# FINAL TECHNICAL AND ECONOMIC FEASIBILITY STUDY ON THE APPLICATION OF A HEAT INTEGRATED POST-COMBUSTION $CO_2$ CAPTURE SYSTEM WITH HITACHI ADVANCED SOLVENT INTO EXISTING COAL-FIRED POWER PLANT

**TOPICAL REPORT**


**PRINCIPAL AUTHOR:**

Abhoyjit S. Bhown, Electric Power Research Institute, Palo Alto, CA

**CONTRIBUTING CO-AUTHORS:**

Ron Schoff, Andrew Maxson, Yang Du, and Alex Jimenez, Electric Power Research Institute, Palo Alto, CA

Kunlei Liu, Jim Neathery, Joe Remias, Jesse Thompson, Lisa Richburg, Andrew Placido and Heather Nikolic, University of Kentucky, Lexington, KY

Mike Bartone and Jay White, WorleyParsons Group Inc., Reading, PA

Sandhya Eswaran and Song Wu, Hitachi Power Systems America, Ltd, Basking Ridge, NJ



**REPORTING PERIOD**

10/01/2011 – 05/31/2020

**SUBMISSION DATE**

May 2020

**WORK PERFORMED UNDER AWARD NUMBER**

DE-FE0007395 – Task 19



**SUBMITTED BY**

University of Kentucky Research Foundation
109 Kinkead Hall
Lexington, KY, 40506-0057

**PRINCIPAL INVESTIGATOR**

Kunlei Liu
+1-859-257-0293
kunlei.liu@uky.edu

**DOE PROGRAM MANAGER**

Jose Figueroa
Jose.Figueroa@netl.doe.gov
Andy Aurelio
Isaac.Aurelio@netl.doe.gov

**SUBMITTED TO**

U.S. Department of Energy
National Energy Technology Laboratory

## NOTICES



**ACKNOWLEDGEMENT OF GOVERNMENT SUPPORT.** This material is based upon work supported by the Department of Energy under Award Number DE-FE0007395.

## Abstract

This report contains the results of a techno-economic assessment (TEA) conducted of a heat integrated post-combustion $CO_2$ capture process with Hitachi advanced solvent for retrofit into an existing coal-fired power plant (but treated as greenfield plant on cost analysis). The process has been developed by the University of Kentucky Center for Applied Energy (UK CAER). EPRI was chiefly responsible for this analysis, with significant input from WorleyParsons, Hitachi Power Systems America (Hitachi) and UK CAER.

The project also involves the design, fabrication, installation, testing, and analyses of a slipstream facility located at L&GE-KU's E.W. Brown Generating Station to demonstrate the UK CAER carbon capture system that could utilize heat integration with the main power plant. The design, start-up, and baseline of the pilot system was performed with a generic 30 wt% MEA solvent to obtain data for direct comparison with the DOE/NETL Reference Case [1] followed by testing Hitachi's proprietary solvent H3-1.

In this techno-economic analysis, two cases utilizing the UK CAER process are compared, using different approach temperatures and solvent, against the DOE/NETL Reference Case (Case 10). The results are shown comparing the energy demand for post-combustion $CO_2$ capture and the net higher heating value (HHV) efficiency of the power plant integrated with the post-combustion capture (PCC) plant. A levelized cost of electricity (LCOE) assessment was performed showing the costs of the options presented in the study. The key factors contributing to the reduction of LCOE were identified as $CO_2$ partial pressure increase at the flue gas inlet, thermal integration of the process, and performance of the Hitachi H3-1 solvent.

Recent UK CAER process pilot-scale testing data and process simualtion data showed that the packing heights of absorber and stripper columns were significantly oversized in the prelimanary TEA (Task 2 of this project) and thus updated in this final TEA for the H3-1 case only. In addition, the solvent make-up cost for H3-1 was updated based on lattest test results. Finally, a heat integration with the main power plant was applied in this final TEA to increase overall energy effciency for both the MEA and H3-1 cases. Additonal reductions in capital and operational costs are expected but not taken into account here. Shorter columns result in reduced pressure drops, smaller blower head and pump hydraulic head requirements. An increase in overall energy efficiency resuls in a decreased size of the power plant, the CCS and a reduced parasitic steam requirement to the CCS.

The net efficiency of the UK CAER integrated PC power plant with $CO_2$ capture changes from 26.2% for the Reference Case 10 plant in 2010 revised DOE/NETL baseline report to 27.6% for the MEA options considered, and 29.1% for the options utilizing the Hitachi advanced solvent. The UK CAER Process + Hitachi case also produces an extra 30.9 MW of generation compared to the UK CAER Process + MEA case and total 60.9 MW more than DOE Case 10. LCOE ($/MWh) values are $172.08/MWh for the MEA option and $157.65/MWh for the Hitachi H3-1 solvent cases considered in comparison to $189.59/MWh in January 2012 dollar for the Reference Case 10.


---

[1] United States Department of Energy (DOE), National Energy Technology Laboratory (NETL). (2010). *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity Rev. 2*. (DOE/NETL-2010/1397).Pittsburgh, Pennsylvania: U.S. DOE.

The UK CAER CCS process with MEA case lowers energy consumption for $CO_2$ capture to 1340 Btu/lb-$CO_2$ captured as compared to 1540 Btu/lb-$CO_2$ in the Reference Case 10. The UK CAER CCS process with H3-1 case further lowers energy consumption for $CO_2$ capture to 973 Btu/lb-$CO_2$ captured, for an advantage of 36.8% less energy consumption than Case 10. The study also shows 38.1% less heat rejection associated with the carbon capture system from 3398 MBtu/hr (Case 10) to 2104 MBtu/hr for the UK CAER + MEA system. Heat rejection is reduced to 2464 MBtu/hr in the UK CAER + H3-1 case, for a 27.5 % decrease compared to Case 10. Modeling outputs show that in the UK CAER process, the cooling water that is 2-5°C cooler than conventional cooling tower water can be achieved for ambient conditions common to the midwest and other regions. The results from the techno-economic assessment show that the proposed technology can be investigated further as a viable alternative to conventional $CO_2$ capture technology.

The evaluation also shows the effect of the critical parameters on the LCOE, with the main variables being the approach temperature and $CO_2$ partial pressure increase at the flue gas inlet. A summary of the key advantages of the UK CAER Process + H3-1 case for LCOE and other economic factors compared to the DOE Case 10 is as follows:

- A lower variable operating cost by \$1.56/MWh (\$1.08MWh less than the UK CAER Process + MEA Case), a 11.7% reduction compared to the DOE Case 10
- A lower COE by \$25.32MWh (\$13.94/MWh lower than the UK CAER Process + MEA Case), a 16.9% reduction compared to the DOE Case 10
- A lower LCOE by \$31.94/MWh (\$17.51/MWh lower than the UK CAER Process + MEA Case), a 16.9% reduction compared to the DOE Case 10
- A lower cost of $CO_2$ captured by \$18.65/tonne $CO_2$ (\$9.44/tonne $CO_2$ lower than the UK CAER Process + MEA Case), a 30.4% reduction compared to the DOE Case 10
- A lower cost of $CO_2$ avoided by \$34.95/tonne $CO_2$ (\$18.53 tonne $CO_2$ lower than the UK CAER Process + MEA Case), a 38.7% reduction compared to the DOE Case 10

# Table of Contents

## List of Figures

## List of Tables

## Abbreviations

BP – Budget Period
Btu – British thermal unit
UK CAER – University of Kentucky Center for Applied Energy Research
CCS – Carbon Capture and Storage
$CO_2$ – Carbon dioxide
COE – Cost of electicity
DCC – Direct Contact Cooler
DOE – Department of Energy
EPRI – Electric Power Research Institute
FEED – Front End Engineering Design
FGD – Flue Gas Desulphurisation
HHV – Higher Heating Value
ID Fan – Induced Draught/Draft Fan
KU – Kentucky Utilities
kW – Kilowat
kWh – Kilowat-hour
LCOE – Levelized Cost Of Electricity
LG&E – Louisville Gas & Electric
LHV – Lower Heating Value
MEA – Monoethanolamine
MW – Megawatt
MWh – Megawatt-hour
NETL – National Energy Technology Laboratory
O&M – Operation and Maintenance
PC – Pulverized Coal
PCC – Post Combustion Carbon Capture
PFD – Process Flow Diagram
TEA – Techno-Economic Assessment
TS&M -- Transportation, Storage, and Monitoring
TTD – Terminal Temperature Difference

# 1 Introduction

## 1.1 *Background*

In order to meet the DOE's goals, significant improvements and breakthroughs in cost-effective techniques for carbon capture are needed. Here, the techno-economic analysis (TEA) of the UK CAER heat-integrated post-combustion $CO_2$ capture system using an advanced solvent as the reagent for post-combustion $CO_2$ capture from utility flue gas is detailed. The process uses a two-stage stripping unit for solvent regeneration. This approach includes the addition of an air-based second stage stripping process inserted between a conventional rich-lean crossover heat exchanger and a lean solution temperature polishing heat exchanger. The secondary stripper outlet stream is used as boiler combustion air, consequently enriching the flue gas at the absorber inlet with $CO_2$. The proposed process also could use a heat-integrated cooling tower system which recovers waste energy from the carbon capture system. In this process, the conventional cooling tower would include two sections – the top section with 100% cooling water collection for the conventional cooling function; the bottom section to remove moisture from cooling air using a liquid desiccant prior to entering the top section for cooling recirculating water from steam turbine condenser. The working principle is that reducing the relative humidity of the cooling air will lower the turbine condenser cooling water temperature and thereby reduce the steam turbine back pressure for efficiency improvement.

In order to find new methods of lowering CCS costs, especially those from energy consumption, it is useful to consider the steam requirement for the stripper in an energy balance. This balance has three elements: the heat of desorption of $CO_2$ ($Q_{des}$) (sometimes referred to as the heat of reaction), the solvent sensible heat ($Q_{sens}$), and the latent heat of evaporation for stripping in the regenerator outlet ($Q_{strip}$). For instance, in a reference monoethanolamine (MEA)-based system, using the units of moles of steam required per mole of $CO_2$ desorbed, $Q_{des}$ = 2.2, $Q_{sens}$ = 0.6, and $Q_{strip}$ = 2.7, approximately 49% of energy is used for water evaporation. In this case, the stream temperature at stripper outlet is assumed to be 93 °C without any heat recovery downstream. For a given solvent the heat of desorption of $CO_2$ is set by thermodynamics, and the sensible heat requirement is practically fixed by the crossover heat exchanger (EHX) approach temperature (typically 5 °C differential temperature by design because of capital cost concerns, but operated at 10-15 $^{o}$C in practice). Therefore, recovering the water evaporation energy will be the main variable to reduce CCS energy consumption.

As presented in Figure 1-1, the energy consumption could be reduced significantly by dropping the evolved stream temperature at the stripper outlet through the installation of a heat recovery unit downstream and effective heat integration inside this unit. Energy savings of 70% could be realized if the temperature of the evolved stream ($CO_2$ + $H_2O$) is cooled to 71 °C from 93 °C through heat integration.

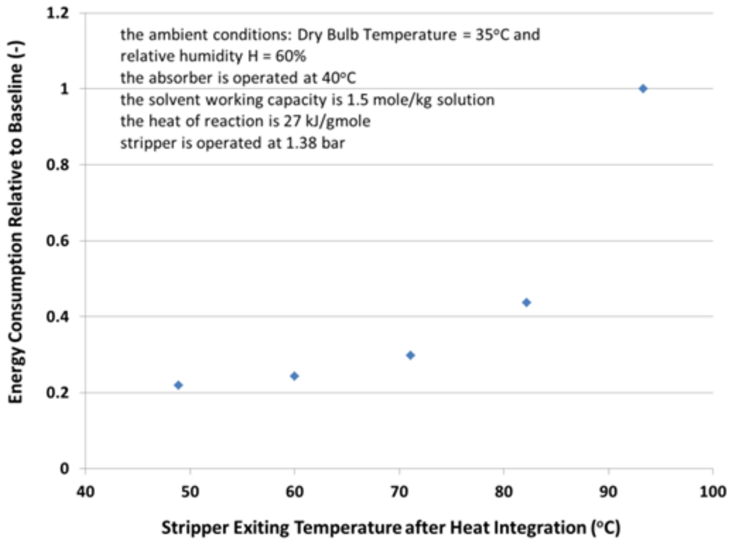


**Figure 1-1**
**The Impact of Energy Recovery from Stripping Evolved Stream**

Presently, three possible configurations have been suggested and studied to integrate the low-quality heat from CCS (specifically stripper exhaust and compressor intercooler) into the main power plant for energy recovery, which include (1) heating the carbon-rich solution prior to stripper; (2) heating the condensate from the steam turbine to replace one or two stages of feed water heater; and (3) integrating with plant HVAC system. Considering the large amount of low quality energy available from post-combustion CCS (approximately 25% of total energy input to power plant with CCS), all these configurations cannot be provided at an adequate scale for energy recovery. Further, these heat recovery approaches are constrained by the optimum temperature approach across the heat transfer unit and its capital investment, and energy loss from the elimination of feed water heaters due to steam condensation in the CCS reboiler.

Compared to conventional heat integrations as listed above, there are two key features of the proposed heat-integrated post-combustion $CO_2$ capture process. The first is the deployment of an air-based secondary stripper. An extra lean solvent produced from the regeneration process and partial $CO_2$ recycling (3-4 vol% in the stream) into the boiler combustion system will result in a smaller scrubber and stripper, which will reduce capital costs. Further reduction of carbon loading in the lean solution would result in a higher free amine concentration (higher pH), and lower liquid $CO_2$ partial pressure at the top of the scrubber. The recycling of $CO_2$ to the absorber inlet will yield a higher $CO_2$ concentration, 16.6% in this initial analysis. As illustrated in Figure 1-2, higher gas phase $CO_2$ concentration will increase the driving force for $CO_2$ diffusion through liquid/gas reaction film, and result in a higher mass transfer flux through increasing internal liquid circulation for a sturctured packed column. High $CO_2$ concentration in the gas stream will also enhance the final carbon loading in the solution at the scrubber bottom, which results in reduced stripper energy, as seen in Figure 1-3. Using the higher mass transfer flux possible in this system, permits a rich loading of 0.52 mol $CO_2$/mol amine (MEA case) which is approximately 17% higher than the value obtained without the enhanced $CO_2$ concentration.

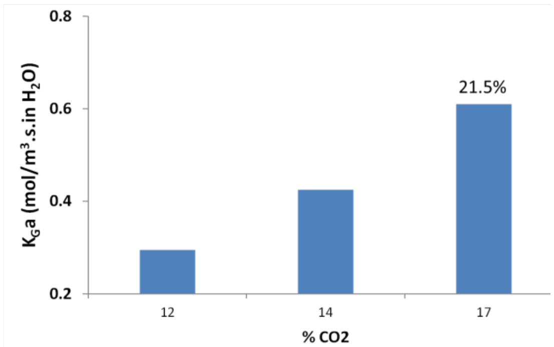


**Figure 1-2**
**Mass Transfer Flux with Higher $CO_2$ Concentrations**

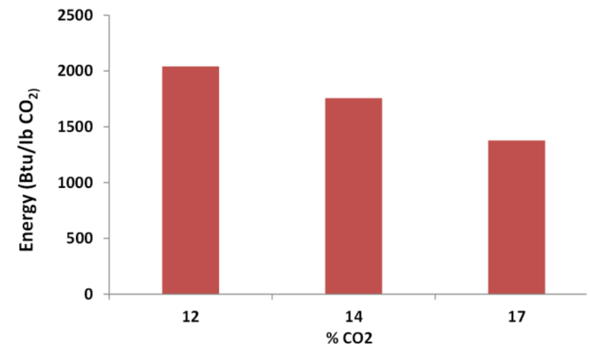


**Figure 1-3**
**Reduced Stripper Energy Requirements with Higher $CO_2$ Concentration in the Gas Stream**

The second key feature in the proposed heat-integrated post-combustion $CO_2$ capture process is the deployment of an integrated cooling tower system using a liquid dessicant if waste heat is available. Over the history of modern power plant design, a tremendous effort has been made to minimize the heat rejection from the steam turbine condenser though operated at high vacuum, which accounts for more than 30% of the fuel energy input in any steam-cycle utility power plant. Single crystal long blade technology for the last stage of the low pressure (LP) steam turbine has successfully demonstrated the capability to withstand the steam condition at 2 inch Hg (Abs) backpressure. To take advantage of this low backpressure, a larger condenser and cooling tower have been designed to achieve low temperature inside the condenser which determines the steam pressure (turbine back pressure); however, the selection is based on reference ambient conditions. For instance, in the DOE Reference Case 9 and 10, ambient conditions are stated as 59 $^oF$ dry bulb temperature with 60% relative humidity. With cooling water temperature at 60 $^oF$ and 20 $^oF$ temperature increase inside the condenser, a 100 $^oF$ environment in the condenser is achieved, which will result in a 2 inch Hg (Abs) steam backpressure.

As we know, for an existing power generation unit without any retrofit at given ambient conditions, the only way to reduce the turbine back pressure, e.g. cooling water temperature, is to reduce wet bulb temperature of cooling air which can be achieved by removing moisture/water content in the air through liquid desiccant as proposed by UK CAER. Again, as presented in the UK CAER system, the power generation efficiency, as illustrated in Figure 1-4, could be improved by 2.5% if the air relative humidity was decreased from 70% to 30% on a typical summer day.  Due to the low ambient temperature specified in the DOE Reference Case, as mentioned above, the liquid desiccant was not utilized in this techno-economic analysis. A sensitivity study was performed using Aspen Plus® simulation software to assess the performance.

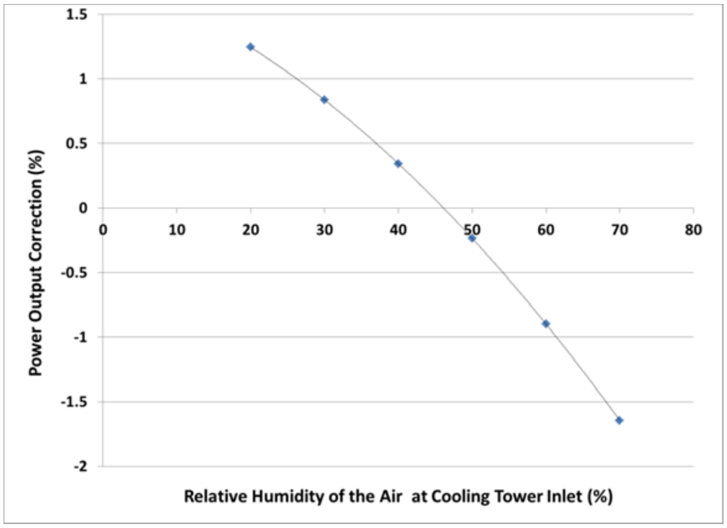


**Figure 1-4**
**The Impact of Relative Humidity on Overall Plant Thermal Efficiency at 90 ºF dry bulb temperature (Correction Curve was obtained from ASME PTC 6 for Steam Turbine)**

Additionally, the proposed heat-integrated post-combustion $CO_2$ capture process will also feature additional technologies incorporated into the system including:

- UK CAER proposes splitting the feed water after the boiler feed water pump into two streams. While the main portion of the feed water maintains the normal flow path, 20-25% of the flow will be heated to the same parameters as the boiler economizer in a split, last-stage feed water heater powered by steam extracted for the CCS reboiler. An Aspen Plus® steam cycle simulation shows an additional 8 $MW_e$ of net power can be produced when the superheat of CCS steam supply is recovered.

- The packed column $CO_2$ scrubber is equipped with an intermediate cooler. The proposed system will have two sets of solution cycles – an internal scrubber circulation at the lower part of scrubber to take advatange of low pressure drop of structured packing and an external liquid cycle to the top of scrubber from the stripper. The cooled solution pump-around in the scrubber will have two direct impacts: 1) enhanced gas-liquid contact through increasing local liquid/gas ratio allowing the ability to maintain mass balance between liquid and gas without impacting balance of plant and reduce the sensible heat rejection from lean solution temperature polisher; and 2) flexible temperature control inside the scrubber through multi-port cooled solvent injection.

## 1.2 *Project Overview*

In this research project, the UK CAER team proposed a 2 MWth (0.7 MWe equivalent) slipstream post-combustion $CO_2$ capture system for a coal-fired power plant using a heat integration method and novel concepts coupled with Hitachi's proprietary solvent (H3-1). The project involved the design, fabrication; installation and testing of a slipstream facility to demonstrate an innovative carbon capture system which utilizes heat integration with the main power plant.

The knowledge gained from this project on various aspects such as material coatings, process simplification/optimization, system compatibility and operability, solvent degradation & secondary environmental impact, water management and potential heat integration could be applied to future commercial applications to achieve DOE's current goals on post-combustion $CO_2$ capture.

The facility is located at LG&E and KU's E.W. Brown Generating Station, located near Harrodsburg, Ky. The design, start-up/commissioning of the test facility was performed with a 30 wt% MEA solvent to obtain baseline data, followed by Hitachi's proprietary amine solvent (H3-1).

## 1.3 *Report Objectives*

The objective of this report is to summarize process modeling studies that provide detailed mass and energy balances needed to conduct an economic assessment of the proposed process. The basis for the analysis was a nominal 550 MW (net) power plant according to NETL guidelines. Process modeling was conducted in order to optimize the proposed process, determine power plant integration strategies, and conduct sensitivity analyses. EPRI has developed an Aspen Plus® model for a pulverized coal power plant, as well as process models for $CO_2$ capture with solvent absorption using Aspen Plus®.  EPRI has used the Aspen Plus® solvent models and the coupled Aspen Plus® power plant model to conduct optimization, integration, and sensitivity analyses in order to determine integration strategies and system-level performance.

Using DOE guidelines, EPRI has conducted an economic assessment of the proposed capture process. From the results of that effort, EPRI and WorleyParsons developed the LCOE estimates, compared the COE to DOE/NETL Reference Case (Case 10) in 2010 revised NETL baseline report, and also evaluated the COE increase relative to DOE's goals. EPRI also estimated the expected plant equivalent availability based on estimated planned and scheduled outage rates. The impact of fuel costs, $CO_2$ compression technologies, solvent degradation and heat integration configurations on system performance and process economics were determined for each process to aid in the cost comparisons as described in the DOE's Carbon Capture and Sequestration Systems Analysis guideline and according to the assumptions listed in Attachment 5 of the FOA (DE-FOA-000043). A list of item costs was compiled. Costs included capital investment for major components and operational costs such as power, chemical, and water consumption.

# 2 Evaluation Basis

The post-combustion $CO_2$ capture and compression block includes a direct contact flue gas cooler/pre-treatment tower for polishing flue gas containments (SPU), two-trains of $CO_2$ capture, regeneration and compressions consisting of a packed column scrubber (Absorber) with solvent recovery water wash, two packed-bed stripper with reboiler and reclaimer (Stripper), a six-stage compressor, balance of plant (BOP) consisting of several heat exchangers for sensible heat recovery, several pumps for liquid recirculation, and a filtration device to remove entrained slurry droplets from the $SO_2$ scrubber and solids formed during the process for each train. The process is summarized as follows:

## 2.1 *Pre-treatment Tower Block*

### 2.1.1 Booster fan

As shown in Figure 2-1, the PCC system uses a booster fan to overcome the ducting and downstream components  (Direct Contact Cooler (DCC) and Absorber) pressure drop. The booster fan is designed for continuous stable operation over the full flue gas operation range specified in stream 16 of Exhibit 4-28 of the DOE/NETL 2010 study. The fan used here is a variable-speed centrifugal type, complete with inlet vane control. The design capacity and static pressure rise are calculated for the design conditions, with a suitable margin added, to ensure that the flue gas is delivered to the PCC plant at the required conditions.

At this point, the flue gas is saturated with water at a temperature of approximately 55 °C, water content of 17 vol%, and $CO_2$ concentration around 14-18 vol% (16 vol% DOE/NETL Case 10) in the total wet gas stream.

> *Note: the total $CO_2$ concentration consists of 2 vol % from $CO_2$ recycling via. the secondary air stripper, and 12-16 vol% $CO_2$ from coal combustion.*

### 2.1.2 Direct Contact Cooler/Pre-Treatment Tower

To minimize the accumulation of heat-stable salts (HSS), the incoming flue gas must have an $SO_2$ concentration of 10 ppmv or less. The gas exiting the FGD system passes through an $SO_2$ polishing step to achieve this objective. The polishing step consists of a non-plugging, low-differential-pressure, spray-baffle-type scrubber using soda ash. A 20 wt% solution of sodium hydroxide (NaOH) was used for DOE/NETL Case 10. Because hydroxide immediately reacts with the $CO_2$ containing flue gas to produce sodium carbonate, which is soda ash, and then sodium bicarbonate, the process chemistry remains the same.  Regardless of starting point, bicarbonate is the predominately recirculated species under process conditions (pH <7). The caustic is continously made up to maintain the target pH minimizing $CO_2$ capture while maximizing acid gas sulfur compound removal.

A removal efficiency of about 75 percent is necessary to reduce $SO_2$ emissions from the FGD outlet to 10 ppmv as required by the process. The polishing scrubber proposed for this application has been demonstrated in numerous industrial applications throughout the world and can achieve removal efficiencies of over 95 percent if necessary.

The polishing scrubber also serves as the flue gas cooling system. Cooling water from the PC plant is used to reduce the flue gas temperature to below the adiabatic saturation temperature, resulting in a reduction of the flue gas moisture content. Flue gas is cooled beyond the $CO_2$ absorption process requirements to 32 °C for the purpose of downstream water management. Without pre-capture water removal, the CCS will be out of water balance and the excess water will have to be purged from the system. It would not be beneficial to remove the excess water from the CCS because of the large losses of reagent. Removal of water from the stripper condensate is inefficient. Also, excessive heat has to be removed from the absorber to maintain an optimal reaction temperature; cooling the flue gas prior to the scrubber will provide more flexibility for unit operations.

The recycled reagent is introduced at the top of a single packed-bed through a liquid distributor for even liquid distribution to the packing surface. The distributor is designed to prevent splashing and droplet formation. The column has an internal diameter of approximately 15 meters, with Sulzer-Mellapak 350Y packing.

One option for the removal of the sulfur products is to reduce the temperature of the spent sulfur rich solution in a cooling device, which results in crystallization of a portion of the sulfate product. The solids can then be removed via filtration. Another option is include level control on the pretreatment controlled with a blowdown stream routed to the power plant flue gas desulfurization unit as the same chemical species are present. Make-up of fresh caustic solution is controlled by pH.

