COST RESULTS 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

Prepared by: Barr Engineering Co.

Updated April 2020

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4300 MarketPointe Drive, Suite 200
Minneapolis, MN 55435
952.832.2600
www.barr.com

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Contents

List of Tables

List of Figures

List of Appendices

Acronyms

AACE	Association for the Advancement of Cost Engineering
ACM	Administrative Controls Management Inc.
AFUDC	Allowance for Funds Used During Construction
ATWACC	After-Tax Weighted Average Cost of Capital
BEC	Bare Erected Cost
BOP	Balance of Plant
CBM	Condition Based Monitoring
CF	Capacity Factor
CEMS	Continuous Emissions Monitoring System
CCW	Closed Cycle Water
COE	Cost of Electricity
CRF	Capital Recovery Factors
CTG	Combustion Turbine Generator
DCS	Distributed Control System
DHI	Doosan Heavy Industries
EME	Electrostatic Mist Eliminator
EOR	Enhanced Oil Recovery
EPC	Engineering, Procurement, and Construction
EPCM	Engineering, Procurement, and Construction Management
ESP	Electrostatic Precipitator
ESS	Energy Storage System
ETR	Effective Tax Rate
FCR	Fixed Charge Rate
FEED	Front-End Engineering Design
FGD	Flue Gas Desulfurization
FSEA	Full Stream Elemental Coal Analysis
FWH	Feedwater Heater
GGH	Gas to Gas Heat Exchanger
GE	General Electric
GT	Gas Turbine
HHV	Higher Heating Value
HGCC	Hybrid Coal and Gas Boiler and Turbine Concept with Post Combustion Carbon Capture
HX	Heat Exchanger
IOU	Investor-Owned Utility
LTE	Low Temperature Economizer
LRVP	Liquid Ring Vacuum Pump
MCM	Thousand Circular Mils

MCR	Maximum Continuous Rating
MW	Megawatt
OC	Operating Cost
OEM	Original Equipment Manufacturer
PC	Pulverized Coal
PCC or PCCC	Post Combustion Carbon Capture
PCS	Power Conversion System
QGESS	Quality Guidelines for Energy Systems Studies
SCR	Selective Catalytic Reduction
SJAE	Steam-Jet Air Ejectors
STG	Stream Turbine Generator
TASC	Total As Spent Cost
TMCR	Turbine Maximum Continuous Rating
TOC	Total Overnight Cost
TPC	Total Plant Cost
TR	Transformer
UCC	United Conveyor Corporation
WASC	Wet Surface Air Cooler
ZLD	Zero Liquid Discharge

1.0 Executive Summary

The total project cost including equipment costs based on factoring and vendor quotations for an HGCC power plant are presented in the report. The team used previously developed documents from the preFEED such as the Design Basis Report[1], Performance Report with Energy & Mass Balances[2], and latest vendor quotations as references for developing the costs. The total project cost estimate, divided into 17 different code of accounts similar to Case B12B in 2019 revision of "NETL Cost and Performance Baseline for Fossil Energy Plant Volume 1: Bituminous Coal and Natural Gas to Electricity, corresponds to a Class 4 estimate class (AACE International Recommended Practice No. 18R-97)[3] for the process industries and the range of accuracy for the Hybrid Coal and Gas Boiler and Turbine Concept with Post Combustion Carbon Capture (HGCC) plant is -15 - +30% accuracy.

This report reviews the Approach and Methodology (Section 2), Capital Cost Estimate (Section 3), Owner's Cost (Section 4) Operating and Maintenance Cost (Section 5), Cost of Electricity (Section 5), Risk and Sensitivity Cost Discussion (Section 7 & 8 Respectively), and Value Engineering Discussions (Section 9). Table 1-1 provides a summary of cost results and highlights some key results from the sensitivity evaluation.

Table 1-1 Cost Results Summary

Description for HGCC Plant (Base Case)	Greenfield	Demonstration at Existing Facility
Total Project Cost ($\$/MW_{net}$-w/ ESS, $\$/MW_{net}$-w/o ESS)	$1.86 Billion ($5,300, $6,200)	$1.26 Billion ($3,600, $4,200)
Total Overnight Cost ($\$/MW_{net}$-w/ ESS, $\$/MW_{net}$-w/o ESS)	$2.25 Billion ($6,400, $7,500)	$1.53 Billion ($4,400, $5,100)
Total As Spent Cost ($\$/MW_{net}$-w/ ESS, $\$/MW_{net}$-w/o ESS)	$2.80 Billion ($8,000, $9,300)	$1.90 Billion ($5,400, $6,300)
Total Annual O&M	$111,500,000	
Cost of Electricity (COE, $\$/MW_{net}h$-w/o ESS)	$160	$126
Cost of Electricity (COE, $\$/MW_{net}h$-w/ ESS) 1 hour per day	$138	$108
Cost of Electricity (COE, $\$/MW_{net}h$-w/o ESS) 47% Load	$303	$233
Cost of Electricity (COE, $\$/MW_{net}h$-w/o ESS) $7 /MMBTU N.G.	$173	$138
Cost of Electricity (COE, $\$/MW_{net}h$-w/o ESS) $35/ton CO_2 Credit	$138	$103
Cost of Electricity (COE, $\$/MW_{net}h$-w/o ESS) $50/ton CO_2 Credit	$128	$93

[1] Barr Engineering Co., Doosan Heavy Industries, University of North Dakota, Envergex LLC., Microbeam Technologies, Inc., MLJConsulting, Performance Results Report - Coal-Based Power Plants of the Future – Hybrid Coal and Gas Boiler and Turbine Concept with Post Combustion Carbon Capture (HGCC), Rev 0. January 2020.

[2] Barr Engineering Co., Doosan Heavy Industries, University of North Dakota, Envergex LLC., Microbeam Technologies, Inc., MLJConsulting, 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. February 2020.

[3] AACE International. 18R-97: Cost Estimate Classification System - As Applied in Engineering, Procurement, and Construction for the Process Industries. March 6, 2019

2.0 Methodology and Approach

2.1 Cost Estimation Qualifications

The Class 4 constructed cost estimate provided in this report is based on our experience and qualifications and represents our best judgment as experienced and qualified professionals familiar with the project. This opinion is based on project-related information available to team at this time, current information about probable future costs, and a concept-level design of the project. The construction cost opinion will likely change as more information becomes available and more of the design is completed. In addition, because we have no control over the eventual cost of labor, materials, equipment, or services furnished by others; the contractor's methods of determining prices; competitive bidding; or market conditions, we cannot and do not guarantee that proposals, bids, or actual construction costs will not vary from the opinion of probable construction cost presented in this report. Greater assurance as to the probable construction cost can be achieved through additional design to provide a more complete project definition. Qualifying assumptions and exclusions on which the estimate is based are included in Section 2.5.

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

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

- The B12B plant design contains a Cansolv Carbon Dioxide (CO_2) Removal system that differs from the proposed plant's PCC system (amine-based system provided by Doosan Babcock).

2.2 Estimate Type

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

Table 2-1 AACE Generic Cost Estimate Classification Matrix[i]

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

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

2.3 Cost Estimate Scope

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

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

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

2.4 System Code-of-Accounts

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

Table 2-2 includes a description of the HGCC code of accounts used to break down the cost evaluation.

