Reference Number: 89243319CFE000015 Coal-Based Power Plants of the Future.

Title of Project: Allam Cycle Zero Emission Coal Power
Concept Area of Interest: Inherently Capture
Report Title: Cost Results Report

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Contents

COST ESTIMATING METHODOLOGY

General Cost Estimation Methodology

The cost analysis has been compiled to the level of accuracy for a nominal AACE 18R-97[i] Class 4 Estimate. A Cost Confidence Assessment has been provided later on in the report to demonstrate the cost is within the expected accuracy range for a AACE 18R-97 Class 4 Estimate.

The cost analysis has been built up with reference to the NETL Cost Estimation Methodology Report[ii] and the NETL Baseline for Fossil Energy Plants - Volume 1 Report (NETL Baseline Report)[iii]. Using the definitions outlined in the NETL Cost Estimation Methodology Report, the following levels of capital cost have been included:

- Bare Erected Cost (BEC) - Comprises the cost of process equipment, on-site facilities and infrastructure that support the plant, delivery of all equipment and material and the direct labor required for construction and / or installation.
- Engineering, Procurement and Construction Cost (EPCC) - An EPC contracting strategy will be used, as given the newness of this technology we believe this approach compared to an EPCM is more likely to yield a bankable project. The cost comprises the BEC plus the cost of services provided by the EPC contractor. These include engineering and design costs, contractor permitting and project / construction (direct and indirect) management costs. If an Engineering, Procurement and Construction Management (EPCM) contracting strategy is assumed, the NETL Cost Estimation Methodology Report indicates the EPCC add-on should be 15 – 20% of the BEC, depending on the technology considered. For this cost analysis, 15% of the BEC has been assumed for all cost lines.
- Total Plant Cost (TPC) - Comprises the EPCC cost plus project and process contingencies. To determine project contingency, a percentage of the Total Process Capital, EPC Contractor Services and Process Contingency has been used. The percentages range from 10% to 30%, with a percentage assigned based on the certainty of bare erected cost for that line item, as per the recommendation in AACE 16R-90[iv]. Process contingency has only been included for process items where there are uncertainties associated with the development status of the technology. These include the Heat Exchanger Network and the CO2 Purification unit (off-the shelve technology but when combined, original design). A percentage (factor) of the BEC for the specific line item has been assumed based on the guidelines outlined in AACE 16R-90 and EPRI[v]. The below provides a summary the allowances outlined in AACE 16R-90 and EPRI:

State of Technology Development	Process Contingency Allowances as Percentages of Total Process Capital Cost
New concept with limited data	40+
Concept with bench-scale data	30% to 70%
Small pilot plant data	20% to 35%
Full-size modules have been operated	5% to 20%
Process is used commercially	0% to 10%

Table 1: Guidelines to aid in assigning process contingency allowances to various sections of the plant.

- Total Overnight Cost (TOC) - Comprises the TPC plus 'overnight' costs, including owner's cost. The methodology used to determine the owner's cost is provided later within this section.

The TOC is an overnight cost, expressed in base-year dollars and as such does not include escalation during construction or construction financing costs. To determine a cost expressed in mixed, current-year dollars over the capital expenditure period, the Total As-Spent Cost needs to be calculated.

- Total As-Spent Cost (TASC) - Comprises the sum of all capital expenditures as they are incurred during the capital expenditure period for construction, including their escalation. TASC also includes interest during construction, comprised of interest on debt and a return on equity (ROE).

  The TASC can be calculated from the TOC using specific factors as outlined in Exhibit 3-7 within the NETL Cost Estimation Methodology Report. The specific factor used for this cost analysis has been chosen based on the assumption of real dollars and a duration of construction for 5 years. The factor has been verified by ensuring the economic assumptions (Exhibit 3-1) and the financial structures for investor-owned utilities (Exhibit 3-2) outlined within the NETL Cost Estimation Methodology Report align with the specific economics for the project. Amongst others, these include:
  - Income Tax Rates of 21% and 6% at federal and state level, respectively;
  - An effective tax rate of 25.74%;
  - A financing structure of 55% debt and 45% equity

Owners Costs

Owner's Costs were established from the guidance within the NETL Cost Estimation Methodology Report.

Pre-production costs to include a proportion of operating labor, maintenance materials, non-fuel consumables, waste disposal and fuel consumables. An additional 2% of TPC added to cover all other pre-production costs.

Inventory capital costs includes 60-day supply of fuel and 60-day supply of non-fuel consumables assuming 100% capacity factor and an additional 0.5% of TPC for spare parts.

Other owner's costs include for initial purchase of catalyst and chemicals, cost for land ($3,000/acre, with estimated 27.073 acres as per Indicative Site Layout produced), financing cost of 2.7% of TPC and 10% of TPC added to cover all other owner's costs.