> *Note: The heat exchanger A is to cool a slipstream of pre-treatment solution to a certain temperature at which sulfate/sulfite/chloride/nitric salts will precipitate and are removed by a mechanical filter along with solids uncaptured in WFGD. If those precipitations cannot be formed, the heat exchanger A will be eliminated.*

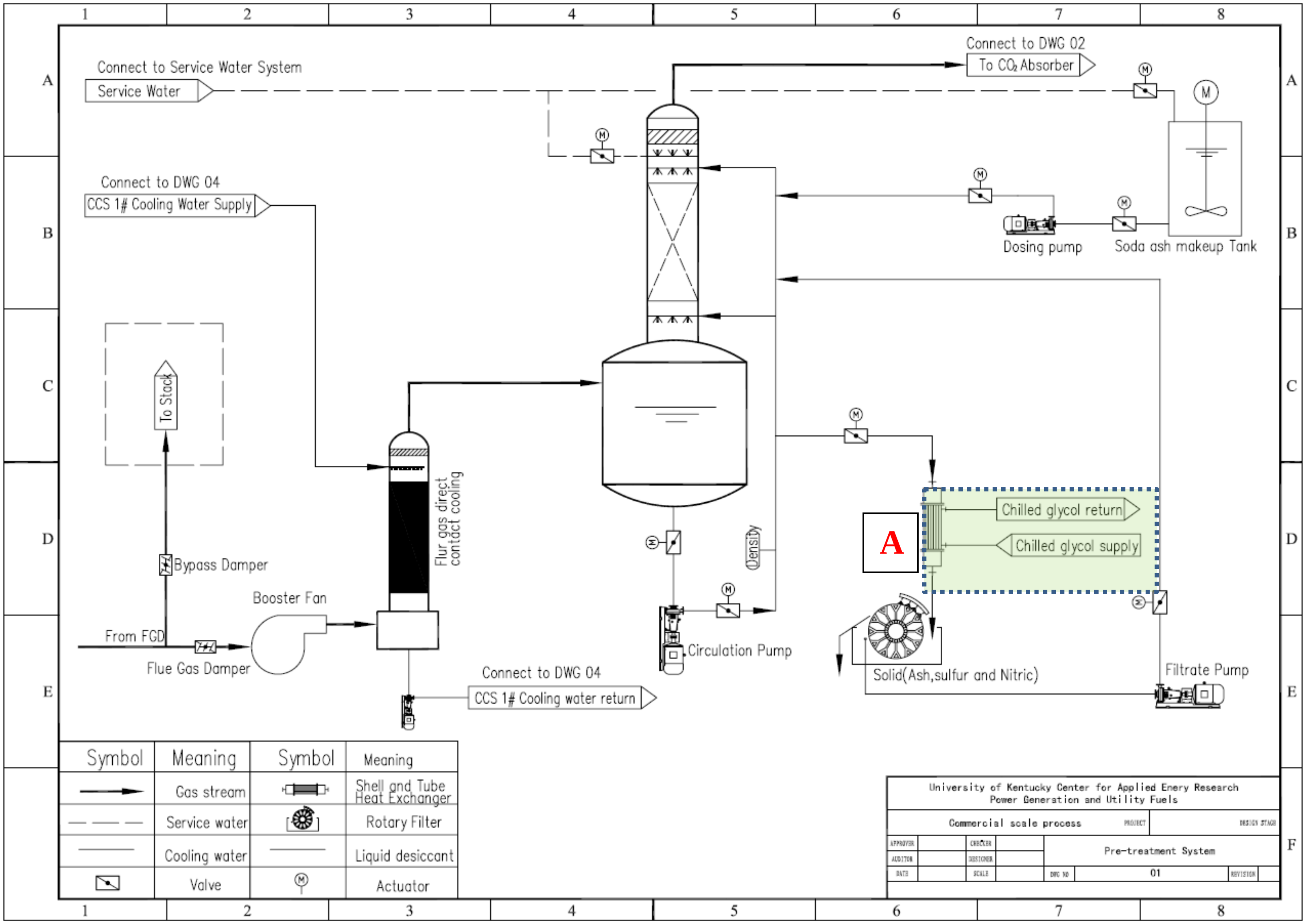


**Figure 2-1**
**Direct Contact Cooler/Pre-Treatment Tower**

## 2.2 ***$CO_2$ Scrubber Block***

### 2.2.1 **$CO_2$ Absorber**

The absorption column is designed to remove 90% of the $CO_2$ from the flue gas using the MEA and Hitachi H3-1 solvents. The lean (low liquid $CO_2$ content) amine solution is introduced at the top of the column at the desired temperature, approximately 40 °C. The solution is introduced using a liquid distributor for even liquid distribution to the packing surface. The distributor is designed to prevent splashing and droplet formation. The cooled flue gas from the DCC/polisher enters the column horizontally at the bottom between the sump and lower packing section. A gas inlet nozzle is designed to minimize liquid entrainment.

The countercurrent solvent flows down the column over the two sections of packing. The stainless steel structured packing, Mellapack 250, is selected to provide sufficient interfacial area, low pressure drop, and minimal overall column size. As the solvent flows down the column, it forms a thin film over the surface area of the structured packing material, allowing maximum gas-liquid interfacial contact within the column. This contact allows both the diffusion of the $CO_2$ into the solvent surface and the reaction between the solvent and the $CO_2$ to take place, capturing the $CO_2$ from the flue gas. The absorber column is approximately 11.6 meters in diameter and has 36 meters of packing for UK CAER process for MEA and approximately 10.4 meters in diameter and has 18.3 meters of packing for UK CAER process with the Hitachi solvent. To ensure even distribution throughout the total height of the absorber column, solvent collection and re-distribution is utilized. The $CO_2$ rich solution (high in $CO_2$ content) exits the bottom of the absorber to be passed through heat exchange en route to be regenerated.

The absorber utilizes intercooling to maximize mass transfer of the solvent and promote a high rich $CO_2$ loading. The solution collected at the bottom of the first packing section will be pulled out for intermediate cooling by recycle water from the cooling tower. The liquid collector is designed to have the function of adjusting the flowrate for external cooling (between none and full external). The intercooling heat exchanger is depicted in Figure 2-2 as section block (B). The gaseous $CO_2$ reacts exothermically with aqueous solvent to form ionic carbon species in the scrubber. Much of the generated heat is removed by the intercooling to maintain the temperature of the rich solution at pump outlet to approximately 36 $^{o}$C. Through the intercooling, the $CO_2$ carrying capacity of the solvent is increased at lower temperature, which reduces the solvent circulation rate.

The remaining flue gas, with $CO_2$ removed, passes upwards through a chimney tray into the water wash section. A one stage water wash is adopted to reduce amine, amine degradation products, and amine aerosol loss. Water for the process will be taken from the direct water contactor and recycled in the process with monitoring of buildup of trace components. At this point, the flue gas is saturated with water at a temperature of approximately 42 °C.

### 2.2.2 **Heat Exchangers (Rich/Lean Solvent)**

After the gaseous $CO_2$ is converted into aqueous carbon species, the carbon-rich solution travels from the bottom of the scrubber, is pressurized, and is sent to the heat exchanger (C) for sensible heat recovery prior to going to the compressor intercoolers (F), followed by L/R crossover heat exchanger (I) and then the stripper for solution regeneration. The heat exchanger is a plate and frame exchanger optimized for the viscosity of the design solvent.

*Note: The heat exchanger (C) is the overhead condenser for the secondary air stripper. Based on the UK CAER process simulation, the temperature of saturated gaseous stream (hot stream) at heat exchanger (C) inlet is in the range 90-105 °C. However, the water condensed from the heat exchanger (C) will NOT be used as Reflux for the secondary air stripper, instead, the water will be combined with the lean solution from the lean solution polisher (the heat exchanger D) prior to going to the* $CO_2$ *scrubber. Heat exchanger (E) is additionally used to recover the energy by steam condensate from main plant. The outlet temperature of the E hot stream (*$CO_2$ *contained air from air stripper) is approximately 40 °C prior to feeding into the boiler as secondary combustion air. It is suggested that the condensate from steam turbine condenser is used for further energy recovery but could result a complicate system integration and operating difficult to balance the main plant and CCS. In the TEA, the cooling water is used as coolant to simplify the process.*

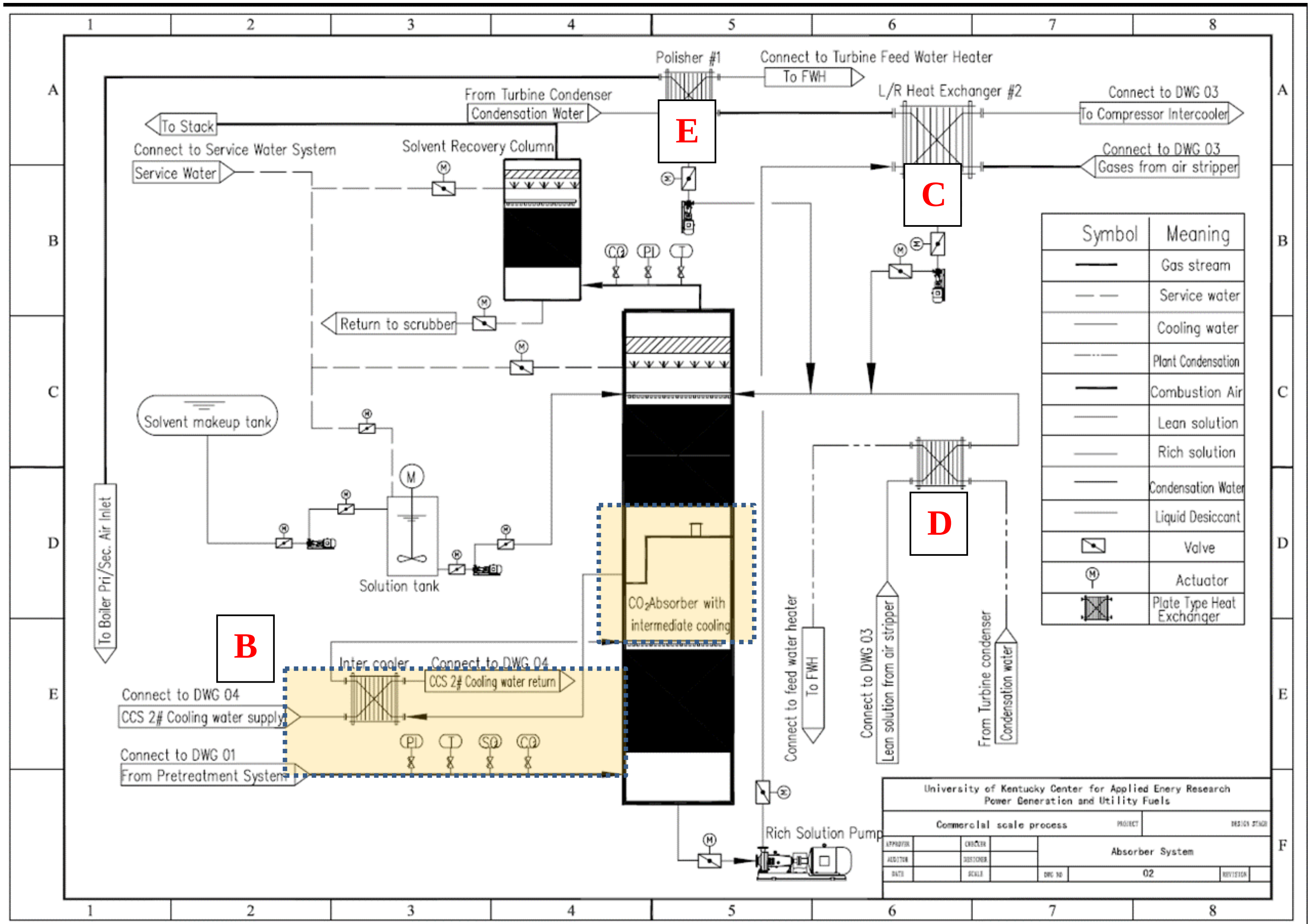


**Figure 2-2**
**$CO_2$ Scrubber**

## 2.3 ***Stripping Systems Block***

The designed process is composed of two strippers. One a primary stripper that removes the bulk of the $CO_2$ from the liquid process solution. The secondary stripper is used to further reduce the liquid $CO_2$ concentration providing a leaner solution to be introduced at the top of the absorber. The $CO_2$ enriched air stream is then introduced to the boiler as secondary combustion air.

### 2.3.1 **Primary Stripper**

The primary stripper column has a diameter of approximately 5.5 m for UK CAER process for MEA only and 4.9 meters for UK CAER process with Hitachi solvent. The rich amine solution is introduced at approximately the top 3rd quarter through a liquid distributor. The distributor acts to evenly spread the process solution over the packing material and minimize solution spray into the condensor section. The stripper contains a single section of structured packing of Mellapak 350Y with a height of 22.3 meters for UK CAER process with MEA and 10.7 meters for UK CAER process with Hitachi solvent. The upper quarter of the column includes additional packing as a demister to minimize water droplets carried to the heat exchanger/condenser (H). At the exit of the primary stripper, the gas stream primarily consists of $CO_2$ (45-50 vol%) and water vapor (50-55 vol%) at elevated pressure of 1.38 bar and temperature of 105 °C.

> *Note: the temperature at the bottom of primary stripper is operated in the range of 120-130 °C. The outlet temperature of the carbon lean solution(hot stream) for the heat exchanger (I) is in the range of 100-105 °C without the cold stream flux.*
>
> *The carbon loading in the rich solution entering the stripper is approximately 7-9% richer than that obtained from conventional process without $CO_2$ recycling based on the experimental data from UK CAER pilot-plant.*
>
> *The carbon loading in lean solution from the primary stripper is approximately 0.25-0.3 mole carbon/mole alkalinity.*

From the stripper overhead condenser, the $CO_2$ enriched gas stream from the primary stripper will enter the heat exchanger (H), for energy recovery via the Liquid Desiccant or Rich Amine solution (described in detail in Figure 2-3). After the heat recovery unit (G) (via condensate from turbine), the $CO_2$ stream will be pressurized, intercooled [heat exchanger (F) for heating up Liquid Desiccant or Rich Amine solution] and compressed to 138 bars for downstream utilization or sequestration.

> *Note: the saturated gaseous temperature at the outlet of heat exchanger (H) is approximately 60-65°C. As indicated in the diagram, the water condensed in this heat exchanger will NOT be sent back to the stripper as reflux. Instead, it will be combined with the lean solution stream from the bottom of the secondary air stripper prior to or after the pump located underneath the secondary air stripper. The purpose for this configuration is to (1) increase the energy quality for the heat exchanger (H) through raising the temperature; and (2) increase the $CO_2$ partial pressure in the air stripper by dewatering the lean solution from the primary stripper.*
>
> *If condensate from the turbine condenser isn't available for the heat exchanger (G), cooling water will be used as coolant.*

### 2.3.2 Secondary Stripper

The lean stream from the heat exchanger (I) will be sent to the top of an ambient pressure (secondary) air stripper to drop the carbon loading further in the lean solution. The $CO_2$ enriched air (3-4 vol% $CO_2$ content) from the top of this stripper will be used to provide recovered heat in the heat exchanger (C) in Figure 2-2, then cooled to approximately 40 °C by condensate from steam turbine or cooling water, and sent to the boiler as secondary combustion air. The air used here comes from a liquid desiccant water evaporator in Figure 2-4 which is saturated with water. In this assessment the liquid dessicant is not implemented due to low ambient air temperature and humidity as described below.

> *Note: the temperature of the lean solution from the bottom of secondary air stripper is in the range of 65-70 °C. Its sensible heat will be recovered in the heat exchanger (D) presented in Figure 2-2.*

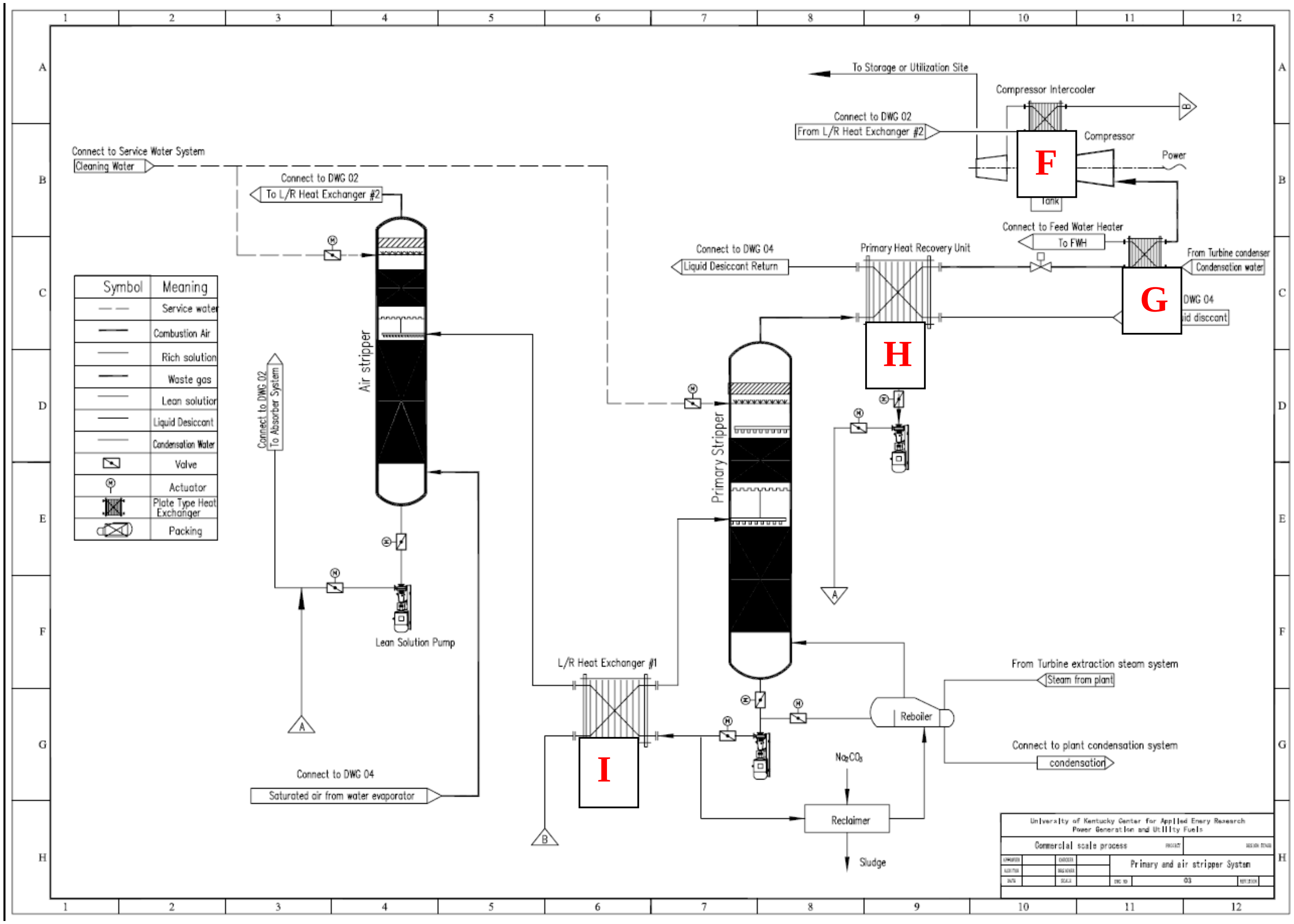


**Figure 2-3**
**Stripping Systems (Primary and Secondary Strippers)**

## 2.4 ***Heat Integration Cooling Tower Block***

The low quality heat with temperature less than 50 ºC rejected from the Rankine steam cycle as circulating water accounts for more than 35% of the energy loss for the steam utility power plant. In simplistic form, the Rankine cycle commonly used in modern power plants consist of a steam generator, steam turbine, and a water or air-cooled condenser. In this cycle, liquid water is heated in the steam generator to produce high temperature steam under pressure. Kinetic energy from the steam is converted to work from expansion in a turbine to produce electricity from a generator connected mechanically to the turbine. The turbine exhaust steam with quality at approximately 0.92 flows on the shell-side, while circulating water flows in the tube-side of the condenser. Most modern power plants employ a closed loop system with an evaporative cooling tower. The resulting steam condensate is collected in a hotwell below the condenser tubes where it is recirculated to the boiler to repeat the cycle.

As the steam condenses, the specific volume of the water is reduced significantly, thereby resulting in low pressure or vacuum that is a function of the circulating water outlet temperature. For a given inlet steam pressure, the enthalpy drop across the turbine increases as the operating pressure of the condenser is lowered. This will increase the amount of available work from the turbine and thereby increase the electrical power output of the generator, particularly in the wet steam region. Therefore, by minimizing the steam-side condenser pressure (i.e. vacuum), the turbine output and efficiency will be optimized for a given set of operating conditions.

For all other parameters being constant and assuming any non-condensable components have been ejected, the water outlet temperature from the condenser determines the operating shell-side pressure of the condenser according to the saturated steam tables. As the circulating water temperature is lowered, the condenser pressure will also decrease. During the daily operation, plant operators have limited options available to minimize the condenser vacuum; they usually strive to limit air in-leakage and to keep the tube-side of the condenser clean from fouling organic matter. Otherwise, the turbine efficiency is at the mercy of ambient temperature and humidity or wet bulb temperature of the air used to evaporate water in the cooling tower.

Similar to the DOE Case 10 (a retrofitting case), there is the need for additional cooling capacity to meet the heat rejection requirement from carbon capture system (CCS). In the UK CAER process, a two-section tower is adopted to contain two divided sections– the top section with open packing media with 100% liquid (water) collection for the conventional cooling function; the bottom section is also a packed structure column which will be used to remove moisture from cooling air using a liquid desiccant prior to entering the top section for cooling recirculating water from the steam turbine condenser. The purpose of the desiccant unit is to utilize low-quality waste heat from the CCS process and possibly flue gas energy to dry air for the main evaporative cooling tower, thereby lowering the wet bulb temperature. The heat-integrated cooling tower will lower condenser vacuum in the proposed carbon capture system using a liquid desiccant. This will proportionately lower the cooling water temperature supplied to the LP steam condenser. In a full demonstration of the concept the heat integrated cooling tower block would replace the existing power plant cooling tower and provide both the turbine and CCS cooling water requirements.

*Note: the temperature of water-rich liquid desiccant at pump outlet is less than 50 °C dependent on the ambient temperature.*

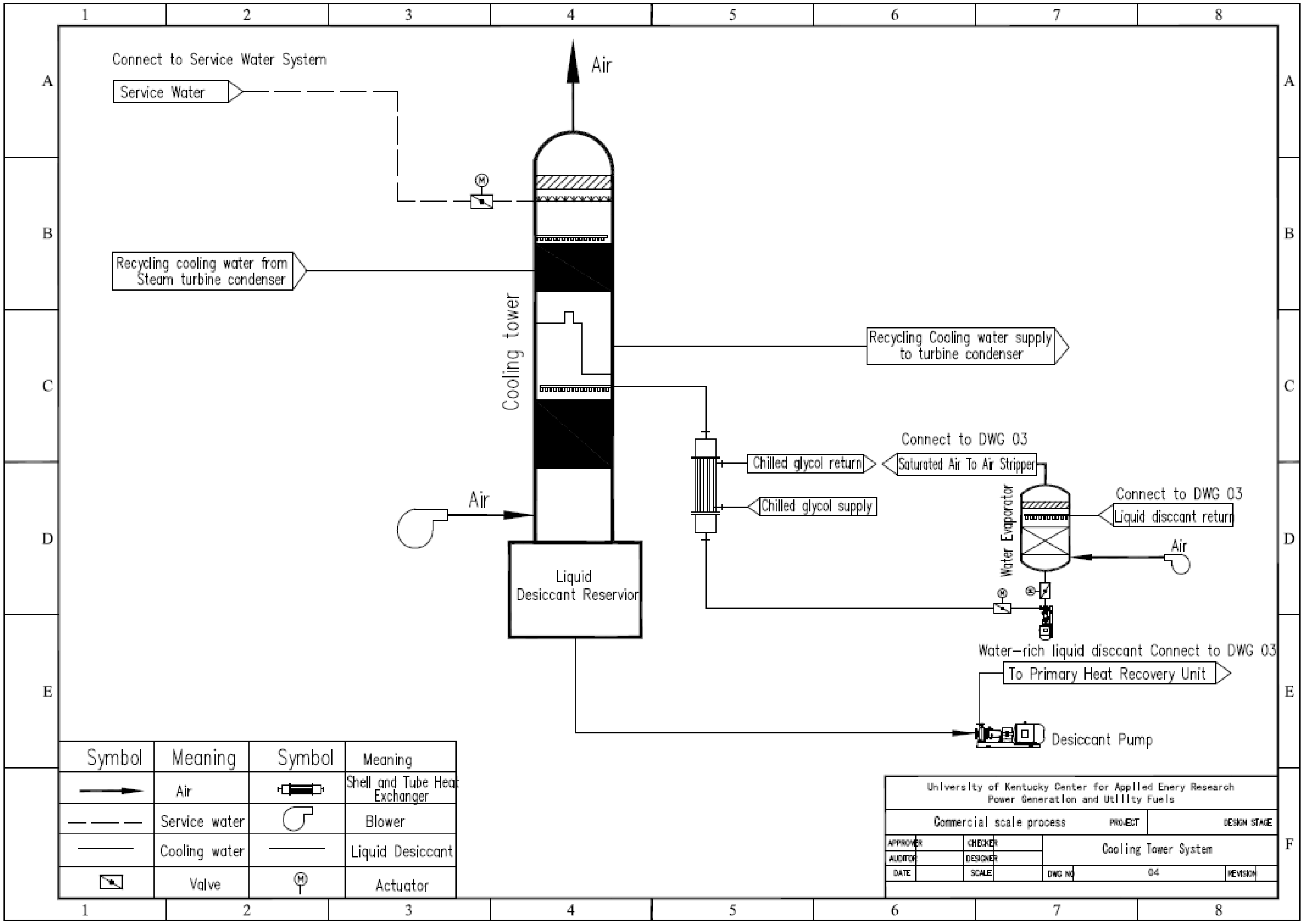


**Figure 2-4**
**Integrated Cooling Tower**

The system is comprised of a conventional evaporative cooling tower that has been modified to accept dried air from a liquid desiccant moisture absorbing tower. A concentrated brine solution used as a desiccant, such as $CaCl_2$, is circulated in the moisture absorption tower and contacted with ambient humid air to remove water, effectively lowering the wet bulb temperature of the air entering the cooling tower. The water-loaded brine is pumped through a heat exchanger (H in Figure 2-3) to gain temperature from waste heat in the CCS unit. A secondary heat exchanger could be added to extract low quality heat from low-temperature flue gas (between 90 and 150 $^oC$). The heated brine is then pumped to an evaporative tower (brine regenerator) and contacted with ambient air. At the higher regeneration temperature (about 55-80 °C), the water-rich brine tends to release moisture into the air and is cooled considerably from the latent heat of the liquid moisture evaporated. The water-lean desiccant will be collected from the bottom, and further cooling may be required using a chilling unit to reduce the sensible heat of the brine [heat exchanger (J)] before being recycled to the water absorption tower. The high-temperature saturated air from the evaporator will be fed to the secondary (air-sweeping) stripper as carrier gas for $CO_2$ removal.

> *Note: the temperature of water-rich liquid desiccant entering water evaporator is approximately 90-100°C. The temperature drop for liquid desiccant across the heat exchanger is expected to be in the range of 5-10 °C.*

The proposed air-drying system for evaporative cooling towers would be most useful in late Spring through early Fall as the average temperature rises above 80 $^oF$ (27 $^oC$). During these warm-weather months, steam plant operators are not able to maximize their plant generating capacity due to limitations of the cooling systems caused by the increased relative humidity levels as the wet bulb temperature rises above 70 $^oF$ (21 $^oC$). As mentioned in the introduction, the power generation efficiency could be improved by 2.5% if the air relative humidity was decreased from 70% to 30% on a typical summer day. However, these seasonal changes cannot be integrated into the present study due to the static ambient baseline of the DOE Reference Cases 9 and 10 that is based upon annual average conditions of the mid-western United States. Here the ambient conditions are stated as 59 $^oF$ (15 $^oC$) dry bulb temperature with the wet bulb temperature as 51.5 $^oF$ (10.8 $^oC$). With absolute humidity levels being lower than 0.009 lbs moisture per pound of dry air, the proposed drying system could not achieve wet bulb temperatures less than 46 $^oF$ (7.8 $^oC$) without a significant heat input and electricity consumption for the brine chilling unit. After thorough discussion between UK CAER and EPRI, it was concluded that the liquid desiccant will not be utilized in the techno-economic analysis. As an alternative, a sensitivity study was using an Aspen Plus® simulation to assess the performance of the effectiveness of evaporative air drying for warm weather months when wet-bulb suppression can offer benefits for increasing vacuum in the low pressure turbine condenser. In order to have a capital cost as reference point the cost analysis was on the liquid desiccant cooling tower to incorporate into the analysis.

## 2.5 ***Heat Integration with Main Plant***

The heat integration of the UK CAER process is a scheme in which the heat integration does not impact the main turbine steam cycle. For example, there is no waste heat from the CCS block used to heat steam for the turbine cycle. Doing so has too large of an impact on the steam extraction point as described below. As presented in Appendix A.4, the UK CAER process utilizes auxillary boiler with back pressure turbine to retrofit the existing power plant. This removes the problems associated with LP steam extraction (multiple extraction points needed at different loads) and provides operating flexibility for meeting power plant output demands.

The auxillary boiler consists of a stand-alone intermediate-pressure boiler with the back-pressure steam. In order to maintain the same net output requirements the boiler would be additional to the existing power plant infrastructure. The boiler uses a carbon-neutral biomass fuel, or even natural gas (NG) for fuel to minimize emissions. On the other hand, the makeup boiler will only be equipped with SCR for NOx reduction if needed. The exhaust flue gas stream after the SCR will combine with main flue gas stream prior to the in-duct cooling section in the proposed $CO_2$ capture process. $SO_2$ in the flue gas stream from the makeup boiler will be removed by aqueous ammonia solution in the pre-treatment tower.