Table 2-2 Description of HGCC Code of Accounts

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

2.4.1 Code of Accounts Detailed Breakdown

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

1. <u>Coal and Sorbent Handling</u>
    1. Prepare site, concrete foundations, slabs, and equipment to install; coal unload station, coal storage yard, push walls, coal stackers, conveyors and towers
    2. Concrete foundations, support steel, equipment to install; limestone unload, limestone conveyors, and feeder
    3. Concrete foundations, support steel, piping, and equipment to install
    4. Concrete foundations, support steel, piping, and equipment to install; activated carbon unload and storage silo and feeder

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

3. <u>Feedwater and Misc. BOP Systems</u>
    1. Concrete foundations, piping, and equipment to install; makeup water, water pretreatment, low pressure feedwater heaters, high pressure feedwater heaters, feedwater pumps, deaerator and storage tank
    2. Piping and valves for service water system
    3. Service air compressor, piping, and outlets
    4. Ground water pumps and piping to pretreatment
    5. Natural gas piping to feed gas turbine
    6. Natural gas piping boiler for startup
    7. Fire sprinklers pumps and piping
    8. Wastewater piping to ZLD
    9. Concrete foundation, support steel, runway rail, and equipment to install; canes and hoist

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

5. Gas Cleanup
    1. Concrete foundations, support steel, ductwork, piping, and equipment to install; electrostatic precipitator
    2. Support steel, ductwork, piping, and equipment to install; flue gas desulfurization wet scrubber
    3. Ductwork for ESP and scrubber
6. CO_2 Removal and Compression
    1. Concrete foundations, support steel, piping, ductwork, and equipment to install; carbon capture absorber vessel, compression and drying systems, and regeneration equipment
7. Ductwork/Piping/Support/Insulation
    1. Exhaust flue; concrete foundations
    2. Continuous emissions monitoring system (CEMS) in stack
    3. Duct from FGD scrubber to PCC
8. Steam Turbine and Auxiliaries
    1. Concrete foundations, support steel, piping, and equipment to install; steam turbine/generator
    2. Concrete foundations, support steel, piping, and equipment to install; steam condenser and condensate pumps
9. Cooling Water System
    1. Concrete foundations, support steel, piping, and equipment to install; cooling tower and circulating pumps
10. Ash and Spent Sorbent Handing System
    1. Concrete foundations, support steel, ductwork, piping, and equipment to install
11. Accessory Electric Plant
    1. Concrete foundations, support steel, conduit, cable tray, and equipment to install; main power transformers, STG isolated phase bus duct, and tap bus
    2. Medium and low voltage switchgear
    3. Concrete foundations, piping, conduit, wire, and equipment to install; emergency diesel generator
12. Instrumentation and Control
    1. Operator station, panels and microprocessors for DCS Main Control
    2. Control instruments and fiber optic cabling to complete the DCS system

3. Data acquisition system for condition based monitoring (CBM) computers

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

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

15. Gas Turbine
    1. Concrete foundations, support steel, piping, flue duct, and equipment to install; 6F.03 gas turbine generator
    2. Flue duct to USC Boiler and external heaters

16. Battery ESS
    1. Concrete foundations, support steel, conduit, cable tray, wire, and equipment to install; battery storage system

17. Water Treatment / Zero Liquid Discharge System
    1. Concrete foundations, support steel, piping, and equipment to install; zero liquid discharge system.

The summary and detail tables of the total plant cost (TPC) estimate prepared for the project are included in Appendix A.

2.5 Assumptions and Exclusions

Key assumptions are included below and also summarized in Appendix B.

2.5.1 Base Case Assumptions

1. Bituminous coal per DOE requirements.
2. 85% capacity factor (O&M Base Case), redundancy based on 50% capacity factor for low risk equipment. Capacity of this plant is anticipated to range from 30-85%.

3. Greenfield site / Midwest U.S.
4. 300-acre site.
5. The plant includes a substation bus that can be connected to the grid and the railroad siding with a coal receiving area, equipment and facilities.
6. The natural gas supply is assumed to be available at the site boundary at a pressure of between 400-600 psig and with hydrocarbon dewpoint lower than -20ºF; water from the municipality is assumed to be at pressure between 100-150 psig and available flow rate of >3000 gpm; electricity tie-in is assumed to be at a 345kV dead-end structure near the switchyard; revenue metering will be at a single point on the 345kV interconnect.
7. CO_2 off-take will be by pipeline at the plant boundary and 1000 psig interface pressure; pipeline and booster compressors (if needed) are by others.
8. Prices may fluctuate due to the varying costs of material and equipment that are driven by multiple market variables. Vendor quotes were provided in 2019 and 2020 dollars, except the battery estimates, which are based on 2030 equipment cost that is projected to be reduced by Doosan between now and that time. The quotes provided by the vendor may vary over time and as the scope and design becomes more defined.

Table 2-3 Updated Energy Storage System Specifications

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

	Cooling	Air Cooling, HVAC
	Protection	DC Switch, DC Fuse, ACB, AC Fuse, GFD
	Standard	SGSF-04-2012-07, EMC CISPR11 : 2011, EN61000-4-2, 4, 6, 11 / IEEE1547, MESA
	Communication	Ethernet(TCP/IP), CAN, RS232/485
TR	Main TR	50MVA, 22.9kV, 6.9kV
	Sub TR	6MVA, 6.9kV, 440V

2.5.2 Base Case Exclusions

The following items are excluded from the project cost estimate:

1. Hazardous, contaminated materials and remediation
    a. Asbestos
    b. Lead abatement
    c. PCBs
    d. Contaminated soils
        i. Contaminated ground water
    e. Site conditions
        i. Piles or caissons
        ii. Rock removal
        iii. Excessive dewatering
        iv. Expansive soil considerations
        v. Excessive seismic considerations
        vi. Extreme temperature considerations
        vii. Demolition or relocation of existing structures
        viii. Unforeseen conditions
        ix. Sub-surface conditions
        x. Existing unknown conditions
    f. Fees and Permits
        i. State licenses
        ii. Local license
        iii. Environmental permits
        iv. Building permits
        v. Third party, professional fees, material testing, and inspections
    g. Leasing of off-site land for parking or laydown
    h. Busing of craft to site
    i. Costs of off-site storage
    j. Furnishings and special items
        i. Any furniture, window treatments, or other furnishings

k. Transportation and storage (T&S) is not considered in the capital cost, owner's costs, O&M, or COE results. T&S includes items such as:
    i. New access roads and railroad tracks
    ii. Upgrades to existing roads to accommodate increased traffic
    iii. Makeup water pipe outside the "fence line"
    iv. Landfill for onsite waste (slag) disposal
    v. Backup fuel provisions
    vi. Plant switchyard
    vii. Electrical transmission lines outside of plant boundary
    viii. Carbon unloading, sequestration, or transport pipeline

2.6 Cost of Mature Technologies and Designs

The cost estimates of mature technologies and designs are based on vendor quotes procured for this cost estimate. These quotes were used in a capital cost estimate conducted by Barr and ACM. Table 2-4 provides a list of major equipment vendors for HGCC.

Table 2-4 List of Major Equipment and Vendors

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

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

2.7 Costs of Emerging Technologies, Designs, and Trends

There are some areas where the technology is not common or commercially available. Table 2-5 lists these areas. The cost was obtained from the OEM for each of these areas. A process contingency is included to account for the emerging technology status.

Table 2-5 List of Emerging Technologies

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

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

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

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

2.7.1 Project Contingency

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

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

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

3.0 Capital Cost Estimate

The Total Plant Cost (TPC) was determined to estimate the project's cost. The TPC is the sum of the Bare Erected Cost (BEC) for the project, plus the cost of the engineering, procurement, and construction (EPC) contractor, as well as process and project contingencies. The TPC is an overnight cost calculated in 2019 and 2020 dollars.

The BEC consists of the cost of equipment and materials. The major equipment vendors provided Original Equipment Manufacturer (OEM) costs to be used to estimate the BEC. The BEC also contains new onsite facilities, site infrastructure, and balance-of-plant equipment necessary to support the HGCC process. The direct and indirect construction labor required for installation is included.