The NETL Performance and Cost Assessment of a natural Gas-Fueled Direct sCO2 Power Plant report[vi] (NETL Direct sCO2 report) utilized a 15% of TPC unit for this "other owner's costs" category, stating that: "Significant deviation from this value is possible, because it is very site and owner specific. AACE 18R-97 indicates the "other owner's cost" of 15% of TPC is only an estimate based on rule of thumb and so flexibility to adjust based on site and owner specifics. The lumped 'Other Owner's Costs' 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; Owner's contingency." Given the chosen siting on an existing coal mine, the lower permitting burden due to the near-zero air emissions and zero-liquid-discharge nature of the Allam-Fetvedt Cycle, and the higher overall Total Plant Cost of the coal cycle, the project team has deemed that 15% of TPC is an inaccurate representation and agreed that taking 10% of TPC provides a more realistic cost.

Initial and Annual Operating and Maintenance Costs.

The O&M costs have been split by fixed operating costs, variable operating costs and fuel costs.

Fixed Operating Costs

The fixed operating cost includes a cost for the annual operating labor for the Allam-Fetvedt Cycle, ASU and gasification plants. An average base labor of $38.50/hr was assumed cross all operating staff, with a 30% labor burden and 25% of labor plus burden to cover overheads.

The maintenance labor was calculated as a percentage of the maintenance material in line with the NETL Baseline Report.

For administrative and support labor, 25% of the annual operating and maintenance labor was assumed.

For property taxes and insurance, 2% of the TPC was assumed.

Variable Operating Costs

For Maintenance materials, 1.95% of the TPC was assumed, in line with the NETL Baseline Report.

Non-fuel consumables and waste disposal specific to the Coal Allam Cycle Plantwas determined from per unit rates and assuming the plant capacity factor when calculating annual cost.

Fuel Cost

The 2018 unit cost of fuel of $12.68/ton was taken from EIA Table 31, Annual Coal Report 2018 [vii] for the Wyoming average coal price at the mine mouth. Because of the chosen location at the North Antelope Rochelle Mine, a mine mouth coal price was determined to be more representative than the delivered coal price used in the Conceptual Design.

Adjusting the 2018 cost of fuel to 2023 cost of fuel ($13.11) and levelizing over 30 year operational period (Year over year escalation for Wyoming, taken from Exhibit 2-2, Fuel Prices for NETL Quality Guidelines for Fuel Prices for Selected Feedstocks in NETL Studies[viii]), results in a levelized fuel price of $14.69/ton or $7.12/MWh. Based on the net plant HHV efficiency, this corresponds to a levelized fuel cost of $0.83/mmbtu.

This is a significantly lower fuel cost compared to $1.72/mmbtu for delivered PRB coal as stated in the Conceptual Design, and so a sensitivity case is also run for non-mine mouth PRB coal.

Byproduct Revenues

For CO_2 transport and storage, it was assumed that 60 total miles pipeline would be built and that CO_2 would be utilized for Enhanced Oil Recovery (EOR). The FE/NETL CO2 Transport Cost Model from 2018 was utilized with a 10% return on debt and equity, leading to a $3.23/MT cost of CO2 transport, which was then converted into dollars per MWh.[ix]

The Wyoming Enhanced Oil Recovery Institute provided a list of nearby oil fields that are CO2 miscible and potentially suitable for CO2-EOR. This provides 141.6 million tonnes of total CO2 demand, shown in the below table. The value of CO2 for EOR is assumed to be $15 / MT, which is both a standard and a conservative value in the industry.

Distance	Field	Reservoir	Cumulative Oil	CO2	Incremental Oil
Miles	Name	Name	mmbo	Demand Bcf	mmbo
25	Porcupine	Turner	4.9	26.22	3.2
25	Highlight	Muddy	81.7	261.37	32.2
25	Steinle Ranch	Muddy	4.3	23.60	2.9
50	Big Hand	Minnelusa	8.1	25.35	3.2
50	Bone Pile	Minnelusa	9.4	29.72	3.7
50	Clareton	Turner	7.4	23.60	2.9
50	Donky Creek	Minnelusa	17.3	46.33	5.7
50	Dry Gulch	Minnelusa	5.5	17.48	2.2
50	Halverson	Minnelusa	17.5	55.95	6.9
50	Hartzog Draw	Shannon	120.2	382.88	47.2
50	Hawk Point	Minnelusa	4.7	25.35	3.2
50	Heldt Draw	Shannon	7.9	20.98	2.6
50	Hornbuckle	Sussex	14.1	76.05	9.4
50	House Creek	Sussex	65.7	208.92	25.8
50	Jepson Draw	Shannon	1.9	6.99	0.77
50	Kaye	Teapot	10.1	32.34	3.9
50	Lance Creek	Leo	121.2	393.37	48.4
50	Meadow Creek	Minnelusa	35.7	96.16	11.9
50	Meadow Creek North	Frontier	9.5	51.57	6.4
50	Mush Creek	Muddy	14.8	48.08	5.9
50	Mush Creek West	Muddy	4.2	22.73	2.8
50	Pine Tree	Frontier	11.4	60.32	7.4
50	Powell	Frontier	29.4	156.47	19.3
50	Raven Creek	Minnelusa	47.7	154.72	19
50	Reel	Minnelusa	10.6	34.09	4.2
50	Salt Creek East	Tensleeep	13.6	43.71	5.4
50	Sand Dunes	Frontier	27	142.49	17.5
50	Scott	Parkman	22.7	72.55	8.9
50	Slattery	Minnelusa	14.8	47.20	5.8
50	Spearhead Ranch	Sussex	9.4	49.83	6.1
50	Table Mountain	Shannon	6.3	20.98	2.5
50	Timber Creek	Minnelusa	22.9	73.43	9
			Totals	2,730.84	336.27

