Pre-FEED – Cost Results Report

A Low Carbon Supercritical CO_2 Power Cycle / Pulverized Coal Power Plant Integrated with Energy Storage: Compact, Efficient and Flexible Coal Power

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1. Costing Methodology and Assumptions

Capital Cost Estimating Basis

Capital costs are reported in June 2019 dollars (base-year dollars) to put them on a consistent and up-to-date basis. Construction costs at the reference site were based on union labor.[1]

For cost-estimating purposes, the plants are generally assumed to be in a "mature" state of development meaning that no extra equipment or costs are included to account for unit malfunction or extra equipment outages.

As illustrated in Figure 1, this study will report capital cost at four levels: Bare Erected Cost (BEC), Total Plant Cost (TPC), Total Overnight Cost (TOC), and Total As-spent Capital (TASC). BEC, TPC, and TOC are "overnight" costs and are expressed in "base-year" dollars. The base year is the first year of capital expenditure, which for this study is 2019. TASC is expressed in mixed-year, current-year dollars over the entire capital expenditure period, which is assumed to last five years for coal plants (2019 to 2023).

BEC comprises the cost of delivered process equipment, on-site facilities, and infrastructure that support the plant (e.g., shops, offices, labs, roads), and the direct and indirect labor required for its construction and/or installation. The cost of engineering, procurement, and construction (EPC) services and contingencies are not included in BEC. BEC is an overnight cost expressed in base-year dollars.

TPC comprises the BEC plus the cost of services provided by the EPC contractor and project and process contingencies. EPC services include detailed design, contractor permitting (i.e., permits that individual contractors must obtain to perform their scopes of work, as opposed to project permitting, which is not included), and project/construction management costs. TPC is an overnight cost expressed in base-year dollars.

TOC comprises the TPC plus owner's costs. TOC is an "overnight" cost, expressed in base-year dollars and as such does not include escalation during construction or interest during construction. TOC is an overnight cost expressed in base-year dollars. TOC is calculated using a on TPC. The multiplier used for this study was 1.21. This multiplier was calculated using the methodology described in Table 3 to calculate the owners cost for the plant. It was found to be the same across all cases considered in this study.

TASC is the sum of all capital expenditures as they are incurred during the capital expenditure period including their escalation. TASC also includes interest during construction. Accordingly, TASC is expressed in mixed, current-year dollars over the capital expenditure period. TASC is also calculated using a simple multiplier, this time on TOC. The multiplier of 1.154 used for this study was taken from U.S. Department of Energy (DOE) / National Energy Technology Laboratory (NETL) guidelines for five-year construction projects.[2]

[1] NETL economic studies typically assume non-union labor rates. Union labor rates were chosen to better match up with conditions in 2019 and based on other studies performed by EPRI.

[2] "Quality Guidelines for Energy Systems Studies Cost Estimation Methodology for NETL Assessments of Power Plant Performance," NETL-PUB-22580, September 2019.

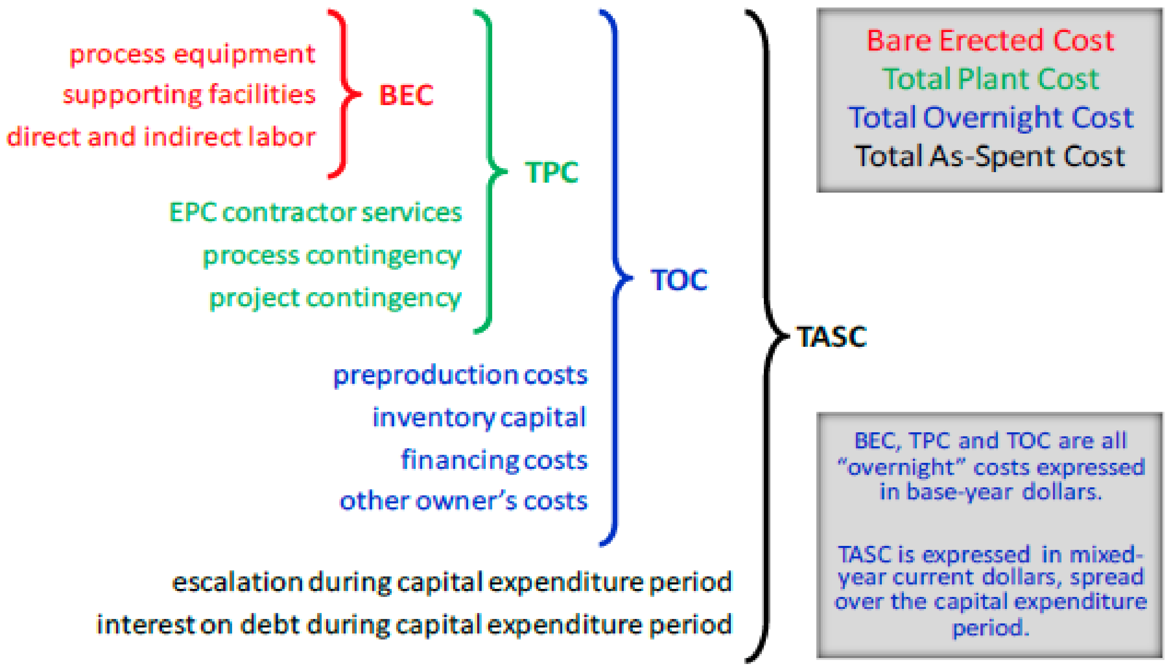

Figure 1 Capital Cost Levels and Their Elements

Cost Estimate Classification

The capital cost estimate completed for this study is consistent with DOE/NETL QGESS guidelines[2] and is classified as a Class 4 cost estimate. The accuracy range for a Class 4 estimates is -15% on the low side, and +30% on the high side. Table 1 describes the characteristics of an Association for the Advancement of Cost Engineering (AACE) Class 4 Cost Estimate.[3]

Table 1 DOE/NETL QGESS Class 4 Cost Estimate Description

Estimate Class	**Degree of Project Definition** % of complete definition	**End Usage** Purpose of Estimate	**Methodology** Typical Estimating Method	**Expected Accuracy Range** Typical variation in low and high ranges
Class 4	1% - 15%	Study or Feasibility	Equipment factored or parametric models	-15% - 30%

System Code of Accounts

The costs are grouped according to a process/system-oriented code of accounts. Consistent with other DOE/NETL economic studies, 14 accounts are used for the power plant plus one additional account (15) for the energy storage system. Note, because this is a supercritical CO_2 (sCO_2) power cycle, Account 8 has been modified to account for the differences between a steam and sCO_2 power cycle. This type of code-of-account structure has the advantage of grouping all reasonably allocable components of a system or process, so they are included in the specific system account. In addition, each code of account is further

[3] "Cost Estimate Classification System – As Applied In Engineering, Procurement, and Construction for the Process Industries," AACE International Recommended Practice No. 18R-97.

broken down into major equipment cost, material cost, and labor cost. Labor cost includes both direct and indirect costs.

Plant Maturity

Cost estimates in this report reflect the cost of the next commercial offering for plants that include technologies that are not yet fully mature and/or which have not yet been deployed in a commercial context. These cost estimates for next commercial offerings do not include the unique cost premiums associated with first-of-a-kind plants that must demonstrate emerging technologies and resolve the cost and performance challenges associated with initial iterations. However, these estimates do utilize currently available cost bases for emerging technologies.

Contracting Strategy

The estimates are based on an EPC approach utilizing multiple subcontracts. This approach provides the owner with greater control of the project, while minimizing, if not eliminating, most of the risk premiums typically included in an EPC contract price.

In a traditional lump sum EPC contract, the contractor assumes all risk for performance, schedule, and cost. However, as a result of current market conditions, EPC contractors appear more reluctant to assume that overall level of risk. Rather, the current trend appears to be a modified EPC approach, where much of the risk remains with the owner. Where contractors are willing to accept the risk in EPC type lump-sum arrangements, it is reflected in the project cost. In today's market, contractor premiums for accepting these risks, particularly performance risk, can be substantial and increase the overall project costs dramatically.

This approach is anticipated to be the most cost-effective approach for the owner. While the owner retains the risks, the risks become reduced with time, as there is better scope definition at the time of contract award(s).

Battery Limits for Capital Cost Estimate

The estimates represent a complete power plant facility on a generic site located in the Midwestern U.S. The plant boundary limit is defined as the total plant facility within the "fence line" including coal receiving and water supply system but terminating at the high-voltage side of the main power transformers. Coal transportation cost is not included in the reported capital or operations and maintenance (O&M) costs (storage and coal handling maintenance are, however). CO_2 transport and storage (T&S) cost is also not included in the costs for the cases that capture CO_2 but is treated separately and added to the cost of electricity (COE) by adding \$10/tonne-CO_2.

Labor Rates

The all-in union construction craft labor rate for the generic Midwestern U.S. site is assumed to be \$81.28/hour[4]. This rate is based on EPRI's Technical Assessment Guide[5].

[4] "High-Efficiency Thermal Integration of Closed Supercritical CO2 Brayton Power Cycles with Oxy-Fired Heaters", DE-FE002595, 2018

[5] "Technical Assessment Guide (TAG®) for Power Generation and Storage Technologies; 2016 Topics". EPRI, Palo Alto, CA: 2016. 3002008947.

The estimates are based on a competitive bidding environment with adequate skilled craft labor available locally. Labor is based on a 50-hour work week (five x 10-hour days).

Exclusions

The capital cost estimate includes all anticipated costs for equipment and materials, installation labor, professional services (engineering and construction management), and contingency. The following items are excluded from the capital costs:

- All taxes except for payroll and property
- Site specific considerations – including, but not limited to, seismic zone, accessibility, local regulatory requirements, excessive rock, piles, laydown space, etc.
- Labor incentives
- Additional premiums associated with an EPC contracting approach.

Contingency

Process and project contingencies are included in estimates to account for unknown costs that are omitted or unforeseen due to a lack of complete project definition and engineering. Contingencies are added because experience has shown that such costs are likely, and expected, to be incurred even though they cannot be explicitly determined at the time the estimate is prepared. Capital cost contingencies do not cover uncertainties or risks associated with:

- Changes in labor availability or productivity
- Changes in regulatory requirements
- Delays in equipment deliveries
- Performance of the plant after startup (e.g., availability and efficiency)
- Scope changes
- Unexpected cost escalation.