*Note: For the techno-economic analysis the steam is extracted from the LP steam stream. This allows consistency and comparison to the NETL baseline Case 10.*

## 2.6 *Solvent Agnostic Nature of the UK CAER CCS*

The UK CAER CCS can be applied with any solvent and since operation of the 0.7 MWe small pilot facility started in 2015, six solvent campaigns have been conducted with the advanced solvents performing similarly despite differences in chemical compositions and physical properties (Table 2-1). The solvent regeneration energy applied in this economic anaysis will apply for most adavanced solvents.

**Table 2-1**
**UK CAER Small Pilot CCS Campaign Results**

| Performance Compared to 30 wt% MEA | Hitachi H3-1 | Proprietary Solvent C | 6 M MEA | CAER AS1 | CAER AS2 |
|---|---|---|---|---|---|
| Energy Penalty | 33% savings | ~21% savings | ~14% | ~30% savings | ~14% savings |
| Solvent Circulation Rate | ~35-45% reduction | ~40% reduction | ~20% reduction | ~30% reduction | ~same |
| Cyclic Capacity | ~1.5X | ~2X | ~1.3X | ~1.5X | ~1.0X |
| Viscosity | 2.5 – 3X | 3 – 3.5X | ~1.5X | ~1.5X | ~1.0X |
| Surface Tension | ~0.6X | -1.1X | ~1X | ~1.0X | ~0.8X |
| Degradation Products | Low | Low | Low | Low | Low |
| Solvent Regeneration Energy Measured at UK CAER 0.7 MWe CCS (Btu/lb $CO_2$ ) | 1020-1500 | 1200-1400 | 1330-1480 | 1070-1600 | 1320-1580 |

# 3 Description of Hitachi Advanced Solvent

## 3.1 *Development Background*

Since the early 1990's, when the first bench-scale studies and pilot-scale demonstration were conducted, Hitachi has been continually improving process designs and the technology for full-scale power plant applications through extensive research and development, demonstrations, and installations.

### 3.1.1 Bench-Scale R&D

At Hitachi's Kure Research Laboratory near Hiroshima, Japan, bench-scale studies with simulated flue gas have been performed regularly on a small test rig (absorber ID = 50 mm, shown in Figure 3-1) and a larger rig with a 300 mm ID vessel. These test rigs were used to screen over 30 combinations of amines and additives and identify promising combinations for maximum $CO_2$ removal efficiencies while keeping solvent degradation and energy consumption low.

**Figure 3-1**
**Bench-Scale Test Rig**

### 3.1.2 Pilot-Plant Testing

Figure 3-2 shows Hitachi's first $CO_2$ capture pilot plant built at Yokosuka Thermal Power Plant Unit 2 of Tokyo Electric Power Co., built and tested in the early 1990s. A slipstream of 1000 $m^3N/h$ (620 scfm ~ 1 MWth) of flue gas generated from combustion of coal – oil mixture (COM) was treated for $CO_2$ removal.  During the two-year demonstration period, Hitachi tested a range of commercial and proprietary amine-based solvents (including H1, H2, and H3, of which H3-1 is based) and logged more than 3000 hours of test data. The large volume of test data formed a solid foundation for Hitachi's solvent refinement and design of larger units.

**Figure 3-2**
**Pilot plant at Yokosuka**

In recent years, the Hitachi solvent has also been evaluated independantly by other researchers in their test facilities. These include the pilot plants at the Energy and Environmental Research Center at the University of North Dakota and the National Carbon Capture Center operated by Southern Company.

### 3.1.3 **Technology Demonstration**

Hitachi and SaskPower, a utility company in Saskatchewan, Canada, collaborated to design and build a 20 MWth Carbon Capture Test Facility (CCTF) at SaskPower's coal-fired Shand Power Station. The plant provided slipstream flue gas at a flow rate of about 20,000 $Nm^3/h$. The H3-1 solvent wase tested at this CCTF, with unit opertations starting on June of 2015.

### 3.1.4 **Scale-up & Commercialization**

Hitachi successfully completed the Phase I FEED of a 50 MWe slipstream $CO_2$ capture system under the DOE Industrial Carbon Capture and Storage (ICCS) program in 2010. By developing a detailed design for the $CO_2$ capture system along with optimized integration into the balance of plant, detailed project schedule and commercial assessment, the objectives of the DOE-ICCS program were achieved.

As a leading global supplier of complete thermal power plants, Hitachi's experience in boilers, steam turbines and air quality control systems provides a solid knowledge base for integration of a commercial-scale $CO_2$ capture system with the proposed novel concepts, and balance of the plant.

## 3.2 *Performance of the Hitachi Solvent*

Figure 3-3 shows Hitachi solvent, H3, achieving an average of 90% $CO_2$ removal over 2000 hours of continuous testing under various plant loads, inlet $CO_2$ concentrations and other operating conditions.

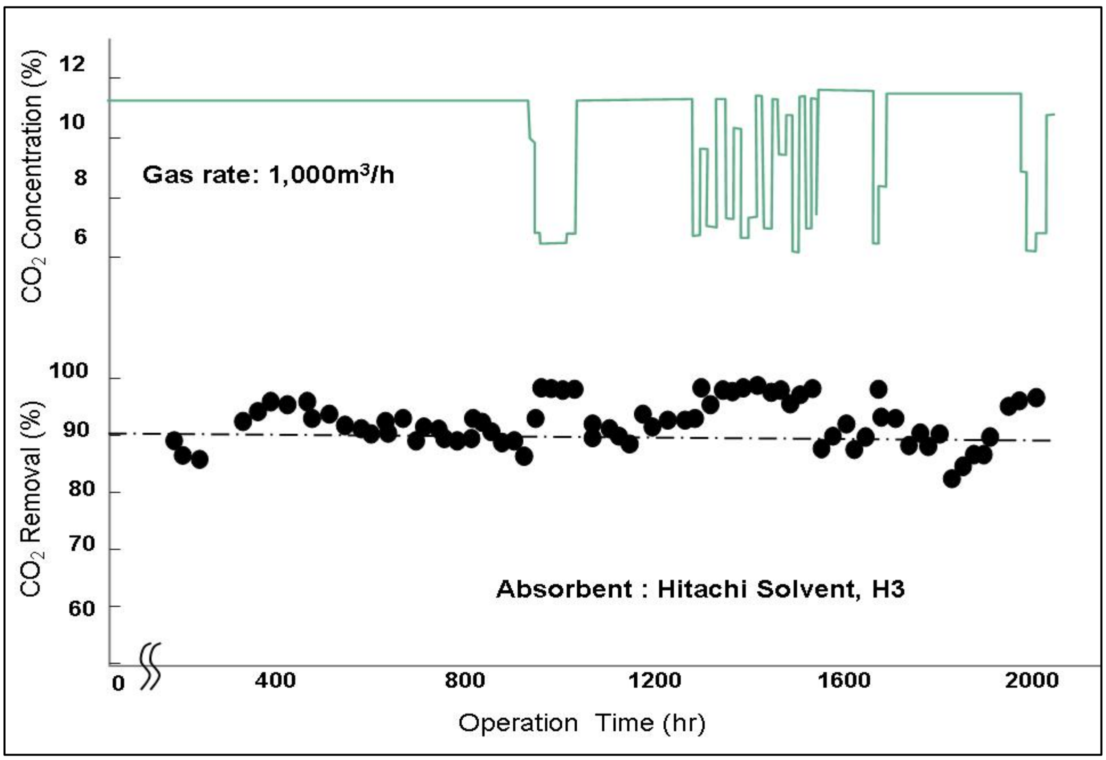


**Figure 3-3**
**Long-term pilot testing of H3 solvent under various conditions**

The latest refinement of the H3 solvent formulation, H3-1, is a proprietary blend that has the same advantages of high $CO_2$ absorption capacity and low regeneration heat as H3, and has further reduced amine loss. The sterically hindering effect of the base amine in H3-1 results in a lower $CO_2$ absorption heat than that of MEA solution. The $CO_2$ regeneration energy of the H3-1 based process is 2,800 kJ/kg $CO_2$, with ongoing research efforts to further lower to 2,500 kJ/kg $CO_2$ through both solvent improvement and optimization of absorber-stripper loop.

The reaction heat for $CO_2$ absorption was measured for H3-1 solvent and MEA under standard operating conditions. As shown in Figure 3-4, the heat of absorption (and desorption) of $CO_2$ from H3-1 is about 5 to 15% less than that for MEA at varying $CO_2$ loading.

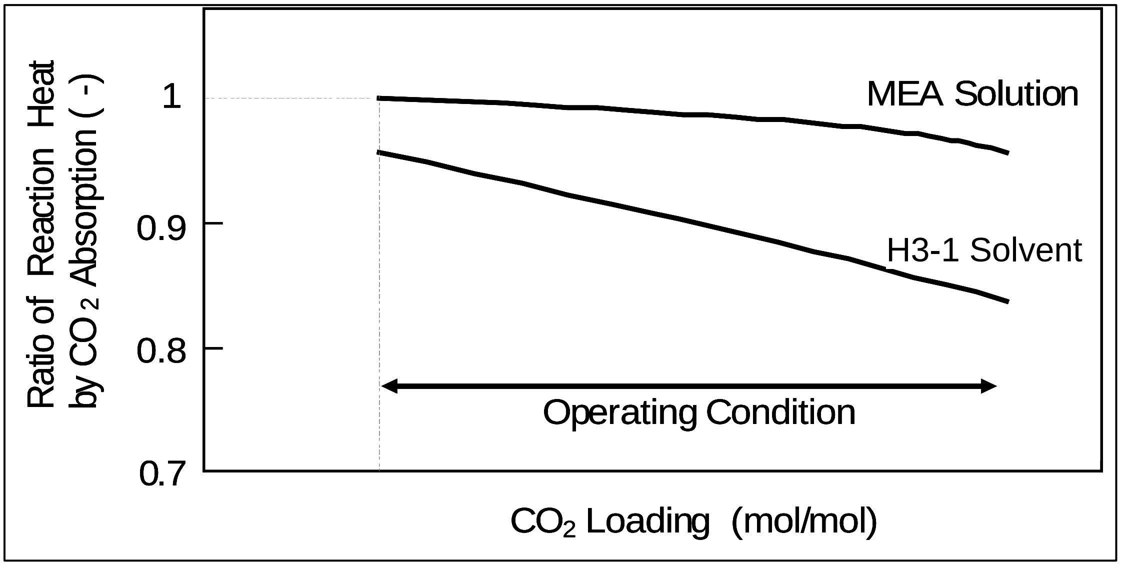


**Figure 3-4**
**Reaction Heat by $CO_2$ Absorption of MEA Solution and H3-1 Solvent**

Figure 3-5 and Figure 3-6 show comparisons of solvent performance based on third-party independent test data including those by a government research institute in Japan. H3 and H3-1 have the lowest regeneration heat compared to 30% MEA solution and two advanced amine solutions by other leading developers (A solv and B solv). H3-1 also has the lowest amine loss, which is 86% lower than that of the MEA solution. The reduced level of solvent losses and lower heat requirement of H3-1 translate to great savings in utility and operating costs.

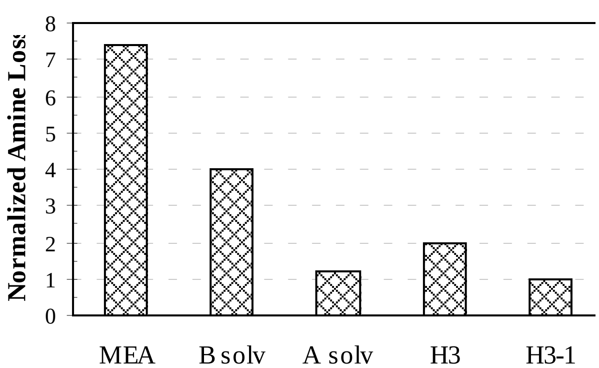


**Figure 3-5**
**Comparison of Amine Loss from Different Solvents**

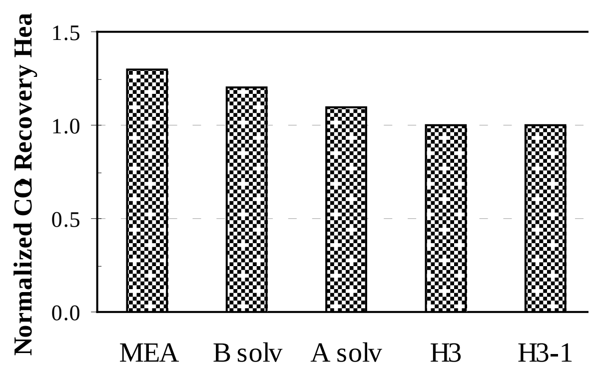


**Figure 3-6**
**Comparison of $CO_2$ recovery Heat from Different Solvents**

The H3-1 solvent was independently tested by the Energy and Environmental Research Center (EERC), University of North Dakota at the 400 $m^3N/h$ (250 scfm) $CO_2$ capture pilot plant. An average of 90% of the $CO_2$ was removed at steady state even when test parameters were varied during the test period. Figure 3-7 and Figure 3-8 show a comparison of the effect of liquid-to-gas ratio and regeneration energy on $CO_2$ capture with two other solvents tested under similar conditions[2]. For 90% $CO_2$ capture, the solvent recirculation rate needed is about 45% lower than that for MEA and the energy required to regenerate the H3-1 solvent is about 30% lower than 30 wt% MEA solution. Both these factors would result in significant capital and operating cost savings.

In 2012, the H3-1 solvent was tested at the 0.5 MWe pilot plant at the National Carbon Capture Center (NCCC). The NCCC facility is sponsored by DOE and industry. The pilot plant takes a slipstream of flue gas from the coal-fired Gaston power station. H3-1 was tested for over 1,300 hours under various plant operating conditions. Preliminary results of the NCCC pilot test confirm, and in some areas surpass, the H3-1 performance as described in this section.

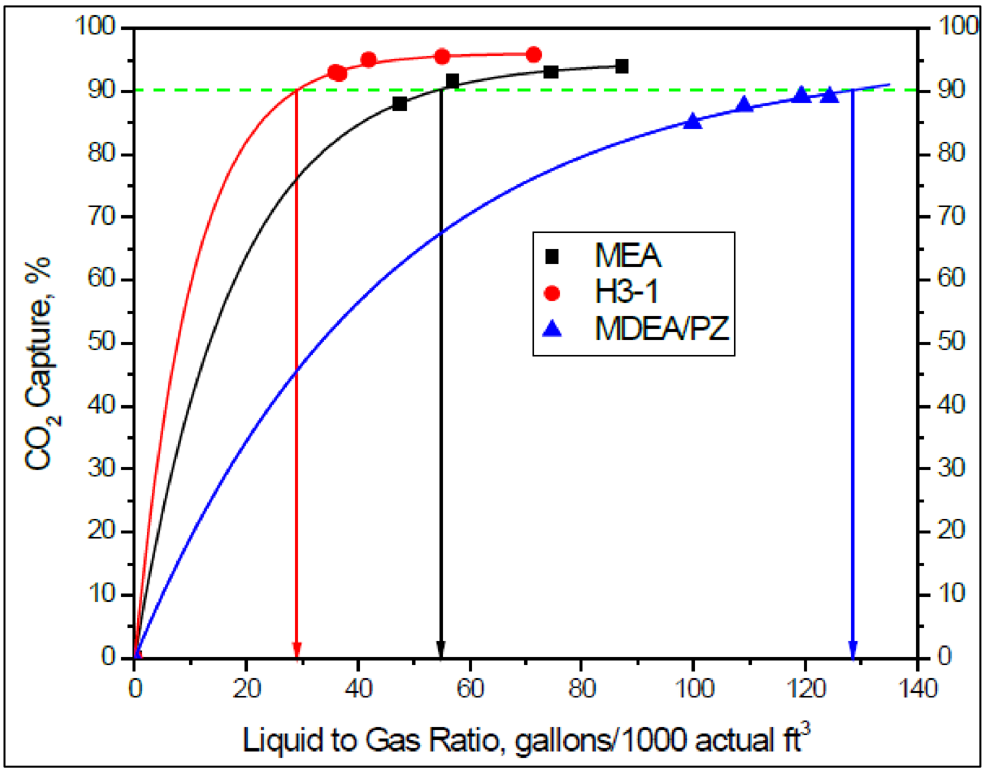


**Figure 3-7**
**Comparison of the Effect of L/G of Various Solvents**

[2] Pavlish, B. "Partnership for CO2 Capture: Results of the Pilot-Scale Solvent Evaluations". 2010 NETL CO2 Capture Technology Meeting, Pittsburgh, PA. September 13-17, 2010.

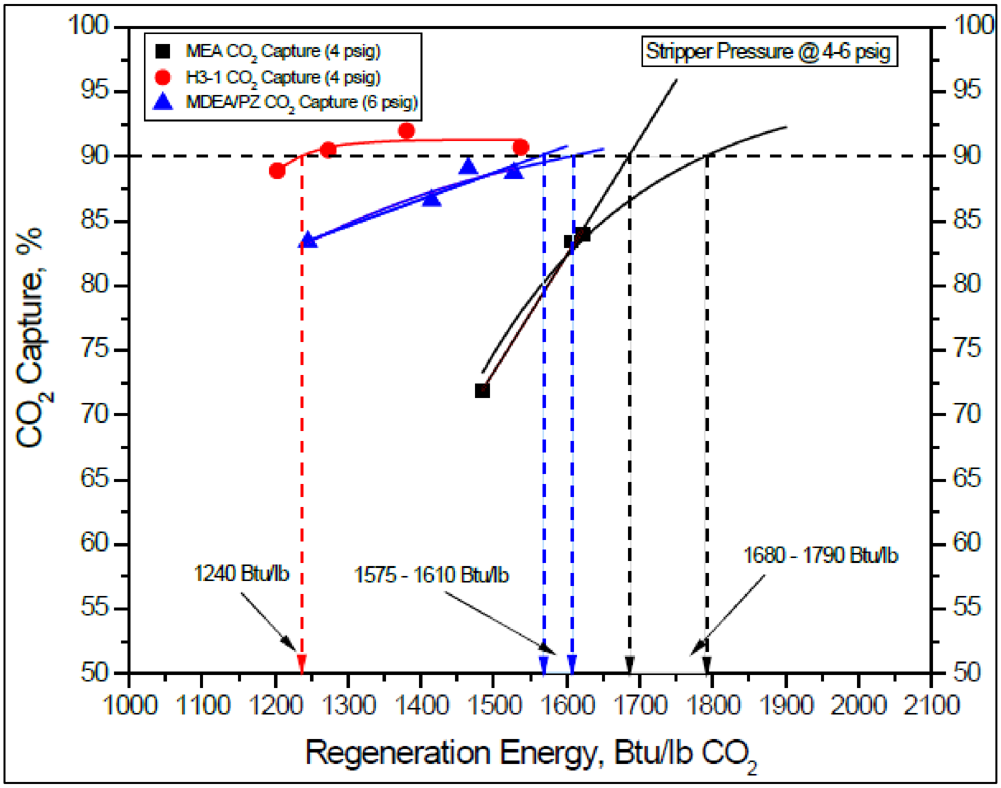


**Figure 3-8**
**Comparison of Regeneration Energy of Various Solvents**

# 4 PC Power Plant with $CO_2$ Capture

## 4.1 *Brief Process Description*

In this report, results are provided for a technical and economic analysis of the proposed UK CAER process design. The basis for the analysis was a nominal 550-MW power plant according to NETL guidelines and parameters. The objective was to conduct process modeling studies providing detailed mass and energy balances to conduct a performance assessment of the proposed process and then develop an associated equipment list based on the data. In addition, using DOE guidelines, an economic assessment of the UK CAER capture process was conducted to determine its capital and operating costs as well the levelized cost of electricty (LCOE).

## 4.2 *Key System Assumptions*

The process design was based on a nominal 550 MW (net), greenfield PC plant (a high-level schematic is shown in Figure 4-1). It was identical to that used for Cases 9 and 10 of the DOE/NETL Bituminous Baseline Report Volume 1, Rev. 2, 2010[3]:

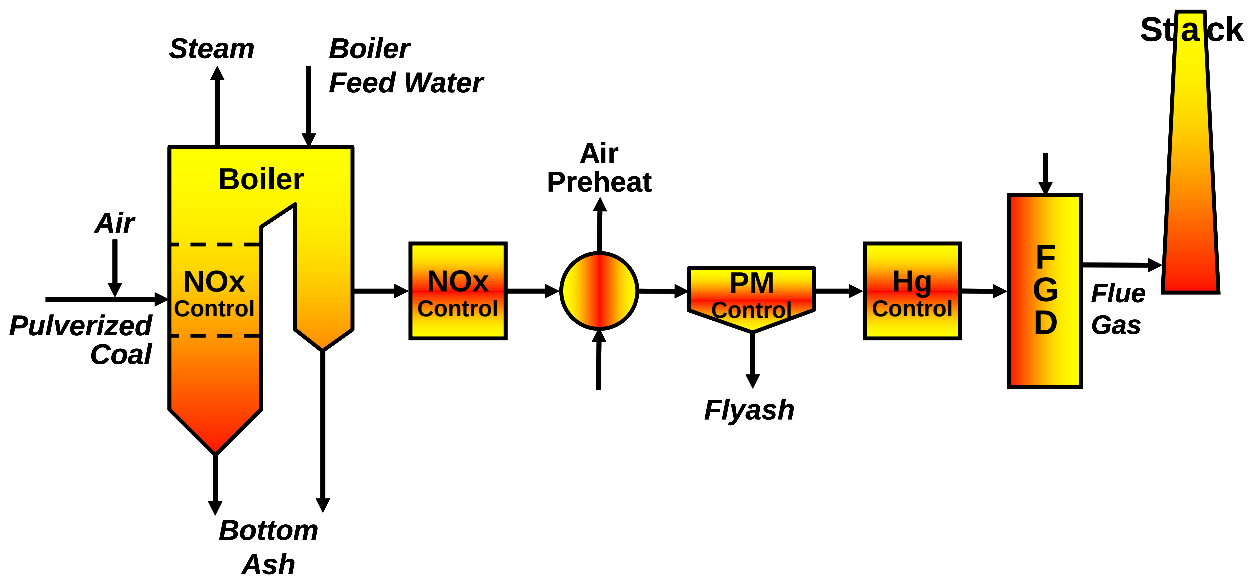


**Figure 4-1**
**Typical PC Boiler with Pollution Controls**

Assumptions for coal quality and the normal flue-gas composition from PC boiler after pollution controls (dry basis) is shown in Table 4-1.

[3] United States Department of Energy (DOE), National Energy Technology Laboratory (NETL). (2010). *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity Rev. 2*. (DOE/NETL-2010/1397).Pittsburgh, Pennsylvania: U.S. DOE.

**Table 4-1**
**Typical PC Boiler with Pollution Controls**

| Coal | Illinois No. 6 |
|---|---|
| Moisture | 11 wt% |
| Carbon | 64 |
| Hydrogen | 4.5 |
| Nitrogen | 1.2 |
| Chlorine | 0.3 |
| Sulfur | 2.5 |
| Oxygen | 6.9 |
| Ash | 9.7 |
| Mercury | 0.15 ppm (dry) |

| Dry Flue Gas | After Combustion (1) | After NOx Control (2) | After PM & Hg Control (3) | After SOx Control (4) |
|---|---|---|---|---|
| $CO_2$ | 15.8 vol% | 15.9 vol% | 15.9 vol% | 15.9 vol% |
| $N_2$+Ar | 80.8 | 81.1 | 81.1 | 81.3 |
| $O_2$ | 2.8 | 2.8 | 2.8 | 2.8 |
| NOx | 0.30 | 74 ppmv | 74 ppmv | ~80 ppmv |
| SOx | 0.21 | 0.21 | 0.21 | ~45 ppmv |
| Moisture | 8.7 vol% | 8.7 vol% | 8.7 vol% | 17 vol% |
| PM | 7,100 ppmw | 7,100 ppmw | ~9 ppmw | ~9 ppmw |
| Hg | 12 ppbw | 12 ppbw | ~1.2 ppbw | ~1.2 ppbw |

The design basis used for $CO_2$ capture and compression was:

- $CO_2$ Removal from flue gas: > 90%
- $CO_2$ Purity: > 95 vol%
- $CO_2$ Delivery Pressure and Temperature: 2,215 psia (152.7 bar)/124°F (51.1°C)
- Cost of $CO_2$ Transport, Storage & Monitoring: \$4.05/ton $CO_2$
- Steam Extraction Location: Medium to Low Pressure Steam Turbine Crossover Pipe

## 4.3 *Performance Modeling Approach and Validation*

Rate-based performance calculations were performed for more accurate results using Aspen Plus® steady state simulation software with the Ratesep plugin. Two equations of state (ELECNRTL and NRTL-RK) were used throughout the model to closely match expected results for the design based on published data. As the model results were produced, they were checked by EPRI and UK CAER against published data to ensure that they fell within the expected range. This includes estimation of secondary stripper performance, which is one innovation included in the design offered by UK CAER. The $CO_2$ capture system was modeled in a stand-alone model with the overall results merged into a power plant model to ensure overall process results convergence. Some manual iteration was required to ensure accuracy. Figure 4-2 shows the complete Aspen Plus® flowsheet for the UK CAER process.