Table 2: Adjacent Wyoming CO2-EOR Opportunities

On top of CO2-EOR sales, an additional $35 / MT of CO2 is added due to the value of the 45Q tax credit (in the year 2026). This credit is then grossed up to its Pre-Tax value for the levelized cost analysis using the 21% federal corporate income tax rate. To claim the 45Q tax credit, construction for the project must start before January 2024. The Project Execution Plan developed as part of this Pre-FEED indicates construction is scheduled to commence Q1 2023 and so the project will be entitled to claim the 45Q tax credit. Once qualified, the tax credit is available for 12 years. The revenue has therefore been adjusted to reflect claiming the 45Q tax credit for only 12 years but levelized over the 30 years of operation. To do this, the net present value of the total CO2-EOR sales over 30 years and net present value of toal income from 45Q tax credit over the first 12 years was determined (using a discount rate of 5%). The NPV ratio and the levelized CO2-EOR sales was used to determine the levelized 45Q over the 30 years of operation.

The prices for sales of Argon and Nitrogen, both byproducts of Air Separation, were calculated from 8 Rivers in-house data, estimates, and conversations with industrial gas distributors. Prices in the industrial gas market are very localized and kept quite confidential. Given the remote location of this facility and its low value, nitrogen is assumed to be too expensive to transport and thus have no value. Argon is in high demand in Salt Lake City, Denver, and California, all of which are reachable by rail from the NARM site. Argon routinely sells for over $400/ton, but to allow for this project to break into the market, a $300/ton argon pick-up price is assumed to undercut the existing supply. Different sensitivity analyses were run with different Argon prices to show the impact on the cost of electricity. To include the additional revenue from producing and selling excess Argon, a cost add-on has been included on top of the equipment cost for the ASU, along with an efficiency hit. This cost add-on has been provided from the ASU vendor based on the additional cost to produce the gases at required flowrate.

Levelized Cost of Energy (LCOE)

The Levelized Cost of Energy (LCOE) is determined from summation of the levelized capital cost, levelized annual O&M cost and levelized annual fuel cost. Alternate LCOE figures have also been determined, which include and/or exclude CO2 transport & storage (T&S) and revenue from other byproducts.

The levelized capital cost has been determined as a function of the after-tax weight average cost of capital, tax depreciation and effective tax rate in line with the equations included within the NETL Cost Estimation Methodology Report. The following economic assumptions and finance structure has been assumed:

- Number of operating years: 30
- Number of years of depreciation: 21
- Effective tax rate: 25.74%
- Finance Structure:
    - Debt: 55%
    - Equity: 45%
- Capital Recovery Factor: 6.305%

The levelized O&M cost assumes the same financial structure as the levelized capital cost but also considers annual escalation rate over the number of operating years (30 years assumed). For the purpose of this cost assessment, a 0% annual escalation rate has been assumed, which is consistent with the NETL Baseline Report.

The levelized fuel cost assumes the same financial structure as the levelized capital cost, with details outlined of the build-up of the levelized fuel cost detailed previously within this report.

Specific Equipment Cost Estimation Methodology

The capital cost estimate for entire plant was developed based on the equipment sizes defined by the process HMB. Cost for each piece of major equipment was estimated based on either vendor quotes, WSP and Gas Technology Institute's (GTI) in house estimating software, scaled from historical project data or were developed based on the NETL Baseline Report. The costs were adjusted for differences in unit or plant capacity according to NETL's guidelines as described in the NETL Cost Estimation Methodology Report.

Bulk material, packing & delivery and installation costs are added to complete the major equipment direct installation costs. Bulk material costs, which include instrumentation, piping, structure steel, insulation, electrical, painting, concrete & platform preparation works that are needed to complete the major equipment installations, were factored from major equipment cost (MEC) based on WSP and GTI's in house historical data for similar services where available.