Process Contingency

Process contingency is intended to compensate for uncertainty in costs caused by performance uncertainties associated with the development status of a technology. Process contingency is applied to each component based on its current technology status. The majority of the proposed plant is made up of commercially available systems and equipment that is in use commercially. For all of these plant sections 0% process contingency is applied to the bare erected costs (BEC). However, several systems are presently under development and have not been commercially deployed at full scale and as such process contingencies have applied. These are summarized in Table 2.

Table 2 Process Contingency as Applied to Plant Cost Categories

Plant System or Equipment	Process Contingency (% of Bare Erected Costs)
(4.1) Fired heater furnace and radiant platens, convective and economizer elements, air preheaters, dry ash system, soot blowers, heater intimate steel	10
(8B.1 & 8B.4) sCO_2 Power Cycle Turbomachinery	15
(15.1) ETES Generating and Charging Systems	15
(15.2) ETES Storage Systems	20

Project Contingency

Project contingencies were added to each capital account to cover project uncertainties and the cost of additional equipment that would be identified in a detailed design. The project contingencies represent costs that are expected to occur but were not identified in the individual cost accounts. The project contingencies are applied to the BEC, engineering fees, and process contingencies. The project contingencies used for each individual cost account in the NETL Case B12B[6] were also used for the proposed plant. These contingencies ranged from 10–20%. For new equipment, the contingencies were either set to 15% or based on the contingency used in DOE Case B12B for similar equipment. The total project contingency for this was 13.3% - slightly less than the total project contingency of the NETL supercritical PC Case B12B (13.9%).

Owner's Costs

Owner's costs include:

- Initial cost for catalyst and chemicals
- Inventory capital (fuel storage, consumables, etc.)
- Land
- Prepaid royalties or license fees
- Preproduction (or startup) costs. For this plant the initial fill of CO_2 is considered as part of the startup costs and is factored into the TPC to TOC multiplier.

Royalty charges or license fees may apply to some portions of generating units incorporating new technologies. If known, royalty charges must be included in the capital requirement.

Preproduction costs cover operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel and other materials during startup. For this project's purposes, pre-production costs were estimated as follows:

[6] "Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity," NETL-PUB-22638, September 2019.

- One month fixed operating costs (O&M labor, administrative and support labor, and maintenance materials). In some cases, this could be as high as two years of fixed operating costs due to new staff being hired two years before commissioning.
- One to three months of variable operating costs (consumables) at full capacity, excluding fuel. (These variable operating costs include chemicals, water, and other consumables plus waste disposal charges.)
- 25% of full-capacity fuel cost for one month. This charge covers inefficient operation that occurs during the startup period.
- 2% of TPC. This charge covers expected changes and modifications to equipment that will be needed to bring the unit up to full capacity.

The following should be included:

- Value of inventories of fuels, consumables, and by-products was capitalized
- An allowance for spare parts of 0.5% of the TPC
- The initial cost of any catalyst or chemicals contained in the process equipment (but not in storage, which is covered in inventory capital)
- A nominal cost of $7413/hectare ($3000/acre) for land.

Table 3 summarizes the procedure for estimating owner's costs. The methodology is defined by the U.S. Department of Energy (DOE) / National Energy Technology Laboratory (NETL) guidelines[7] and mostly follows the guidelines from Sections 12.4.7 to 12.4.12 of AACE International Recommended Practice No. 16R-90.[8]

Table 3 Estimation Method for Owner's Costs

Owner's Cost	Estimate Basis
Prepaid Royalties	Any technology royalties are assumed to be included in the associated equipment cost, and thus are not included as an owner's cost.
Preproduction (Start-Up) Costs	• 6 months operating labor • 1-month maintenance materials at full capacity • 1-month non-fuel consumables at full capacity • 1-month waste disposal • 25% of one month's fuel cost at full capacity • 2% of TPC. Compared to AACE 16R-90, this includes additional costs for operating labor (6 months vs. 1 month) to cover the cost of training the plant operators, including their participation in startup, and involving them occasionally during the design and construction.

[7] "Quality Guidelines for Energy Systems Studies Cost Estimation Methodology for NETL Assessments of Power Plant Performance," NETL-PUB-22580, September 2019

[8] "Conducting Technical and Economic Evaluations – As Applied for the Process and Utility Industries," AACE International Recommended Practice No. 16R-90, 1991.

<table>
<tr><td>Working Capital</td><td>Although inventory capital is accounted for, no additional costs are included for working capital.</td></tr>
<tr><td>Inventory Capital</td><td>0.5% of TPC for spare parts
60-day supply (at full capacity) of fuel. Not applicable for natural gas (NG).
60-day supply (at full capacity) of non-fuel consumables (e.g., chemicals and catalysts) that are stored on site. Does not include catalysts and adsorbents that are batch replacements such as water-gas shift, carbonyl sulfide, and selective catalytic reduction catalysts and activated carbon.
AACE 16R-90 does not include an inventory cost for fuel.</td></tr>
<tr><td>Land</td><td>$3000/acre (300 acres for coal; 100 acres for NG)
Note: This land cost is based on a site in a rural location.</td></tr>
<tr><td>Financing Cost</td><td>2.7% of TPC
This financing cost (not included by AACE 16R-90) covers the cost of securing financing, including fees and closing costs but not including interest during construction (or Allowance for Funds Used During Construction). The “rule of thumb” estimate (2.7% of TPC) is based on a communication with Black & Veatch.</td></tr>
<tr><td>Other Owner’s Costs</td><td>15% of TPC

This additional lumped cost is not included by AACE 16R-90. The “rule of thumb” estimate (15% of TPC) is based on a communication with Black & Veatch. The lumped cost includes:
Preliminary feasibility studies, including a front-end engineering design study
Economic development (costs for incentivizing local collaboration and support)
Construction and/or improvement of roads and/or railroad spurs outside of site boundary
Legal fees
Permitting costs
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)
Owner’s contingency (sometimes called “management reserve” — these are funds to cover costs relating to delayed startup, fluctuations in equipment costs, and 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)

This lumped cost does not include:
EPC risk premiums (costs estimates are based on an EPC Management approach utilizing multiple subcontracts, in which the owner assumes project risks for performance, schedule, and cost)
Transmission interconnection: the cost of interconnecting with power transmission infrastructure beyond the plant busbar
Taxes on capital costs: all capital costs are assumed to be exempt from state and</td></tr>
</table>

	local taxes • 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, and noise regulations.

O&M Costs

O&M costs are to be estimated for a year of normal operation and presented in the base-year dollars. O&M costs for a generating unit are generally allocated as fixed and variable O&M costs.

Fixed O&M costs are essentially independent of actual capacity factor, number of hours of operation, or number of kilowatts produced, and are expressed in $/kW-year. Fixed O&M costs are composed of the following components:

- Operating labor
- Total maintenance costs (may also have a variable component)
- Overhead charges.

Taxes and insurance are considered as fixed O&M costs and are estimated as 2% of the TPC.

Variable O&M costs and consumables are directly proportional to the number of kilowatts produced or tonnes of CO_2 captured. They are generally in mills/kW-hour.

The estimation of these cost components is discussed below.

Operating Labor

Operating labor is based on the number of personnel required to operate the plant per shift. The total operating cost is based on the labor rate, supervision, and overhead. For this study, a fully loaded cost of $213,500 per person per year was assumed.

Total Maintenance Costs

Annual maintenance costs for the plant are estimated as a percentage of the TPC of the facilities for this study it was 2% of the TPC. Estimates are expressed separately as maintenance labor and maintenance materials. A maintenance labor-to-materials ratio of 40% labor cost and 60% material cost was used for this breakdown.

Overhead Charges

The only overhead charge included in this study is a charge for administrative and support labor, which is taken as 30% of the O&M labor.

Consumables

Consumables are the principal components of variable O&M costs. These include water, catalysts, chemicals, solid waste disposal, and other materials that are consumed in proportion to energy output. Costs for consumable items are shown in Table 4.

Table 4 Cost Data for Consumable Items

Consumables and Variable Cost Items	Unit Cost
H_2O and Chemicals	
Raw Water, $/1000 liters	0.45
Ammonia (aqueous 29.4% weight), $/tonne	194
Sorbent (Delivered)	
Lime, $/tonne	155
Limestone, $/tonne	45
Dry Disposal	
Bottom and Fly Ash, $/tonne	15
Other	
Activated Carbon, $/tonne	1455

Financial Structure Section

The financial structure for this study was based on a 5-year capital expenditure period, as specified in the DOE/NETL guidelines.[9] The financial structure for is shown in Table 5.

Table 5 Nominal and Real Rates Financial Structure for Investor-Owned Utility

Type of Security	% of Total	Current-Dollar Cost	Weighted Average Cost of Capital	After-Tax Weighted Average Cost of Capital
Nominal				
Debt	55%	5%	2.75%	2.04%
Equity	45%	10%	4.50%	4.50%
Total			7.25%	6.54%
Real (based on 2.01% average real Gross Domestic Product deflator, 1990–2018[10])				
Debt	55%	2.94%	1.61%	1.20%
Equity	45%	7.84%	3.53%	3.53%
Total			5.14%	4.73%

Global Economic Assumptions

Table 6 summarizes the global economic assumptions that were used for evaluating the economic performances of the cases in this study. The assumptions are specified in the DOE/NETL guidelines.

[9] "Quality Guidelines for Energy Systems Studies Cost Estimation Methodology for NETL Assessments of Power Plant Performance," NETL-PUB-22580, September 2019.

[10] "Real Gross Domestic Product [GDPC1]," U.S. Bureau of Economic Analysis, Federal Reserve Bank of St Louis. https://fred.stlouisfed.org/series/GDPC1/.