The Engineering, Procurement, and Construction Management (EPCM) costs include detailed design, building-related permits obtained by the contractor, as well as project and construction management costs. EPC costs are based on a construction management approach utilizing a prime contractor with multiple subcontractors. This approach provides the owner with greater scope control and flexibility, while mitigating the risk premium typically included in a traditional EPC lump-sum pricing structure.

3.1 Quantities and Allowances

High-level quantity takeoffs for major system components such as sorbent regeneration, flue gas clean-up, and conveyance systems were developed from the general arrangement drawings and the process flow diagram.

3.2 Escalation

Escalation was not considered for the TPC. Therefore, the TPC is in the current dollar amount (for 2020).

3.3 Labor Cost Basis

The estimate was not adjusted for local area labor rates. Labor rates reflect a burden rate, including: worker's compensation, state and federal unemployment taxes, fringe benefits, medical insurances, and other typical burdens. The labor rates are based upon a work week of 50 hours: 10 hours per day / 5 days per week. The average labor rate is $68.20 per hour with burdens. Productivity labor adjustments have been figured as standard with a labor productivity based on 70%.

3.4 Freight and Shipping Costs

The estimate provided includes freight and shipping cost, duties for all major items of equipment.

3.5 Contingency

Contingency represents an allowance to cover unknowns, uncertainties, and/or unanticipated conditions that are not possible to evaluate adequately from the information at hand at the time the cost estimate is prepared but must be represented by a sufficient cost to cover the identified risks. Contingency relates to a known defined project scope and is not used to predict future project scope or schedule changes. Contingency will normally decrease as more design information is known. This section summarizes important cost-estimating considerations related to cost contingency.

Contingencies, as used in this estimate, are intended to help identify an estimated construction cost amount for the items included in the current project scope. The contingency percentage includes process contingency and project contingency. These contingency amounts are based on AACE guidelines and professional judgment considering the level of design completed, the complexity of the work, and uncertainties in quantities and unit prices. The contingency includes the estimated cost of ancillary items not currently identified in the quantity estimates and allowances, but commonly identified in more detailed design and required for completeness of the work.

Contingencies are assigned to the cost estimate of each project feature on the basis of engineering judgment and on the relative completeness of project definition. Contingency, as used in this cost estimate, will decrease with future design efforts.

The contingency provided with the estimate does not account for:

- changes in labor availability or productivity
- delays in equipment deliveries
- changes in current industry standards or regulations
- major changes in quantities
- major changes in unit pricing
- major changes in scope during detailed design or construction
- major changes or revisions to the design basis
- costs that may result from actual site conditions differing from generic site conditions assumed in this estimate
- costs that result from construction change orders
- costs that result from sequencing or expediting work to avoid critical path slippage
- costs that result from possible project schedule slippage
- costs that result from differing economic conditions or future cost growth
- costs related to plant performance during and after start-up
- force majeure

The contingency included in the cost estimate is based upon the Risk Management or Estimating Judgement process. The following contingencies are included in the cost estimate.

3.5.1 Process Contingency

Process contingency provides for uncertainty in the cost estimate related to the technology's maturity development. The configuration of the key technology pieces of this concept is currently unproven at the commercial scale in power-generation applications. However, many aspects of the project use current proven and accepted technology for balance-of-plant and structural aspects. Therefore, process contingencies are applied to individual aspects of the cost estimate based on the current status of the technology for individual aspects of the cost estimate. AACE recommends the following guidelines in Table 3-1 for the amount of process contingency to apply.

Table 3-1 AACE Guidelines for Process Contingency

Technology Status	Process Contingency (% of Associated Process Capital)
New concept with limited data	40+
Concept with bench-scale data	30-70
Small pilot plant data	20-35
Full-sized modules have been operated	5-20
Process is used commercially	0-10

Process contingencies used in this estimate were assigned as shown in Table 3-2.

Table 3-2 Process Contingency for Developing Technology

Technology	Process Contingency (% of Associated Process Capital)
Indirect Firing System Controls	5
Energy Storage System	3
Wastewater / ZLD	2

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

- **Indirect Firing System.** The indirect firing system itself is a straightforward concept which poses little uncertainty. The two factors which are undefined is the flowability of the pulverized coal, and it's proclivity toward spontaneous combustion. These factors will influence the design of the fluidizing nozzles, the blanketing gas quantity, and any special features required to prevent caking, bridging or rat holing.

- **Integration of CTG and boiler.** The principal unknown with this concept is the design and routing of a large diameter duct, rated for 1200F, and connected into the boiler so that allowable CTG exhaust losses are not exceeded.

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

3.5.2 Project Contingency

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

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

The project contingency was determined by taking various percentages of the Bare Erected Costs plus all the costs up through process contingency.

3.6 Capital Cost Results

The TPC cost for the HGCC system is summarized in Table 3-3.

Table 3-3 HGCC Capital Cost Summary

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

4.0 Owner's Costs

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

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

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

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

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

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

1. Preliminary feasibility studies (including a Front-End Engineering Design (FEED) study)
2. Economic development (costs for incentivizing local collaboration and support)
3. Construction and/or improvement of roads and/or railroad spurs outside of site boundary
4. Legal fees
5. Permitting costs
6. Owner's engineering (staff paid by owner to give third-party advice and to help the owner oversee/evaluate the work of the EPC contractor and other contractors)
7. Owner's contingency (sometimes called "management reserve"—these are funds to cover costs relating to delayed startup, fluctuations in equipment costs, unplanned

labor incentives in excess of a five-day/ten-hour-per-day work week; owner's contingency is not a part of project contingency)

The owner's costs do not include:

1. EPC risk premiums (costs estimates are based on an EPCM approach utilizing multiple subcontracts, in which the owner assumes project risks for performance, schedule, and cost)
2. Transmission interconnection: the cost of interconnecting with power transmission infrastructure beyond the plant busbar
3. Taxes on capital costs: all capital costs are assumed to be exempt from state and local taxes
4. Unusual site improvements: normal costs associated with improvements to the plant site are included in the BEC, assuming that the site is level and requires no environmental remediation; unusual costs associated with the following design parameters are excluded: flood plain considerations, existing soil/site conditions, water discharges and reuse, rainfall/snowfall criteria, seismic design, buildings/enclosures, fire protection, local code height requirements, noise regulations

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

4.1.1 Owner's Cost Results

The Owner's costs for the HGCC are summarized in Table 4-1.

Table 4-1 Owner's Costs

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

5.0 Operation and Maintenance Costs

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

- Operating labor
- Maintenance material and labor
- Administrative and support labor
- Consumables
- Waste handling
- Co-products and saleable by-products
- Fuel

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

5.1 Auxiliary Power Consumption

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

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

5.1.1 Operating Labor

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

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

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

5.1.2 Maintenance Material and Labor

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

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

5.1.3 Consumables

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

5.1.4 Waste Disposal

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

5.1.5 Co-Products and Saleable By-Products

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

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

5.1.6 Fuels

The consumption of coal and natural gas is based on the base-case heat balance and heat rates as well as input from boiler and natural gas turbine vendors. The price of coal is assumed to be $1.6/MMBTU based on an average Midwest price of coal from Table 4.10A in the January 2020 Electric Power Monthly from the U.S. Energy Information Administration. The price of natural gas is assumed to be $3.00 based on an average high price of natural gas in 2019 from the Henry Hub's Historical Prices records. A sensitivity analysis on how the cost of coal and natural gas influences COE is outlined in Section 8.4.