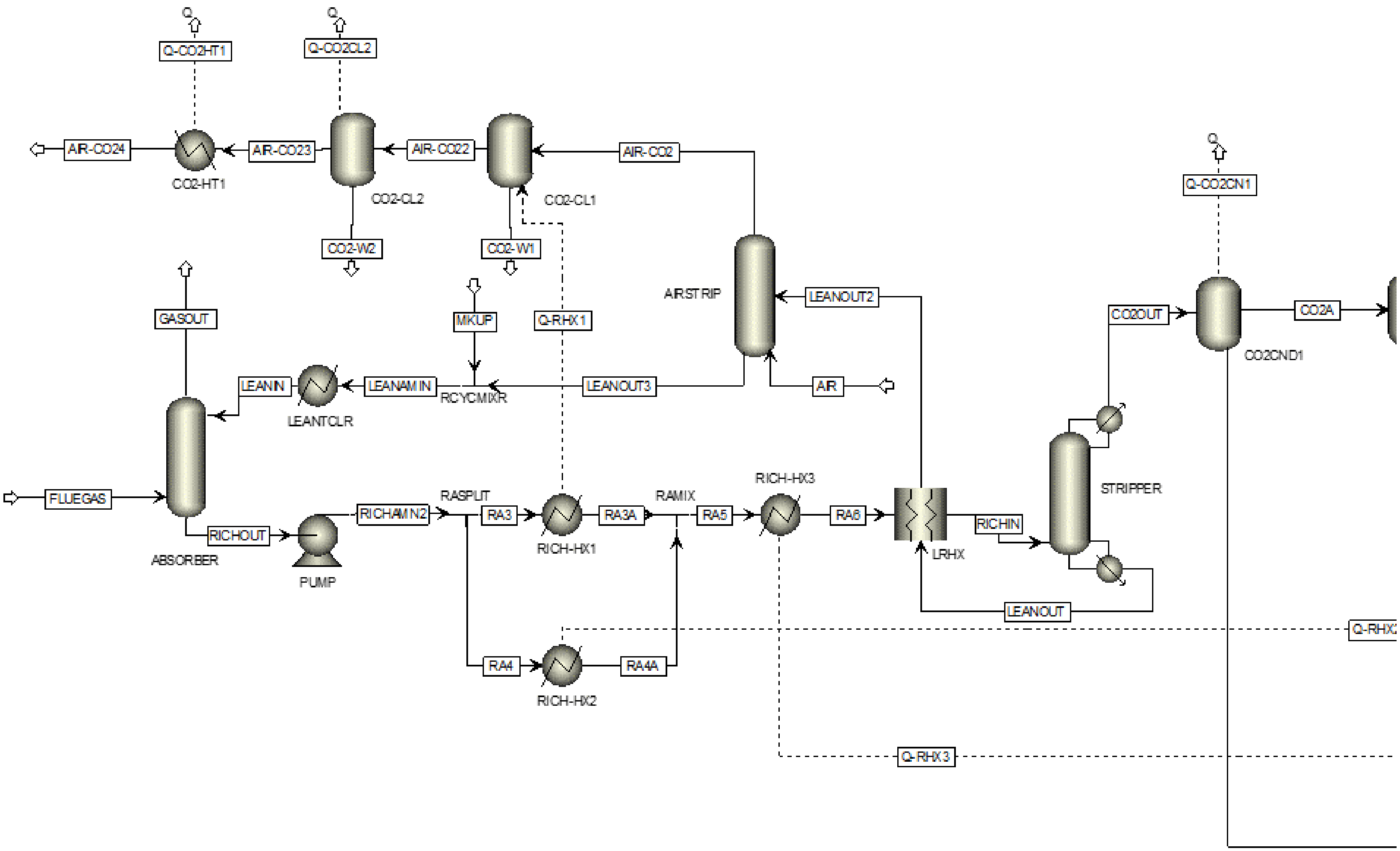


**Figure 4-2**
**Aspen Plus® Flowsheet of UK CAER Process**

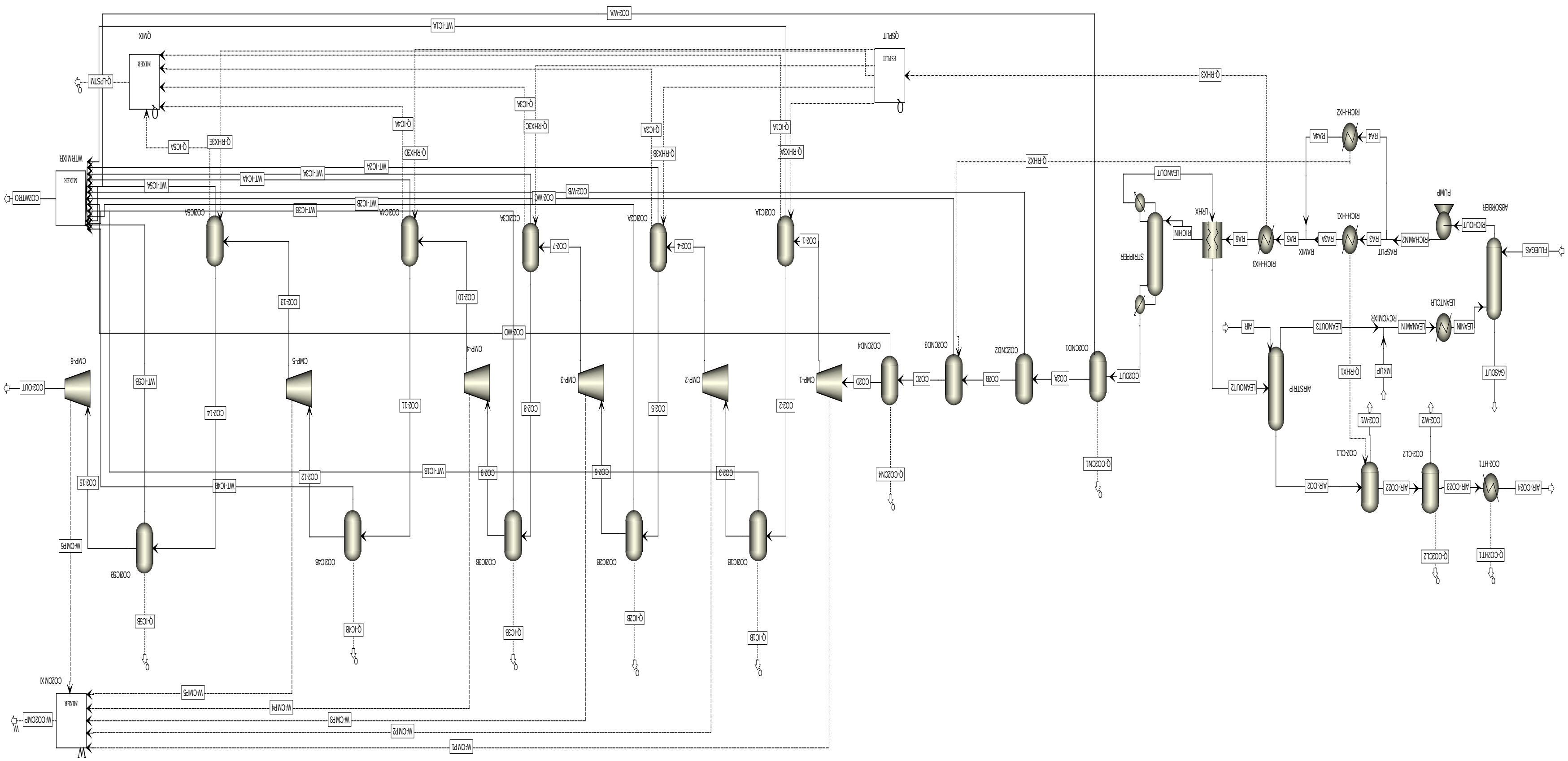

**Figure 4-3**
**Aspen Plus® Flowsheet of UK CAER Process**

During power plant performance modeling, an adjustment was made to boiler performance due to the recycle of non-combustible gas into the secondary set of burners. The estimated reduction in boiler efficiency is 0.7% (HHV basis) and is based on results observed during a related study on membrane separation of $CO_2$ from flue gas that has a recycle to the boiler.

The poposed case is retrofit with a $CO_2$ capture system using H3-1 solvent to remove 90% of the $CO_2$ present in the flue gas. The process lineup includes:

- Flue gas desulfurization unit to remove greater than 95% of the suflur.
- Direct contact cooler that uses water and soda ash ($Na_2CO_3$) with a pH less than 7.0 to further reduce sulfur content to less than 10 ppmv and the temperature to less than 100 $^oF$.
- Fan to pressurize flue gas in order to overcome the pressure drop of downstream $CO_2$ capture equipment
- Reactive absorption distillation column to remove 90% of the $CO_2$. The column includes a pumparound and cooler to help reduce solvent flowrate.
- Primary stripper using pressure drop and low pressure steam to drive off the majority of $CO_2$ from the rich solvent. The primary stripper overhead is cooled by preheating solvent and other process streams
- Secondary stripper using air to remove remainder of $CO_2$ from semi-rich solvent, which is then cooled and returned to the Secondary Air Fans upstream of the boiler

## 4.4 ***$CO_2$ Equipment Sizing Methodology, Cost Estimating, and Financial Analysis Methodology***

The following describes that approach to sizing the major equipment in the $CO_2$ capture process.

*Column Towers*

Column towers, such as the $CO_2$ Absorber and Primary Stripper, were identified as vertical towers with structured packed bed internals for gas-liquid interface. Tower diameters are based on 75% of flooding velocity. Packing height is based on various correlations for unit-heights of mass-transfer. Total column height incorporates packing height along with any of the following if appropriate: sump depth, freeboard space coupled with mist eliminators, flow redistributors. No sparing was used and the number of units in operation is based on generic rules-of-thumb for column sizes. Design conditions are a standard function of operating conditions; typically 50 psia (3.4 bar) above operating pressure and 50 $^oF$ (27.7 $^oC$) above operating temperature. All materials were specified as carbon steel except for the upper sections of the Primary Stripper which was specified as 304 stainless clad.

*Heat Exchangers*

All heat exchangers are specified as plate and frame other than the reboiler which has been identified as a kettle-type. Additional engineering and economic comparison would have to be done to evaluate if the reboiler can be specified as plate and frame. All heat exchangers were sized utilizing rate-based traditional log-mean temperature equations where the overall heat transfer coefficient was selected based on past experience and vendor quotes. Design conditions are a standard function of operating conditions; typically 50 psia (3.4 bar) above operating pressure and 50 $^oF$ (27.7 $^oC$) above operating temperature. All materials were specified as carbon steel except the Lean/Rich heat exchanger.

*Pumps*

Pumps were sized based on dynamic head values that took column heights and friction pressure drop into account. Fluid properties and head values were used to calculate required motor power via traditional calculation procedures. As noted above, design conditions are a standard function of operating conditions and all materials of construction were specified as carbon steel.

*Cooling Tower*

The basic sizing criteria for a cooling tower is the approach temperature, range and cooling duty. For this study, the cooling tower approach and range were kept the same as those used in DOE/NETL Bituminous Coal Baseline study for comparison purposes. The cooling duty was based on the total cooling requirement for the power block and process plant. GEA's proprietary cooling tower sizing program was used to estimate the cooling tower size and fan power requirement. The liquid to air ratio for the cooling tower was selected to match the value used in the DOE/NETL Baseline study. The packing of cooling tower is assumed to be film type.

It should be noted that the 8.5 °F (4.7 $^oC$) of cooling tower approach temperature used in the DOE/NETL Baseline study is very aggressive at 59 °F (15 $^oC$) DB/60%RH ambient. Although this design approach temperature is achievable, it results in a very large size cooling tower size and high capital cost. In addition, there is no performance improvement with this tight cooling tower approach because the Terminal Temperature Difference (TTD) of the steam turbine condenser is at 21°F (11.7 $^oC$), which is much higher than the typical value for a cooling tower application. From both performance and economical points of view, about 18 °F (10 $^oC$) approach temperature for the cooling tower and approximate 10 °F (5.6 $^oC$) condenser TTD are more reasonable and optimal design parameters for the power plant cooling system Cost Estimating Methodology.

### 4.4.1 **Capital Costs**

Capital costs were developed using a combination of commercial capital cost estimating software, factored equipment estimates, and WorleyParsons in-house parametric models supplemented by WorleyParsons' extensive in-house equipment cost database.

The Aspen In-Plant Cost Estimator® software was used to develop costs for most of the major equipment in the UK CAER $CO_2$ removal process. This includes reactor vessels, absorbers, and other specialized process equipment. The associated capital costs for bulk materials and installation were developed by applying a factor to the established equipment cost to derive a total installed cost. Factors vary by type of equipment, metallurgy, and complexity, and conform to WorleyParsons standards.

Costs for other equipment and balance of plant items were developed via scaling and/or parametric modelling based on key project and equipment parameters, and in accordnace with

DOE guidelines[4]. These were the primary methods used to estimate the capital costs of balance of plant equipment and systems whose costs are impacted by the change in $CO_2$ removal process from that used in Case 10 of the DOE/NETL Bituminous Coal Baseline Study[5]. Costs not impacted by the change in $CO_2$ removal process, and whose performance characteristics did not change from the DOE Study remained the same as in the updated (to January 2012 dollars) costs for Case 10.

The total capital cost estimates include the cost of equipment, freight, materials, and labor for equipment installation and erection; materials and labor for construction of buildings, supporting structures, and site improvements; engineering, construction management, and start-up services (Professional Services); and process and project contingency. The estimate excludes owner's costs and is provided as "overnight" costs; that is, escalation to period of performance is excluded.

Home office expenses and other owner's costs were based on an allocation included in the COE analysis.

### 4.4.2 **Operating and Maintenance Cost Estimates**

The operating costs and related maintenance expenses (O&M) pertain to those charges associated with operating and maintaining the plant over its expected life. These costs include:

- Operating Labor
- Maintenance – Material and Labor
- Administrative and Labor Support
- Consumables
- Waste Disposal
- Fuel
- Co-Product or By-Products credit (that is, a negative cost for any byproducts sold)

There are two components of O&M costs; fixed O&M, which is independent of power generation, and variable O&M, which is proportional to annual power generation. The fixed operating costs do not include the cost of capital. The variable O&M cost includes an estimate of fuel cost. The annual consumables costs include accounting for the annual capacity factor; that is:

Annual Cost = Hourly Consumption Rate x 8760 hours/yr x 0.85 x Unit Cost.

---

[4] United States Department of Energy (DOE), National Energy Technology Laboratory (NETL). (2013). *Quality Guidelines for Energy System Studies: Capital Cost Scaling Methodology*. (DOE/NETL-341-013113).

[5] United States Department of Energy (DOE), National Energy Technology Laboratory (NETL). (2010). *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity Rev. 2*. (DOE/NETL-2010/1397).Pittsburgh, Pennsylvania: U.S. DOE.

The operating labor cost is assumed to be the same as in the DOE/NETL Bituminous Coal Baseline study Case 10. The maintenance cost is determined based on on the basis of relationship to initial capital cost. The administrative and labor support cost is estimated based on 25 percent of the burdened operating and mantenance labor cost. The maintenance material cost is estimated as a percentage of the plant capital cost.

Consumables, waste disposal, and fuel costs are estimated based on a unit cost times the annual quantity consumed or disposed. With the exception of the solvent cost and water, the unit costs for all consumables, wastes, and fuel were assumed to be the same as in the updated (to January 2012 dollars) costs for the DOE/NETL Bituminous Coal Baseline study Case 10. In addition, the waste water treatment chemicals are expressed as a percentage of the consumed water.

Consistent with the assumptions of the DOE/NETL Bituminous Coal Baseline study, no credit or cost of disposal was included for gypsum produced by the plant flue gas desulfurization (FGD) system.

### 4.4.3 Transport Storage and Monitoring

$CO_2$ transport storage and monitoring costs were estimated based on the quantity of $CO_2$ captured and the TS&M unit cost ($ per ton of $CO_2$) used in the DOE/NETL Bituminous Coal Baseline study Case 10.

### 4.4.4 Finance Structure, Discounted Cash Flow Analysis, and Cost of Electricity

The methodology and assumptions for the financial analysis are consistent with those presented for use on updating the base cases for the DOE/NETL Bituminous Coal Baseline Report. The only difference in this costing analysis compared to the DOE/NETL Base Cases relates to the basis for the owner's costs as summarized in Table 4-2.

Plant specific inputs, both technical and cost, are taken from the capital and O&M cost estimates specific to the case being evaluated.

**Table 4-2**
**Owner's Costs Basis and Assumptions**

| **Owner's Costs** | **Basis** |
|---|---|
| Preproduction costs | |
| 6 Months all labor | Sum of Operating, Maintenance and Administrative Labor |
| 1 Month maintenance materials | Annual maintenance materials @ 85% capacity |
| 1 Month non-fuel consumables | Annual consumables @ 85% capacity |
| 1 Month waste disposal | OPEX disposal costs @ Capacity Factor (CF)=85% |
| 25% of 1 months fuel cost at 100% CF | Annual fuel costs @ 85% capacity |
| 2% TPC | TPC |
| Inventory Capital | |
| 60 day supply of fuel and consumables at 100% CF | OPEX fuel and consumables |
| Spare parts | 0.5% of TPC |
| | |
| Land | $3,000/acre, 300 acre for PC plants |
| Financing Costs | 2.7% of TPC |
| Other Owner's Costs includes:<br>• Preliminary feasibility studies, including Front-End Engineering Design (FEED) study<br>• Economic development<br>• Construction and/or improvement of roads and/or railroad spurs outside of site boundary<br>• Legal Fees<br>• Permitting costs<br>• Owner's engineering<br>• Owner's Contingency (Management reserve, funds to cover costs relating to delayed startup, fluctuations in equipment costs, unplanned labor incentives)<br>Costs not included:<br>• EPC risk premium<br>• Transmission interconnection-cost of connecting to grid beyond plant busbar<br>• Taxes on capital costs<br>• Unusual site improvements | 15% of TPC |

### 4.4.5 **Levelized Cost of Electricity**

The financial analysis uses the capital and O&M cost estimates along with global economic assumtions to determine the following financial metrics to compare the technologies:

- First-year COE breakdown including:
  - Capital
  - Fuel
  - Variable O&M
  - Fixed O&M
  - TS&M
- Thirty-year levelized COE (using DOE/NETL Power System Financial Model [PSFM])[6]
- Cost of $CO_2$ avoided
- Cost of $CO_2$ captured

The following equations were used to determine the economic metrics in the analysis. These are based on those presented in the DOE/NETL PSFM.

*Cost of Electricity*

The COE ($/MWh) is calculated using the following equation from the BB report.

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

$$COE = \frac{(CCF)(TOC) + OC_{FIX} + (CF)(OC_{VAR})}{(CF)(MWH)}$$

where:

COE = cost of electricity, revenue received by the generator ($/MWh) during the power plant's first year of operation (expressed in base-year dollars) assuming that the COE escalates thereafter at a nominal annual rate equal to the general inflation rate

[6] Worhach, P. , "Power Systems Financial Model Version 6.6," DOE/NETL-2011/1492, May 2011, available from http://www.netl.doe.gov/energy-analyses/refshelf/PubDetails.aspx?Action=View&PubId=382

CCF = capital charge factor based on financial structure and determined using the NETL PSFM. This factor takes into account the financial structure and construction period to distribute the costs of the plant operational life (unitless)

TOC = total overnight capital costs, expressed in base-year dollars ($)

$OC_{FIX}$ = the sum of all fixed annual operating costs, expressed in base-year dollars ($)

$OC_{VAR}$ = the sum of all variable operating costs (fuel and variable O&M costs), expressed in base-year dollars ($/MWh)

CF = Capacity factor (unit-less)

MWH = Total generation from facility operating for 1 year, 8760 hours (MWh).

*Levelized Cost of Electricity*

The LCOE ($/MWh) is determined using the following equation from the PSFM.

$$LCOE = L_{COE} COE$$

where:

$L_{COE}$ = COE levelization factor as defined by:

$$L_{COE} = \frac{i(1+i)^n \left(1 - \frac{(1+e_{COE})^n}{(1+i)^n}\right)}{((1+i)^n - 1)(i - e_{COE})}$$

where:

n = levelization period

i = discount rate, rate of return on equity RROE

$e_{COE}$ = COE escalation rate

*Cost of $CO_2$ Avoided ($/tonne $CO_2$)*

The cost of $CO_2$ avoided is calculated using the following equation:

$$CO_2\ Avoided\ Cost = \frac{COE_{Capture} - COE_{No\,Capture}}{CO_2\ Emissions_{No\,Capture} - CO_2\ Emissions_{Capture}}$$

where:

$COE_{Capture}$ = COE of generation facility with $CO_2$ capture ($/MWh)

$COE_{No\ Capture}$ = COE of generation facility without $CO_2$ capture ($/MWh)

$CO_2$ $Emissions_{Capture}$ = $CO_2$ emissions from generation facility with $CO_2$ capture (tonne $CO_2$/MWh)

$CO_2$ $Emissions_{No\ Capture}$ = $CO_2$ emissions from generation facility without $CO_2$ capture (tonne $CO_2$/MWh)

*Cost of $CO_2$ Captured*

Cost of $CO_2$ captured ($/tonne $CO_2$) is calculated using the following equation:

$$CO_2\ Capture\ Cost = \frac{COE_{Capture} - COE_{No\ Capture}}{CO_2\ Captured_{Per\ Net\ Output}}$$

where:

$CO_2$ $Captured_{Per\ Net\ Output}$ = amount of $CO_2$ captured per unit of generation (tonne $CO_2$/MWh)

The economic analysis assumptions were taken from the original DOE/NETL report. The global assumptions are summarized in Table 4-3. The financial structure for low risk (no-capture) and high risk (capture) projects and the resulting factors are summarized in Table 4-4.

**Table 4-3**
**Global Economic Assumptions**

| Parameter | Value |
|---|---|
| TAXES | |
| Income Tax Rate | 38% (Effective: 34% Federal, 6% State) |
| Capital Depreciation | 20 years, 150% declining balance |
| Investment Tax Credit | 0% |
| Tax Holiday | 0 years |
| CONTRACTING AND FINANCING TERMS | |
| Contracting Strategy | Engineering Procurement Construction 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 | 15 years |
| Grace Period on Debt Repayment | 0 years |
| Debt Reserve Fund | None |
| ANALYSIS TIME PERIODS | |
| Capital Expenditure Period | 5 years |
| Operational Period | 30 years |
| Economic Analysis Period (used for IRROE) | 35 years (capital expenditure period plus operation period) |
| Treatment of Capital Costs | |
| Capital Cost Escalation During Capital Expenditure Period (nominal annual rate) | 3.6%[1] |
| Distribution of Total Overnight Capital over the Capital Expenditure Period (before escalation) | 10%, 30%, 25%, 20%, 15% |
| Working Capital | Zero for all parameters |
| % of Total Overnight Capital that is Depreciated | 100% (this assumption introduces a very small error even in a substantial amount of TOC is actually non-depreciable |
| ESCALATION OD OPERATING REVENUES AND COSTS | |
| Escalation of COE (Revenue), O&M Costs, and Fuel Costs (nominal annual rate) | 3%[2] |

Notes:

1. The nominal average rate of 3.6 percent is assumed for escalation of capital costs during construction. This rate is equivalent to the nominal average annual escalation rate for process plant construction costs between 1947 and 2008 according to the *Chemical Engineering* Plant Cost Index.
2. An average annual inflation of 3.0% is assumed. This rate is equivalent to the average annual escalation rated between 1947 and 2008 for the US Department of Labor’s Producer Price Index for Finished Goods, the so-called “headline” index of the various Producer Price Indices.

**Table 4-4**
**Financial Structure for Investor Owned Utility**

| Finance Structure | High Risk $CO_2$ Capture Cases | | Low Risk Non – $CO_2$ Capture Cases | |
|---|---|---|---|---|
| | Debt | Equity | Debt | Equity |
| Percent of Total | 45% | 50% | 50% | 50% |
| Current (Nominal) Dollar Cost | 5.50% | 12.00% | 4.50% | 12.00% |
| Weighted Current (Nominal) Cost | 2.48% | 6.60% | 2.25% | 6.00% |
| Weighted Current (Nominal) Cost Combined | 9.08% | | 8.25% | |
| After Tax Weighted Cost of Capital | 8.13% | | 7.39% | |
| Capital Charge Factor | 0.124 | | 0.116 | |
| Levelization Factor | 1.268 | | 1.268 | |

### 4.5 *Update of the DOE/NETL Base Cases*

The capital costs, O&M costs, and the cost of electricity (COE) estimates for Case 9 and Case 10 of the DOE/NETL Bituminous Baseline Report Volume 1, Rev. 2, 2010[7] were updated from June 2007 year dollar basis to January 2012 year dollar basis using the methodolgy described in Section 4.5.

Case 9 is a 550-MWe net sub-critical pulverized coal power plant without $CO_2$ capture and utilization and sequestration (CCUS) and Case 10 is a 550-MWe net sub-critical pulverized coal power plant with CCUS based on the Fluor Economine FG Plus $CO_2$ removal technology. The purpose of the cost update is to provide a basis for comparison with the cost developed for the commercial-scale pulverized coal power plant with post-combustion $CO_2$ removal based on the UK CAER $CO_2$ removal process.

The bituminous baseline cases were escalated from a cost basis date June 2007 to a cost basis date of January 2012 using information derived from a number of sources. These include published indices such as the Chemical Engineering (CE) Plant Cost Index, recent vendor quotations for similar equipment and materials, monthly mill pricing updates for structural steel, cost trending input from vendors, published wage rate information, and WorleyParsons in-house cost data base. In general, the CE index tends to trend slightly lower than costs developed using other sources. This can be due to several reasons including specific equipment design/sizing parameters and market conditions. In particular, the index value for construction labor and

[7] United States Department of Energy (DOE), National Energy Technology Laboratory (NETL). (2010). *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity Rev. 2*. (DOE/NETL-2010/1397).Pittsburgh, Pennsylvania: U.S. DOE.

engineering services was not used because it almost always trends at a much lower rate than other sources employed.

Equipment accounts that don't follow the general cost escalation trend include consumables, that generally are escalated using the index for producer prices for industrial chemicals (per HIS Global Insight, Inc. and reported in Chemical Engineering), and $CO_2$ compressor and main power transformer costs that were re-calibrated using more recent quotes in additional to the general cost of escalation.

The coal price was estimated based on the NETL Quality Guidelines for Energy System Studies[8].

Plant specific inputs, both technical and cost, are listed in Table 4-5. The operational parameters for Case 9 and Case 10 are taken from the DOE/NETL report. The cost data for Case 9 and Case 10 from were escalated from 2007$ to 2012$ for this study.

**Table 4-5**
**Plant Specific Operational and Cost Inputs**

| OPERATING PARAMETERS | Case 9 | Case 10 |
|---|---|---|
| **Net Plant Output** | 550.0 | 550.0 |
| **Net Plant Heat Rate, Btu/kWh (kJ/kWh)** | 9,277 (9,787) | 13,046 (13,764) |
| **$CO_2$ Captured, lb/MWh (kg/MWh)** | 0 | 2,390 (1,084) |
| **$CO_2$ Emitted, lb/MWh net (kg/MWh net)** | 1,888 (856) | 266 (221) |
| **COSTS** | | |
| **Total Plant Costs (2012$)** | 2,000 | 3,689 |
| **Total Overnight Cost (2012$/kw)** | 2,477 | 4,548 |
| Bare Erected Cost | 1,629 | 2,836 |
| Home Office Expenses | 147 | 257 |
| Project Contingency | 224 | 465 |
| Process contingency | 0 | 131 |
| Owners Costs | 477 | 860 |
| **Total Overnight Cost (2012$x1,000)** | 1,362,516 | 2,501,457 |
| **Total As Spent Capital (2012$)** | 2809 | 5185 |
| **Annual Fixed Operating Costs ($/yr)** | 39,039,238 | 66,263,173 |
| **Variable Operating Costs ($/MWh)** | 7.63 | 13.35 |
| **Fuel** | | |
| **Coal Price ($/ton)** | 69.00 | |

[8] U. S. Department of Energy National Energy Technology Laboratory (NETL), *Quality Guideline for Energy System Studies: Fuel Prices for Selected Feedstocks in NETL Studies*, DOE/NETL-341/121211, August 2011.

### 4.5.1 **Results for the Update of the DOE Base Cases**

Economic metrics determined during this analysis are listed in Table 4-6. The percent increase in the COE for Case 10 compared to the non-capture configuration in Case 9 is 80%. The COE and a breakdown of the COE are graphically compared in Figure 4-3.

**Table 4-6**
**Economic Metrics**

| | Case 9 | Case 10 |
|---|---|---|
| **COE($/MWh, 2012$)** | **83.19** | **149.65** |
| $CO_2$ TS&M Costs | | 5.80 |
| Fuel Costs | 27.43 | 38.57 |
| Variable Costs | 7.63 | 13.35 |
| Fixed Costs | 9.53 | 16.18 |
| Capital Costs | 38.59 | 75.75 |
| **LCOE (2012$/MWh)** | 105.36 | 189.59 |
| **Cost of $CO_2$ Captured ($/tonne $CO_2$)** | | 61.31 |
| **Cost of $CO_2$ Avoided ($/tonne $CO_2$)** | | 90.35 |

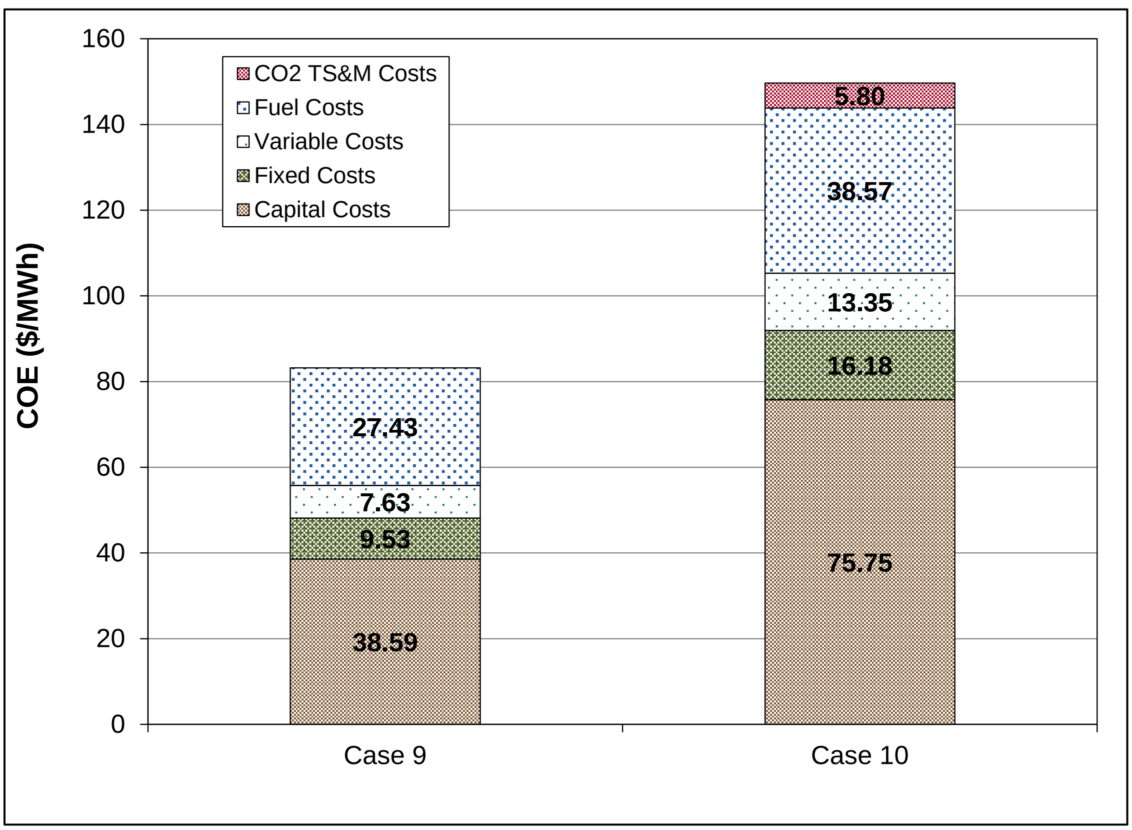


**Figure 4-4**
**Comparison and Breakdown of COE for Case 9 and Case 10**

The summary and detailed updated capital costs for Case 9 are shown in the Appendix in Table A-3 and Table A-4, and the O&M cost is shown in Table A-5. The summary and detailed updated capital costs for Case 10 are also shown in the Appendix in Table A-6 and Table A-7, and the O&M cost is shown in Table A-8.