Table 6 Global Economic Assumptions

Parameter	Value
Taxes	
Income Tax Rates	21% federal, 6% state (effective tax rate of 25.74%)
Capital Depreciation	20 years, 150% declining balance
Investment Tax Credit	0%
Tax Holiday	0 years
Contracting and Financing Terms	
Contracting Strategy	EPC Management (owner assumes project risks for performance, schedule, and cost)
Type of Debt Financing	Non-recourse (collateral that secures debt is limited to the real assets of the project)
Repayment Term of Debt	Equal to operational period in formula method
Grace Period on Debt Repayment	0 years
Debt Reserve Fund	None
Analysis Time Periods	
Capital Expenditure Period	NG plants: 3 years; Coal plants: 5 years
Operational Period	30 years
Economic Analysis Period	33 or 35 years (capital expenditure period plus operational period)
Treatment of Capital Costs	
Capital Cost Escalation During Capital Expenditure Period	0% real (3% nominal)
Distribution of Total Overnight Capital over the Capital Expenditure (before escalation)	5-year period: 10%, 30%, 25%, 20%, 15%
Working Capital	Zero for all parameters
% of Total Overnight Capital Depreciated	100% (actual amounts are likely lower and do not influence results significantly)
Escalation of Operating Costs and Revenues	
Escalation of COE (revenue), O&M Costs	0% real (3% nominal)[11]
Fuel Costs[12]	Natural Gas (Reference Case) – $15.08/MWh Coal (Midwest PRB) – $42.12/tonne

[11] "The Handy-Whitman Index of Public Utility Construction Costs, 1912 to January 1, 2018," Whitman, Requardt & Associates, LLP, 2018.

[12] "Quality Guidelines for Energy Systems Studies Fuel Prices for Selected Feedstocks in NETL Studies," NETL-PUB-22458, Januaury 2019.

Cost of Electricity

The first-year COE (or power cost) is the revenue received by the generator per net MWh during the first year of operation assuming that the COE escalates at a nominal annual rate equal to the general inflation rate (i.e., remains constant in real terms over the operational period of the plant).

The approach used to calculate the first-year power costs is described below.

Estimating COE Using Formulas

The following simplified equation can be used to estimate COE as a function of TASC, fixed O&M, variable O&M, fuel costs, capacity factor, and net output. The equation requires the application of fixed charge rates (FCR), which are based on the capital recovery factors (CRF). These FCRs and CRFs are valid only for scenarios that adhere to the global economic assumptions listed in Table 6 and utilize the stated finance structure listed in Table 5 and the stated capital expenditure period. The formulas for calculating FCR and CRF values based on other assumptions are shown below in the equations below. The formulas for calculating the FCR values include an adjustment to the CRF value to account for depreciation.:

$$COE = [(FCR)(TASC) + OC_{FIX} + (CF)\ OC_{VAR}] / (CF)\ (MWh)$$

where:

- COE = revenue received by the generator ($/MWh) during the power plant's first year of operation (expressed in 2019 dollars), if the COE escalates at a nominal annual rate equal to the general inflation rate; i.e., that it remains constant in real terms over the operational period of the power plant
- FCR = fixed charge rate based on CRF values that matches the finance structure and capital expenditure period. The interest rate used in the formula must by necessity be the after tax weighted average cost of capital
- TASC = total as spent capital expressed in on-line year cost in 2019 dollars
- OC_{FIX} = the sum of all fixed annual operating costs in 2019 dollars
- OC_{VAR} = the sum of all variable annual operating costs, including fuel at 100% capacity factor, in 2019 dollars
- CF = plant capacity factor, assumed to be constant over the operational period
- MWh = annual net megawatt-hours of power generated at 100% capacity factor.

Based on the economic factors specified by the DOE, the FCR for a five-year capital expenditure period is 0.0707.

Cost of CO_2 Captured and Avoided

The cost of CO_2 captured was calculated both from the standpoint of the cost of CO_2 removed and the cost of CO_2 avoided.

The cost of CO_2 captured or removed in $/tonne is given by:

$$\text{Cost of } CO_2 \text{ Captured} = (COE_{\text{with removal}} - COE_{\text{w/o removal}}) / (CO_2 \text{ Captured})$$

where:

- COE = cost of electricity ($/MW-hr$_{net}$)
- CO_2 Captured = CO_2 captured for case (tonnes/MW-hr$_{net}$)

Note that for cost of CO_2 captured, the COE does not include the cost of CO_2 T&S.

The equation used to calculate the cost of CO_2 avoided in $/ton or $/tonne is given by:

- Cost of CO_2 Avoided = ($COE_{with\ removal}$ – $COE_{w/o\ removal}$) / ($CO_{2w/o\ removal}$ – $CO_{2with\ removal}$)

where:

- COE = cost of electricity ($/MW-hr$_{net}$)
- CO_2 = CO_2 emissions for case (tonnes/MW-hr$_{net}$). Note The difference in CO_2 emissions (with removal or without removal) is not equal to CO_2 captured (previously defined) since the addition of CO_2 capture technology may increase CO_2 generation (if gross power generation is increased) and/or may reduce MW-hr$_{net}$ (if gross generation is not increased to maintain net power generation).

Costs of CO_2 Transport and Storage

The cost of CO_2 T&S is included in the COE to derive the complete cost of capturing and storing CO_2. The updated DOE Bituminous Baseline Report[6] specified the conditions and T&S costs to be used for DOE system studies. The costs are based on transporting high-pressure (15.17 MPa) CO_2 from the power plant through a 100-km pipeline to the sequestration or enhanced oil recovery site. The CO_2 leaves the pipeline at a pressure of 8.27 MPa still in a supercritical state. For the Midwest location used for this study, the T&S value specified by DOE is $10/tonne-$CO_2$.

Levelized Cost of Storage

To quantify the value of storage and compare different electrical storage technologies, "Levelized Cost of Storage" (LCOS) is used. This calculated system parameter combines the economic costs of storing and later generating electrical energy. There are several formulas that can be used to calculate LCOS. For this study, following LCOS equation was used[13]:

$$LCOS = \frac{I_0 + \sum_{t=1}^{n} \frac{C_{ESS_t}}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_{ESS_t}}{(1+r)^t}}$$

where

I_0	Initial investment cost
C_{ESS}	Total annual cost, year t
E_{ESS}	Total net energy produced, year t
r	Discount rate (assumed 10%)
t	Year
n	Plant life (assumed 30 years)

Initial investment cost is calculated as:

[13] Lai, C. S., and McCulloch, M. D., 2017, "Levelized Cost of Energy for PV and Grid Scale Energy Storage Systems," Appl. Energy, **190**(C), pp. 191–203.

I_0=Generation system cost (\$/kW) + Capacity cost (\$/kWh) + BOP (\$/kW) + Installation (\$/kW)

These costs are summarized in item 15 (ETES System) in Table 11. The generation system cost, balance-of-plant (BOP), and installation costs are shown in 15.1, 15.3, and 15.4. The Capacity (storage) costs are shown in line 15.2. Note that "Capacity cost" is evaluated in terms of the electrical output (\$/kW_e), rather than thermal energy stored (\$/kW_{th}).

The total annual energy produced (E_{ESS}) is calculated assuming a generating duty cycle of 33% (8 hours per day)—the fraction of time the system is operating in generating mode. The Depth-of-Discharge (DoD) for ETES systems is 1. Other technologies, such as lithium ion systems are limited to 80% due to the impact of high DoD values on battery life.

E_{ESS}=Power output (kW) · Duty cycle · 8760 hrs/yr · DoD

The total annual cost is calculated as:

C_{ESS}=Net electricity cost + O&M cost

Electricity cost is the electrical power used to charge the system during the assumed annual usage profile, which is calculated as function of E_{ESS}, round-trip-efficiency (RTE), and purchased price of power:

Net electricity cost = E_{ESS} (kWh) · (1 - 1/RTE) · purchased price of power (\$/kWh)

For electricity cost, \$0.025/kWh was assumed, which is consistent with the ARPA-E DAYS[14] program assumptions, and roughly consistent with the median EIA wholesale price of electricity for 2017, implicitly assuming utility-scale plants would be operated by utilities. This assumption does not take advantage of negative pricing as seen in the California ISO markets during high solar PV production periods.

2. Economic Analysis

This section provides details on how the specific costs were estimated for the plant and highlights key components with individual cost estimates for: fired heater, post-combustion capture system (PCC), sCO_2 power cycle, and electrothermal energy storage (ETES) system. Based on equipment and system data provided by the team, CDM Smith developed a cost estimate for plant installation, piping, foundations, and balance-of-plant (BOP) equipment. EPS provided equipment cost estimates for the sCO_2 power cycle and ETES systems. RPI provided equipment costs for the fired heater, fuel system, and air quality control system (AQCS). MHI provided installed cost estimates for the PCC system. These descriptions are followed by the presentation of the capital and O&M costs for the plant along with first-year COE, and CO_2 captured and avoided costs.

Fired Heater and Air Quality Control System

Details on the cost estimates provided by RPI for the fired heater (air-fired pulverized coal heater) and its associated air quality control systems (AQCS) are given in this section. RPI developed a heat-and-mass balance for the fired heater and AQCS and subsequently designed them for this plant. A conceptual layout, shown in Figure 2 and Figure *3*, was developed to support the equipment and installation cost estimate. A summary of the costs and the corresponding bases are shown in Table 7.

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[14] "Duration Addition to Electricity Storage (DAYS)," Funding opportunity DE-FOA-0001906, May 2018.