5.2 O&M Cost Results

The operating and maintenance costs for the HGCC system are summarized in Table 5-1. The O&M was calculated based on the methods described in Section 5.0. The resulting O&M costs are approximately $111,500,000 per year or around $50/MWhr. Fuel is the highest contributor of the O&M costs at approximately $51,000,000. The O&M cost is used to calculate the COE in Section 6.0. The sensitivity analysis in Section 8.4 was performed to determine how fuel cost affects the COE.

Table 5-1 O&M Cost Summary

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

Operations and Maintenance Costs						
Operating & Maintenance Labor						
Position	**Required**	**Labor Rate ($/hour)**	**Weekly Coverage (hr)**	**Weekly Costs ($)**	**Monthly Costs ($)**	**Annual Costs ($)**
Plant Manager	1	150	40	6,000	26,000	313,000
Operations Manager	1	135	40	5,400	23,000	282,000
Maintenance Manager	1	135	40	5,400	23,000	282,000
Senior Engineer	1	140	40	5,600	24,000	292,000
Junior Engineer	1	120	40	4,800	21,000	250,000
Engineering Technician	1	90	40	3,600	16,000	188,000
Financial Accountant	2	75	40	6,000	26,000	313,000
Procurement & Warehouse Manager	2	70	40	5,600	24,000	292,000
Control Room Operator	2	120	168	40,320	175,000	2,104,000
Outside Operator	5	100	168	84,000	365,000	4,383,000
Coal Reclaim Operator	2	110	168	36,960	161,000	1,928,000
Train Unloading Operator	2	110	84	18,480	80,000	964,000
Maintenance Mechanic	3	100	40	12,000	52,000	626,000
I&C Technician	1	120	40	4,800	21,000	250,000
Maintenance Electrician	2	110	40	8,800	38,000	459,000
General Laborer	4	70	40	11,200	49,000	584,000
Security	1	40	168	6,720	29,000	351,000
Subtotal:				**$265,680**	$1,153,000	**$13,860,000**
Fixed Operating Costs						
Description					**Cost ($)**	**$/kWnet (Without ESS)**
Annual Operating Labor:					13,860,000	6
Maintenance Labor:					5,560,000	2
Property Taxes and Insurance:					26,970,000	12
Subtotal:					$46,390,000	21
Variable Operating Costs						
Description					**Cost($)**	**$/MWh$_{net}$ (Without ESS)**
Maintenance Material:					5,560,000	2
Subtotal:					**$5,560,000**	**2**
Consumables						
	Consumption/ Production		**Cost**			
	Initial Fill	**Per Day**	**Cost Per Unit ($)**	**Initial Fill**	**Cost ($)**	**$/MWh$_{net}$ (Without ESS)**
Ammonia, lb		5280	0.417		684,000	0
Water,/1000 gal		2,570	1.927		1,538,000	1
Limestone, ton (FGD Reagent)		193	22.317		1,338,000	1

Operations and Maintenance Costs						
CO_2 Capture System Solvent, lb		6,085	0.000		3,030,000	1
Caustic Soda (50% wt.), lb		7,408	0.500		4,000	0
Sulphuric Acid (98% wt.), lb		4,762	0.100		0	0
Nitrogen (GAS), lb		18,519	2.280		42,000	0
Water Systems Chemicals					964,000	0
Subtotal:				**-**	**$7,600,000**	**3**
Waste Disposal						
	Consump./Production		**Cost**			
	Initial Fill	**Per Day**	**Cost Per Unit ($)**	**Initial Fill**	**Cost ($)**	**$/MWh$_{net}$ (Without ESS)**
Wastewater Solid Waste, ton		20	38.00		236,000	2
ZLD Crystallized Waste, ton		40	38.00		472,000	0
Amine Purification Unit Waste, ton		0.23	596.00		43,000	0
Thermal Reclaimer Unit Waste, ton		1	280.00		64,000	0
Subtotal:					**$ 820,000**	**2**
Saleable By-Products						
Bottom Ash, ton	-	40			0	
Fly Ash, ton	-	151			**0**	
FGD Gypsum Waste, ton		230			0	
CO_2 Capture Amine Waste, ton		4,467			0	
Subtotal:	**-**				**$0**	
Variable Operating Costs Total:				**$-**	**$14,000,000**	**$6**
Fuel Cost						
As-Received Coal Feed, ton	-	1,918	$-	$-	$30,900,000	$14
Natural Gas, ton	-	480	$-	$-	$20,200,000	$9
Subtotal:				**$-**	**$51,100,000**	**$23**
				Total O&M:	**$111,500,000**	**$50**

6.0 Cost of Electricity (COE)

The method for calculating the cost of electricity (COE) is based on the methods described in the 2019 revision of the QGESS document “Cost Estimation Methodology for NETL Assessment of Power Plant Performance.” This report makes assumptions provided in Section 6.1. This is used to develop the finance structure in Section 6.2. Both are used to calculate the cost of electricity (COE) in Section 6.3.

6.1 Global Economic Assumptions

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

1. Taxes
    a. The Federal Income Tax Rate is 21%, the State Income Tax Rate is 6%, and the Effective Tax Rate (ETR) is 25.74%
    b. Capital depreciation over 20 years is 150% (declining balance)
    c. There is no Investment Tax Credit
    d. There is no Tax Holiday
2. Contracting and Financing Terms
    a. The Contracting Strategy consists of Engineering Procurement Construction Management (owner assumes project risks for performance, schedule, and cost)
    b. Debt Financing is Non-recourse (collateral that secures debt is limited to the real assets of the project)
    c. The Repayment Term of Debt is equal to operational period in formula method
    d. There is no grace period on debt repayment
    e. There is no debt reserve fund
3. Analysis Time Periods
    a. The capital expenditure period is 3 years for natural gas plants and 5 years for coal plants
    b. The operational period is 30 years
    c. The economic analysis period is 33 years for natural gas plants or 35 years for coal plants (capital expenditure period plus operational period)
4. Treatment of Capital Costs
    a. The capital cost escalation during the capital expenditure period is 0% real (or 3% nominal)

b. The distribution of Total Overnight Capital over the capital expenditure (before escalation) is 10%, 60%, 30% for a 3-year period and 10%, 30%, 25%, 20%, 15% for a 5-year period.

c. There is no working capital

d. 100% of the Total Overnight Capital depreciates (actual amounts are likely lower and do not influence results significantly)

5. Escalation of Operating Costs and Revenues

 a. Escalation of COE (revenue), O&M Costs is 0% real (3% nominal)

 b. Fuel costs are based on the Quality Guidelines for Energy Systems Studies Fuel Prices for Selected Feedstock in NETL Studies

6.2 Finance Structure

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

6.3 COE Calculation

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

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

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

OC_{FIX} is the sum of all fixed annual operating costs during the first year of operation. OC_{VAR} is the sum of all variable annual operating costs during the first year of operation at 100% capacity factor, including fuel and other feedstock costs. This is offset by any byproduct revenues. CF is the plant capacity factor expressed as a fraction of the total electricity that would be generated if the plant operated at full load without interruption. It is assumed that this factor be constant or levelized over the operational period. The fixed charge rate (FCR) is based on capital recovery factors (CRF) that match the finance structure and capital expenditure period. The CRF includes an after-tax weighted average cost of capital (ATWACC) appropriately to address the actual cost of repaying the interest on debt accrued during construction and included in the total as spent capital (TASC) factor. The FCR is provided by the 2019 revision of the QGESS document "Cost Estimation Methodology for NETL Assessment of Power Plant Performance" and shown in Table 6-1. The rate chosen for this study was a nominal three-year FCR.