# 5 Performance Results

Figure 5-1 presents the high-level block flow diagram showing all of the principal systems in the power plant, including the $CO_2$ capture system. Figure 5-2 presents the steam cycle heat and mass balance diagram, with the tabulated data summarized in Table 5-1.

## 5.1 *UK CAER Process + MEA Case*

### 5.1.1 Performance Results

The stream numbers given at the inlet and outlets for each system correspond to the stream data given in Table 5-1, which includes composition (on a volumetric basis), flowrate, and thermodynamic state conditions (temperature, pressure, and density) for each stream. A more detailed look at the steam cycle is given in a heat and mass balance chart in Figure 5-1.

The high-level performance results for the UK CAER process + MEA case are shown in Table 5-2. In summary, the net efficiency of the UK CAER integrated PC power plant with $CO_2$ capture changes from 26.2% with the Reference Case 10 plant in 2010 revised DOE/NETL baseline report to 27.6% for the MEA options considered. Simularly, the UK CAER process + MEA case lowers energy consumption for $CO_2$ capture to 1,340 Btu/lb-$CO_2$ captured, as compared to 1,540 Btu/lb-$CO_2$ in the Case 10. The study also shows 38.1% less heat rejection associated with carbon capture system, with a decrease from 3,398 MBtu/hr (Case 10) to 2,104 MBtu/hr. Modeling outputs show that the UK CAER process can achieve 2-5 $^{o}$C lower cooling water temperatures than conventional cooling tower water for ambient conditions common to the midwest and other regions.

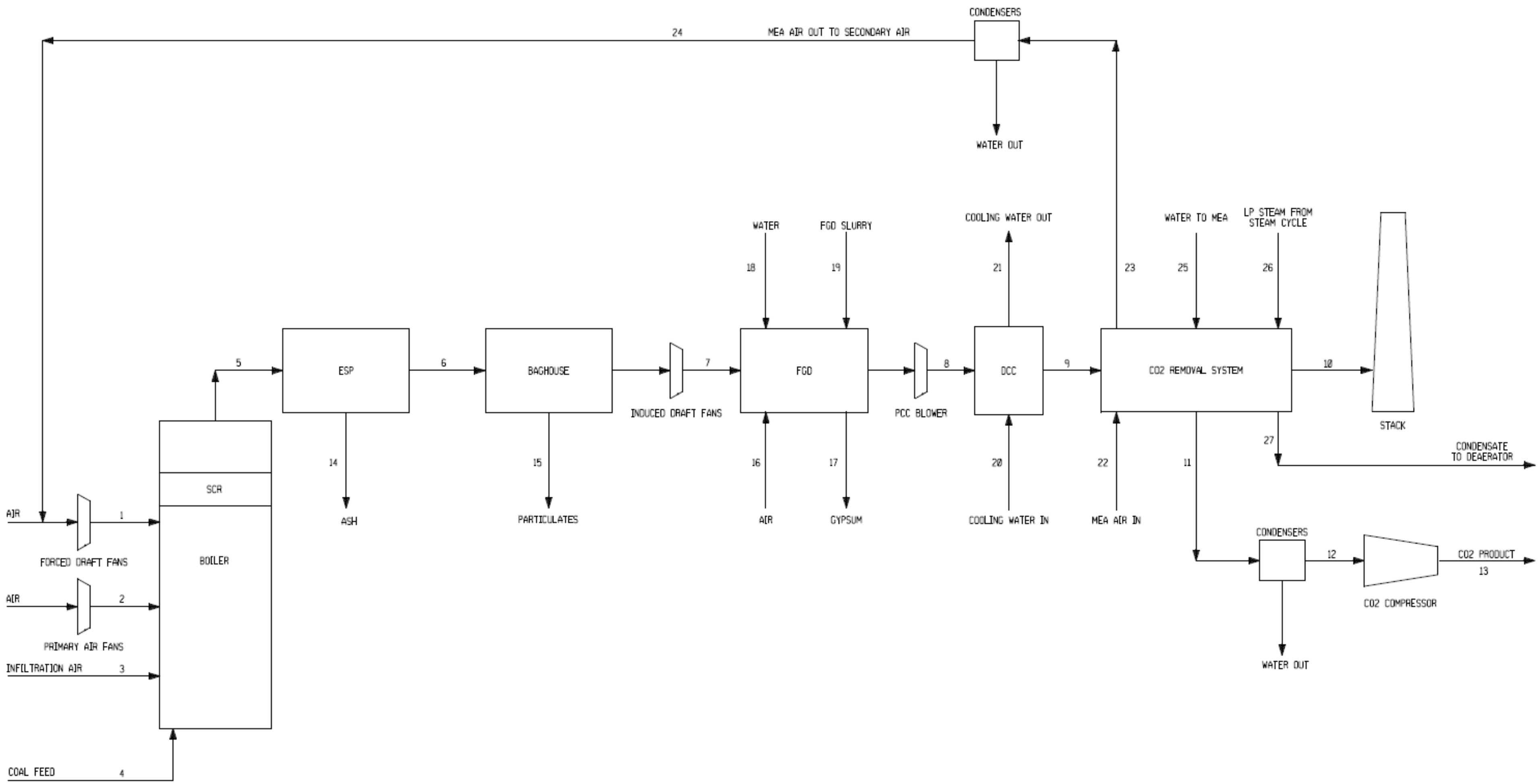


**Figure 5-1**
**High-Level Block Flow Diagram for the MEA Case**

**Table 5-1**
**High-Level Stream Conditions for the MEA Case (numbers match with those in Figure 5-1)**

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| V-L Mole Fraction | | | | | | | | | | | | | | |
| Ar | 0.009 | 0.009 | 0.009 | 0.000 | 0.008 | 0.008 | 0.008 | 0.008 | 0.009 | 0.009 | 0.000 | 0.000 | 0.000 | 0.000 |
| CO2 | 0.012 | 0.000 | 0.000 | 0.000 | 0.154 | 0.154 | 0.154 | 0.145 | 0.166 | 0.017 | 0.550 | 0.962 | 0.997 | 0.000 |
| H2 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| H2O | 0.026 | 0.010 | 0.010 | 0.000 | 0.099 | 0.099 | 0.099 | 0.155 | 0.034 | 0.153 | 0.449 | 0.037 | 0.002 | 0.000 |
| N2 | 0.752 | 0.773 | 0.773 | 0.000 | 0.717 | 0.717 | 0.717 | 0.673 | 0.769 | 0.798 | 0.000 | 0.000 | 0.000 | 0.000 |
| O2 | 0.202 | 0.207 | 0.207 | 0.000 | 0.020 | 0.020 | 0.020 | 0.019 | 0.022 | 0.023 | 0.000 | 0.000 | 0.000 | 0.000 |
| SO2 | 0.000 | 0.000 | 0.000 | 0.000 | 0.002 | 0.002 | 0.002 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| Total | 1.000 | 1.000 | 1.000 | 0.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 0.000 |
| | | | | | | | | | | | | | | |
| V-L Flowrate (lbmol/hr) | 158,846 | 49,614 | 3,589 | 0 | 224,369 | 224,369 | 224,369 | 242,053 | 211,732 | 204,196 | 53,583 | 30,636 | 29,553 | 0 |
| V-L Flowrate (kgmol/hr) | 72,039 | 22,501 | 1,628 | 0 | 101,755 | 101,755 | 101,755 | 109,775 | 96,024 | 92,606 | 24,301 | 13,894 | 13,403 | 0 |
| V-L Flowrate (lb/hr) | 4,583,690 | 1,431,710 | 103,571 | 0 | 6,674,330 | 6,674,330 | 6,674,330 | 7,007,820 | 6,462,100 | 5,507,740 | 1,732,050 | 1,318,380 | 1,298,860 | 0 |
| V-L Flowrate (kg/hr) | 2,079,125 | 649,412 | 46,979 | 0 | 3,027,423 | 3,027,423 | 3,027,423 | 3,178,691 | 2,931,157 | 2,498,267 | 785,644 | 598,007 | 589,153 | 0 |
| Solids Flowrate (lb/hr) | 0 | 0 | 0 | 614,994 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 11,927 |
| Solids Flowrate (kg/hr) | 0 | 0 | 0 | 278,956 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 5,410 |
| | | | | | | | | | | | | | | |
| Temperature (°F) | 85 | 78 | 59 | 59 | 270 | 270 | 292 | 168 | 90 | 134 | 221 | 100 | 206 | 270 |
| Temperature (°C) | 29.4 | 25.6 | 15.0 | 15.0 | 132.2 | 132.2 | 144.4 | 75.6 | 32.2 | 56.7 | 105.0 | 37.8 | 96.7 | 132.2 |
| Pressure (psia) | 15.3 | 16.1 | 14.7 | 14.7 | 14.4 | 14.4 | 15.4 | 17.4 | 15.7 | 14.7 | 27.3 | 25.8 | 2,214.70 | 14.4 |
| Pressure (bar) | 1.1 | 1.1 | 1.0 | 1.0 | 1.0 | 1.0 | 1.1 | 1.2 | 1.1 | 1.0 | 1.9 | 1.8 | 152.7 | 1.0 |
| Density (lb/ft3) | 0.076 | 0.081 | 0.076 | --- | 0.055 | 0.055 | 0.057 | 0.075 | 0.081 | 0.062 | 0.122 | 0.186 | 21.541 | --- |
| Density (kg/m3) | 1.216 | 1.296 | 1.216 | --- | 0.88 | 0.88 | 0.912 | 1.2 | 1.296 | 0.992 | 1.952 | 2.976 | 344.656 | --- |

**Table 5-1**
**High-Level Stream Conditions for the MEA Case (numbers match with those in Figure 5-1) (cont.)**

| | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 | 27 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| V-L Mole Fraction | | | | | | | | | | | Not Used | | |
| Ar | 0.000 | 0.009 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.009 | 0.005 | 0.008 | | 0.000 | 0.000 |
| CO2 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.017 | 0.028 | | 0.000 | 0.000 |
| H2 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | | 0.000 | 0.000 |
| H2O | 0.000 | 0.010 | 0.000 | 1.000 | 1.000 | 0.999 | 0.999 | 0.053 | 0.420 | 0.048 | | 1.000 | 1.000 |
| N2 | 0.000 | 0.773 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.740 | 0.440 | 0.722 | | 0.000 | 0.000 |
| O2 | 0.000 | 0.207 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.198 | 0.118 | 0.194 | | 0.000 | 0.000 |
| SO2 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | | 0.000 | 0.000 |
| Total | 0.000 | 1.000 | 0.000 | 1.000 | 1.000 | 0.999 | 0.999 | 1.000 | 1.000 | 1.000 | | 1.000 | 1.000 |
| | | | | | | | | | | | | | |
| V-L Flowrate (lbmol/hr) | 0 | 2,550 | 0 | 8,329 | 7,983 | 532,916 | 563,227 | 67,510 | 118,496 | 66,643 | | 93,347 | 93,347 |
| V-L Flowrate (kgmol/hr) | 0 | 1,156 | 0 | 3,777 | 3,620 | 241,685 | 255,432 | 30,617 | 53,740 | 30,224 | | 42,334 | 42,334 |
| V-L Flowrate (lb/hr) | 0 | 73,571 | 0 | 150,057 | 143,821 | 9,612,340 | 10,158,100 | 1,948,130 | 2,917,330 | 1,923,000 | | 1,681,680 | 1,681,670 |
| V-L Flowrate (kg/hr) | 0 | 33,371 | 0 | 68,065 | 65,236 | 4,360,081 | 4,607,633 | 883,506 | 1,323,278 | 872,257 | | 762,797 | 762,792 |
| Solids Flowrate (lb/hr) | 47,708 | 0 | 96,194 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | 0 | 0 |
| Solids Flowrate (kg/hr) | 21,640 | 0 | 43,633 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | 0 | 0 |
| | | | | | | | | | | | | | |
| Temperature (°F) | 270 | 64 | 138 | 59 | 59 | 75 | 75 | 80 | 181 | 100 | | 551 | 310 |
| Temperature (°C) | 132.2 | 17.8 | 58.9 | 15.0 | 15.0 | 23.9 | 23.9 | 26.7 | 82.8 | 37.8 | | 288.3 | 154.4 |
| Pressure (psia) | 14.2 | 15 | 14.9 | 15 | 15 | 18 | 20 | 16.5 | 15.2 | 14.7 | | 78 | 130 |
| Pressure (bar) | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.2 | 1.4 | 1.1 | 1.0 | 1.0 | | 5.4 | 9.0 |
| Density (lb/ft3) | --- | 0.077 | --- | 47.503 | 47.503 | 47.16 | 47.165 | 0.082 | 0.055 | 0.071 | | 0.131 | 56.97 |
| Density (kg/m3) | --- | 1.232 | --- | --- | 760.048 | 754.56 | 754.64 | 1.312 | 0.88 | 1.136 | | 2.096 | 911.52 |

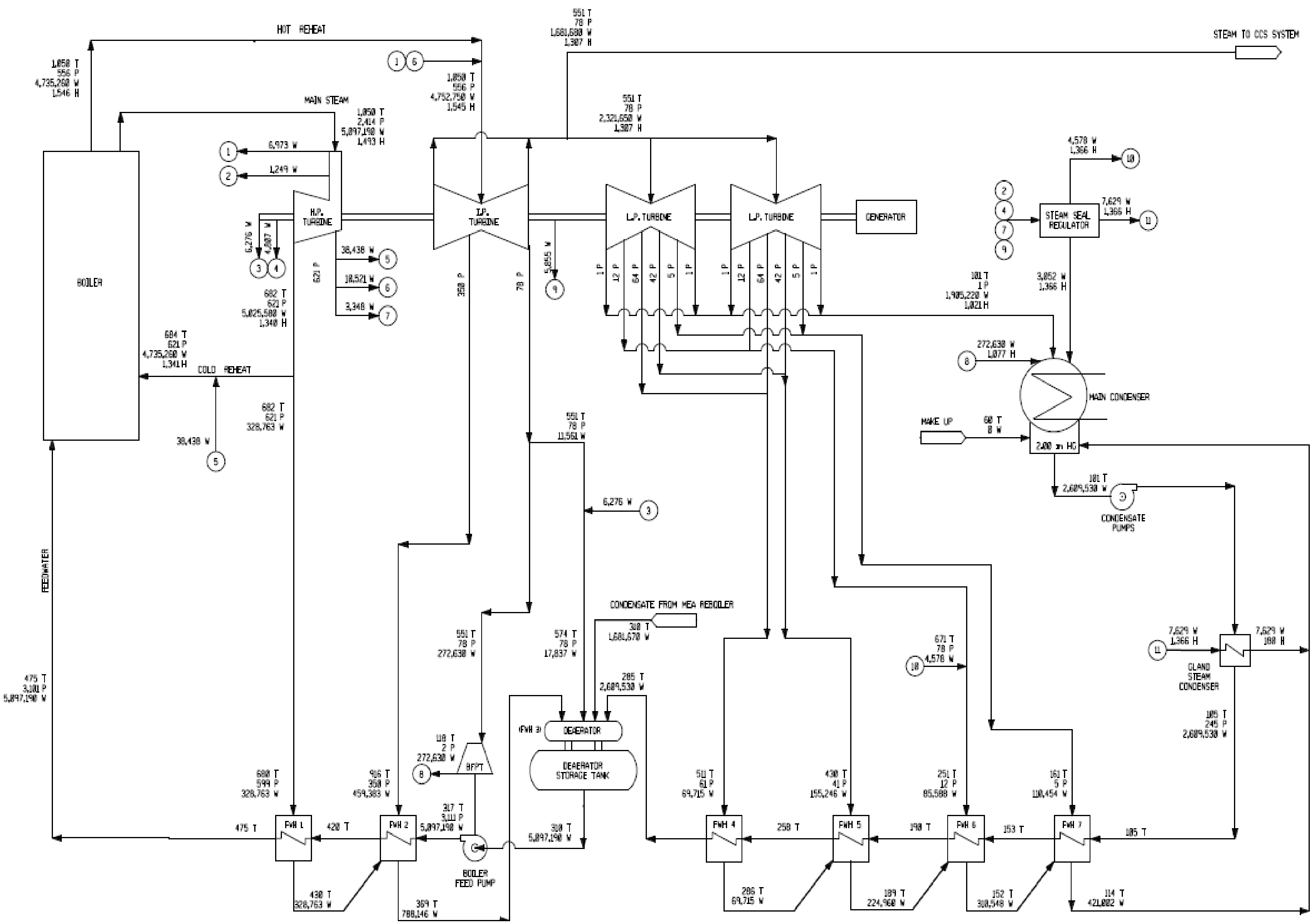

**Figure 5-2**
**Heat and Mass Balance for the Steam Cycle for the MEA Case**

**Table 5-2**
**MEA Performance Summary**

| POWER SUMMARY (Gross Power at Generator Terminals kWe) | |
|---|---|
| Case | UK CAER + MEA 2020 Case |
| Steam Turbine Power | 699,000 |
| TOTAL (STEAM TURBINE) POWER, kWe | 699,000 |
| AUXILIARY LOAD SUMMARY, kWe | |
| Coal Handling & Conveying | 540 |
| Pulverizers | 4,180 |
| Sorbent Handling & Reagent Preparation | 1,370 |
| Ash Handling | 800 |
| Primary Air Fans | 1,980 |
| Forced Draft Fans | 2,890 |
| Induced Draft Fans | 11,410 |
| SCR | 70 |
| Baghouse | 100 |
| Wet FGD | 4,470 |
| $CO_2$ Removal System Auxiliaries | 22,122 |
| $CO_2$ Compression | 48,930 |
| Miscellaneous Balance of Plant[2,3] | 2,000 |
| Steam Turbine Auxiliaries | 400 |
| Condensate Pumps | 750 |
| Circulating Water Pump | 8,830 |
| Ground Water Pumps | 720 |
| Cooling Tower Fans | 4,590 |
| Transformer Losses | 2,440 |
| TOTAL AUXILIARIES, kWe | 118,142 |
| NET POWER, kWe | 580,858 |
| Net Plant Efficiency (HHV) | 27.6% |
| Net Plant Heat Rate, Btu/kWhr HHV (kJ/kWhr) | 12,352 (13,032) |
| Net Plant Efficiency (LHV) | 28.6% |
| Net Plant Heat Rate, Btu/kWhr LHV (kJ/kWhr) | 11,913 (12,569) |
| COOLING TOWER DUTY, MBtu/hr (GJ/hr) | 4,200 (4,431) |
| Consumables | |
| As-Received Coal Feed, lb/hr (kg/hr) | 614,994 (278,956) |
| Limestone Sorbent Feed, lb/hr (kg/hr) | 62,235 (28,229) |

1. *HHV of As-Received Illinois #6 coal is 11,666 Btu/lb (27,135 kJ/kg)*
2. *Boiler feed pumps are turbine driven*
3. *Includes plant control systems, lighting, HVAC, and miscellaneous low-voltage loads*

### 5.1.2 **Major Equipment List**

The major equipment list for the UK CAER process + MEA Case is provided in Table 5-3 through Table 5-14, with information broken down into the following plant sub-sytems:

- Fuel and Sorbent Handling
- Coal and Sorbent Preparation and Feed
- Feedwater and Miscellaneous Systems and Equipment
- Boiler And Accessories
- Flue Gas Cleanup
- $CO_2$ Capture (high-level)
- HRSG, Ducting,and Stack
- Steam Turbine Generator and Auxiliaries
- Cooling Water System
- Ash/Spent Sorbent Recovery and Handling
- Accessory Electric Plant
- Instrumentation and Control

In each table, a label for the piece of equipment is given, a brief decription, the type if applicable, the design condition for it, the quantity used in the plant, and the number of spares, if any.

**Table 5-3**
**Fuel and Sorbent Handling Equipment List**

| Equipment No. | Description | Type | Design Condition | Operating Qty. | Spares |
|---|---|---|---|---|---|
| 1 | Bottom Trestle Dumper and Receiving Hoppers | N/A | 181 tonne (200 ton) | 2 | 0 |
| 2 | Feeder | Belt | 572 tonne/hr (630 tph) | 2 | 0 |
| 3 | Conveyor No. 1 | Belt | 1,134 tonne/hr (1,250 tph) | 1 | 0 |
| 4 | Transfer Tower No. 1 | Enclosed | N/A | 1 | 0 |
| 5 | Conveyor No. 2 | Belt | 1,134 tonne/hr (1,250 tph) | 1 | 0 |
| 6 | As-Received Coal Sampling System | Two-stage | N/A | 1 | 0 |
| 7 | Stacker/Reclaimer | Traveling, linear | 1,134 tonne/hr (1,250 tph) | 1 | 0 |
| 8 | Reclaim Hopper | N/A | 54 tonne (60 ton) | 2 | 1 |
| 9 | Feeder | Vibratory | 227 tonne/hr (250 tph) | 2 | 1 |
| 10 | Conveyor No. 3 | Belt w/ tripper | 463 tonne/hr (510 tph) | 1 | 0 |
| 11 | Crusher Tower | N/A | N/A | 1 | 0 |
| 12 | Coal Surge Bin w/ Vent Filter | Dual outlet | 227 tonne (250 ton) | 2 | 0 |
| 13 | Crusher | Impactor reduction | 8 cm x 0 - 3 cm x 0<br>(3 in x 0 - 1-1/4 in x 0) | 2 | 0 |
| 14 | As-Fired Coal Sampling System | Swing hammer | N/A | 1 | 1 |
| 15 | Conveyor No. 4 | Belt w/tripper | 463 tonne/hr (510 tph) | 1 | 0 |
| 16 | Transfer Tower No. 2 | Enclosed | N/A | 1 | 0 |
| 17 | Conveyor No. 5 | Belt w/ tripper | 463 tonne/hr (510 tph) | 1 | 0 |
| 18 | Coal Silo w/ Vent Filter and Slide Gates | Field erected | 998 tonne (1,100 ton) | 3 | 0 |
| 19 | Limestone Truck Unloading Hopper | N/A | 36 tonne (40 ton) | 1 | 0 |
| 20 | Limestone Feeder | Belt | 118 tonne/hr (130 tph) | 1 | 0 |
| 21 | Limestone Conveyor No. L1 | Belt | 118 tonne/hr (130 tph) | 1 | 0 |
| 22 | Limestone Reclaim Hopper | N/A | 27 tonne (30 ton) | 1 | 0 |
| 23 | Limestone Reclaim Feeder | Belt | 91 tonne/hr (100 tph) | 1 | 0 |
| 24 | Limestone Conveyor No. L2 | Belt | 91 tonne/hr (100 tph) | 1 | 0 |
| 25 | Limestone Day Bin | w/ actuator | 372 tonne (410 ton) | 2 | 0 |

**Table 5-4**
**Coal and Sorbent Preparation and Feed Equipment List**

| Equipment No. | Description | Type | Design Condition | Operating Qty. | Spares |
|---|---|---|---|---|---|
| 1 | Coal Feeder | Gravimetric | 54 tonne/hr (60 tph) | 6 | 0 |
| 2 | Coal Pulverizer | Ball type or equivalent | 54 tonne/hr (60 tph) | 6 | 0 |
| 3 | Limestone Weigh Feeder | Gravimetric | 31 tonne/hr (34 tph) | 1 | 1 |
| 4 | Limestone Ball Mill | Rotary | 31 tonne/hr (34 tph) | 1 | 1 |
| 5 | Limestone Mill Slurry Tank with Agitator | N/A | 121,133 liters (32,000 gal) | 1 | 1 |
| 6 | Limestone Mill Recycle Pumps | Horizontal centrifugal | 2,006 lpm @ 12m $H_2O$ (530 gpm @ 40 ft $H_2O$) | 1 | 1 |
| 7 | Hydroclone Classifier | 4 active cyclones in a 5 cyclone bank | 492 lpm (130 gpm) per cyclone | 1 | 1 |
| 8 | Distribution Box | 2-way | N/A | 1 | 1 |
| 9 | Limestone Slurry Storage Tank with Agitator | Field erected | 673,803 liters (178,000 gal) | 1 | 1 |
| 10 | Limestone Slurry Feed Pumps | Horizontal centrifugal | 1,401 lpm @ 9m H2O (370 gpm @ 30 ft H2O) | 1 | 1 |

**Table 5-5**
**Feedwater and Miscellaneous Systems and Equipment List**

| Equipment No. | Description | Type | Design Condition | Operating Qty. | Spares |
|---|---|---|---|---|---|
| 1 | Demineralized Water Storage Tank | Vertical, cylindrical, outdoor | 1,563,375 liters (413,000 gal) | 2 | 0 |
| 2 | Condensate Pumps | Vertical canned | 21,735 lpm @ 213 m $H_2O$ (5,750 gpm @ 700 ft $H_2O$) | 1 | 1 |
| 3 | Deaerator and Storage Tank | Horizontal spray type | 2,543,335 kg/hr (5,607,000 lb/hr), | 1 | 0 |
| 4 | Boiler Feed Pump/Turbine | Barrel type, multi-stage, centrifugal | 43,532 lpm @ 2,591 m $H_2O$ (11,500 gpm @ 8,500 ft $H_2O$) | 1 | 1 |
| 5 | Startup Boiler Feed Pump, Electric Motor Driven | Barrel type, multi-stage, centrifugal | 12,870 lpm @ 2,591 m $H_2O$ (3,400 gpm @ 8,500 ft $H_2O$) | 1 | 0 |
| 6 | LP Feedwater Heater 1A/1B | Horizontal U-tube | 650,900 kg/hr (1,435,000 lb/hr) | 2 | 0 |
| 7 | LP Feedwater Heater 2A/2B | Horizontal U-tube | 650,900 kg/hr (1,435,000 lb/hr) | 2 | 0 |
| 8 | LP Feedwater Heater 3A/3B | Horizontal U-tube | 650,900 kg/hr (1,435,000 lb/hr) | 2 | 0 |
| 9 | LP Feedwater Heater 4A/4B | Horizontal U-tube | 650,900 kg/hr (1,435,000 lb/hr) | 2 | 0 |
| 10 | HP Feedwater Heater 6 | Horizontal U-tube | 2,543,335 kg/hr (5,607,000 lb/hr) | 1 | 0 |
| 11 | HP Feedwater Heater 7 | Horizontal U-tube | 2,543,335 kg/hr (5,607,000 lb/hr) | 1 | 0 |
| 12 | Auxiliary Boiler | Shop fabricated, water tube | 18,144 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F) | 1 | 0 |
| 13 | Fuel Oil System | No. 2 fuel oil for light off | 1,135,624 liter (300,000 gal) | 1 | 0 |
| 14 | Service Air Compressors | Flooded Screw | 28 $m^3$/min @ 0.7 MPa (1,000 scfm @ 100 psig) | 2 | 1 |
| 15 | Instrument Air Dryers | Duplex, regenerative | 28 $m^3$/min (1,000 scfm) | 2 | 1 |
| 16 | Closed Cycle Cooling Heat Exchangers | Shell and tube | 53 GJ/hr (50 MMBtu/hr) each | 2 | 0 |
| 17 | Closed Cycle Cooling Water Pumps | Horizontal centrifugal | 20,820 lpm @ 30 m $H_2O$ (5,500 gpm @ 100 ft $H_2O$) | 2 | 1 |
| 18 | Engine-Driven Fire Pump | Vertical turbine, diesel engine | 3,785 lpm @ 88 m $H_2O$ (1,000 gpm @ 290 ft $H_2O$) | 1 | 1 |
| 19 | Fire Service Booster Pump | Two-stage horizontal centrifugal | 2,650 lpm @ 64 m $H_2O$ (700 gpm | 1 | 1 |
| 20 | Raw Water Pumps | Stainless steel, single suction | 12,265 lpm @ 18 m $H_2O$ (3,240 gpm @ 60 ft $H_2O$) | 2 | 1 |
| 21 | Ground Water Pumps | Stainless steel, single suction | 4,921 lpm @ 268 m $H_2O$ (1,300 gpm @ 880 ft $H_2O$) | 5 | 1 |
| 22 | Filtered Water Pumps | Stainless steel, single suction | 2,953 lpm @ 49 m $H_2O$ (780 gpm | 2 | 1 |
| 23 | Filtered Water Tank | Vertical, cylindrical | 2,839,059 liter (750,000 gal) | 1 | 0 |
| 24 | Makeup Water Demineralizer | Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit | 1,022 lpm (270 gpm) | 1 | 1 |
| 25 | Liquid Waste Treatment System | -- | 10 years, 24-hour storm | 1 | 0 |