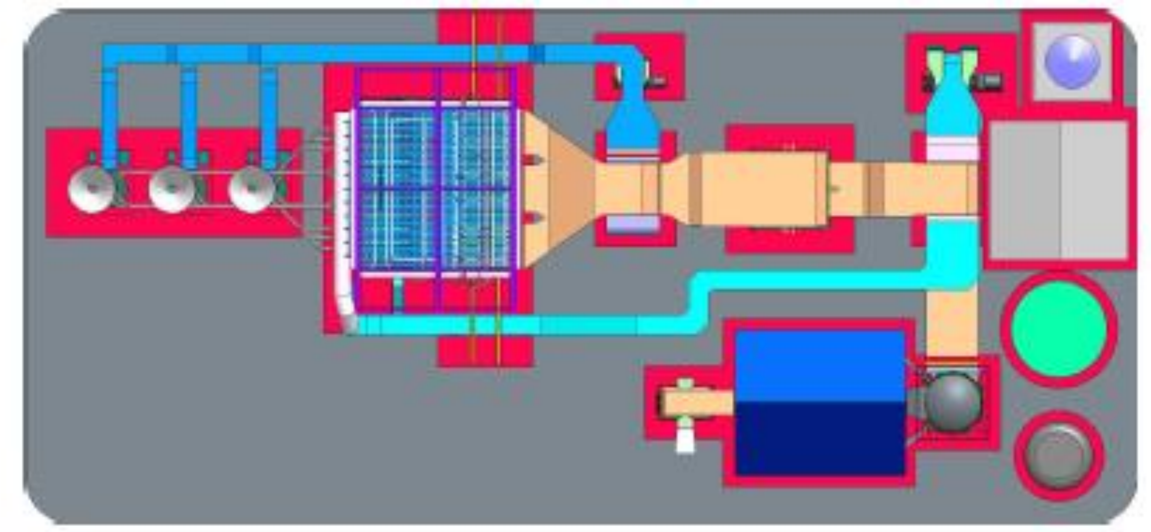

Figure 2 Conceptual Layout of RPI's Air Fired Heater and AQCS Equipment – Top-Down View for layout

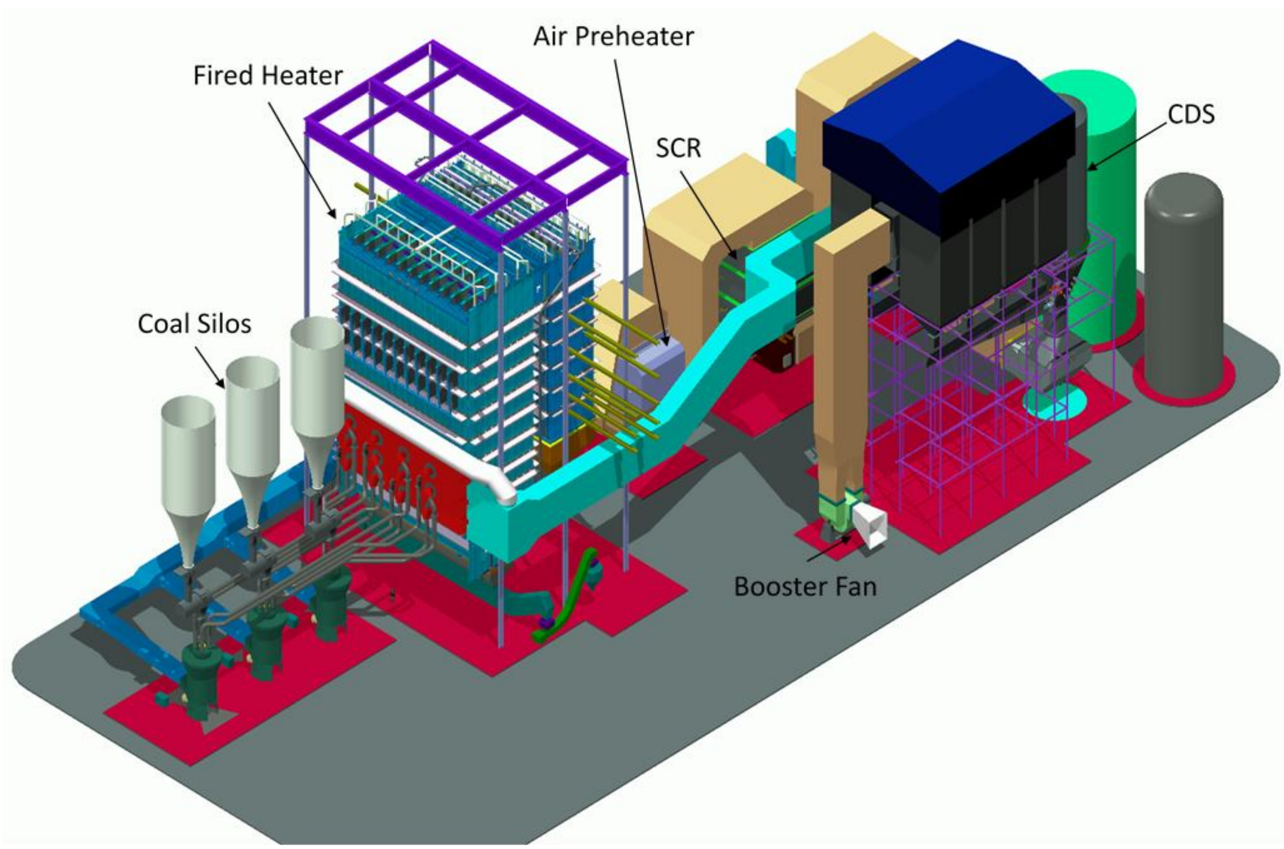

Figure 3 *RPI's, Fired Heater and AQCS Conceptual 3D Arrangement - Circulating Dry Scrubber (CDS), Selective Catalytic Reduction (SCR)*

Table 7 RPI's Fired Heater and AQCS Cost Summary

Major Equipment	Subsystems	Cost Basis	Cost ($)
Fired Heater	Furnace and Radiant Platens	Scaling from similar equipment	177,875,500
	Convective Elements	Scaling from similar equipment	
	Economizer Elements	Scaling from similar equipment	
	Hot and Cold Air Preheaters	Scaling from similar equipment	
	Dry Ash System	Budget quotation	
	Sootblowers	In house allowance	
	Heater and Intimate Steel	In house take off and unit pricing	
Fuel System	Coal Feeders	Scaling from similar equipment	10,011,100
	Coal Mills	Scaling from similar equipment	
	Coal Pipe	In house take off and unit pricing	
	Burners	Scaling from similar equipment	
	Natural Gas Skids	Scaling from similar equipment	
Selective Catalytic Reactor	SCR Casing	In house take off and unit pricing	4,788,600
	Catalyst	Scaling from similar equipment	
	Ammonia System	Scaling from similar equipment	
Circulating Dry Scrubber	Scrubber Vessel	In house take off and unit pricing	8,770,600
	Lime System	Scaling from similar equipment	
	Water System	Scaling from similar equipment	
	Air System	Scaling from similar equipment	
	Air Slide - Product Recirculation	In house take off and unit pricing	
Pulse Jet Fabric Filter		Scaling from similar equipment	5,881,100
Instrument and Controls		In house allowance	1,414,800
Fans	Forced Draft Fan	Scaling from similar equipment	3,233,000
	Primary Air Fan	Scaling from similar equipment	
	Booster Fan	Scaling from similar equipment	
Ductwork	Combustion Air	In house take off and unit pricing	6,332,000

PCC System

MHI provided capital cost estimates for the PCC system. These estimates assume a turn-key delivery of MHI's complete scope of supply and are consistent with an AACE Class 4 estimation. MHI's scope of supply ends at the breaching interface to the booster fan, the outlet of the CO_2 compressor discharge cooler and the tie points to their required plant utilities. The scope of supply includes the following:

1. KM CDR Process™ license
2. Engineering
3. Procurement
    a. Mechanical Equipment
    b. Piping
    c. Instrumentation
    d. Electric
    e. Structural Assemblies
    f. Process
        i. KS-1™ Solvent (initial fill through end of commissioning)
        ii. Catalyst/Chemicals
        iii. Laboratory Equipment
4. Logistics and Transportation
5. Site Construction
6. Start-up Spares
7. Commissioning Support
8. EPC Indirects

Excluded from the capital costs are any atypical site preparation (e.g. removal of existing obstructions and foundations) and owners costs (e.g. land, engineering studies, delivery of utilities to CO_2 capture plant boundary, permitting, etc.). A summary of the costs provided by MHI is shown in Table 1. Note the CO_2 compression unit costs include the hydrogen generation unit, low-pressure/high-pressure compressor, low-pressure compressor discharge cooler, CO_2 compressor discharge cooler, piping, CO_2 gas cooling unit, and the dehydration unit.

To support the plant design and layout a 2-D layout was developed by MHI, shown in Figure 4.

Table 8 PCC and Compression System Cost Summary

System Description	Cost Basis	Estimated Cost ($)
CO_2 Capture Unit	Equipment factored and similar equipment	135,000,000
CO_2 Compression Unit	Equipment factored and similar equipment	30,000,000
Total		165,000,000

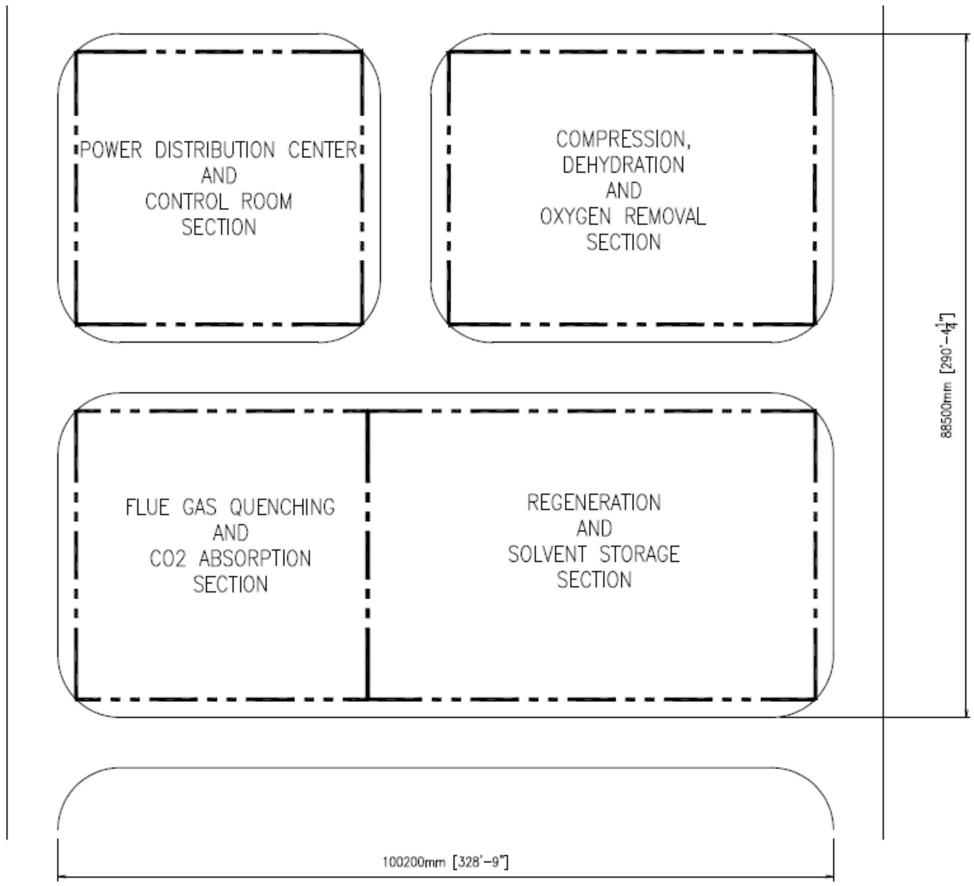

Figure 4 MHI, Layout and Footprint for PCC System

sCO_2 Power Cycle

Details on the cost estimates provided by EPS for the sCO_2 power cycle are provided in this section. Note that a special Account 8B was created to capture the sCO_2 power cycle costs as the system has intrinsic differences from a steam-Rankine power cycle and hence required a different set of sub-accounts as presented in Table 11.