Packing and delivery costs have been assumed as a percentage of combined equipment and material costs. With the exception of the gasifier, US supply has been assumed (to be confirmed at the next project stage). It is understood that a sales tax would apply for any goods delivered to Wyoming from US but it has been assumed that this would be waivered or if not, the tax would be reclaimed back on any goods purchased. For US supply, a band system has been used to determine packing and delivery. For low equipment cost (<$1million), 9% of that cost has been assumed, for medium equipment cost (<$5million), 6% of that cost has been assumed and for high equipment costs (>$5million), 3% of that cost has been assumed. Further details on the packing, delivery and import duty cost for the gasifier has been provided later on in this report.

Labor costs were obtained from real project data and factored to align with the equipment size and Wyoming labor rates (Again, obtained from real project data). When this information was not available, labor rates were scaled from the NETL Baseline Report.

Coal Handling

WSP were responsible to generate the cost estimate for coal handling from the mine up to the coal dryer. A coal vibrating feeder is required at the coal mine to distribute coal onto a conveyor. A 1km coal ground mounted conveyor has been assumed which supplies a short-term coal storage silo (1 day).

Previous project data was used and scaled to obtain the cost for the coal vibrating feeder and storage silo and the cost for the conveyor was obtained by a vendor quote.

Gasifier and Syngas Cleanup

GTI were responsible to generate the cost estimate for gasification island and syngas clean up. Gasifier Island consist of sections like coal drying, coal milling and pulverization system, dry coal pressurize feed system; gasifier, syngas scrubber, quench and grey water system along with slag and ash handling system (conveyed and disposed within hooklift type trailers for easy removal from site). While the syngas cleanup consists of COS hydrolysis reactor, mercury removal, SG cooler, AGR and tail gas treatment for sulfur recovery unit.

Gasification technology selected for this project is SE entrained flow gasifier developed by SINOPEC and East China University of Science and Technology (ECUST). Costs for equipment in the SE gasification system that are proprietary to ECUST, such as SE gasifier and sub system were provided by ECUST.

The level of detail provided in these cost estimates was determined by ECUST itself. WSP and GTI used and reported these costs on an as-provided basis. It is assumed that all the equipment in the gasification island will be manufactured in China and shipped to the site in the US. For delivery, import duty (tariffs) from China has been assumed to be 25% of equipment / material cost and 0.21% of equipment / material cost for insurance. This is on top of shipping and haulage cost for delivery of the equipment to site. The import duty, insurance and shipping and haulage costs have been obtained from a logistics company which has calculated from cost and volume of equipment / material. Direct Labor Cost was scaled from similar reference gasification project in comparable location. As SE entrained flow gasification technology is matured and commercially available with over ten thousand hours of operation experience from multiple projects, no process contingency was included for gasification island

In syngas cleanup section, cost for equipment and material were obtained from vendors for given sizes. Direct labor costs were estimated based on NETL Baseline Report. Like gasification technology all syngas clean technologies are commercially available, hence no process contingency was included for the systems.

Air Separation Unit (ASU)

The ASU includes the plant to obtain the required oxygen for the Allam-Fetvedt Cycle and gasifier and the required nitrogen for coal drying.

The equipment cost for the ASU plant has been obtained through a vendor quote and assumes a single stream, with storage for oxygen and nitrogen. US supply has been assumed and 3% of equipment cost has been included for packing and delivery. An assumption of 38% of the equipment cost is used for direct labor for erection and installation, which aligns with the NETL Baseline Report.

The ASU vendor have provided an additional add-on cost for when an ASU is supplied which produces excess Argon and Nitrogen for sale off site. Given the additional cost, energy usage, and low project specific value, Nitrogen is not projected to be sold for this Wyoming project. Cases with Argon sales, and the associated cost, will be shown.

The ASU vendur has confirmed that the system is designed to produce additional N2 (45,000Nm3/h / 56.22 MT/hr) with no impact on cost or electrical load. This will be more than sufficient for internal use for adsorbent regeneration

Allam-Fetvedt Cycle Power Island

Syngas and CO2 Compressors

Two stage compressors with aftercoolers are required to compress the syngas and CO2 as part of the process. The equipment cost for the compressors has been obtained from vendor quotes. US supply has been assumed and so 3% of equipment cost has been assumed for packing and delivery. 5% of the equipment cost has been assumed for direct labor for interconnection of pipes, instruments and ancillaries. The syngas compressor cost used for this project is from vendor quote with ancillaries included. Connecting pipework, fitting and valves for the Allam Cycle Plant is included as a separate line item. Assumed equipment will be delivered as skid unit, so minimal labor required for installation and connections hence the assumption of 5% of equipment cost for direct labor.

Although the same vendor has provided a cost for both compressors, a combined supply discount has not been explored at this stage.