Table 6-1 Fixed Charge Rate for COE

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

The TASC is expressed in mixed-year, current or real dollars over the entire capital expenditure period. It is calculated from the total overnight cost (TOC) by using the following factors taken from the 2019 revision of the QGESS document "Cost Estimation Methodology for NETL Assessment of Power Plant Performance" shown in Table 6-2. The TASC/TOC chosen for this study was a nominal three-year ratio.

Table 6-2 TASC/TOC Factors

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

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

6.4 Cost of Electricity (COE) Results

The results of the cost of electricity, with and without the energy storage system, calculations are shown in Table 6-3.

Table 6-3 Cost of Electricity

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

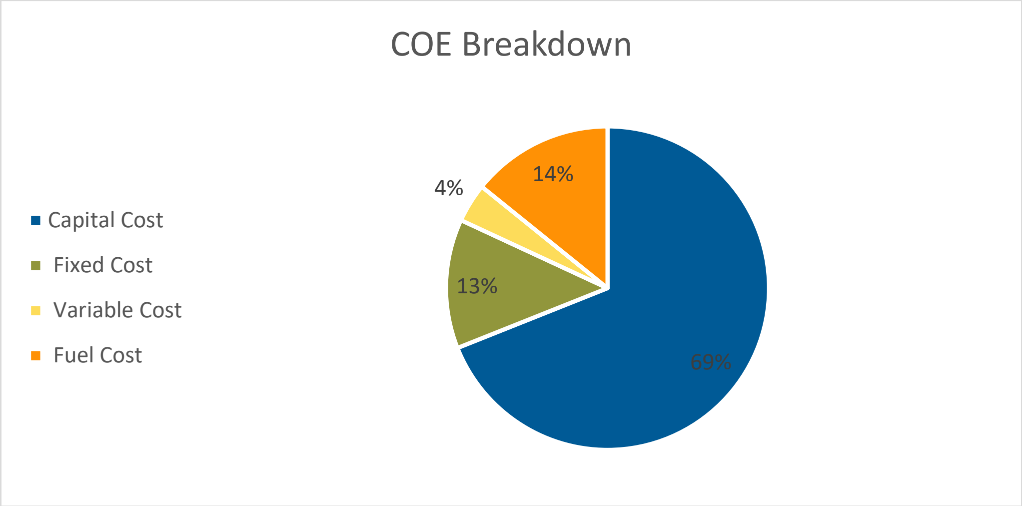

Figure 6-1 Cost of Electricity Breakdown for Base Case

7.0 Risk Factors

7.1 Risk Factors

As discussed in Section 3.0 of this report, the contingencies of areas that are considered emerging technologies include higher-process contingencies and, in some areas, engineering compared to the common commercialized technologies. We also included cost for several systems noted in the risk management discussions. The following list describes a summary of cost considerations based on risk management:

- A bypass stack was considered so the plant could operate if the CO_2 compressor or carbon capture system was not functioning as expected. A stub stack was considered in the original cost, but additional cost for a bypass stack was added for bypass functionality.
- Cost of the LTO/NCM lithium ion battery system includes a real-time temperature monitoring system and a fire suppression system based on NFPA 855.The redox flow battery considers a real-time monitoring system for liquid pressure, flow rate, liquid level, temperature and automated valve system. A drain tank is included to prepare for an accidents like earthquake a dike or emergency.
- A redundant line for the CO_2 purge was considered in case the CO_2 compressors or the purge line was not functioning properly. No added cost was included under the assumption an existing pipeline is near the plant.
- There is an efficiency at risk when considering this plant will need to ramp up and ramp down quickly. During these situations we are considering this power plant will have greater instrumentation and controls complexity over traditional power plants to smooth out the charges during ramp changes. The ability to maintain efficiency during these swings will need to be investigated further in the FEED study.
- Added steam capacity from the auxiliary steam plant may be required during low-load scenarios for the carbon capture and ZLD system operation.
- Contingency was added around the electrical and process controls.

8.0 Sensitivity Analysis

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

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

The seventeen cost categories were assigned a percent reduction based on potentially existing equipment at the coal-fired power plant. This is illustrated in Table 8-1. As a result, it can be estimated that demonstrating at an existing coal-fired power plant can save approximately $600M or ~32% of the total capital cost.

Table 8-1 Percent Reduction of Cost for Demonstration at an Existing Coal-Fired Power Plant

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

8.2 Effect of COE by Varying TPC

Capital cost varies with a range of accuracy. The capital cost also varies depending on a plant's ability to use some demonstration options or the variable battery cost changes. Visual representations of the COE and TPC relationship can be found in Figure 8-1. This figure illustrates that the anticipated COE is estimated to vary between $100 and $250 depending on the TPC.

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

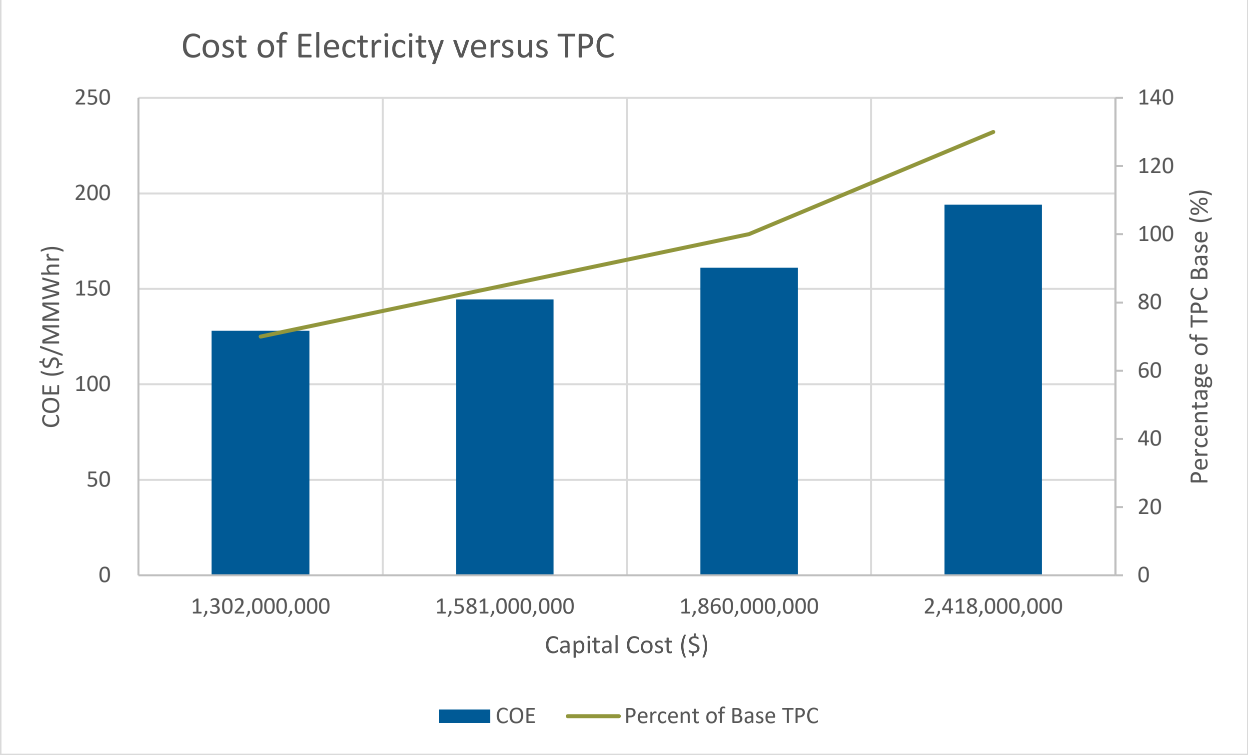

Figure 8-1 Cost of Electricity versus Capital Cost

8.3 Plant Loading Sensitivity

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

For this study, there are five different loading scenarios.