**Table 5-6**
**Boiler and Accessories Equipment List**

| Equipment No. | Description | Type | Design Condition | Operating Qty. | Spares |
|---|---|---|---|---|---|
| 1 | Boiler | Subcritical, drum wall-fired, low NOx burners, overfire air | 2,599,084 kg/hr steam @ 17.9 MPa/574°C/574°C (5,730,000 lb/hr steam @ 2,600 psig/1 ,065°F/1 ,065°F) | 1 | 0 |
| 2 | Primary Air Fan | Centrifugal | 357,210 kg/hr, 4,853 $m^3$/min @ 123 cm WG (787,500 lb/hr, 172,200 acfm @ 48 in. WG) | 2 | 0 |
| 3 | Forced Draft Fan | Centrifugal | 1,168,473 kg/hr, 16,510 $m^3$/min @ 47 cm WG (2,576,000 lb/hr, 583,000 acfm @ 19 in. WG) | 2 | 0 |
| 4 | Induced Draft Fan | Centrifugal | 1,665,166 kg/hr, 32,060 $m^3$/min @ 104 cm WG (3,671,000 lb/hr, 1,132,200 acfm @ 41 in. WG) | 2 | 0 |
| 5 | SCR Reactor Vessel | Space for spare layer | 3,347,512 kg/hr (7,380,000 lb/hr) | 2 | 0 |
| 6 | SCR Catalyst | -- | -- | 3 | 0 |
| 7 | Dilution Air Blower | Centrifugal | 198 $m^3$/min @ 108 cm WG (7,000 acfm @ 42 in. WG) | 2 | 1 |
| 8 | Ammonia Storage | Horizontal tank | 219,554 liter (58,000 gal) | 5 | 0 |
| 9 | Ammonia Feed Pump | Centrifugal | 42 lpm @ 91 m $H_2O$ (11 gpm @ 300 ft $H_2O$) | 2 | 1 |

**Table 5-7**
**Flue Gas Clean-up Equipment List**

| Equipment No. | Description | Type | Design Condition | Operating Qty. | Spares |
|---|---|---|---|---|---|
| 1 | Fabric Filter | Single stage, high-ratio with pulse-jet online cleaning system | 1,665,166 kg/hr (3,671,000 lb/hr) 99.8% efficiency | 2 | 0 |
| 2 | Absorber Module | Counter-current open spray | 67,102 $m^3$/min (2,370,000 acfm) | 1 | 0 |
| 3 | Recirculation Pumps | Horizontal centrifugal | 230,910 lpm @ 64 m $H_2O$ (61,000 gpm @ 210 ft $H_2O$) | 5 | 1 |
| 4 | Bleed Pumps | Horizontal centrifugal | 6,095 lpm (1,610 gpm) at 20 wt% solids | 2 | 1 |
| 5 | Oxidation Air Blowers | Centrifugal | 128 m3/min @ 0.3 MPa (4,525 acfm @ 37 psia) | 2 | 1 |
| 6 | Agitators | Side entering | 50 hp | 5 | 1 |
| 7 | Dewatering Cyclones | Radial assembly, 5 units each | 1,514 lpm (400 gpm) per cyclone | 2 | 0 |
| 8 | Vacuum Filter Belt | Horizontal belt | 48 tonne/hr (53 tph) of 50 wt % slurry | 2 | 1 |
| 9 | Filtrate Water Return Pumps | Horizontal centrifugal | 908 lpm @ 12 m $H_2O$ (240 gpm @ 40 ft $H_2O$) | 1 | 1 |
| 10 | Filtrate Water Return Storage Tank | Vertical, lined | 605,666 lpm (160,000 gal) | 1 | 0 |
| 11 | Process Makeup Water Pumps | Horizontal centrifugal | 4,883 lpm @ 21 m $H_2O$ (1,290 gpm @ 70 ft $H_2O$) | 1 | 1 |

**Table 5-8**
**$CO_2$ Capture Equipment List (high-level)**

| Equipment No. | Description | Type | Design Condition | Operating Qty. | Spares |
|---|---|---|---|---|---|
| 1 | CAER $CO_2$ Capture System | Amine-based $CO_2$ capture technology | 1,748,300 kg/h (3,854,300 lb/h) 22.0 wt % $CO_2$ concentration | 2 | 0 |
| 2 | CAER Condensate Pump | Centrifugal | 13,984 lpm @ 52 m $H_2O$ (3,700 gpm @ 170 ft $H_2O$) | 1 | 1 |

**Table 5-9**
**HRSG, Ducting, and Stack Equipment List**

| Equipment No. | Description | Type | Design Condition | Operating Qty. | Spares |
|---|---|---|---|---|---|
| 1 | Stack | Reinforced concrete with FRP liner | 152 m (500 ft) high x 5.8 m (19 ft) diameter | 1 | 0 |

**Table 5-10**
**Steam Turbine Generator and Auxiliaries Equipment List**

| Equipment No. | Description | Type | Design Condition | Operating Qty. | Spares |
|---|---|---|---|---|---|
| 1 | Steam Turbine | Commercially available advanced steam turbine | 699 MW 16.5 MPa/566°C/566°C (2400.3 psig/ 1050°F/1 050°F) | 1 | 0 |
| 2 | Steam Turbine Generator | Hydrogen cooled, static excitation | 790 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase | 1 | 0 |
| 3 | Surface Condenser | Single pass, divided waterbox including vacuum pumps | 2,215 GJ/hr (2,099 MMBtu/hr), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F) | 1 | 0 |

**Table 5-11**
**Cooling Water System Equipment List**

| Equipment No. | Description | Type | Design Condition | Operating Qty. | Spares |
|---|---|---|---|---|---|
| 1 | Circulating Water Pumps | Vertical, wet pit | 794,200 lpm @ 30 m (209,800 gpm @ 100 ft) | 2 | 1 |
| 2 | Cooling Tower | Evaporative, mechanical draft, multi- cell | 11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT / 4434 GJ/hr (4203 MMBtu/hr) heat duty | 1 | 0 |

**Table 5-12**
**Ash/Spent Sorbent Recovery and Handling Equipment List**

| Equipment No. | Description | Type | Design Condition | Operating Qty. | Spares |
|---|---|---|---|---|---|
| 1 | Economizer Hopper (part of boiler scope of supply) | -- | -- | 4 | 0 |
| 2 | Bottom Ash Hopper (part of boiler scope of supply) | -- | -- | 2 | 0 |
| 3 | Clinker Grinder | -- | 6.4 tonne/hr (7 tph) | 1 | 1 |
| 4 | Pyrites Hopper (part of pulverizer scope of supply included with boiler) | -- | -- | 6 | 0 |
| 5 | Hydroejectors | -- | -- | 12 | |
| 6 | Economizer /Pyrites Transfer Tank | -- | -- | 1 | 0 |
| 7 | Ash Sluice Pumps | Vertical, wet pit | 227 lpm @ 17 m $H_2O$ (60 gpm @ 56 ft $H_2O$) | 1 | 1 |
| 8 | Ash Seal Water Pumps | Vertical, wet pit | 7,571 lpm @ 9 m $H_2O$ (2000 gpm @ 28 ft $H_2O$) | 1 | 1 |
| 9 | Hydrobins | -- | 227 lpm (60 gpm) | 1 | 1 |
| 10 | Baghouse Hopper (part of baghouse scope of supply) | -- | -- | 24 | 0 |
| 11 | Air Heater Hopper (part of boiler scope of supply) | -- | -- | 10 | 0 |
| 12 | Air Blower | -- | 22 $m^3$/min @ 0.2 MPa (770 scfm @ 24 psi) | 1 | 1 |
| 13 | Fly Ash Silo | Reinforced concrete | 1,451 tonne (1,600 ton) | 2 | 0 |
| 14 | Slide Gate Valves | -- | -- | 2 | 0 |
| 15 | Unloader | -- | -- | 1 | 0 |
| 16 | Telescoping Unloading Chute | -- | 136 tonne/hr (150 tph) | 1 | 0 |

**Table 5-13**
**Accessory Electric Plant Equipment List**

| Equipment No. | Description | Type | Design Condition | Operating Qty. | Spares |
|---|---|---|---|---|---|
| 1 | STG Transformer | Oil-filled | 24 kV/345 kV, 650 MVA, 3-ph, 60 Hz | 1 | 0 |
| 2 | Auxiliary Transformer | Oil-filled | 24 kV/4.16 kV, 129 MVA, 3-ph, 60 Hz | 1 | 1 |
| 3 | Low Voltage Transformer | Dry ventilated | 4.16 kV/480 V, 20 MVA, 3-ph, 60 Hz | 1 | 1 |
| 4 | STG Isolated Phase Bus Duct and Tap Bus | Aluminum, self-cooled | 24 kV, 3-ph, 60 Hz | 1 | 0 |
| 5 | Medium Voltage Switchgear | Metal clad | 4.16 kV, 3-ph, 60 Hz | 1 | 1 |
| 6 | Low Voltage Switchgear | Metal enclosed | 480 V, 3-ph, 60 Hz | 1 | 1 |
| 7 | Emergency Diesel Generator | Sized for emergency shutdown | 750 kW, 480 V, 3-ph, 60 Hz | 1 | 0 |

**Table 5-14**
**Instrumentation and Control Equipment List**

| Equipment No. | Description | Type | Design Condition | Operating Qty. | Spares |
|---|---|---|---|---|---|
| 1 | DCS - Main Control | Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W) | Operator stations/printers and engineering stations/printers | 1 | 0 |
| 2 | DCS - Processor | Microprocessor with redundant input/output | N/A | 1 | 0 |
| 3 | DCS - Data Highway | Fiber optic | Fully redundant, 25% spare | 1 | 0 |

The detailed equipment list for the $CO_2$ capture system used for the UK CAER process + MEA Case is provided in Table 5-15. The table provides a label for the piece of equipment, a brief decription, the type if applicable, the design condition for it, and the quantity used in the capture plant.

**Table 5-15**
**$CO_2$ Capture Equipment List for the MEA Case (detailed)**

| Equipment No. | Description | Type | Design Condition | Quantity |
|---|---|---|---|---|
| 1 | Direct Contact Cooler | Vertical | 50 ft (15.2 m) dia, 110 ft (33.5 m) T/T,<br>Operating: 2 psig (1.2 bara) / 90°F (32.2°C),<br>Design: -2/+10 psig (0.88/+1.7 bara) / 150°F (65.6°C),<br>Pressure Drop: 1.7 psia (0.11 bar)<br>Carbon Steel | 2 op |
| 2 | $CO_2$ Absorber | Structured Packed Bed | 38 ft (11.6 m) Dia, 138 ft (42 m) T/T,<br>Operating: 2 psig (1.2 bara) / 134°F (56.7°C),<br>Design: -2/+10 psig (.88/+1.7 bara) / 190°F (87.8°C),<br>Pressure Drop: 1.79 psi (0.12 bar)<br>Carbon Steel<br>118 ft (36 m) structured packing | 2 op |
| 3 | Primary Stripper | Structured Packed Bed | 18 ft (5.5 m) Dia, 93 ft (28.3 m) T/T,<br>Operating: 12.7 psig (1.89 bara) / 254°F (123°C),<br>Design: 110 psig (8.6 bara) / 360°F (182.2°C),<br>Pressure Drop: 7 psi (0.48 bar),<br>Carbon Steel / Upper 35 ft (10.7 m) 304SS clad<br>73 ft (22.3 m) of structured packing | 2 op |
| 4 | Reclaimer | Vertical Tank | 14 ft (4.3 m) Dia, 26ft (7.9 m) T/T ft Length,<br>Steam Pressure/Temp: 63.3 psig (5.4 bara) / 310°F (154.4°C),<br>Design: 110 psig (8.6 bara) / 360°F (182.2°C),<br>Heat Required: 120 MBtu /hr (127 GJ/hr),<br>Carbon Steel | 1 op |
| 5 | Air Stripper | Structured Packed Bed | 19 ft (5.8 m) Dia, 90 ft (27.4 m) T/T ft Length,<br>Operating: 0.6 psig (1.1 bara)/ 210°F (99°C),<br>Design: 10 psig (1.7 bara) / 360°F (182.2°C),<br>Pressure Drop: 12.6 psi (0.87 bar),<br>Carbon Steel<br>78 ft (23.8 m) of structured packing | 2 op |
| 6 | Saturator (Water Evaporator) | Structured Packed Bed | 16 ft (4.9 m) Dia, 69 ft (21 m) T/T ft Length,<br>Operating: 1.3 psig (1.1 bara)/ 108°F (42°C),<br>Design: 10 psig (1.7 bara) / 160°F (71°C),<br>Pressure Drop: 8 psi (0.55 bar),<br>Carbon Steel<br>49 ft (15 m) of structured packing | 1 op |

| Equipment No. | Description | Type | Design Condition | Quantity |
|---|---|---|---|---|
| 7 | Reboiler | Kettle | Heat Duty: 782 MBtu/hr (825 GJ/hr),<br>OHTC:250 Btu/ft$^2$-h-F (1419.6 W/(m$^2$K)),<br>Steam Pressure/Temp :63.3 psig (5.4 bara) / 310°F (154.4°C),<br>Heat Transfer Area: 50,740 ft$^2$ (4714m$^2$)<br>Design: 110 psig (8.6 bara) / 600°F (316°C),<br>Carbon Steel | 2 op |
| 8 | Lean/Rich Exchanger | Plate & Frame | Heat Duty: 240 MBtu/hr (253 GJ/hr),<br>OHTC: 600 Btu/ft$^2$-h-F (3407 W/(m$^2$K))<br>Temp(F) In/Out: 190/217 (Cold); 251/211(Hot)<br>Temp(C) In/Out: 87.8/103 (Cold); 122/99 (Hot)<br>Heat Transfer Area: 14,850 ft$^2$(1380 m$^2$),<br>Op. Pressure: 30 psig (3.08 bara),<br>Design: 80 psig (6.5 bara) / 300°F (149°C),<br>304 Alloy Plate material / Carbon Steel | 2 op |
| 9 | Recycle Air Cooler #1 | Plate & Frame | Heat Duty: 330 MBtu/hr (348 GJ/hr),<br>OHTC: 600 Btu/ft$^2$-h-F (3407 W/(m$^2$K))<br>Temp(F) In/Out: 97/171(Cold); 180/138(Hot) Temp(C) In/Out 36/72(Cold); 82/59(Hot)<br>Heat Transfer Area: 26,102 ft$^2$ (2,425 m$^2$)<br>Op. Pressure: 47 psig (50.9 bara),<br>Design: 100 psig / 250°F (7.9 bara / 121°C),<br>Carbon Steel | 2 op |
| 10 | $CO_2$ Cond #2 | Plate & Frame | Heat Duty: 180 MBtu/hr (189.9 GJ/hr)<br>OHTC: 600 Btu/ft$^2$-h-F (3407 W/(m$^2$K))<br>Temp(F) In/Out: 97/189(Cold); 200/141(Hot)<br>Temp(C) In/Out 36/87 (Cold); 93/61 (Hot),<br>Heat Transfer Area: 12,620 ft$^2$(1172 m$^2$),<br>Op. Pressure: 45 psig (4.1 bara),<br>Design: 100 psig (7.9 bara) / 250°F (121°C),<br>Carbon Steel | 2 op |

| Equipment No. | Description | Type | Design Condition | Quantity |
|---|---|---|---|---|
| 11 | Rich Amine Preheater #3 | Plate & Frame | Heat Duty: 24 MBtu/hr (25.3 GJ/hr),<br>OHTC: 600 Btu/ft$^2$-h-F (3407 W/(m$^2$K))<br>Temp(F) In/Out: 177/190(Cold); 213/187(Hot)<br>Temp(C) In/Out 81/88 (Cold); 101/31 (Hot),<br>Heat Transfer Area: 2,560 ft$^2$ (238 m$^2$),<br>Op. Pressure: 43 psig, (4 bara)<br>Design: 100 psig / 270°F (7.9 bara / 132°C),<br>Carbon Steel | 2 op |
| 12 | $CO_2$ Condenser #1 | Plate & Frame | Heat Duty: 21.7 MBtu/hr (22.9 GJ/hr),<br>OHTC: 600 Btu/ft$^2$-h-F (3407 W/(m$^2$K))<br>Temp(F) In/Out: 60/180(Cold); 211/200(Hot)<br>Temp© In/Out 15.6/82 (Cold); 99/93 (Hot),<br>Heat Transfer Area: 1,160 ft$^2$ (108 m$^2$),<br>Op. Pressure: 15 psig (2.0 bara),<br>Design: 70 psig (5.8 bara) / 270°F (132°C),<br>Carbon Steel | 2 op |
| 13 | Saturated Air Preheater | Plate & Frame | Heat Duty: 11.2 MBtu/hr (11.8 GJ/hr),<br>OHTC: 600 Btu/ft$^2$-h-F (3407 W/(m$^2$K))<br>Temp(F) In/Out: 108/131(Cold); 138/129(Hot)<br>Temp(C) In/Out: 42/55(Cold); 59/54(Hot),<br>Heat Transfer Area: 1,470 ft$^2$ (137 m$^2$),<br>Op. Pressure: 1.5 psig (1.1 bara),<br>Design: 60 psig (5.2 bara) / 200°F (93°C),<br>Carbon Steel | 1 op |
| 14 | Absorber Intercooler | Plate & Frame | Heat Duty: 265.7 MBtu/hr (280.3 GJ/hr),<br>OHTC: 600 Btu/ft$^2$-h-F (3407 W/(m$^2$K))<br>Temp In/Out: 144/100°F (62/38°C),<br>Heat Transfer Area: 8,672 ft$^2$ (806 m$^2$),<br>Op. Pressure: 1 psig (1.08 bara),<br>Design: 60 psig (5.2 bara) / 200°F (93.3°C),<br>Utility: CWS<br>Carbon Steel | 2 op |

| Equipment No. | Description | Type | Design Condition | Quantity |
|---|---|---|---|---|
| 15 | Lean Cooler | Plate & Frame | Heat Duty: 170 MBtu/hr (179.3 GJ/hr),<br>OHTC: 600 Btu/ft$^2$-h-F (3407 W/(m$^2$K))<br>Temp In/Out: 128/90°F (53.3/31.2°C),<br>Heat Transfer Area: 7,398 ft$^2$ (687 m$^2$),<br>Op. Pressure: 1.5 psig, (1.1 bara)<br>Design: 60 psig (5.2 bara) / 200°F (93.3°C),<br>Utility: CWS<br>Carbon Steel | 2 op |
| 16 | $CO_2$ Condenser #3 | Plate & Frame | Heat Duty: 31.7 MBtu/hr (33.4 GJ/hr),<br>OHTC: 600 Btu/ft$^2$-h-F (3407 W/(m$^2$K))<br>Temp In/Out: 142/100°F (61/38°C),<br>Heat Transfer Area: 1,055 ft$^2$ (98 m$^2$),<br>Op. Pressure: 10 psig (1.7 bara),<br>Design: 60 psig (5.2 bara) / 200°F (93.3°C),<br>Utility: CWS<br>Carbon Steel | 2 op |
| 17 | Recycle Air Cooler #2 | Plate & Frame | Heat Duty: 122.64 MBtu/hr (129.4 GJ/hr),<br>OHTC: 600 Btu/ft$^2$-h-F (3407 W/(m$^2$K))<br>Temp In/Out: 138/95 F (59/35°C),<br>Heat Transfer Area: 4,489 ft$^2$ (417 m$^2$),<br>Op. Pressure: 0.5 psig (1.04 bara),<br>Design: 60 psig (5.2 bara) / 200°F (93.3°C),<br>Utility: CWS<br>Carbon Steel | 2 op |
| 18 | Recycle Air Heater | Plate & Frame | Heat Duty: 0.99 MBtu/hr (1.04 GJ/hr),<br>OHTC: 600 Btu/ft$^2$-h-F (3407 W/(m$^2$K))<br>Temp In/Out: 95/99 F (35/37.2°C),<br>Heat Transfer Area: 10 ft$^2$ (0.9 m$^2$),<br>Op. Pressure: 0.2 psig (1.02 bara),<br>Design: 110 psig / 600°F (8.6 bara / 316°C),<br>Utility: LP Steam<br>Carbon Steel | 1 op |

| Equipment No. | Description | Type | Design Condition | Quantity |
|---|---|---|---|---|
| 19 | LD Preheater | Plate & Frame | Heat Duty: 12.7 MBtu/hr (13.4 GJ/hr),<br>OHTC: 600 Btu/ft$^2$-h-F (3407 W/(m$^2$K))<br>Temp In/Out: 180/200°F (82/93°C),<br>Heat Transfer Area: 220 ft$^2$ (20.4 m$^2$),<br>Op. Pressure: 10 psig (1.7 bara),<br>Design: 110 psig / 600°F (7.9 bara / 316°F),<br>Utility: LP Steam<br>Carbon Steel | 1 op |
| 20 | Rich Amine Preheater #4 | Plate & Frame | Heat Duty: 78 MBtu/hr (82.3 GJ/hr),<br>OHTC: 600 Btu/ft$^2$-h-F (3407 W/(m$^2$K))<br>Temp In/Out: 177/190°F (81/88°C),<br>Heat Transfer Area: 1,290 ft$^2$ (119.8 m$^2$),<br>Op. Pressure: 10 psig (1.7 bara),<br>Design: 110 psig / 600°F (8.6 bara / 316°C),<br>Utility: LP Steam<br>Carbon Steel | 2 op |
| 21 | DCC Cooler | Plate & Frame | Heat Duty: 758 MBtu/hr (800 GJ/hr),<br>OHTC: 600 Btu/ft$^2$-h-F (3407 W/(m$^2$K))<br>Temp In/Out: 140/75°F (60/24°C),<br>Heat Transfer Area: 38,510 ft$^2$ (3,578 m$^2$),<br>Op. Pressure: 1.5 psig (1.1 bara),<br>Design: 60 psig (5.2 bara) / 200°F (93.3°C),<br>Utility: CWS<br>Carbon Steel | 1 op |
| 22 | Lean Solution Pump | Centrifugal | Solvent @ 15,200 GPM (56,782 lpm),<br>Pressure In/Out: 0.6/158 psig (1.05/11.9 bara),<br>Power: 1,130 hp (843 kW), Efficiency: 85%,<br>Design: 275 psig / 300°F (20 bara / 149°C),<br>Estimated Shutoff: 225 psig (16.5 bara)<br>Carbon Steel | 2 Op<br>2 Spare |
| 23 | Rich Solution Pump | Centrifugal | Solvent @ 17,000 GPM (64,352 lpm),<br>Pressure In/Out: 1.1/ 62 psig (1.09/5.3 bara),<br>Power: 630 hp (470 kW), Efficiency: 85%,<br>Design: 150 psig / 200°F (11.4 bara / 93.3°C),<br>Estimated Shutoff: 95 psig (7.6 bara)<br>Carbon Steel | 2 Op<br>2 Spare |

| Equipment No. | Description | Type | Design Condition | Quantity |
|---|---|---|---|---|
| 24 | Primary Stripper Pump | Centrifugal | Solvent @ 14,280 GPM (54,056 lpm),<br>Pressure: In/Out: 12.8/ 68 psig (1.9/5.7 bara),<br>Power: 420 hp (313 kW), Efficiency: 85%,<br>Design: 150 psig / 150°F (11.4 bara / 65.6°C),<br>Estimated Shutoff: 100 psig (7.9 bara)<br>Carbon Steel | 2 Op<br>2 Spare |
| 25 | Liquid Desiccant Pump | Centrifugal | Solvent @ 4,050 GPM (15,331 lpm),<br>Pressure In/Out: 10/ 138 psig (1.7/10.5 bara),<br>Power: 135 hp (101 kW), Efficiency: 85%,<br>Design: 250 psig / 20° F (18.3 bara / -6.7°C),<br>Estimated Shutoff: 190 psig (14.1 bara)<br>Carbon Steel | 1 Op<br>1 Spare |
| 26 | Saturated LD Pump | Centrifugal | Water/LD @ 41,000 GPM (155,202 lpm),<br>Pressure In/Out: 10/ 130 psig (1.7/10.0 bara),<br>Power: 1,410 hp (1,051 kW), Efficiency: 85%,<br>Design: 250 psig / 200°F (18.3 bara / 93.3°C),<br>Estimated Shutoff: 190 psig (14.1 bara)<br>Carbon Steel | 2 Op<br>1 Spare |
| 27 | Soda Ash Injection Pump | Centrifugal | Solvent @ 50 GPM (189 lpm),<br>Pressure In/Out: 0/ 1.23 psig (1.0/9.5 bara),<br>Power: 235 hp (175 kW), Efficiency: 85%,<br>Design: 50 psig / 150°F (4.5 bara / 65.6°C),<br>Estimated Shutoff: 10 psig (1.7 bara)<br>304L SS casing with CS body | 1 Op<br>1 Spare |
| 28 | Inter Stage Cooling Pump | Centrifugal | Solvent @ 5,460 GPM (20,668 lpm),<br>Pressure In/Out: -0.47 / 50 psig (0.98 / 4.5 bara),<br>Power: 130 hp (96.9 kW), Efficiency: 85%,<br>Design: 50 psig / 200°F (4.5 bar a/ 93.3°C),<br>Estimated Shutoff: 10 psig (1.7 bara)<br>Carbon Steel | 2 Op<br>1 Spare |

| Equipment No. | Description | Type | Design Condition | Quantity |
|---|---|---|---|---|
| 29 | Solvent Make-up Pump | Centrifugal | Solvent @ 100 GPM (379 lpm),<br>Pressure In/Out: 0/ 10.23 psig (1/1.7 bara),<br>Power: 5 hp (3.7 kW), Efficiency: 80%,<br>Design: 50 psig / 200°F (4.5 bar a/ 93.3°C),<br>Estimated Shutoff: 20 psig (14.8 bara)<br>Carbon Steel | 1 Op<br>1 Spare |
| 30 | DCC Pump | Centrifugal | Water @ 20,300 GPM (76,844 lpm),<br>Pressure In/Out: 0.5 / 75 psig (1.05 / 6.2 bara),<br>Power: 820 hp (611 kW), Efficiency: 85%,<br>Design: 160 psig / 150°F (12.05 bar a/ 66°C),<br>Estimated Shutoff: 110 psig (8.6 bara)<br>Carbon Steel | 1 Op<br>1 Spare |
| 31 | ID Fan | Axial | 867,650 ACFM (24,569 $m^3$/min) gas,<br>Pressure In/Out:0.2/ 2.7 psig (1.03/1.20 bara),<br>Power: 10,963 hp (8,175 kW)<br>Design: -2/+10 psig / 150 F (0.88/+1.7 bara / 65.6°C,<br>Carbon Steel | 2 Op |
| 32 | Saturator Air Blower | Centrifugal | 425,900 ACFM gas (12,060 $m^3$/hr),<br>Pressure In/Out: 0/ 1.8 psig (1 / 1.14 bara),<br>Power:3,969 hp (2,960 kW)<br>Design: 10 psig / 150°F (1.7 bara / 65.6°C),<br>Carbon Steel | 1 Op |
| 33 | $CO_2$ Compressor | Inter-Cooled<br>Multi-Staged<br>Centrifugal | 58,950 ACFM (1,669 $m^3$/min) w/ 5-stages<br>Pressure In/Out: 11.1/2200 psig (1.78/153 bara)<br>Power: 32,808 hp (24,465 kW)<br>Design: 2,410 psig / 350°F (167 bara/ 177°C),<br>Carbon Steel with 316SS at wet/dry areas<br>TEG Drying Unit | 2 Op |

### 5.1.3 Economic Results

The cost estimating methodology described in Section 4.5 was used to calculate the capital and O&M costs for the UK CAER process + MEA Case as well as the LCOE. The summary and detailed updated capital costs for the UK CAER process + MEA Case are shown in the Appendix in Table A-9 and Table A-10, and the O&M cost is shown in Table A-11. Table 5-16 compares operating parameters and costs between the DOE/NETL Case 10 and the UK CAER process + MEA case. Key observations are summarize as follows:

- An extra 30.9 MW of generation

- A lower net plant heat rate by 694 Btu/kWh (732 kJ/kWh), a 5% improvement in efficiency
- A lower variable operating cost by $1.08/MWh, an 8% reduction.