Syngas Combustor and Turbine

Siemens provided a quote for the syngas combustor and turbine set for this project. US supply has been assumed and so 3% of equipment cost has been included for packing and delivery. Further, 5% of the equipment cost has been assumed for direct labor for interconnection works with the other plant.

Recuperative Heat Exchanger

The recuperative heat exchanger is a multiple high pressure and temperature stream network, with the arrangement still under discussion with vendors. At this stage, a vendor quote has not been obtained and so the cost of the heat exchanger unit has been estimated from scaling the equipment cost from the NET Power Demonstration Plant. At this stage, this is deemed a sufficient estimate due to the process conditions being comparable for the two projects.

US supply has been assumed and so 3% of equipment cost has been included for packing and delivery, with 5% of the equipment cost assumed for direct labor for interconnection works.

CO2 Pumps and Oxidant Pump

The equipment cost for the pumps has been obtained from vendor quotes. US supply has been assumed and so 3% of equipment cost has been included for packing and delivery. An additional 5% of the equipment cost has been assumed for direct labor for installation and interconnection of pipes, instruments and ancillaries.

Although the same vendor has provided a cost for both pumps, a combined supply discount has not been explored at this stage.

Additional Equipment

The additional equipment included in the Power Island are the following: Syngas Turbine Generator, Direct Contact Cooler, Civils / Foundations, and Allam Cycle Connection Pipework, Fittings, and Valves. Each of these has no process contingency, and a 15% project contingency, with the exceptions of the Civils / Foundations category which has a 20% project contingency.

Cooling Water System

A hybrid (wet / dry) mechanical draft cooling tower with circulating cooling water pumps is required to provide the plant cooling.

During the winter months, the system uses indirect dry cooling. Circulating water heated through the plant process is cooled through finned tubes, by passing air over the exterior surface of the tubes. The wet system is not in use and so water lost through evaporation, drift or blowdown is minimized.

During the summer months, the system uses dry cooling in series with wet cooling. Similar to operation in winter months, the circulating water heated through the plant process is cooled through the finned tubes. It then undergoes further cooling by evaporation of a proportion of the water through direct contact with the air in a wet fill section. Although the dry cooling section reduces the amount of evaporation, the system is open and water is still lost and so make-up water is required.

Based on the extreme winter conditions seen in Wyoming, a no-plume design point of -4°C (dry bulb temp, with relative humidity of 70%) has been chosen to size the dry part of the cooling tower. This has been discussed and agreed with vendors to allow the best compromise between performance and costs.

Three similar vendor quotes have been obtained and the cost used is an average of the three quotes. 35% of the equipment cost has been assumed for direct labor for erection and installation which aligns with the NETL Baseline Report. Thermoflow PEACE cost estimating software has been used to estimate the cost of the circulating water pump based on required flow.

Waste-Water Treatment and ZLD

The exact quality and analysis of the different process waste-water streams is not yet known but through discussion with a waste water treatment vendor, indicative zero liquid discharge (ZLD) waste water treatment systems have been formulated.

For the black water from the gasification water scrubber, it is understood the waste is mostly contaminated with COD (Assumed COD contents have molecular weight > 100). To treat this, a two stage reverse osmosis (RO), with a final evaporator stage, to allow the distillate from the RO stages and the evaporator to be recycled within the plant.

The other waste water streams is predominantly made up of the cooling tower blowdown. To treat this, a softening plant for removal of heavy metals and silica is required, followed by a two stage RO and a salt crystallization plant to saturate the brine to a slurry. The slurry will be collected and disposed of off-site and the distillate is recycled back to the plant process.

A vendor quote has been obtained for these waste water treatment systems. The vendor has indicated 25% cost for direct labor for erection and installation of the water treatment plants.

Miscellaneous / BOP

Cost for miscellaneous plant and BOP have been obtained from a mixture of vendor quotes, from Thermoflow PEACE cost estimating software or scaled from historical projects. Once the definition of this plant is more refined at the next stage, vendor quotes can be obtained.

Electrical Plant

For the electrical plant, all electrical and distribution equipment has been assumed up to the busbars within the electrical switchyard i.e. no electrical transmission from the switchyard have been assumed at this stage.

All electrical plant equipment costs have been obtained from vendor quotes, with the cost for the electrical switchyard being estimated by WSP electrical team.

Instrumentation and Control

The cost for the site wide DCS has been determined from historical project data and scaled to align with the control and instrumentation requirements for this project. A quote from a vendor is being awaited and will feed into the cost estimate when available.

Buildings / Structures and Civil Works

The cost for buildings has been obtained by laying out the equipment within buildings on a site layout, with consideration given to operation and maintenance requirements. The equipment footprints and heights have been taken from information provided by vendors.