- 20% Plant Load: This consists of the gas turbine load being at 0% and the coal power load being at 30%
- 33% Plant Load: This consists of the gas turbine load being at 0% and the coal power load being at 50%

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

Table 8-2 and Figure 8-2 calculate COE based on these different loading scenarios. The variable operating costs are expected to decrease as load decreases with water and chemical consumption and waste disposal. This reduction is not linear as the number of starts on the gas engine and maintenance outage work is anticipated to increase as the operating capacity for this plant is reduced. The values in the table below show fixed labor operating cost, which includes plant personnel, would not change as the load would decrease. Table 8-2 and Figure 8-2 display the COE compared to the plant load and illustrate how the cost decreases as the load increases.

Table 8-2 Effect of Cost of Electricity with Reduction in Loading

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

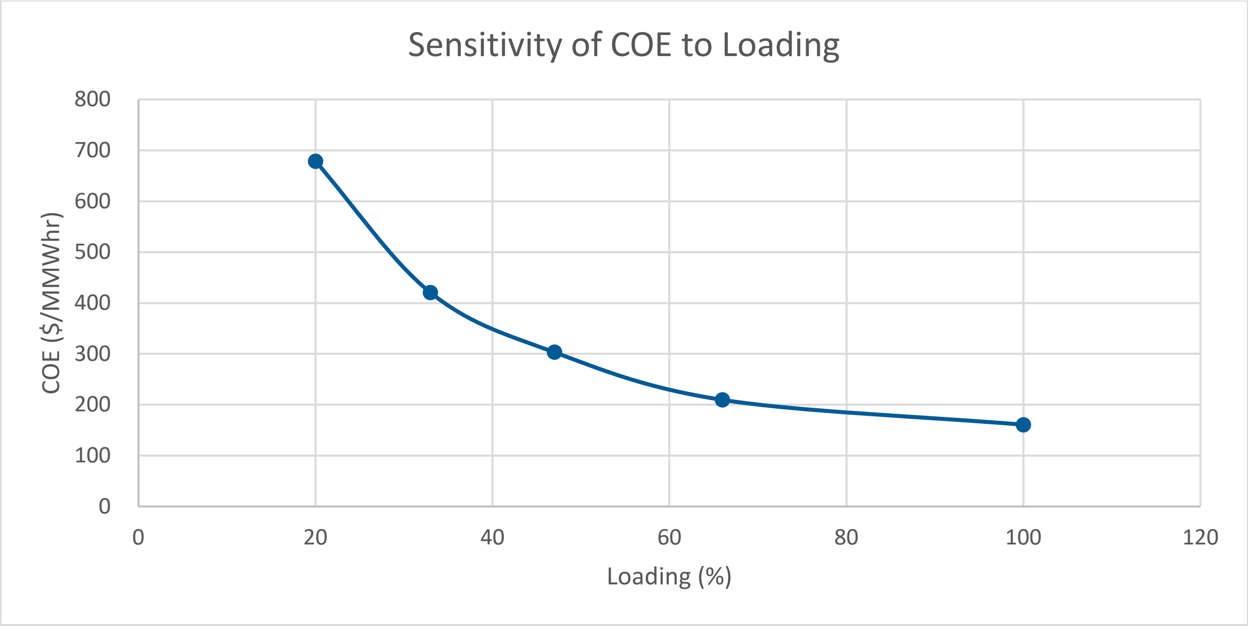

Figure 8-2 Sensitivity of Cost of Electricity based on Plant Loading

8.4 COE with Varying Fuel Prices

8.4.1 Coal Pricing

The cost of coal used to develop the operations and maintenance cost estimate was $1.6/MMBTU. Since the price of coal varies based on other factors such as type, plant location, and transport, the cost of coal can affect the cost of electricity. This cost was calculated based on a cost of coal from $0.5/MMBTU to $5/MMBTU. These results are represented visually in Figure 8-3 which demonstrates the COE will be between approximately $150 and $190 without ESS, based on an 85% capacity factor.

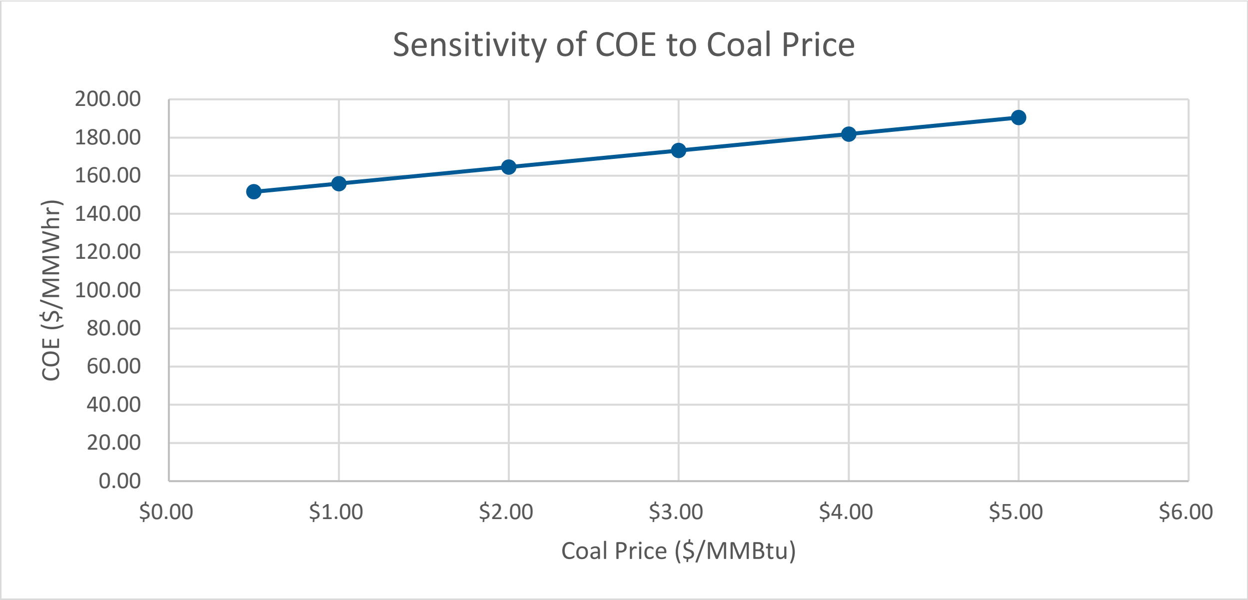

Figure 8-3 COE versus the Price of Coal

8.4.2 Natural Gas Pricing

Much like the price of coal, the price of natural gas varies. The cost of fuel gas used to develop the operations and maintenance cost estimate was $3.0/MMBTU. The cost was calculated based on a cost of natural gas from $0.5/MMBTU to $10/MMBTU as shown in Figure 8-4. This chart demonstrates the COE will be between $150 and $185 without ESS, based on an 85% capacity factor.