**Table 5-16**
**Comparison of Operating Parameters and Costs between the DOE Base Cases and the MEA Case**

| | Case 9 | Case 10 | UK CAER + MEA 2020 |
|---|---|---|---|
| **OPERATING PARAMETERS** | | | |
| **Net Plant Output, MWe** | 550.0 | 550.0 | 580.9 |
| **Net Plant Heat Rate, Btu/kWh HHV (kJ/kWh)** | 9,277 (9,787) | 13,046 (13,764) | 12,352 (13,032) |
| **$CO_2$ Captured, lb/MWh (kg/MWh)** | 0 (0) | 2,390 (1,084) | 2,264 (1,027) |
| **$CO_2$ Emitted, lb/MWh net (kg/MWh net)** | 1,888 (856) | 266 (121) | 252 (114) |
| **COSTS** | | | |
| **Risk** | Low | High | High |
| **Capital Costs (2012$)** | 2,000 | 3,689 | 3,258 |
| **Total Overnight Cost (2012$/kW)** | 2,477 | 4,548 | 4,024 |
| Bare Erected Cost | 1,629 | 2,836 | 2,521 |
| Home Office Expenses | 147 | 257 | 229 |
| Project Contingency | 224 | 465 | 406 |
| Process contingency | 0 | 131 | 102 |
| Owners Costs | 477 | 860 | 766 |
| **Total Overnight Cost (2012$x1,000)** | 1,362,516 | 2,501,457 | 2,337,245 |
| **Total As Spent Capital (2012$)** | 2,809 | 5,185 | 4,587 |
| **Annual Fixed Operating Costs ($/yr)** | 39,039,238 | 66,263,173 | 62,361,303 |
| **Variable Operating Costs ($/MWh)** | 7.63 | 13.35 | 12.27 |
| **Fuel** | | | |
| **Coal Price ($/ton)** | 69.00 | | |

The comparison in COE and LCOE between the DOE Case 9 and 10 and the UK CAER process + MEA Case is shown in Table 5-17. The UK CAER Process + MEA Case has the following key advantages compared to DOE/NETL Case 10, which also has CCS:

- A lower COE by $13.9/MWh, an 9.3% reduction
- A lower LCOE by $17.5/MWh, also an 9.2% reduction
- A lower cost of $CO_2$ captured by $9.44/tonne $CO_2$, a 15.4% reduction
- A lower cost of $CO_2$ avoided by $18.53/tonne $CO_2$, a 20.5% reduction

**Table 5-17**
**Comparison of COE between the DOE Base Cases and the MEA Case**

| | Case 9 | Case 10 | UK CAER + MEA 2020 Case |
|---|---|---|---|
| **COE ($/MWh, 2012$)** | **83.19** | **149.65** | **135.71** |
| $CO_2$ TS&M Costs | | 5.80 | 5.49 |
| Fuel Costs | 27.43 | 38.57 | 36.53 |
| Variable Costs | 7.63 | 13.35 | 12.27 |
| Fixed Costs | 9.53 | 16.18 | 14.42 |
| Capital Costs | 38.59 | 75.75 | 67.00 |
| **LCOE (2012$/MWh)** | 105.36 | 189.59 | 172.08 |
| **Cost of $CO_2$ Captured ($/tonne $CO_2$)** | | 61.31 | 51.87 |
| **Cost of $CO_2$ Avoided ($/tonne $CO_2$)** | | 90.35 | 71.82 |

A further breakdown of the cost quantities that comprise LCOE is shown between the MEA Case and the two DOE Base Cases in Figure 5-3.

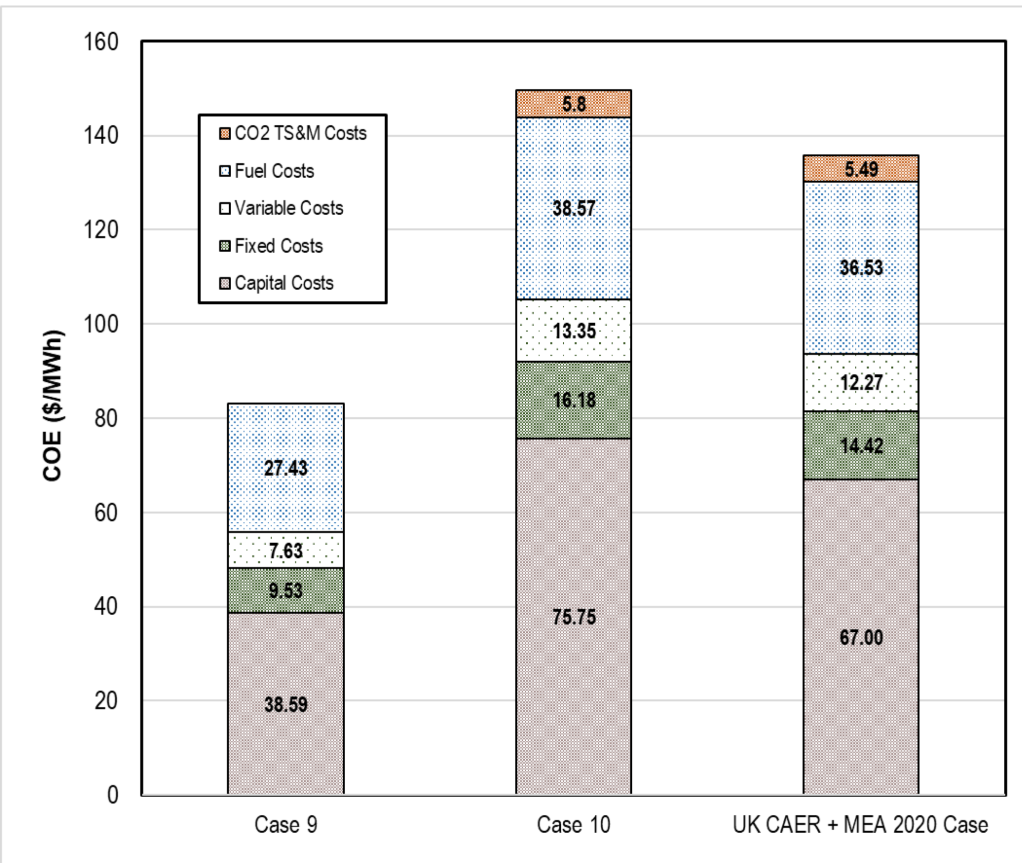


**Figure 5-3**
**Comparison and Breakdown of COE for the MEA and DOE Cases**

## 5.2 ***UK CAER Process + H3-1 Solvent Case***

### 5.2.1 Performance Results

A simulation of the UK CAER process with H3-1 would require physical and chemical property information to the same level of detail as MEA. Though information was made avaiable on H3-1, it was not sufficiently detailed to conduct an Aspen Plus® kinetic model simulation of the complete system. Therefore, scaling factors provided by Hitachi for performance of H3-1 relative to MEA were used. These scaling factors were based on Hitachi's prior test results. Key amongst these test results were 74% regeneration energy relative to MEAwhich under those test conditions was assumed to be 3.6 GJ/t (1547 BTU/lb). That is, in a conventional process, H3-1 solvent would exhibit a regeneration energy of 2.66 GJ/t (1145 BTU/lb). Further improvement would be expected for H3-1 when used in the UK CAER process. In the absense of data, these improvements were estimated to be the same ratio as that for MEA in a conventional process relative to that in the UK CAER process. Simulations with MEA showed this improved to be about 15% further reduction between a conventional process and the UK CAER process, and therefore the H3-1 regegeneration energy was assumed to be 2.26 GJ/t (973 BTU/lb) when used in the UK CAER process. Other improvements provided by Hitachi based on their prior work included higher cycle capacity, a higher mass transfer coefficients compared with MEA, and other performance improvments. A 20% cycle capacity improvement was used for this preliminary analysis. The impact of the higher viscosity of the H3-1 solvent was deemed to be relatively minor relative to the other assumptions and hence not considered in this initial analysis. We note that in full simulations or actual operations, it is often not possible to achieve all improvements simultaneously. That is, attributes such as solvent regeneration energy, mass transfer coefficients, circulation rates are functions not only of the solvent, but also functions of the equipment and the process conditions under which the system is operated. Attempting to optimize one attribute often leads to detriment of another. Hence, without a full process simulation or full testing campaign, it is not possible to ascertain whether all or only part of these improvements may be actually realized in any given process. An optimization of a solvent in a process must be conducted, either by simulations or by testing, such that the overall capture and plant can be optimized with respect to typical objective functions such as net plant output or lowest COE increase. Given our assumptions as stated, the high-level performance results for the UK CAER CCS process with H3-1 case are shown in Table 5-18.

In summary, the net efficiency of the UK CAER integrated PC power plant with $CO_2$ capture changes from 26.2% with the Reference Case 10 plant in 2010 revised DOE/NETL baseline report to 29.1% for the UK CAER process + H3-1 case; the UK CAER process + H3-1 case lowers energy consumption for $CO_2$ capture to 973Btu/lb-$CO_2$ captured as compared to 1,540 Btu/lb-$CO_2$ in the Case 10. The study also shows 27.5% less heat rejection associated with carbon capture system, decreased from 3,398 MBtu/hr (Case 10) to 2,464 MBtu/hr for the UK CAER process + H3-1 case.

**Table 5-18**
**Hitachi Performance Summary**

| POWER SUMMARY (Gross Power at Generator Terminals kWe) | |
|---|---|
| Case | UK CAER + H3-1 2020 Case |
| Steam Turbine Power | 730,300 |
| TOTAL (STEAM TURBINE) POWER, kWe | 730,300 |
| AUXILIARY LOAD SUMMARY, kWe | |
| Coal Handling & Conveying | 540 |
| Pulverizers | 4,180 |
| Sorbent Handling & Reagent Preparation | 1,370 |
| Ash Handling | 800 |
| Primary Air Fans | 1,980 |
| Forced Draft Fans | 2,890 |
| Induced Draft Fans | 11,410 |
| SCR | 70 |
| Baghouse | 100 |
| Wet FGD | 4,470 |
| $CO_2$ Removal System Auxiliaries | 21,485 |
| $CO_2$ Compression | 48,930 |
| Miscellaneous Balance of Plant[2,3] | 2,000 |
| Steam Turbine Auxiliaries | 400 |
| Condensate Pumps | 870 |
| Circulating Water Pump | 9,580 |
| Ground Water Pumps | 780 |
| Cooling Tower Fans | 4,990 |
| Cooling Tower Chillers | 0 |
| Transformer Losses | 2,550 |
| TOTAL AUXILIARIES, kWe | 119,395 |
| NET POWER, kWe | 610,905 |
| Net Plant Efficiency (HHV) | 29.1% |
| Net Plant Heat Rate, Btu/kWhr HHV (kJ/kWhr) | 11,744 |
| Net Plant Efficiency (LHV) | 30.1% |
| Net Plant Heat Rate, Btu/kWhr LHV (kJ/kWhr) | 11,327 |
| Condenser duty, MBtu/hr (GJ/hr) | 2,625 (2,770) |
| COOLING TOWER DUTY, MBtu/hr (GJ/hr) | 4,560 (4,811) |
| Consumables | |
| As-Received Coal Feed, lb/hr (kg/hr) | 614,994 |
| Limestone Sorbent Feed, lb/hr (kg/hr) | 62,235 |
| Thermal Input (kWth HHV)[1] | 2,102,643 |
| Thermal Input (kWth LHV) | 2,028,027 |
| Raw Water Withdrawal, gpm ($m^3$/min) | 11,224 (42.5) |
| Raw Water Consumption, gpm ($m^3$/min) | 8,620 (32.6) |

*1. HHV of As-Received Illinois #6 Coal is 27,135 kJ/kg (11,666 Btu/lb)*

*2. Boiler feed pumps are turbine driven*

*3. Includes plant control systems, lighting, HVAC, and miscellaneous low-voltage loads*

### 5.2.2 **Major Equipment List**

The major equipment list for the UK CAER process + H3-1 Case for the balance of plant is similar to the UK CAER process + MEA case given in Section 5.1.2, except for the following sub-systems:

- Steam Turbine Cycle LP Feedwater Heaters
- Steam Turbine Generator and Auxiliaries
- Cooling Water System

Tables showing the components of these sub-systems are given in Table 5-19, Table 5-20, and Table 5-21.

**Table 5-19**
**Steam Turbine Generator and Auxiliaries Equipment List**

| Equipment No. | Description | Type | Design Condition | Operating Qty. | Spares |
|---|---|---|---|---|---|
| 6 | LP Feedwater Heater 1A/1B | Horizontal U-tube | 755,700 kg/hr (1,666,000 lb/hr) | 2 | 0 |
| 7 | LP Feedwater Heater 2A/2B | Horizontal U-tube | 755,700 kg/hr (1,666,000 lb/hr) | 2 | 0 |
| 8 | LP Feedwater Heater 3A/3B | Horizontal U-tube | 755,700 kg/hr (1,666,000 lb/hr) | 2 | 0 |
| 9 | LP Feedwater Heater 4A/4B | Horizontal U-tube | 755,700 kg/hr (1,666,000 lb/hr) | 2 | 0 |

**Table 5-20**
**Steam Turbine Generator and Auxiliaries Equipment List**

| Equipment No. | Description | Type | Design Condition | Operating Qty. | Spares |
|---|---|---|---|---|---|
| 1 | Steam Turbine | Commercially available advanced steam turbine | 730.3 MW<br>16.5 MPa/566 °C/566 °C<br>(2400.3 psig/<br>1050 °F/1050 °F) | 1 | 0 |
| 2 | Steam Turbine Generator | Hydrogen cooled, static excitation | 810 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase | 1 | 0 |
| 3 | Surface Condenser | Single pass, divided waterbox including vacuum pumps | 2,535 GJ/hr (2,403 MMBtu/hr), Inlet water temperature 16 °C (60 °F), Water temperature rise 11 °C (20 °F) | 1 | 0 |

**Table 5-21**
**Cooling Water System Equipment List**

| Equipment No. | Description | Type | Design Condition | Operating Qty. | Spares |
|---|---|---|---|---|---|
| 1 | Circulating Water Pumps | Vertical, wet pit | 899,640 lpm @ 30 m (238,000 gpm @ 100 ft) | 2 | 1 |
| 2 | Cooling Tower | Evaporative, mechanical draft, multi- cell | 11°C (51.5 °F) wet bulb / 16 °C (60 °F) CWT / 27 °C (80 °F) HWT / 4811 GJ/hr (4560 MMBtu/hr) heat duty | 1 | 0 |

The detailed equipment list for the $CO_2$ capture system used for the UK CAER process + H3-1 case is provided in Table 5-22. The table provides a label for the piece of equipment, a brief decription, the type if applicable, the design condition for it, and the quantity used in the capture plant.

**Table 5-22**
**$CO_2$ Capture Equipment List for the 2020+H3-1 Solvent Case (detailed)**

| Equipment No. | Description | Type | Design Condition | Quantity |
|---|---|---|---|---|
| 1 | Direct Contact Cooler | Vertical | 50 ft (15.2 m) dia, 110 ft (33.5 m) T/T,<br>Operating: 2 psig (1.2 bara) / 90 °F (32.2 °C),<br>Design: -2/+10 psig (0.88/+1.7 bara) / 150 °F (65.6 °C),<br>Pressure Drop: 1.7 psia (0.11 bar)<br>Carbon Steel | 2 op |
| 2 | $CO_2$ Absorber | Structured Packed Bed | 34 ft (10.4 m) Dia, 80 ft (24.4 m) T/T,<br>Operating: 2 psig (1.2 bara) / 134 ºF,<br>Design: -2/+10 psig (0.88/+1.7 bara) / 190 °F,<br>Pressure Drop: 1.14 psi (0.08 bar)<br>Carbon Steel<br>60 ft (18.3 m) of structured packing | 2 op |
| 3 | Primary Stripper | Structured Packed Bed | 16 ft (4.9 m) Dia, 50 ft (15.2 m) T/T,<br>Operating: 12.7 psig (1.9 bara)/ 254 °F,<br>Design: 110 psig (8.6 bara) / 360 °F (182.2 °C),<br>Pressure Drop: 3.2 psi (0.22 bar),<br>Carbon Steel / Upper 16 ft (4.9 m) 304SS clad<br>35 ft (10.7 m) of structured packing | 2 op |
| 4 | Reclaimer | Vertical Tank | 14 ft (4.3 m) Dia, 26ft (7.9 m) T/T ft Length,<br>Steam Pressure/Temp: 63.3 psig (5.4 bara) / 310 °F (154.4 °C) (154.4 °C),<br>Design: 110 psig (8.6 bara) / 360 °F (182.2 °C),<br>Heat Required: 96 MBtu /hr (101 GJ/hr),<br>Carbon Steel | 1 op |
| 5 | Air Stripper | Structured Packed Bed | 18 ft (5.5 m) Dia, 35 ft (10.7 m) T/T ft Length,<br>Operating: 0.6 psig (1.05 bara)/ 210 °F (99 °C),<br>Design: 10 psig (1.7 bara) / 360 °F (182.2 °C),<br>Pressure Drop: 4.4 psi (0.30 bar),<br>Carbon Steel<br>25 ft (7.6 m) of structured packing | 2 op |
| 6 | Saturator (Water Evaporator) | Structured Packed Bed | 14.5 ft (4.4 m) Dia, 14 ft (4.3 m) T/T ft Length,<br>Operating: 1.3 psig (1.1 bara)/ 108 °F (42.2 °C),<br>Design: 10 psig (1.7 bara) / 160 °F (71.1 °C),<br>Pressure Drop: 1.6 psi (0.11 bar),<br>Carbon Steel<br>10 ft (3.0 m) of structured packing | 1 op |

| Equipment No. | Description | Type | Design Condition | Quantity |
|---|---|---|---|---|
| 7 | Reboiler | Kettle | Heat Duty: 626 MBtu/hr (660 GJ/hr),<br>OHTC:200 Btu/ft$^2$, h, F (1,136 W/(m$^2$K)),<br>Steam Pressure/Temp :63.3 psig (5.4 bara) / 310 °F (154.4 °C),<br>Heat Transfer Area: 50,740 ft$^2$ (4,714 m$^2$),<br>Design: 110 psig (8.6 bara) / 600 °F (316 °C),<br>Carbon Steel | 2 op |
| 8 | Lean/Rich Exchanger | Plate & Frame | Heat Duty: 192 MBtu/hr (202.6 GJ/hr),<br>OHTC: 450 Btu/ft$^2$-h-F (2,555 W/(m$^2$K))<br>Temp(F) In/Out: 190/217 (Cold); 251/211(Hot)<br>Temp(C) In/Out 88/103 (Cold); 122/99(Hot)<br>Heat Transfer Area: 14,850 ft$^2$ (1,380 m$^2$),<br>Op. Pressure: 30 psig (3.1 bara),<br>Design: 80 psig (6.5 bara) / 300 °F (149 °C),<br>304 Alloy Plate material / Carbon Steel | 2 op |
| 9 | Recycle Air Cooler #1 | Plate & Frame | Heat Duty: 264 MBtu/hr (279 GJ/hr),<br>OHTC: 450 Btu/ft$^2$-h-F (2,555 W/(m$^2$K))<br>Temp(F) In/Out: 97/171(Cold); 180/138(Hot)<br>Temp(C) In/Out 36/77(Cold); 82/59 (Hot)<br>Heat Transfer Area: 26,102 ft$^2$ (2,425 m$^2$),<br>Op. Pressure: 47 psig (4.25 bara),<br>Design: 100 psig (7.9 bara) / 250 °F (121 °C),<br>Carbon Steel | 2 op |
| 10 | $CO_2$ Cond #2 | Plate & Frame | Heat Duty: 180 MBtu/hr (190 GJ/hr),<br>OHTC: 450 Btu/ft$^2$-h-F (2,555 W/(m$^2$K))<br>Temp(F) In/Out: 97/189(Cold); 200/141(Hot)<br>Temp(C) In/Out 36/87(Cold); 93/61 (Hot),<br>Heat Transfer Area: 15,144 ft$^2$ (1,407 m$^2$),<br>Op. Pressure: 45 psig (4.1 bara),<br>Design: 100 psig (7.9 bara) / 250 °F (121 °C),<br>Carbon Steel | 2 op |
| 11 | Rich Amine Preheater #3 | Plate & Frame | Heat Duty: 19.2 MBtu/hr (20.3 GJ/hr),<br>OHTC: 450 Btu/ft$^2$-h-F (2,555 W/(m$^2$K))<br>Temp(F) In/Out: 177/190(Cold); 213/187(Hot)<br>Temp(C) In/Out 81/88(Cold); 101/86(Cold),<br>Heat Transfer Area: 2,560 ft$^2$ (238 m$^2$),<br>Op. Pressure: 43 psig (4.0 bar),<br>Design: 100 psig (7.9 bar) / 270 °F,<br>Carbon Steel | 2 op |

| Equipment No. | Description | Type | Design Condition | Quantity |
|---|---|---|---|---|
| 12 | $CO_2$ Condenser #1 | Plate & Frame | Heat Duty: 21.7 MBtu/hr (22.9 GJ/hr),<br>OHTC: 600 Btu/ft$^2$-h-F (3,407 W/(m$^2$K))<br>Temp(F) In/Out: 60/180(Cold); 211/200(Hot)<br>Temp(C) In/Out 15.6/82(Cold); 99/93(Hot),<br>Heat Transfer Area: 1,160 ft$^2$ (108 m$^2$),<br>Op. Pressure: 15 psig (2.05 bara),<br>Design: 70 psig (5.8 bara) / 270 °F (132 °C),<br>Carbon Steel | 2 op |
| 13 | Saturated Air Preheater | Plate & Frame | Heat Duty: 9 MBtu/hr (9.5 GJ/hr),<br>OHTC: 600 Btu/ft$^2$-h-F (3,407 W/(m$^2$K))<br>Temp(F) In/Out: 108/131(Cold); 138/129(Hot),<br>Heat Transfer Area: 1,180 ft$^2$ (110 m$^2$),<br>Op. Pressure: 1.5 psig (1.1 bara),<br>Design: 60 psig (5.2 bara) / 200 °F (93.3 °C),<br>Carbon Steel | 1 op |
| 14 | Absorber Intercooler | Plate & Frame | Heat Duty: 212 MBtu/hr (224 GJ/hr),<br>OHTC: 450 Btu/ft$^2$-h-F (2,555 W/(m$^2$K))<br>Temp In/Out: 144/100 °F (62/38 °C),<br>Heat Transfer Area: 8,672 ft$^2$ (806 m$^2$),<br>Op. Pressure: 1 psig (1.08 bara),<br>Design: 60 psig (5.2 bar) / 200 °F (93.3 °C),<br>Utility: CWS<br>Carbon Steel | 2 op |
| 15 | Lean Cooler | Plate & Frame | Heat Duty: 136 MBtu/hr (144 GJ/hr),<br>OHTC: 450 Btu/ft$^2$-h-F (2,555 W/(m$^2$K))<br>Temp In/Out: 128/90 °F (53/32 °C),<br>Heat Transfer Area: 7,398 ft$^2$ (687 m$^2$),<br>Op. Pressure: 1.5 psig (1.1 bara),<br>Design: 60 psig (5.2 bara) / 200 °F (93.3 °C),<br>Utility: CWS<br>Carbon Steel | 2 op |

| Equipment No. | Description | Type | Design Condition | Quantity |
|---|---|---|---|---|
| 16 | $CO_2$ Condenser #3 | Plate & Frame | Heat Duty: 31.7 MBtu/hr (33.4 GJ/hr),<br>OHTC: 600 Btu/ft$^2$-h-F (3,407 W/(m$^2$K))<br>Temp In/Out: 142/100°F (61/38°C),<br>Heat Transfer Area: 1,055 ft$^2$ (98 m$^2$),<br>Op. Pressure: 10 psig (1.7 bara),<br>Design: 60 psig (5.5 bara) / 200°F (93.3°C),<br>Utility: CWS<br>Carbon Steel | 2 op |
| 17 | Recycle Air<br>Cooler #2 | Plate & Frame | Heat Duty: 98.11 MBtu/hr (103.5 GJ/hr),<br>OHTC: 600 Btu/ft$^2$-h-F (3,407 W/(m$^2$K))<br>Temp In/Out: 138/95°F (59/35°C),<br>Heat Transfer Area: 3,600 ft$^2$ (334 m$^2$),<br>Op. Pressure: 0.5 psig (1.05 bara),<br>Design: 60 psig (5.2 bara) / 200°F (93.3°C),<br>Utility: CWS<br>Carbon Steel | 2 op |
| 18 | Recycle Air Heater | Plate & Frame | Heat Duty: 0.8 MBtu/hr (0.84 GJ/hr),<br>OHTC: 600 Btu/ft$^2$-h-F (3,407 W/(m$^2$K))<br>Temp In/Out: 95/99°F (35/37.2°C),<br>Heat Transfer Area: 8 ft$^2$ (0.74 m$^2$),<br>Op. Pressure: 0.2 psig (1.03 bara),<br>Design: 110 psig (8.6 bara) / 600°F (316°C),<br>Utility: LP Steam<br>Carbon Steel | 1 op |
| 19 | LD Preheater | Plate & Frame | Heat Duty: 10.2 MBtu/hr (10.8 GJ/hr),<br>OHTC: 600 Btu/ft$^2$-h-F (3,407 W/(m$^2$K))<br>Temp In/Out: 180/200°F (82.2/93.3°C),<br>Heat Transfer Area: 176 ft$^2$ (16.4 m$^2$),<br>Op. Pressure: 10 psig (1.7 bara),<br>Design: 110 psig 8.6 (bara) / 600°F (316°C),<br>Utility: LP Steam<br>Carbon Steel | 1 op |
| 20 | Rich Amine<br>Preheater #4 | Plate & Frame | Heat Duty: 62 MBtu/hr 65.4 GJ/hr),<br>OHTC: 450 Btu/ft$^2$-h-F (2,555 W/(m$^2$K))<br>Temp In/Out: 177/190°F (81/88°C),<br>Heat Transfer Area: 1,290 ft$^2$ (119.8 m$^2$),<br>Op. Pressure: 10 psig (1.7 bara),<br>Design: 110 psig (8.6 bara) / 600°F (316°C),<br>Utility: LP Steam<br>Carbon Steel | 2 op |