The site layout produced has also been used to determine the costs for site finishing to include road network, drainage and landscaping and cost for pipe supports and.

POTENTIAL COST SAVING AREAS

GTI contacted different vendors for quotation of sub-systems in gasification and gas clean up island. While reviewing the quotations and discussion with vendors, GTI have identified a few potential cost saving areas. These can be evaluated in detail during FEED stage.

1) Tail Gas Treatment for Sulfur Removal:-

In this study we compared 5 technologies for sulfur removal:- 3 stage Claus SRU, LO-CAT® process, AECOM's Crystasulf , FLEXSORB and GPUR. The technology selected and cost quoted currently is for the Merichem's LO-CAT® process which is a liquid redox technology that converts H2S to elemental sulfur in an inherently safe aqueous solution. The elemental sulfur if filtered from the solution as a 60 wt% sulfur "cake" that is safe for transport and can be used as a fertilizer or disposed of in a landfill. The equipment cost quoted for LO-CAT® process is USD $12,500,000 with low annual operating cost (under $650,000).

There is another gas/liquid contactor technology called GPUR for sulfur removal; which is suitable for the proposed system. The equipment cost quoted from the vendor is about USD $6,000,000 (almost $6,500,000 cheaper than the LO-CAT® process), but the annual operating cost is in the range of USD $3,000,000. Trade study can be done in FEED stage for potential capital cost saving compared to annual operating cost, if this technology is chosen.

2) Zero Liquid Discharge: As stated above a quote has been obtained for a waste water ZLD system based on the assumed quality and preliminary flows for the different streams. The total installed cost comes in at approximately $29 million. USD s range. ZLD requirement is site/project specific, so if the site chosen does not have requirement of ZLD, it could be eliminated and replaced with a simple waste-water treatment plant and be a potential cost saving.

COST ANALYSIS RESULTS

Cost Confidence Assessment

A Cost Confidence Assessment has been carried out to demonstrate the cost is within the expected accuracy range for an AACE 18R-97 Class 4 Estimate. The assessment has looked at the main plant areas as split in the Cost Analysis Results and assigned a cost confidence category (Refer to the Cost Confidence Matrix). An accuracy is then estimated for each line depending on the maturity level of the design and the quality of cost obtained. This methodology presents the accuracies for each of the main plant areas and calculates a total plant cost accuracy of -17.1% to +28.3%.

CONFIDENCE LIMITS	
Increase on Most Likely Price	50%
Decrease on Most Likely Price	30%

Accuracy range taken from Class 4 Estimate within AACE 18R-97

DECREASE ON ESTIMATED PRICE

Quality of Design		Quality of Price: Factored (D)	Estimated / Databank (C)	Budget Price (B)	Fixed Price (A)
No Design. Development Unknown	4	30%	25%	20%	15%
Design Incomplete. Major Development	3	25%	20%	15%	10%
Design Incomplete. Minor Development	2	20%	15%	10%	5%
Design Complete. No Development	1	15%	10%	5%	0%

INCREASE ON ESTIMATED PRICE

Quality of Design		Quality of Price: Fixed Price (A)	Budget Price (B)	Estimated / Databank (C)	Factored (D)
Design Complete. No Development	1	2%	8%	17%	25%
Design Incomplete. Minor Development	2	8%	17%	25%	33%
Design Incomplete. Major Development	3	17%	25%	33%	42%
No Design. Development Unknown	4	25%	33%	42%	50%

Table 3: Cost Confidence Category Matrix

Reference Plant Owner's Costs

Description	$1,000s	$/kW
Pre-Production Costs (Assume 100% Capacity Factor)		
6 months - all labor	10,426	36.5
1 month maintenance materials	1,682	5.9
1 Month Non-Fuel Consumables	312	1.1
1 Month Waste Disposal	8	0.0
25% of 1 Months Fuel Cost (at 100% CF)	320	1.1
2% of TPC	17,594	61.6

Inventory Capital (Assume 100% Capacity Factor)		
60 day supply of fuel	2,526	8.8
60 day supply of non-fuel consumables	616	2.2
0.5% of TPC (Spare Parts)	4,399	15.4
Other Owner's Costs		
Initial Cost for Catalyst and Chemicals	1,283	4.5
Land	81	0.3
Finance Cost: 2.7% of TPC	23,752	83.2
Other Owner's Costs	87,972	308.0
TOTAL Owner's Cost	150,973	529

Table 4: Owner's Costs Table

Reference Plant Operating Costs

Table 5: Operating Costs and Output Table

Coal Mass Flow	125520	kg/hr	
Thermal Input (HHV)	714	MW	
Plant Output (Net)	286	MW	
Plant Capacity Factor	85	%	
CO2 Output	216	MT/hr	
Argon Output	7.14	MT/hr	
Nitrogen Output	0	MT/hr	