Turbomachinery Costs

Power turbine, drive turbines, and compressor costs are based on EPS cost models. Budgetary estimates for turbines and compressors ranging in shaft power from 3 MW to 750 MW with turbine inlet temperatures up to 730°C are used as the basis for the models and estimate.

Recuperator Costs

Both the high and low temperature recuperator are printed circuit heat exchangers. Cost models for these are based budgetary on estimates provided to Echogen by Vacuum Process Engineering in support of an EPRI led DOE study on the integration of sCO_2 power cycles with advanced coal combustion.[4] Costs are scaled with the overall thermal conductance (UA) of the heat exchanger. Design differences between the high and low temperature recuperators are considered and costs per UA is adjusted based on temperature conditions.

Air Cooled Condenser
The air-cooled condenser (ACC) is finned tube type heat exchanger. ACC costs are also scaled with UA. The cost model is based on budgetary quotes for ACCs with UA's in the range of 11.7 MW/°C to 81.7 MW/°C. The UA of the ACC used in the proposed design is 16.3 MW/°C.

The CO_2 inventory control system cost is included in cost category 8.6B along with foundations and utility racks. All other cost categories are self-explanatory. Table 9 shows the major equipment cost summary for the sO2 power cycle.

Table 9 sCO_2 Power Cycle Major Equipment Cost Summary

Equipment	Cost ($K)	Basis
Low Temperature Compressor	7,839.4	EPS Turbine Driven Compressor Cost Models
High Temperature Compressor	11,200.8	EPS Turbine Driven Compressor Cost Models
Power Turbine	15,694.7	EPS axial turbine costs models - Based on supplier budget quotes (15-720 MW shaft power)
High Temperature Recuperator	15,109.7	EPS Cost Models - Based on supplier budget quote for utility scale recuperators (90 MWe plant)
Low Temperature Recuperator	7,662.0	
ACC	4,282.8	EPS Cost Models

ETES System

ETES equipment costs were scaled using EPS cost models for sCO_2 equipment (turbomachinery and heat exchangers) and supplier data for the hot and cold thermal storage.

Balance of Plant and Installation Costs

CDM Smith developed a conceptual plant layout based on equipment information (geometric sizes and weights) provided by EPS, MHI, and RPI. This layout is shown in Figure 5 and was used as the basis for estimating material, labor, and installation costs for the plant. Note that MHI provided costs for a turn-key installation of their scope so CDM Smith only carried the footprint in the site layout.

Coal Handling Equipment Cost Basis
Costs are based on Stock Equipment Company budget estimates for the equipment depicted on the layout. Installation costs are based on the estimated support bents and pits for the system, as well as a factored equipment cost.

Feedwater and BOP Systems
Based on Kansas City Deaerator and Flowserve pump budget quotation from a previous project then scaled for the heat recovery steam generator (HRSG) flow requirements. Cranes and compressed air equipment, as well as piping based on estimating software and conceptual material takeoffs. Fire water tank are based on a budget estimate from Advance Tank.

Fired Heater and Accessories
Foundations and steel costs are based on the layout lineal feet (LF), volumes, and density assumptions. The installation cost is based on a budget estimate from Babcock and Wilcox Construction Co. for a

similarly sized coal-fired boiler and AQCS equipment. Electrical costs are based on estimating software and conceptual material takeoffs.

Gas Fired Generator / HRSG
Costs are based on budgetary estimates from Solar Turbines and Victory Energy.

sCO_2 Power Cycle
Piping costs are based on estimating software and conceptual material takeoffs. Foundations and steel costs are based on the layout LF, volumes, and density assumptions. The installation cost is based on person-hour estimates. Electrical costs are based on estimating software and conceptual material takeoffs.

Cooling Tower
Costs are based on EvapTech and Flowserve budgetary estimates. Foundations and steel costs are based on the layout LF, volumes, and density assumptions. Electrical costs are based on estimating software and conceptual material takeoffs.

Ash Systems
Costs are based on budgetary estimates provided by Tank Connection. Installation costs are based on the layout and preliminary material takeoff for the piping. Foundations and steel costs are based on the layout LF, volumes, and density assumptions.

Plant Electrical Systems and Plant I&C
Electrical system costs are based on the total electrical generation capacity, estimating software and conceptual material take off. Plant I&C costs are based on creating a business and control network for the site with equipment costs based on commercially available hardware and software.

Site Civil
Costs are based on conceptual material takeoff and estimating software. Stormwater management costs are based on a 100-year storm, with the first flush and the entire coal pile going to the wastewater treatment plant.

Buildings
Costs are based on pre-engineered metal buildings with utilities factored into the building costs. The Gas turbine/HRSG and the fired heater buildings are assumed to be stick-built structures.

ETES System
Piping costs are based on estimating software and conceptual material takeoffs. Foundations and steel costs are based on the layout LF, volumes, and density assumptions. The installation cost is based on person-hour estimates. Electrical costs are based on estimating software and conceptual material takeoff

Water Treatment and Wastewater Treatment Plant
Water treatment system costs are based on assuming that river water is pumped to the plant site for use as fire and service water. Treatment equipment costs are based on budgetary estimates from Monroe Environmental and Flowserve. Wastewater treatment system costs are based on two systems, one for the waste stream from the PCC island, and the other for storm water from the coal pile and plant roadways. Treatment equipment costs are based on budgetary estimates from Evoqua.