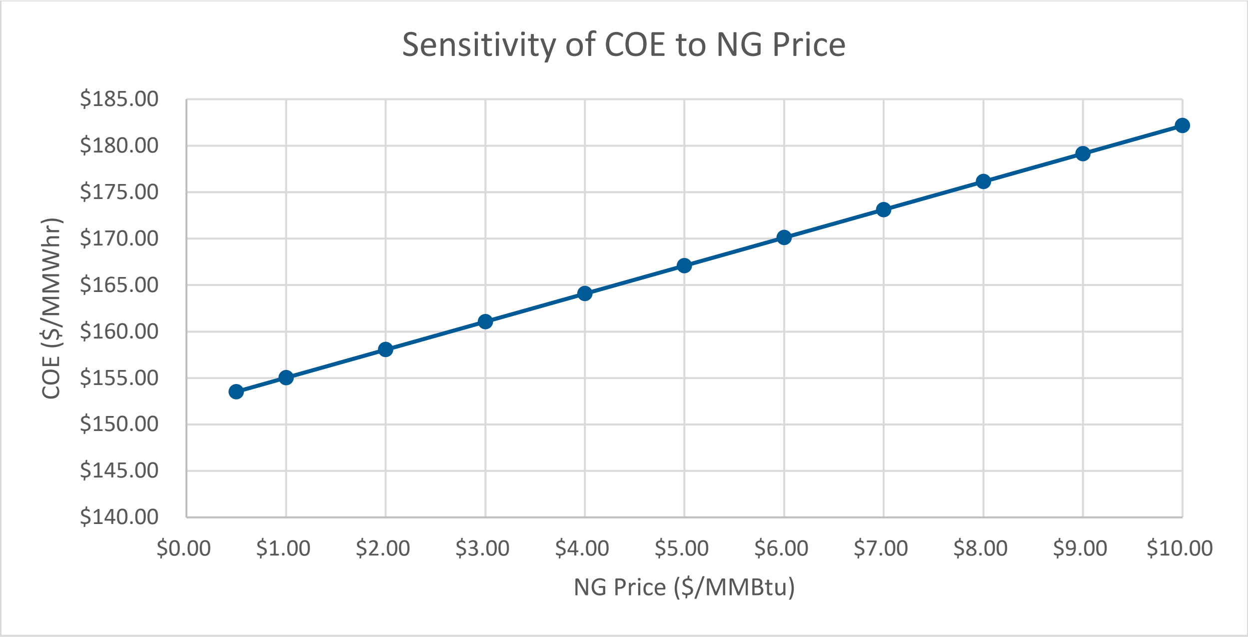

Figure 8-4 COE versus the Price of Natural Gas

8.5 The Effect of COE with Variations in Heat Rate

Variations in heat rate effect the COE in the same way as variations in fuel pricing. For example, a 1% increase in heat rate results in a 1% increase in annual fuel cost—just as a 1% increase in fuel pricing does. Consequently, any variation in heat rate between the calculated value and the as- built value will look the same as a variation in fuel pricing between the pro forma value and the actual value. Therefore, we have not graphed it independently. The economic value of variations in heat rate is important to the topic of value engineering later described in Section 9.0.

8.6 The Effect of COE with Different Fuel Qualities

The base case for the capital cost of the HGCC plant and the performance modeling was based on the bituminous coal specification provided by the Department of Energy[ii]. Currently, performance modeling is being evaluated to determine the effect of efficiency on the existing plant, assuming the same size boiler and turbines. Coal with high moisture or alkalinity would need additional coal conditioning and drying systems, which add capital cost. There would also be an increase in operating and maintenance cost for those systems in parasitic load and chemical additives for variable O&M. The maintenance and labor cost as well as environmental reagents and waste disposal is also anticipated to increase. This could be minimized by adding a coal conditioning system that would reduce the alkalinity or other contaminants in the coal prior to combustion. Figure 8-5 illustrates the effect these different types have on the cost of electricity due to its coal heating input value.

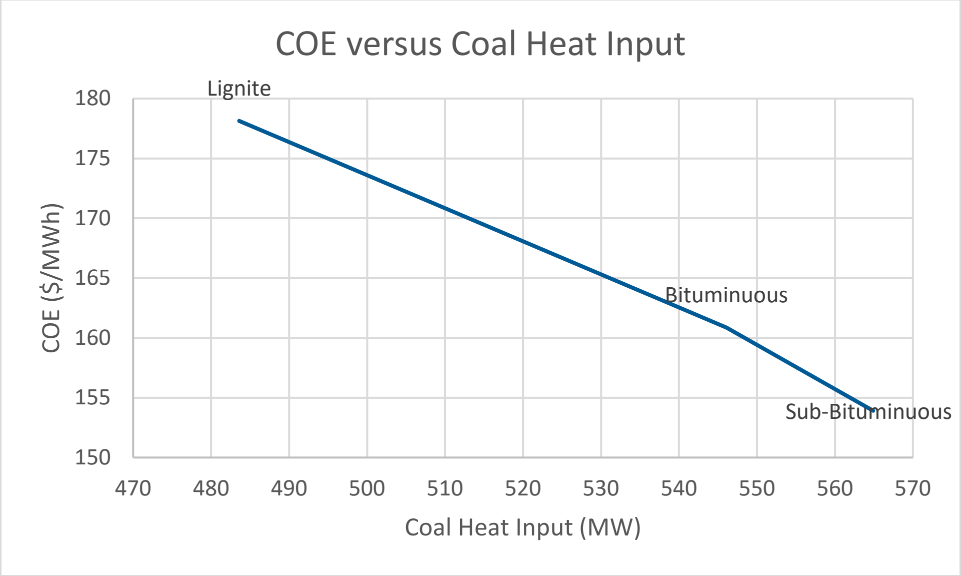

Figure 8-5 Effect of Coal Type on Cost of Electricity

8.7 The Effect of COE with Carbon Tax

Since one of the main objectives of this concept is to lower the amount of CO_2 being released into the atmosphere, it is important to note how this is beneficial from a cost perspective. The COE was originally estimated without a CO_{2e} tax for the sake of simplicity. However, Figure 8-6 shows how the COE increases very slightly with a greater CO_{2e} tax rate. Based on tax rates being considered throughout the world, a tax range of $0–$50/ton CO_2 emitted was considered[iii]. Table 8-3 below shows how the cost of electricity would be effected assuming our base case, which considered 147,000 tons CO_2 emitted per year.

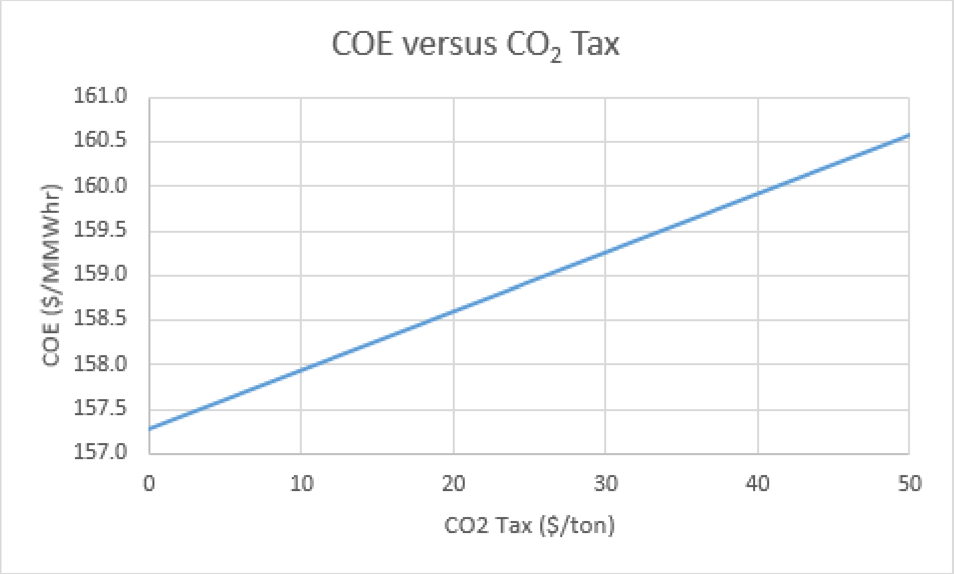

Figure 8-6 COE Increase versus Carbon Tax Base Case

8.8 The Effect of COE with Varying Carbon Capture Credits

For this calculation, it was assumed that the CO_2 production would be approximately 4,500 tons/day and that the carbon capture system would be 90% effective.