O&M Labor - Allam Cycle

	Rate ($/hr)	No. Required / Shift	Annual Cost $
Skilled Operator	62.56	1	465,822
Operator	62.56	3	1,397,465
ASU Operator	62.56	2	931,644
Foreman	62.56	1	465,822
Lab Technician	62.56	1	465,822
			3,726,574

O&M Labor - Gasification Plant

	Rate ($/hr)	No. Required / Shift	Annual Cost $
Shift Supervisor	62.56	1	465,822
Board Operators	62.56	3	1,397,465
Field Operators	62.56	3	1,397,465
Lab Technician	62.56	1	465,822
			3,726,574

Fixed Operating Costs						
	Initial Fill	Per Day	Per Unit	Initial Fill	Annual Cost	
					($)	($/MWh-net)
Annual Operating Labor:					7,453,148	$3.505
Maintenance Labor:					9,229,108	$4.340
Administrative & Support Labor:					4,170,564	$1.961
Property Taxes and Insurance:					17,594,334	$8.274
Fixed Operating Costs Total:					**38,447,155**	**$18.081**

Variable Operating Costs						
					($)	($/MWh-net)
Maintenance Material:					$17,154,476	$8.067
Consumables						
	Initial Fill	Per Day	Per Unit	Initial Fill		
Water (gal/1000):	172.5	1,684	$1.90	$328	$992,676	$0.47
Makeup and Waste Water Treatment Chemicals (gal):	0	1000.0	$2.20	$0	$682,550	$0.32
Sulfur-Impregnated Activated Carbon (ton):	13	0.04	$13,380	$173,940	$147,849	$0.07
COS Hydrolysis Catalyst (ft3):	2389.74	6.55	$338.00	$807,732	$686,572	$0.32
Sulfinol Solution (gal):	18814	12.89	$16.00	$301,024	$63,968	$0.03
Chemicals cost of Merichem (gal)	0	230	$8.59	$0	$612,747	
Subtotal:				**$1,283,024**	**$3,186,362**	$1.50
Waste Disposal						
Sulfur-Impregnated Activated Carbon (ton):		0.035616438	$80.00	$0.00	$884.00	$0.00
COS Hydrolysis Catalyst (ft3):		6.547232877	$2.50	$0.00	$5,078.20	$0.00
Sulfinol Solution (gal):		12.88630137	$0.35	$0.00	$1,399.29	$0.00
Crystallizer Solids (ton):		6.7	$38.00	$0.00	$78,989.65	$0.04
Slag (ton):		236.4	$0.00	$0.00	$0.00	$0.00
Subtotal:				**$0.00**	**$86,351.14**	$0.04
Variable Operating Costs Total:				**$1,283,024**	**$20,427,189**	**$9.61**

Fuel Costs						
Wyoming subbituminous Coal (US ton):	0	3,321	12.68	$0.00	$13,063,353	$6.14
Fuel Cost Total:				**$0.00**	**$13,063,353**	**$6.14**

Flexibility Conditions

The flexibility of Allam Cycle Coal is projected to at least be in-line with NGCC, with the potential to exceed that performance. Flexible performance targets to match and exceed are:

- The current ramp rate assumes that we are targeting an ability to provide 30 MW - 45 MW of load increase or decrease each minute during warm operation.
- Cold Start Up to reach full load in less than 4 hours assuming that pre-heating systems have been adequately sized to operate during the ramping period. This is subject to confirmation in detailed design.
- Turn Down: Zero net load to the grid, enabling low-load operation and rapid dispatch.
- Energy Storage: Approximately 1200 MWH of storage capacity is included as part of the default ASU design with respect to oxygen buffering. This can be increased with additional capacity possible with syngas storage or additional O2 tanks for more duration.
- Peaking: Peak from 286 MW up to approximately 325 MW using stored oxygen and assuming an ASU turndown of 50%.

Minimal O&M impact is expected for the range of these flexibility performance targets. None of these are projected to require increased maintenance nor to require increased personnel at the facility. The main impact to cost of this flexibility would be that a decreased capacity factor from frequent ramping or turn down would increase the levelized cost of energy by spreading the capital cost and fixed O&M cost across fewer megawatt hours. Due to the high by-product revenues, initial Allam Cycle Coal plants are expected to run at a high capacity factor, despite their ability to serve as flexible generators. Further exploration of the cost implications of flexibility will be done in the Final Report.