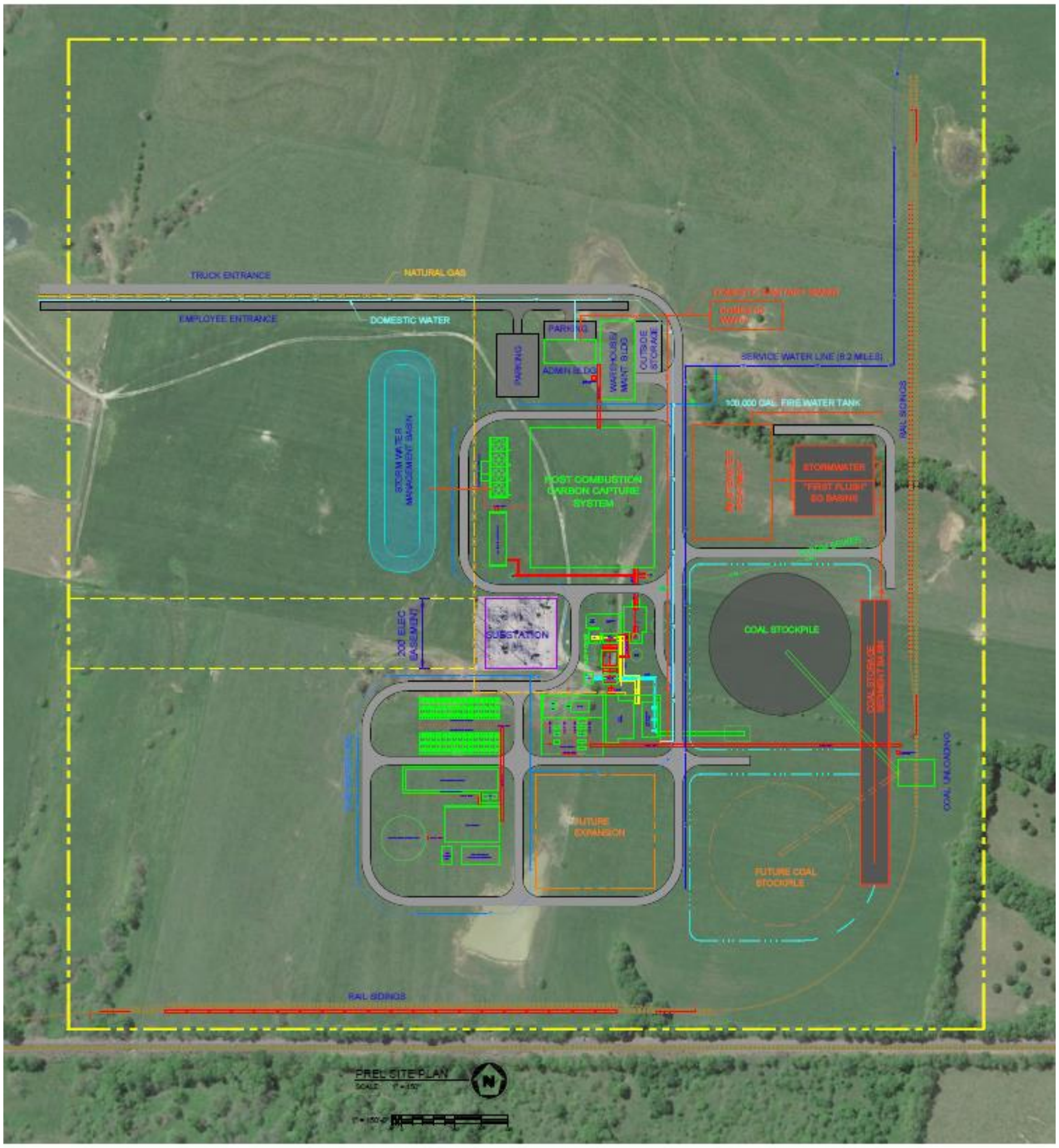

Figure 5 CDM Smith Conceptual Plant Layout

Summary

A detailed breakdown of the capital costs for the proposed Coal FIRST plant, a 120.7 MWe air-fired pulverized coal plant utilizing an sCO_2 power cycle with turbine inlet conditions of 700°C and 27.4 MPa, an amine-based PCC system, and a novel ETES system is shown in Table 11. Unique costs for each of the plant major subsystems were developed by the program partners: EPS – sCO_2 power cycle and ETES system; RPI – air fired heater and AQCS; MHI – PCC system. CDM Smith provided installation, piping, foundation, electrical, and BOP estimates that are based on the conceptual layout (shown in Figure 5) and equipment definition provided by EPS, MHI, and RPI. A capital cost comparison of the proposed plant, the proposed plant (air-fired heater, sCO_2 power cycle, and ETES system) without carbon capture, and the proposed plant without carbon capture and the ETES system is shown in Table 12. To determine costs for the plant without carbon capture; the fired heater, AQCS, sCO_2 power cycle, and ETES system are all assumed to be identical and the systems required for the PCC system have been removed (water treatment, combustion gas turbine, cooling tower, feedwater, and CO_2 removal). Note, the sCO_2 power cycle, fired heater, and AQCS portions of the plant are identical across each of the plant iterations, the difference in net power (120.7 MWe w/ carbon capture and 120 MWe without) is due to the addition of the combustion gas turbine used to supply electricity and steam to the PCC plant.

Table 13 shows the O&M cost breakdown for the proposed plant with and without carbon capture and the plant without carbon capture and ETES. Table 14 shows the first-year power costs, TPC, TOC, TASC, CO_2 costs, and LCOS again for the proposed plant with and without carbon capture. Figure 6 compares the first-year power costs, broken down into their components, of the proposed plant, the proposed plant carbon capture, and the proposed plant without carbon capture and ETES.

Table 15 summarizes the decrease in COE if a credit similar to the 45Q tax credit and if revenue from enhanced oil recovery can be applied to the plant economics. The assumed CO_2 credit for sequestration and EEOR and the sale price of CO_2 is summarized in Table 10 was applied directly as defined in Table 10. Note, when applying the sequestration credit only, the cost for CO_2 T&S is included in the COE calculation.

Table 10 Assumed CO_2 Credits and Sale Price

Application	**CO_2 Value ($/tonne)**
Sequestration	55 (credit)
Enhanced Oil Recovery (EEOR)	38 (credit), 40 (sale price)

Table 11 Plant Cost Summary

Acct No. Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost $	Eng'g CM H.O.& Fee %	Eng'g CM H.O.& Fee Total	Process Contingency %	Process Contingency Total	Project Contingency %	Project Contingency Total	TOTAL PLANT Cost	TOTAL PLANT COST $/kW
1 COAL & SORBENT HANDLING													
1.1 Coal Receive & Unload	$0	$930	$1,344	$0	$2,274	20.0%	$455	0%	$0	15%	$409	$3,138	26.0
1.2 Coal Stackout & Reclaim	w/ 1.1	w/ 1.1	w/ 1.1	$0	$0	0.0%	$0	0%	$0	15%	$0	$0	0.0
1.3 Coal Conveyors	$0	$961	$984	$0	$1,945	20.0%	$389	0%	$0	15%	$350	$2,684	22.2
1.4 Other Coal Handling	$0	$882	$1,323	$0	$2,205	20.0%	$441	0%	$0	15%	$397	$3,043	25.2
SUBTOTAL 1.	$0	$2,773	$3,651	$0	$6,424		$1,285		$0		$1,156	$8,865	73.4
2 Fired Heater Fuel System													
2.1 Fuel System: Coal Feeders, Coal Mills, Coal Pipe, Burners, Natural Gas Skids	$10,011	*Included in 4.1 Material	*Included in 4.1 Direct	$0	$10,011	0.0%	$0	0%	$0	15%	$1,502	$11,513	95.4
2.2 Fired Heater Fuel System Foundations	w/ 4.4	$0	$0	$0	$0	0.0%	$0	0%	$0	15%	$0	$0	0.0
SUBTOTAL 2.	$10,011	$0	$0	$0	$10,011		$0		$0		$1,502	$11,513	95.4
3 FEEDWATER & MISC. BOP SYSTEMS													
3.1 Feedwater System	$11	$632	$22	$0	$665	20.0%	$133	0%	$0	15%	$120	$917	7.6
3.2 Water Makeup & Pretreating	$1	$400	$6	$0	$407	20.0%	$81	0%	$0	20%	$98	$586	4.9
3.7 Waste Treatment Equipment	$0	$3,224	$3,136	$0	$6,360	20.0%	$1,272	0%	$0	20%	$1,526	$9,158	75.9
3.8 Misc. Equip. (Cranes, Air Comp., Comm., Fire Protection, Utility Piping)	$785	$754	$348	$0	$1,887	20.0%	$377	0%	$0	20%	$453	$2,717	22.5
SUBTOTAL 3.	$797	$5,010	$3,511	$0	$9,318		$1,864		$0		$2,196	$13,378	110.8
4 PC FIRED HEATER & ACCESSORIES													
4.1 Furnace and Radiant Platens, Convective and Economizer Elements, Air Preheaters, Dry Ash System, Sootblowers, Heater Intimate Steel.	$177,875	$1,415	$110,000	$0	$289,290	20.0%	$57,858	10%	$28,929	15%	$47,733	$365,952	3,031.9
4.2 Fans – Forced Draft, Primary Air, and Booster Fan	$3,233	w/4.1 Material	w/4.1 Direct	$0	$3,233	0.0%	$0	0%	$0	15%	$485	$3,233	26.8
4.3 Major Component Rigging	w/ 4..1	w/ 4..1	w/ 4..1	$0	$0	0.0%	$0	0%	$0	0%	$0	$0	0.0
4.4 Fired Heater & Accessories Foundations and Support Steel	$0	$773	$1,036	$0	$1,809	20.0%	$362	0%	$0	0%	$0	$2,171	18.0
4.5 Fired Heater Ducting: Combustion Air, Flue Gas	$6,332	w/ 4.1	w/4.1	$0	$6,332	0.0%	$0	0%	$0	15%	$950	$7,282	60.3
SUBTOTAL 4.	$187,440	$2,188	$111,036	$0	$300,664		$58,220		$28,929		$49,168	$378,637	3,137.0
5 FLUE GAS CLEANUP													
5.1 Circulating Dry Scrubber: Scrubber Vessel, Lime System, Water System, Air System, Air Slide – Product Recirculation	$8,770	w/ 4.1 Material	w/ 4.1 Direct	$0	$8,770	0.0%	$0	0%	$0	15%	$1,316	$10,086	83.6
5.2 Selective Catalytic Reduction (SCR)	$4,788	w/ 4.1 Material	w/ 4.1 Direct	$0	$4,788	0.0%	$0	0%	$0	15%	$718	$5,506	45.6
5.3 Bag House & Accessories	$5,881	w/ 4.1 Material	w/ 4.1 Direct	$0	$5,881	0.0%	$0	0%	$0	15%	$882	$6,763	56.0
5.4 Installation, foundations, stack, and support steel	$0	$2,682	$1,262	$0	$3,945	20.0%	$789	0%	$0	15%	$710	$5,443	45.1
SUBTOTAL 5.	$19,439	$2,682	$1,262	$0	$23,384		$789		$0		$3,626	$27,798	230.3

Acct No. Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost $	Eng'g CM H.O.& Fee %	Eng'g CM H.O.& Fee Total	Process Contingency %	Process Contingency Total	Project Contingency %	Project Contingency Total	TOTAL PLANT Cost	TOTAL PLANT COST $/kW
5B CO2 REMOVAL & COMPRESSION													
5B.1 CO2 Removal System	$121,500	w/5B.1 Equipment	w/5B.1 Equipment	$0	$121,500	11.1%	$13,500	0%	$0	15%	$18,225	$139,725	1,157.6
5B.2 CO2 Compression & Drying	$27,000	w/ 5B.2 Equipment	w/ 5B.2 Equipment	$0	$27,000	11.1%	$3,000	0%	$0	20%	$5,400	$32,400	268.4
SUBTOTAL 5B.	$148,500	$0	$0	$0	$148,500		$16,500		$0		$23,625	$172,125	1,426.1
6 COMBUSTION TURBINE/ACCESSORIES													
6.1 Combustion Turbine Generator	$7,500		$28	$0	$7,528	20.0%	$1,506	0%	$0	10%	$903	$9,937	82.3
6.2 Combustion Turbine Accessories	w/ 6.1												0.0
6.3 Compressed Air Piping	w/ 6.1												0.0
6.4 Combustion Turbine Foundations	w/ 6.1												0.0
SUBTOTAL 6.	$7,500	$0	$28	$0	$7,528	$0	$1,506	$0	$0	$0	$903	$9,937	$82
7 HRSG													
7.1 Flue Gas Recycle Heat Exchanger	$0	$0	$0	$0	$0	0.0%	$0	0%	$0	15%	$0	$0	0.0
7.3 Ductwork	$0	$765	$2,295	$0	$3,060	20.0%	$612	0%	$0	15%	$551	$4,223	35.0
7.4 Stack	$35	$397	$24	$0	$456	20.0%	$91	0%	$0	10%	$55	$602	5.0
7.9 HRSG, Duct & Stack Foundations	$6,000	$185	$6,247	$0	$12,432	20.0%	$2,486	0%	$0	20%	$2,984	$17,902	148.3
SUBTOTAL 7.	$6,035	$1,347	$8,566	$0	$15,948		$3,190		$0		$3,589	$22,727	188.3
8B sCO2 POWER CYCLE													
8B.1 Compressor (High and Low Temperature)	$21,339	$5	$12	$0	$21,356	20.0%	$4,271	15%	$3,203	15%	$4,325	$33,155	274.7
8B.2 Internal Recuperation (HTR and LTR)	$22,772	$10	$19	$0	$22,801	20.0%	$4,560	0%	$0	15%	$4,104	$31,465	260.7
8B.3 CO2 Air-Cooled Condenser	$4,283	$1,645	$1,638	$0	$7,566	20.0%	$1,513	0%	$0	15%	$1,362	$10,441	86.5
8B.4 CO2 Power Turbine (Includes 130 MW generator and turbine throttle valve)	$19,895	$25	$18	$0	$19,938	20.0%	$3,988	15%	$2,991	15%	$4,037	$30,953	256.4
8B.5 System Piping and Valves	$0	$5,312	$21,254	$0	$26,566	20.0%	$5,313	0%	$0	15%	$4,782	$36,661	303.7
8B.6 CO2 System Foundations, Storage Tanks, and Utility Rack	$685	$552	$777	$0	$2,014	20.0%	$403	0%	$0	15%	$363	$2,780	23.0
SUBTOTAL 8.	$68,973	$7,549	$23,719	$0	$100,241		$20,048		$6,194		$18,972	$145,455	1,205.1
9 COOLING WATER SYSTEM													
9.1 Cooling Towers (Field Erected)	$1,720	w/ Equipment Cost	w/ Equipment Cost	$0	$1,720	0.0%	$0	0%	$0	15%	$258	$1,978	16.4
9.2 Circulating Water Pumps	$420	$10	$7	$0	$437	20.0%	$87	0%	$0	15%	$79	$603	5.0
9.4 Circ. Water Piping	$0	$315	$230	$0	$545	20.0%	$109	0%	$0	15%	$98	$752	6.2
9.9 Circ. Water System Foundations and Utility Rack	$0	$228	$392	$0	$620	20.0%	$124	0%	$0	20%	$149	$893	7.4
SUBTOTAL 9.	$2,140	$553	$629	$0	$3,322		$320		$0		$584	$4,226	35.0