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

Table 8-3 Effect of Cost of Electricity with Varying Carbon Capture Credits

Cost of Electricity with Different Tax Credits					
Tax Credit	**Base (none), $**	**Storage, $**	**EOR – Min, $**	**EOR – Average, $**	**EOR – Max, $**
Credit, $/ton	0	50	35	66	97
Total As Spent Cost (TASC), $	2,800,520,000	2,800,520,000	2,800,520,000	2,800,520,000	2,800,520,000
Fixed Rate Charge (FRC)	0.0886	0.0886	0.0886	0.0886	0.0886
First Year Capital Charge	248,126,072	248,126,072	248,126,072	248,126,072	248,126,072
First Year Fixed Operating Costs, $	46,539,000	46,539,000	46,539,000	46,539,000	46,539,000
Total Credit, $	0	73,428,000	51,400,000	96,925,000	142,451,000
First Year Variable Operating Costs, $	14,000,000	14,000,000	14,000,000	14,000,000	14,000,000
First Year Fuel Costs, $	51,100,000	51,100,000	51,100,000	51,100,000	51,100,000
Annual Net Power Production, MWh	2,234,000	2,234,000	2,234,000	2,234,000	2,234,000
Cost Of Electricity $/MWh	**$161**	**$128**	**$138**	**$118**	**$97**

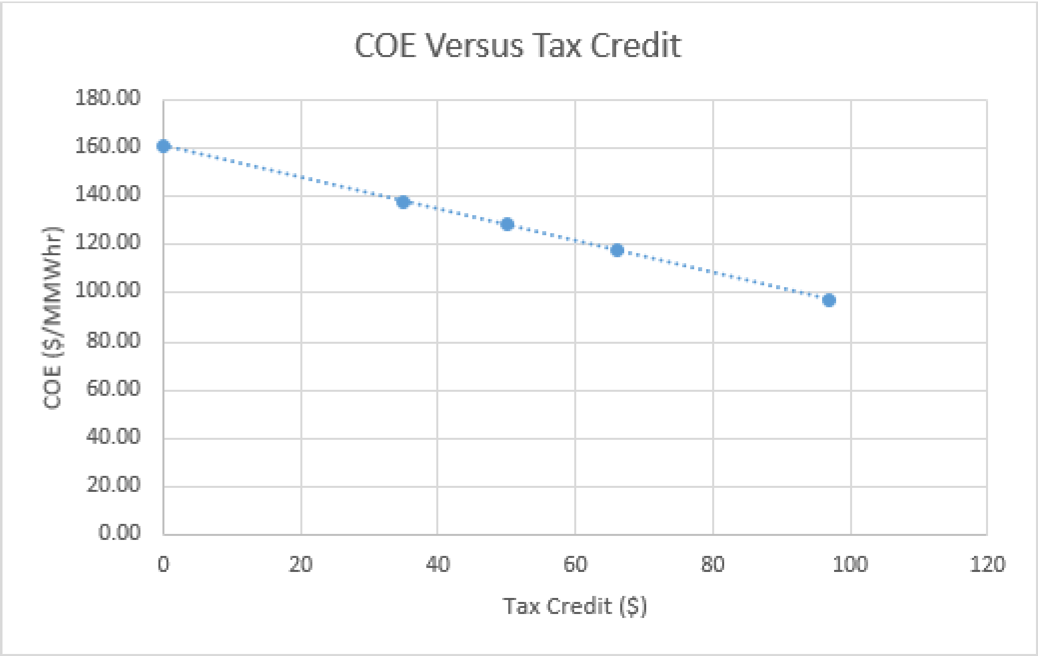

Figure 8-7 COE versus Tax Credits

8.9 US Financing

Electric Cooperatives have the ability to secure RUS financing for their power infrastructure projects. These loans once obtained provide for significant reductions in the COE when compared the financing alternatives available to IOUs. This can be observed in Figure 8-8.

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

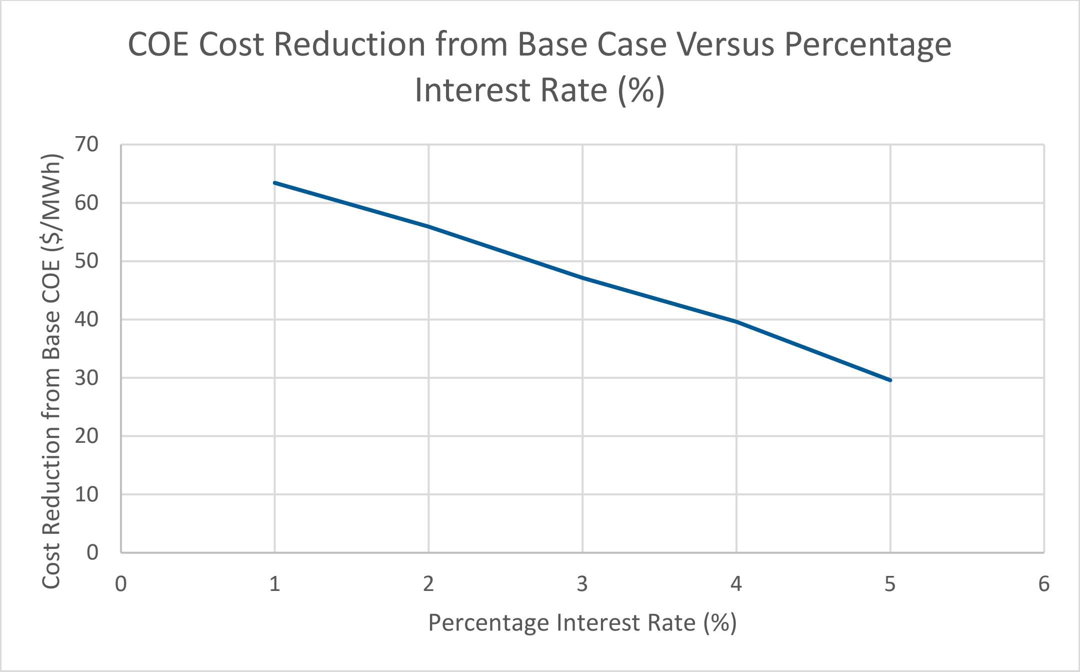

Figure 8-8 COE versus Interest Rate

9.0 Value Engineering

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

Table 9-1 Summary of Value Engineering Considerations

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

10.0 References

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Appendix A Capital Cost Estimate by Code of Accounts

Breakdown of Costs

Class IV Estimate of Capital Costs, Coal First PreFEED Study

Barr Engineering

For the U. S. Department of Energy

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

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

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

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

Appendix B Power Plant of the Future List of Assumptions

Appendix B Assumption List

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

II. Water Balance

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

III. Carbon-Sulfur Balance

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

IV. Civil Assumptions

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

V. Structural Assumptions

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

VI. Mechanical Assumptions

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

VII. EI&C Assumptions

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

[i] AACE International. 18R-97: Cost Estimate Classification System - As Applied in Engineering, Procurement, and Construction for the Process Industries. March 6, 2019.

[ii] U.S. Department of Energy/NETL, Coal Plants of the Future Performance Work Statement Addendum 1 2019.

[iii] World Bank Group, “State and Trends of Carbon Pricing” Washington D.C. 2018.

[iv] [USC02] 26 USC 45Q: Credit for Carbon Oxide Sequestration. , < https://www.law.cornell.edu/uscode/text/26/45Q>.