Cost of Energy and Sensitivity Analysis

Component	Value, $/MWh	Percentage
Capital	39.56	53.2%
Fixed	18.08	24.3%
Variable	9.61	12.9%
Fuel	7.12	9.6%
Total (Excluding T&S)	**74.36**	-
CO2 Transport	2.45	
CO2 EOR Revenue - Sales	-11.36	-
CO2 EOR Revenue - Pre Tax 45Q for 12 years	-19.34	-
Total (Including T&S)	**46.11**	
Argon Revenue	-8.27	
Nitrogen Revenue	0	-

Total (Including T&S and Revenue from Byproducts)	**37.84**	**-**

Table 6: Levelized Cost of Energy Table

The Levelized Cost of Energy (LCOE) is broken down in the above table, based on the assumptions described earlier methodology section. The LCOE is shown first solely based on power sales, then including the cost of CO2 transport and the revenue from 45Q and EOR, and then finally with byproduct revenues from Argon.

This LCOE is depicted in the figure below, with a couple key sensitivity cases applied. There is the baseline case for the First of A Kind (FOAK). Next is a case which assumes \$1.72/MMBtu for delivered Wyoming PRB coal, rather than the \$0.83/MMBtu minemouth coal price. Third is a case using mine mouth coal but including Argon sales at a lower \$50/ton price. The fourth sensitivity case applies the 48a tax credit, a 30% Investment Tax Credit for which AC Coal could qualify under the current requirements. Fifth is a case which assumes that the 45Q tax credit is available for the life of the project, rather than just the first 12 years. And finally for reference, the LCOE of a combined cycle gas plant is included, pulled from the NETL performance baselines case B31A, except with a natural gas cost of \$2.85/MMBtu rather than \$4.42/MMBtu.[x]

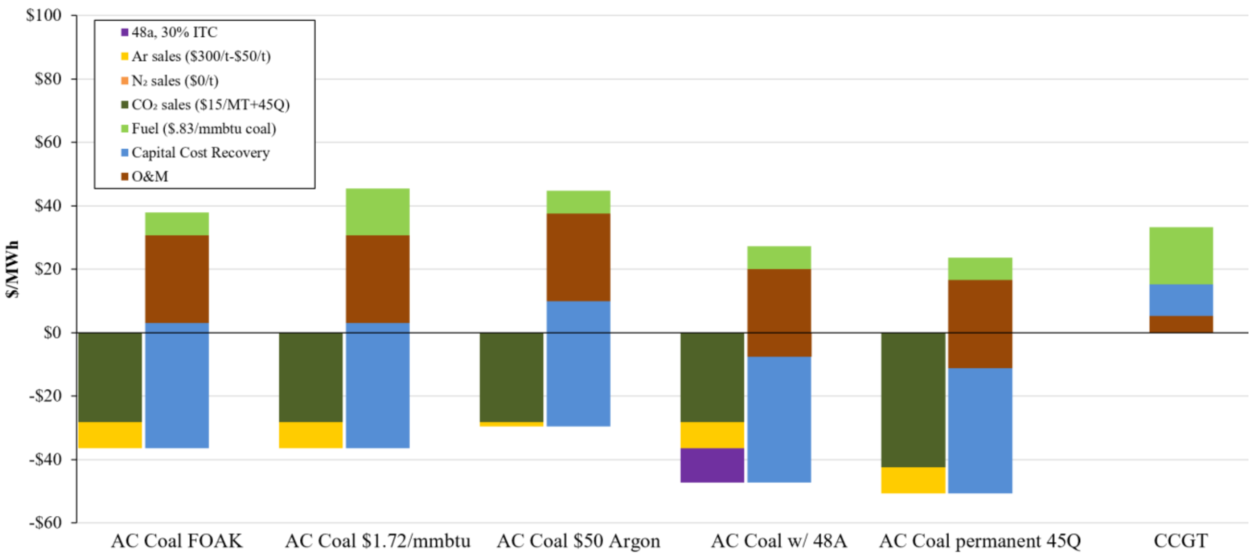

Figure 1: LCOE Sensitivity Analysis

References

[i] AACE International Recommended Practice No. 18R-97 - Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Process Industries – March 6, 2019.

[ii] NETL Quality Guidelines for Energy System Studies – Cost Estimation Methodology for NETL Assessments of Power Plant Performance – September 2019.
[iii] NETL Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity – September 24, 2019.
[iv] AACE International Recommended Practice No. 18R-97 – Conducting the Technical and Economical Evaluations – As applied for the Process and Utility Industries – April 1, 1991.
[v] Electric Power Research Institute (EPRI), TAGtm - Technical Assessment Guide, Vol.1, Electricity Supply - 1989; Vol. 2, Electricity End-Use - Part 1, 1987, Parts 2 & 3
[vi] NETL Performance and Cost Assessment of a natural Gas-Fueled Direct sCO2 Power Plant – March 15, 2019.
[vii] US Energy Information Administration (EIA), Annual Coal Report 2018, October 2019.
[viii] NETL Quality Guidelines for Energy System Studies – Fuel Prices for Selected Feedstocks in NETL Studies – January 2019.
[ix] https://netl.doe.gov/energy-analysis/details?id=543
[x] NETL Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity – September 24, 2019.