Acct No. Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost $	Eng'g CM H.O.& Fee %	Eng'g CM H.O.& Fee Total	Process Contingency %	Process Contingency Total	Project Contingency %	Project Contingency Total	TOTAL PLANT Cost	TOTAL PLANT COST $/kW
10 ASH/SPENT SORBENT HANDLING SYS													
10.6 Ash Storage Silos	$0	$420	$171	$0	$591	20.0%	$118	0%	$0	15%	$106	$816	6.8
10.7 Ash Transport & Feed Equipment	$0	$240	$62	$0	$302	20.0%	$60	0%	$0	15%	$54	$416	3.5
10.9 Ash/Spent Sorbent Foundations and Steel	$0	$372	$498	$0	$870	20.0%	$174	0%	$0	20%	$209	$1,253	10.4
SUBTOTAL 10.	$0	$1,032	$731	$0	$1,763		$353		$0		$370	$2,485	20.6
11 ACCESSORY ELECTRIC PLANT													
11.1 Generator Equipment	$6,804	$0	$4,925	$0	$11,729	20.0%	$2,346	0%	$0	15%	$2,111	$16,186	134.1
11.3 Switchgear & Motor Control	$6,107	$0	$7,194	$0	$13,301	20.0%	$2,660	0%	$0	15%	$2,394	$18,356	152.1
11.5 Wire & Cable	$620	$0	$531	$0	$1,151	20.0%	$230	0%	$0	15%	$207	$1,589	13.2
11.8 Main Power Transformers	$8,500	$0	$6,534	$0	$15,034	20.0%	$3,007	0%	$0	15%	$2,706	$20,747	171.9
11.9 Electrical Foundations	w/ 11.1, 11.3, 11.8	$0	$0	$0	$0	20.0%	$0	0%	$0	20%	$0	$0	0.0
SUBTOTAL 11.	$22,031	$0	$19,184	$0	$41,215		$8,243		$0		$7,419	$56,877	471.2
12 INSTRUMENTATION & CONTROL													
12.1 Fired Heater Control Equipment	$1,414	w/ Equipment Cost	w/ Equipment Cost	$0	$1,414	0.0%	$0	0%	$0	15%	$212	$1,626	13.5
12.2 Combustion Turbine Control	w/6.1	$0	$0	$0	$0	0.0%	$0	0%	$0	0%	$0	$0	0.0
12.3 sCO2 Power Cycle Control	w/8B.4	$0	$0	$0	$0	0.0%	$0	0%	$0	0%	$0	$0	0.0
12.4 Signal Processing Equipment	w/12.1, 6.1, 8B4	$0	$0	$0	$0	0.0%	$0	0%	$0	0%	$0	$0	0.0
12.6 Distributed Control System Equipment	w/12.1, 6.1, 8B4	$0	$0	$0	$0	0.0%	$0	0%	$0	0%	$0	$0	0.0
12.8 Other I & C Equipment	$0	$886	w/ 11.5	$0	$886	20.0%	$177	0%	$0	15%	$160	$1,223	10.1
SUBTOTAL 12.	$1,414	$886	$0	$0	$2,300		$177		$0		$372	$2,849	23.6
13 IMPROVEMENTS TO SITE													
13.1 Site Preparation	$1,119	$861	$850	$0	$2,830	20.0%	$566	0%	$0	20%	$679	$4,075	33.8
13.2 Site Improvements	$286	$2,041	$254	$0	$2,581	20.0%	$516	0%	$0	20%	$619	$3,717	30.8
13.3 Site Facilities (Utilities and Roadways)	$1,524	$2,654	$1,865	$0	$6,043	20.0%	$1,209	0%	$0	20%	$1,450	$8,702	72.1
SUBTOTAL 13.	$2,929	$5,556	$2,969	$0	$11,454		$2,291		$0		$2,749	$16,494	136.7

Acct No. Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost $	Eng'g CM H.O.& Fee %	Eng'g CM H.O.& Fee Total	Process Contingency %	Process Contingency Total	Project Contingency %	Project Contingency Total	TOTAL PLANT Cost	TOTAL PLANT COST $/kW
14 BUILDINGS & STRUCTURES													
14.1 Boiler Building	$0	$9,982	$2,924	$0	$12,906	20.0%	$2,581	0%	$0	15%	$2,323	$17,811	147.6
14.2 Turbine Building (Gas Turbine)	$0	$2,582	$2,366	$0	$4,948	20.0%	$990	0%	$0	15%	$891	$6,828	56.6
14.3 Administration Building	$0	$2,625	w/ Material Cost	$0	$2,625	20.0%	$525	0%	$0	15%	$473	$3,623	30.0
14.4 Circulation Water Pumphouse	$0	$376	w/ Material Cost	$0	$376	20.0%	$75	0%	$0	15%	$68	$519	4.3
14.5 Water Treatment Buildings	$0	$4,200	w/ Material Cost	$0	$4,200	20.0%	$840	0%	$0	15%	$756	$5,796	48.0
14.7 Warehouse	$0	$4,014	w/ Material Cost	$0	$4,014	20.0%	$803	0%	$0	15%	$723	$5,539	45.9
14.8 Other Buildings & Structures (ETES System / sCO2 Power Cycle)	$0	$3,913	w/ Material Cost	$0	$3,913	20.0%	$783	0%	$0	15%	$704	$5,400	44.7
SUBTOTAL 14.	$0	$27,692	$5,290	$0	$32,982		$6,596		$0		$5,937	$45,515	377.1
15 ETES System													
15.1 Generating Equipment Cost (Charge and Generating Cycles)	$31,670	*Included with Equipment	*Included with Equipment	$0	$31,670	20.0%	$6,334	15%	$4,751	15%	$6,413	$49,168	407.4
15.2 Storage Equipment Cost (HTS and LTS)	$12,261	*Included with Equipment	*Included with Equipment	$0	$12,261	20.0%	$2,452	20%	$2,452	15%	$2,575	$19,740	163.5
15.3 ETES Foundations	$0	$1,568	$2,342	$0	$3,909	20.0%	$782	0%	$0	15%	$704	$5,394	44.7
15.4 ETES Installation and Piping Costs	$0	$2,130	$505	$0	$2,635	20.0%	$527	0%	$0	15%	$474	$3,636	30.1
SUBTOTAL 15.	$43,931	$3,698	$2,847	$0	$50,475		$10,095		$7,203		$10,166	$77,939	645.7
TOTAL COST	$521,140	$33,273	$178,134	$0	$765,529		$131,476		$42,326		$132,333	$996,821	8,258.7

Table 12 Cost Summary - Proposed Plant, Plant without Carbon Capture, and Plant without Carbon Capture and ETES

Cost Category	Base Plant ($/kW)	Base Plant w/out CC[1] ($/kW)	Base Plant w/out CC and ETES[1] ($/kW)
1 COAL & SORBENT HANDLING	73.4	73.9	73.9
2 FIRED HEATER FUEL SYSTEM	95.4	95.9	95.9
3 FEEDWATER & MISC. BOP SYSTEMS	110.8	0.0	0.0
4 PC BOILER & ACCESSORIES	3,137.0	3,155.3	3,155.3
5 FLUE GAS CLEANUP	230.3	231.7	231.7
5B CO2 REMOVAL & COMPRESSION	1,426.1	0.0	0.0
6 COMBUSTION TURBINE/	82.3	0.0	0.0
7 HRSG	188.3	0.0	0.0
8B sCO2 POWER CYCLE	1,205.1	1,212.1	1,212.1
9 COOLING WATER SYSTEM	35.0	0.0	0.0
10 ASH/SPENT SORBENT HANDLING	20.6	20.7	20.7
11 ACCESSORY ELECTRIC PLANT	471.2	419.6	322.8
12 INSTRUMENTATION & CONTROL	23.6	23.7	23.7
13 IMPROVEMENTS TO SITE	136.7	137.4	137.4
14 BUILDINGS & STRUCTURES	377.1	379.3	379.3
15 ETES SYSTEM	645.7	649.5	0.0
Total	8,258.7	6,399.2	5,652.9

[1]Plant costs based on 120 MWe net power. The difference is due to the additional power output produced by the CT generator supporting steam auxiliary load requirement of the PCC system.

