sorbent injection followed 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. Options for saleability of the CO_2 system precoat waste, crystallized brine, and wastewater sludge will be reviewed in further engineering, but these waste will be considered for landfill. Bottom ash, gypsum, flyash are considered saleable.

4.4.14 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.

5.0 Project Execution

Greenfield market penetration by 2030.

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 150ppm and maximum O_2 level of 3.5% at boiler exit with 30% gas turbine exhaust combustion co-firing.
Fast startup USC boiler model	Advanced boiler model to minimize full load start up 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.

5.2 Sparing Philosophy

Because our concept is using 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 with exceptions 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 is included to provide 100% redundancy at full load. The plant design consists of the following major subsystems:

- Two (2 x 100%) 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%)

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. Field welding points of high pressure component 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

5.3.1 EPC Approach

Discussions with engineering, procurement, and construction companies (EPC) have been completed and final selection will be completed during the preFEED study. Once selected, a non-disclosure agreement will be signed and a letter of commitment will be submitted by the EPC. A memo of understanding will be 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, it is planned for the EPC to 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

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.

5.4.1 Reliability

Most current coal plants use two scheduled outages (spring and fall) to reduce the number 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 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(utilize DOE Cross Cutting Research Program).

6.0 References

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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	$(1\text{-}x)Al_2O_3 \cdot x(MgO, Na_2O) \cdot 4SiO_2 \cdot H_2O$
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

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	%

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

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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

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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

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Designed	CAH
Approved	

NETL/DOE COAL FIRST - HGCC

PRE-FEED STUDY

HGCC

HFCC 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