Table 13 O&M Cost - Proposed Plant, Plant without Carbon Capture, and Plant without Carbon Capture and ETES

O&M Costs	Base Plant	Base Plant w/out Carbon Capture	Base Plant w/out Carbon Capture and ETES
Total Operating Jobs per Shift	14	8	6
Fixed O&M Costs ($K)			
Administrative and Support Labor	2,392	1,843	1,628
Operating Labor Costs	2,989	1,708	1,281
Maintenance Labor Costs	7,975	6,143	5,427
Property Taxes and Insurance	19,936	15,358	13,567
Total Fixed O&M Costs	33,292	25,052	21,903
Variable O&M Costs ($K)			
Maintenance Material Cost	11,962	9,215	8,140
Consumables ($K)			
Ash Disposal	724	724	724
Chemical	w/ other consumables	w/ other consumables	w/ other consumables
Water	160	-	-
Other Consumables	5,858	2,169	-
Total Variable O&M Costs	18,704	12,109	8,864

Table 14 First-Year Power Cost, TPC, TOC, TASC, CO_2 Captured and Avoided Cost, and LCOS - Proposed Plant, Plant without Carbon Capture, and Plant without Carbon Capture and ETES

Summary	Base Plant	Base Plant w/out Carbon Capture	Base Plant w/out Carbon Capture and ETES
Net Plant Output (MW_e)	120.7	120	120
Efficiency (%)	29.9	40.4	40.4
CO_2 Capture (%)	83.60	0	0
CO_2 Captured, tonne/MWh (net)	0.81	0	0
CO_2 Emitted, tonne/MWh (net)	0.16	0.97	0.97
Fuel Type (Dual Fuel)	Montana Rosebud Subbituminous / NG		
Fuel Cost[12]	Natural Gas (Reference Case) – $15.08/MWh Coal (Midwest PRB) – $42.12/tonne		
Total Plant Cost, Total Overnight Cost, and Total as Spent Capital Costs			
TPC ($/kW)	8,259	6,399	5,653
TOC ($/kW)	9,993	7,871	6,953
TASC ($/kW)	11,532	9,083	8,024
First-Year Power Cost			
Capital ($/MWh)	109.5	84.8	74.9
Fixed OM ($/MWh)	37.0	28.0	24.5
Variable OM ($/MWh)	17.7	13.6	9.9
Fuel Cost ($/MWh)	33.0	19.8	19.8
CO_2 T&S Cost ($/MWh)	8.1	-	-
First-Year Power Cost ($/MWh)	205.3	146.2	129.2
CO_2 Costs			
Cost of CO_2 Avoided ($/tonne)	63.11	-	-
Cost of CO_2 Captured ($/tonne)	78.65	-	-
Levelized Cost of Storage			
LCOS ($/kWh)	0.135	0.135	-

Table 15 COE Benefit of Carbon Credits through 45Q and Enhanced Oil Recovery (EEOR)

Category	Proposed Plant Capture (Sequestration)	Proposed Plant No Capture	Proposed Plant No Capture & No Storage	Proposed Plant Capture & 45Q Credit (Sequestration)	Proposed Plant Capture & 45Q credit (EEOR)
Total COE ($/MWh)	205.3	146.3	129.2	160.8	133.8
Capital ($/MWh)	109.5	84.9	75.0	109.5	109.5
Fixed OM ($/MWh)	37.0	28.0	24.5	37.0	37.0
Fuel ($/MWh)	33.0	19.8	19.8	33.0	33.0
Variable OM ($/MWh)	17.7	13.6	9.9	17.7	17.69
CO_2 Cost / Value ($/MWh)	8.1	-	-	-36.3	-63.4

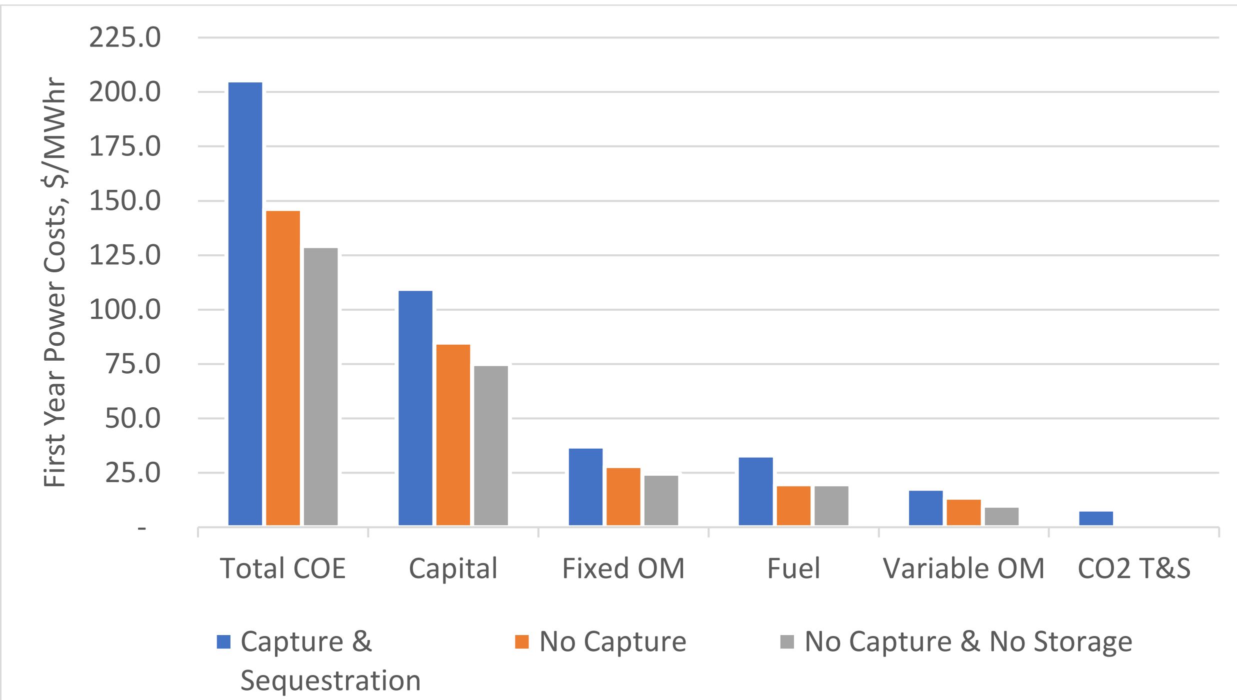

Figure 6 First Year Total and Component Power Cost – Base Plant with and without Carbon Capture

Discussion and Sensitivities

Based on the results of the techno-economic study preformed, the goal of this section to identify ways to improve the overall economics. The following design constraints were identified as key drivers in system economics:

1. *Employ efficiency improving technologies that maintain greater than 40% net plant cycle efficiency for a maximum load range without carbon capture.*

   40% HHV net plant efficiency at the plant scale proposed (120 MW_e) is achievable with sCO_2 power cycles. Even for high efficiency sCO_2 power cycles, to meet this criterion, high turbine inlet temperatures (700°C) are required. This produces significant cost in the fired heater and sCO_2 power cycle (radiant and convective tubes, sCO_2 turbines, sCO_2 high energy piping and valves) mainly due to the need to use stronger, but expensive, nickel-based alloys. Previous studies have shown that moving from 700°C to 600°C greatly reduces plant cost with only a marginal effect on plant efficiency. A 3.5 – 5.0% improvement in first-year COE is expected by moving to lower turbine inlet temperature even if the net efficiency is decreased from 40.3% to 36.5% HHV (not considering carbon capture). Table 16 summarizes the potential improvement in first-year COE if the net plant efficiency requirement is reduced from 40% to 36.5%. This is a result of the fired heater and sCO_2 power cycle representing a significant portion of the TPC (50.9% for the fired heater and 17.5% for the sCO_2 power cycle) and moving to lower temperatures reduces the amount and grade of expensive nickel alloy that is required for the higher turbine inlet temperatures. A 25% reduction fired heater cost and a 19% reduction in sCO_2 power cycle cost is expected when moving from 700 to 600°C.

Table 16 Summary of Effect of Turbine Inlet Temperature on Efficiency and COE for Proposed Plant without Carbon Capture

	Proposed Plant w/out Carbon Capture	**Lower Temperature Plant w/out Carbon Capture**
Turbine Inlet Temperature (°C)	700	600
NET Plant Efficiency HHV (%)	40.3	36.5
First-Year COE Contribution ($/MWh)		
Fired Heater Cost	30.0	25.5
sCO_2 Power Cycle Cost	11.5	9.3
Fuel Cost	19.8	21.9
First-year COE	143.7	139.1

2. *The carbon capture process shall be integrated with the power generating plant to maximize the overall power plant system efficiency. The carbon capture plant shall be designed as close as possible to the DOE goal of 90%, or higher, CO_2 capture efficiency.*

   When considering available technical paths to meet this requirement, options with low technical risk were favored. This led to the decision to consider amine-based PCC as the leading technical choice as there are several commercially operating plants in service today. One key thing to consider regarding these types of PCC systems is the heat input required for the stripping process. Typically, in steam power plants heat for the stripping process is pulled from medium/low pressure stream at an intermediate point in the expansion turbine. The stripping process also requires a relatively tight temperature range to achieve optimal performance, and steam is ideal for this as it can be supplied at saturation conditions. In sCO_2 cycles there is not an ideal place to pull heat for this stripping process. In fact, any heat pulled from the power cycle greatly reduces cycle efficiency. Also, CO_2 is in a supercritical state and holding a narrow temperature range for the stripping process will require complex heating or mixing of CO_2 streams.

The additional equipment required to operate the PCC system (combustion GT and HRSG, water treatment, cooling tower) increases the cost for CO_2 captured. To achieve a cost of CO_2 captured of $50/tonne, a reduction in the TPC of the equipment required for CO_2 capture of 65-70% is required. Options to consider outside of amine-based PCC are oxy-combustion and membrane post combustion capture. Oxy-fired heaters come with more technical risk, but do not require additional heat for CO_2 capture (a plus if integrating with sCO_2 cycles). Membrane CO_2 capture also does not require heat input, but to get over 80-85% capture efficiency requires large membranes and flue gas recirculation. While both options come with some additional technical risk, these should be considered as potential avenues to cost reduction and potential performance improvements for integration with sCO_2 power cycles.