| Equipment No. | Description | Type | Design Condition | Quantity |
|---|---|---|---|---|
| 21 | DCC Cooler | Plate & Frame | Heat Duty: 758 MBtu/hr (800 GJ/hr),<br>OHTC: 600 Btu/ft$^2$-h-F (3,407 W/(m$^2$K))<br>Temp In/Out: 140/75°F (60/23.9°C),<br>Heat Transfer Area: 38,510 ft$^2$ (3,578 m$^2$),<br>Op. Pressure: 1.5 psig (1.1 bara),<br>Design: 60 psig (5.2 bara) / 200°F (93.3°C),<br>Utility: CWS<br>Carbon Steel | 1 op |
| 22 | Lean Solution Pump | Centrifugal | Solvent @ 12,160 GPM (46,031 lpm),<br>Pressure In/Out: 0.6/126 psig (1.05/9.7 bara),<br>Power: 720 hp (537 kW), Efficiency: 85%,<br>Design: 230 psig (16.9 bara) / 300°F (149°C),<br>Estimated Shutoff: 180 psig (13.4 bara)<br>Carbon Steel | 2 Op<br>2 Spare |
| 23 | Rich Solution Pump | Centrifugal | Solvent @ 13,600 GPM (51,482 lpm),<br>Pressure In/Out: 1.1/ 50 psig (1.09/4.46 bara),<br>Power: 400 hp (298.3 kW), Efficiency: 85%,<br>Design: 120 psig (9.3 bara) / 200°F (93.3°C),<br>Estimated Shutoff: 70 psig (5.8 bara)<br>Carbon Steel | 2 Op<br>2 Spare |
| 24 | Primary Stripper Pump | Centrifugal | Solvent @ 11,420 GPM (43,229 lpm),<br>Pressure In/Out: 12.8/ 54 psig (1.9/4.7 bara),<br>Power: 250 hp (186 kW), Efficiency: 85%,<br>Design: 130 psig (10.0 bara) / 150°F (66°C),<br>Estimated Shutoff: 80 psig (bar)<br>Carbon Steel | 2 Op<br>2 Spare |
| 25 | Liquid Desiccant Pump | Centrifugal | Water/LD @ 3,240 GPM (12,265 lpm),<br>Pressure In/Out: 10/ 88 psig (1.7/7.1 bara),<br>Power: 80 hp (60 kW), Efficiency: 85%,<br>Design: 170 psig (12.7 bara) / 200°F (93.3°C),<br>Estimated Shutoff: 120 psig (9.3 bara)<br>Carbon Steel | 1 Op<br>1 Spare |
| 26 | Saturated LD Pump | Centrifugal | Water/LD @ 32,800 GPM (124,162 lpm),<br>Pressure In/Out: 1/10 psig (1.08/1.7 bara)<br>Power: 190 hp (142 kW), Efficiency: 85%,<br>Design: 200 psig (14.8 bara) / 200°F (93.3°C),<br>Estimated Shutoff: 150 psig (11.4 bara)<br>Carbon Steel | 2 Op<br>1 Spare |

| Equipment No. | Description | Type | Design Condition | Quantity |
|---|---|---|---|---|
| 27 | Soda Ash Injection Pump | Centrifugal | Solvent @ 50 GPM (189 lpm),<br>Pressure In/Out: 0/ 1.23 psig (1/1.1 bara),<br>Power: 2 hp (1.5 kW), Efficiency: 80%,<br>Design: 50 psig (4.5 bara) / 150°F (66°C),<br>Estimated Shutoff: 10 psig (1.7 bara)<br>304L SS casing with CS body | 1 Op<br>1 Spare |
| 28 | Inter Stage Cooling Pump | Centrifugal | Solvent @ 4,370 GPM (16,542 lpm),<br>Pressure In/Out: -0.47 / 50 psig (0.98/4.5 bara),<br>Power: 100 hp (74.6 kW), Efficiency: 85%,<br>Design: 50 psig (4.5 bara) / 200°F (93.3°C),<br>Estimated Shutoff: 10 psig (1.7 bara)<br>Carbon Steel | 2 Op<br>1 Spare |
| 29 | Solvent Make-up Pump | Centrifugal | Solvent @ 100 GPM (379 lpm),<br>Pressure In/Out: 0/ 10.23 psig (1/1.7 bara),<br>Power: 5 hp (3.7 kW), Efficiency: 80%,<br>Design: 50 psig (4.5 bara) / 200°F (93.3°C),<br>Estimated Shutoff: 20 psig (2.4 bara)<br>Carbon Steel | 1 Op<br>1 Spare |
| 30 | DCC Pump | Centrifugal | Water @ 20,300 GPM (76,844 lpm),<br>Pressure In/Out: 0.5 / 75 psig (1.05/6.2 bara),<br>Power: 820 hp (611 kW), Efficiency: 85%,<br>Design: 160 psig (12.0 bara) / 150°F (66°C),<br>Estimated Shutoff: 110 psig (8.6 bara)<br>Carbon Steel | 1 Op<br>1 Spare |
| 31 | ID Fan | Axial | 867,650 ACFM (24,569 $m^3$/min) gas,<br>Pressure In/Out: 0.2/ 2.7 psig (1.03/1.20 bara),<br>Power: 10,963 hp (8,175 kW)<br>Design: -2/+10 psig (0.88/+1.7 bara) / 150°F (66°C),<br>Carbon Steel | 2 Op |
| 32 | Saturator Air Blower | Centrifugal | 341,000 ACFM (9,656 $m^3$/min) gas,<br>Pressure In/Out: 0/ 1.8 psig (1/1.1 bara),<br>Power: 3,178 hp (2,370 kW)<br>Design: 10 psig (1.7 bara) / 150°F (66°C),<br>Carbon Steel | 1 Op |
| 33 | $CO_2$ Compression and Drying | Inter-Cooled Multi-Staged Centrifugal | 58,950 ACFM (1,669 $m^3$/min) w/ 5-stages<br>Pressure In/Out: 11.1/2200 psig (1.8/152.7 bara)<br>Power: 32,808 hp (24,465 kW)<br>Design: 2,410 psig (167 bara) / 350°F (177°C),<br>Carbon Steel with 316SS at wet/dry areas<br>TEG Unit | 2 Op |

### 5.2.3 Economic Results

The cost estimating methodology described in Section 4.5 was used to calculate the capital and O&M costs for the UK CAER process + H3-1 case as well as the LCOE. The summary and detailed updated capital costs for the UK CAER process + H3-1 case are shown in the Appendix in Table A-12 and Table A-13, and the O&M cost is shown in Table A-14.

The comparison in operating parameters and costs between the NETL/DOE Case 9 and 10, UK CAER process + MEA, and UK CAER process + H3-1 cases is shown in Table 5-23.

The UK CAER Process + H3-1 case has the following key advantages compared to the DOE/NETL Case 10:

- An extra 60.9 MW of generation
- A lower net plant heat rate by 1,302Btu/kWh (1,373kJ/kWh), a 10% improvement in efficiency

**Table 5-23**
**Comparison of Operating Parameters and Costs between the MEA, Hitachi, and DOE Cases**

| | Case 9 | Case 10 | UK CAER + MEA 2020 Case | UK CAER + H3-1 2020 Case |
|---|---|---|---|---|
| **OPERATING PARAMETERS** | | | | |
| **Net Plant Output, MWe** | 550 | 550 | 580.9 | 610.9 |
| **Net Plant Heat Rate, Btu/kWh HHV (kJ/kWh** | 9,277 (9,787) | 13,046 (13,764) | 12,352 (13,032) | 11744 (12,391) |
| **$CO_2$ Captured, lb/MWh (kg/MWh)** | 0 (0) | 2,390 (1,084) | 2,264 (1,027) | 2,126 (964) |
| **$CO_2$ Emitted, lb/MWh net (kg/MWh net)** | 1,888 (856) | 266 (121) | 252 (114) | 250 (113) |
| **COSTS** | | | | |
| **Risk** | Low | High | High | High |
| **Capital Costs (2012$/kW)** | 2,000 | 3,689 | 3,258 | 2,890 |
| **Total Overnight Cost (2012$/kW)** | 2,477 | 4,548 | 4,024 | 3,587 |
| Bare Erected Cost | 1,629 | 2,836 | 2,521 | 2,270 |
| Home Office Expenses | 147 | 257 | 229 | 206 |
| Project Contingency | 224 | 465 | 406 | 350 |
| Process contingency | 0 | 131 | 102 | 64 |
| Owners Costs | 477 | 860 | 766 | 697 |
| **Total Overnight Cost (2012$x1,000)** | 1,362,516 | 2,501,457 | 2,337,245 | 2,191,483 |
| **Total As Spent Capital (2012$/kW)** | 2,809 | 5,185 | 4,587 | 4,089 |
| **Annual Fixed Operating Costs ($/yr)** | 39,039,238 | 66,263,173 | 62,361,303 | 58,791,430 |
| **Variable Operating Costs ($/MWh)** | 7.63 | 13.35 | 12.27 | 11.79 |
| **Fuel** | | | | |
| **Coal Price ($/ton)** | 69 | | | |

The comparison in LCOE between the DOE Cases 9 and 10, UK CAER process + MEA, and UK CAER process + H3-1 case is shown in Table 5-24. The evaluation results show that the UK CAER Process + H3-1 case has the following key advantages compared to the DOE/NETL Case 10:

- A lower COE by $25.32/MWh, a 16.92% reduction
- A lower LCOE by $31.94/MWh , also a 16.85% reduction
- A lower cost of $CO_2$ captured by $18.65/tonne, a 30.42% reduction
- A lower cost of $CO_2$ avoided by $34.95/tonne $CO_2$, a 38.68% reduction.
- A lower variable operating cost by $1.56/MWh, a 11.69% reduction.

The initial H3-1 filling cost was estimated at $10.3M, while the annual cost was estimated at $1.7M.

The COE and breakdown are graphycally compared in Figure 5-24.

**Table 5-24**
**Comparison of LCOE between the UK CAER + MEA, UK CAER + H3-1, and DOE Cases**

| | Case 9 | Case 10 | UK CAER + MEA 2020 Case | UK CAER + H3-1 2020 Case |
|---|---|---|---|---|
| **COE ($/MWh, 2012$)** | **83.19** | **149.65** | **135.71** | **124.33** |
| $CO_2$ TS&M Costs | | 5.8 | 5.49 | 5.16 |
| Fuel Costs | 27.43 | 38.57 | 36.53 | 34.73 |
| Variable Costs | 7.63 | 13.35 | 12.27 | 11.79 |
| Fixed Costs | 9.53 | 16.18 | 14.42 | 12.92 |
| Capital Costs | 38.59 | 75.75 | 67.00 | 59.73 |
| **LCOE (2012$/MWh)** | 105.36 | 189.59 | 172.08 | 157.65 |
| **Cost of $CO_2$ Captured ($/tonne $CO_2$)** | | 61.31 | 51.87 | 42.66 |
| **Cost of $CO_2$ Avoided ($/tonne $CO_2$)** | | 90.35 | 71.82 | 55.40 |

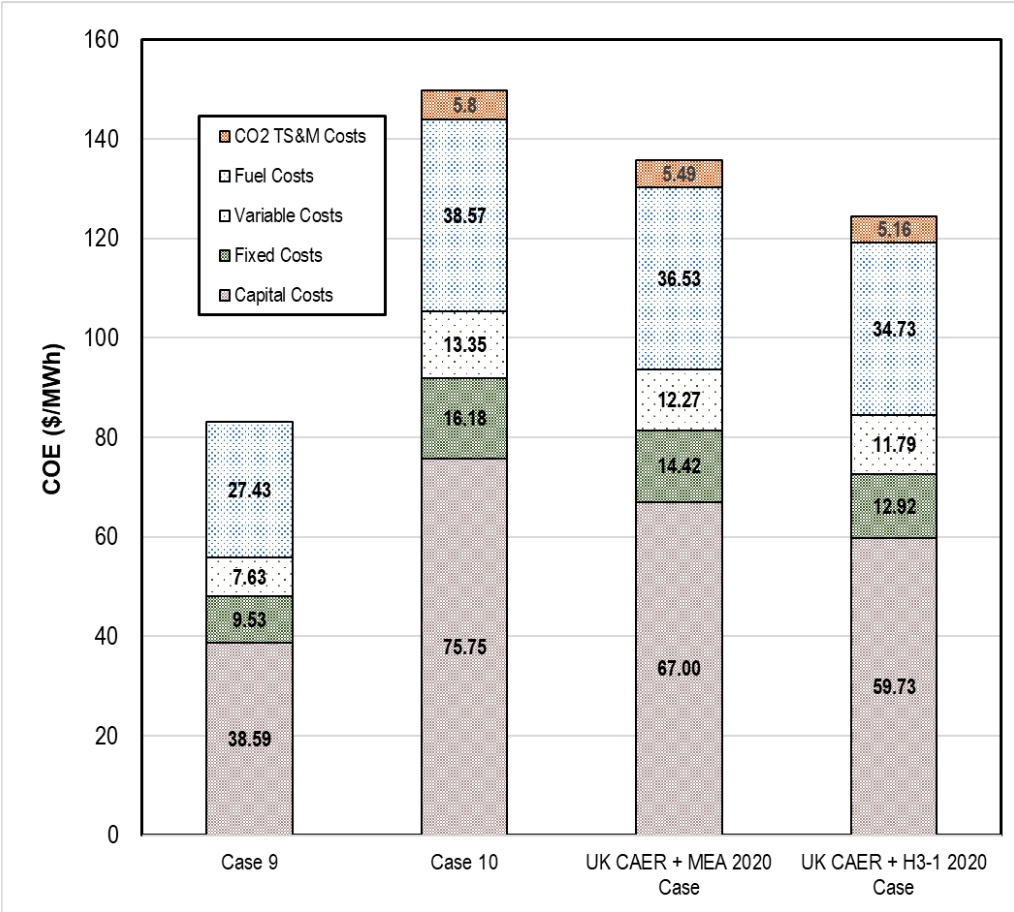


**Figure 5-4**
**Comparison and Breakdown of COE for the Hitachi, and DOE Cases**

### 5.2.4 Space Requirements for Commecial $CO_2$ Capture and Compression Plant

Based on several sudies and guildance on CCS plants land footprint requirements published by IEA Greenhouse Gas R&D Programme (IEA GHG)[9], United States Department of Energy/National Energy Technology Laboratory (DOE/NETL)[10,11], the Global Carbon Capture

[9] IEA Greenhouse Gas R&D Programme (IEA GHG), Retrofit of CO2 Capture to Natural gas Combined Cycle Power Plants (2005/1), prepared by Jacobs Consultancy Netherlands B.V. January 2005.

[10] United States of America Department of Energy/ National Energy Technology Laboratory DOE/NETL, Carbon Dioxide Capture from Existing Coal-Fired Power Plants, DOE/NETL-401/110907 prepared by Science Applications International Corporation (SAIC)/Research and Development Solutions (RDS) and Alstom Power Inc., Final Report, November 2007

[11] United States of America Department of Energy/ National Energy Technology Laboratory DOE/NETL, Carbon Sequestration Program Environmental Reference Document, DE-AT26-04NT42070, August 2007

and Storage Institute (GCCSI)[12] and Department of Energy and Climate Change (DECC)[13], as well as the CCS plant for the Petra Nova project, a minimum of 10 acres footprint is estimated to be needed for the proposed $CO_2$ capture and compression system when integrated into a 550 MW power plant for 90 % $CO_2$ capture. The specific breakdown is two acres for the absorber system, two acres for the stripper system, two acres for the compression system, two acres for the auxiliary boiler system, and two acres for other needs.

# 6 Potential Environmental Benefits

Potential improvements or enviornmental benefits are discussed in this section, and described below.

## 6.1 *Integration of the UK CAER process into a power plant cycle for efficiency improvement*

A typical wet cooling system consisting of a surface condenser, circulating water system and cooling tower results in turbine back pressures between two and five inches of mercury (1-2.5 psi), which is mostly driven by the ambient wet bulb temperatures and by the efficiency of the heat rejection system. Despite these high vacuum conditions in the condenser the amount of energy rejected from a typical steam cycle is very large – the total losses in a cycle are almost twice the amount of the electricity generated and most of these losses occur in the heat rejection system of the plant.

To maximize plant efficiency, it is therefore desirable to reduce the amount of heat rejected to the environment by condensing the turbine exhaust steam at the lowest possible temperature and corresponding pressure (turbine back pressure), which in turn can be achieved by minimizing the cooling water temperature entering the condenser. The liquid desiccant process proposed by UKRF as described later can be used for such purpose.

In the DOE/NETL Reference Cases 9 and 10, ambient conditions are stated as 59 $^{o}$F dry bulb temperature with 60% relative humidity, and the heat rejection system is designed to result in a cooling water temperature of 60 $^{o}$F at the inlet of the condenser, and 80 $^{o}$F at its discharge. This results in a steam turbine backpressure of approximately 2 inches Hg (Abs). Due to the lack of detailed information in the DOE reference report, the cooling tower liquid/gas ratio used as the basis for the DOE heat balance was estimated to be approximately 0.9, which is below the generic design standard of 1.3-1.7. For example, using annual average ambient conditions of the Midwest such as Kentucky, the liquid/gas ratio in the cooling tower based on 109 (cooling water return) – 89 (cooling water leaving) – 79 °F (wet-bulb temperature) would typically be designed at 1.7, according to a commercial cooling tower OEM.

[12] The Global Carbon Capture and Storage Institute (GCCSI), Defining CCS Ready: An Approach to an International Definition, prepared by ICF International and partners, 23rd February 2010.

[13] Department of Energy and Climate Change (DECC), Coal-Fired Advanced Supercritical Retrofit with CO2 Capture, Contract No.: C/08/00393/00/00 URN 09D/739, prepared by Doosan Babcock Energy Limited as part of the DTI Emerging Energy Technologies Programme/Technology Strategy Board, June 2009.

Steam turbines do not always operate at the design backpressure, but may operate at much higher back pressures due to higher cooling water temperatures caused by ambient conditions that are different from design condition. Based on data collected from one KU coal fired power plant, rated at 350 MWe, the average annual condenser pressure *is 3.98" Hg (abs)* and the maximum backpressure could be as high as 4.63" Hg (abs) during the summer time. On the other hand, the unit's 350 MW rating is at backpressure of 2" Hg (abs).

Based on the heat and material balance in the DOE Reference Case 10 (refer to Figure 6-1, below, or page 361 of DOE/NETL 2010 Report), Hitachi determined that a four-flow LP turbine section with a last stage blade length of 40 inches (TC4F-40) would be appropriate. However, if the condenser design pressure deviates from the 2 inches Hg (abs) that are indicated in the Reference Case 10 the performance of the plant would be significantly impacted and a different blade selection may be more appropriate. Hitachi conducted an estimate of the impact of a 4" Hg and 5"Hg condenser pressure on steam turbine power output based on the TC4F-40 design (refer to Table 6-1) and determined that an increase in exhaust pressure from 2" Hg (abs) to 4" Hg (abs) or 5" Hg (abs) results in an output reduction of approximately 43 MWe or 55MWe, respectively. Hence, if the average back pressure is higher than 2" Hg (abs) a shorter last stage blade and/or fewer exhaust ends may be more appropriate, subject to a cost/benefit analysis.

**Exhibit 4-26 Case 10 Heat and Mass Balance, Subcritical Steam Cycle**

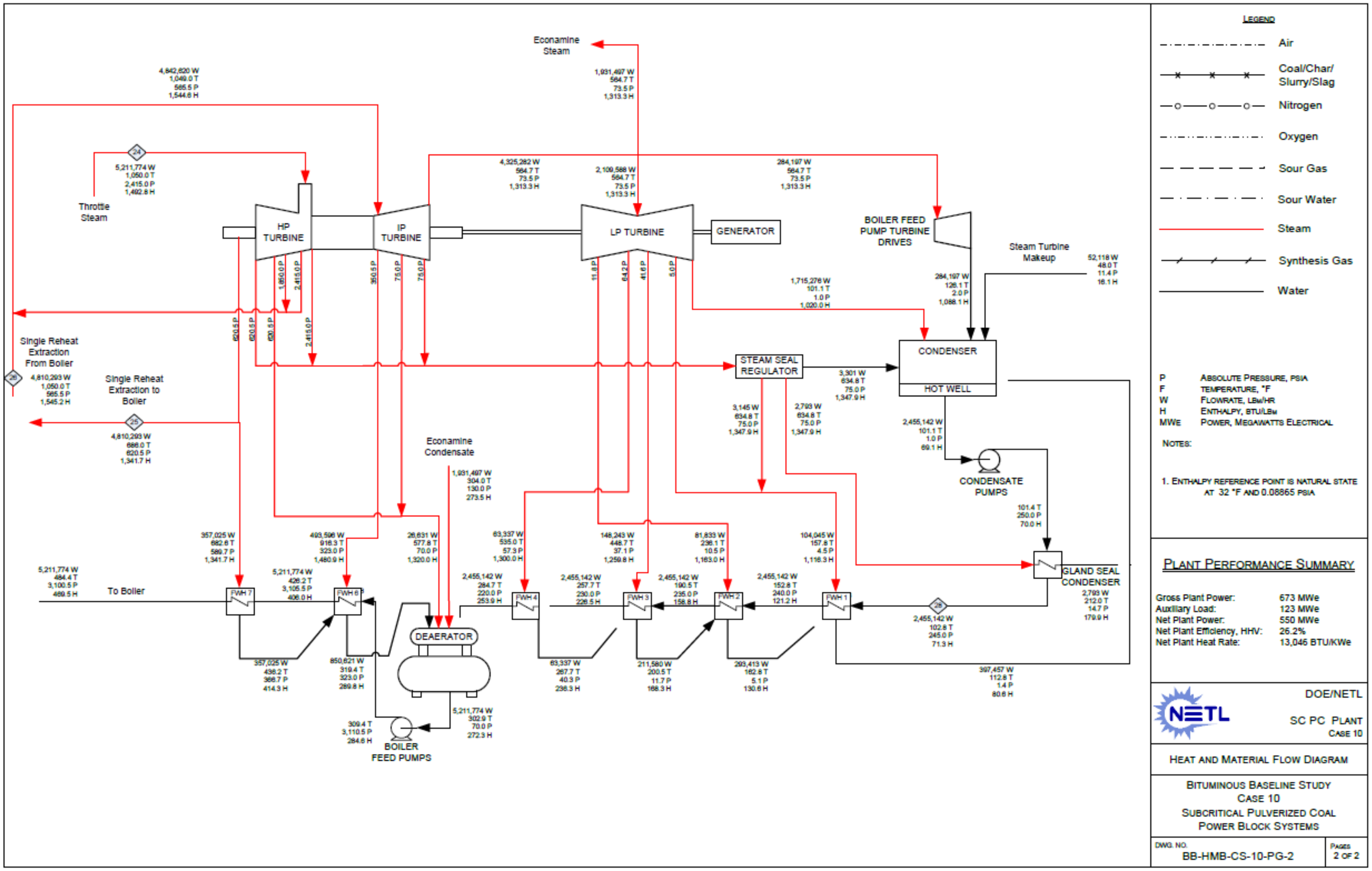

**Figure 6-1**
**Heat and Mass Balance, Subcritical PC Boiler with $CO_2$ Capture in DOE NETL 2010 Report**

**Table 6-1**
**Impact of Condenser Pressure on Steam Turbine Performance (TC4F-40)**

HITACHI
Inspire the Next

**Steam Turbine Performance Change if the Condenser Cold Water Temperature is Varied**

Revision 3 - 2012/11/09

This estimate is based on a simplified spreadsheet calculation and not on a detailed performance model. As a result, the accuracy is considered low.

The estimate is based on the information provided in DOE/NETL Case 10 Heat and Mass Balance, Subcritical Steam Cycle ("Base")

It was assumed that the DOE/NETL heat balance is based on a four-flow LP turbine section with a last stage blade length of 40 inches (4F-40), which is appropriate based on the steam conditions and condenser pressure provided. For significantly higher condenser pressures (such as 4 in HgA or 5 in HgA) the 4F-40 exhaust configuration is oversized and will result in very low exhaust velocities, high exhaust losses and associated vibration potential. Subject to a detailed analysis, continuous operation at such elevated exhaust pressures may not be recommended.

Simplifying Assumptions:

- Constant LPT Efficiency (exhaust losses are adjusted according to operating condition)
- No change in extraction design (i.e. same extraction pressures)
- Constant Condenser Range & TTD
- Constant Heater 1 TTD & DCA

| **Cold Water Temperature Differential** | **Temperature, C** | **Base** | **-3** | **13.5** | **18.1** |
|---|---|---|---|---|---|
| Cold Water Temperature to Condenser | | Base | Base - 5.40 F (-3.0 C) | Base + 24.27 F (13.5 C) | Base + 32.61 F (18.1 C) |
| Conditions Downstream of Heater 1 Extraction | | | | | |
| | Flow, lb/h | 1,715,276 | 1,702,513 | 1,772,631 | 1,792,355 |
| | Pressure, psia | 5.0 | 5.0 | 5.0 | 5.0 |
| | Temperature, F | 162.2 | 162.2 | 162.2 | 162.2 |
| | Enthalpy, Btu/lb | 1,109 | 1,109 | 1,109 | 1,109 |
| | Entropy, Btu/lb F | 1.8090 | 1.8090 | 1.8090 | 1.8090 |
| Conditions at LPT Exhaust | | | | | |
| | Flow, lb/h | 1,715,276 | 1,702,513 | 1,772,631 | 1,792,355 |
| | Pressure, in HgA | 2.0 | 1.7 | 4.0 | 5.0 |
| | Pressure, psia | 0.98 | 0.83 | 1.96 | 2.46 |
| | Temperature, F | 101.1 | 95.7 | 125.4 | 133.7 |
| | UEEP, Btu/lb | 1,020.0 | 1,014.7 | 1,106.1 | 1,127.8 |
| | Quality | 0.918 | 0.915 | 0.991 | 1.000 |
| **Differential Shaft Power** | **Output, MW** | **Base** | **2.3** | **(43.2)** | **(54.6)** |
| **Estimated Changes to Heater 1 Performance** | | | | | |
| Steam to Heater 1 | Flow, lb/h | 104,112 | 116,875 | 46,758 | 27,034 |
| | Pressure, psia | 4.50 | 4.50 | 4.50 | 4.50 |
| | Temperature, F | 157.8 | 157.80 | 157.80 | 157.80 |
| | Enthalpy, Btu/lb | 1,116.3 | 1,116.3 | 1,116.3 | 1,116.3 |
| Condensate to Heater 1 | Flow, lb/h | 2,455,142 | 2,455,142.00 | 2,455,142.00 | 2,455,142.00 |
| | Pressure, psia | 245.0 | 245.00 | 245.00 | 245.00 |
| | Temperature, F | 102.7 | 97.3 | 126.9 | 135.3 |
| | Enthalpy, Btu/lb | 71.3 | 66.0 | 95.5 | 103.9 |
| Drain to Heater 1 | Flow, lb/h | 293,413 | 293,413 | 293,413 | 293,413 |
| | Enthalpy, Btu/lb | 130.6 | 130.6 | 130.6 | 130.6 |
| Heater 1 Duty In, MBtu/h | | 329.7 | 330.7 | 325.1 | 323.5 |
| Condensate to Heater 2 | Flow, lb/h | 2,455,142 | 2,455,142 | 2,455,142 | 2,455,142 |
| | Pressure, psia | 240.0 | 240.00 | 240.00 | 240.00 |
| | Temperature, F | 152.7 | 152.7 | 152.7 | 152.7 |
| | Enthalpy, Btu/lb | 121.2 | 121.2 | 121.2 | 121.2 |
| Heater 1 Drain to Condenser | Flow, lb/h | 397,525 | 410,288 | 340,171 | 320,447 |
| | Pressure, psia | 1.40 | 1.40 | 1.40 | 1.40 |
| | Temperature, F | 112.6 | 112.6 | 112.6 | 112.6 |
| | Enthalpy, Btu/lb | 80.6 | 80.60 | 80.60 | 80.60 |
| Heater 1 Duty Out, MBtu/h | | 329.7 | 330.7 | 325.1 | 323.5 |

As stated above, a reduction of the turbine back pressure can be achieved by removing moisture content in the air through liquid desiccant as proposed by UKRF. The power generation efficiency, as illustrated in Figure 6-2, could be improved by 2.5% if the air relative humidity was decreased from 70% to 30% on a typical summer day (note that the power output correction in Figure 6-2 is based on correction curves provided in ASME PTC 6 and does not represent the output correction provided in Table 6-1 for the reference plant).

Besides utilizing low-quality heat from the carbon capture process for liquid desiccant regeneration, the utilization of flue gas sensible energy from the air preheater exhaust for the heat-integrated cooling tower is also possible. The technology to recover sensible heat from the air preheater exhaust has been developed by Hitachi. UKRF determined that utilizing such sensible heat can achieve a hot stream with 120 °C as terminal temperature if liquid desiccant is used as heat transfer media. The following describes the heat recovery process developed by Hitachi.

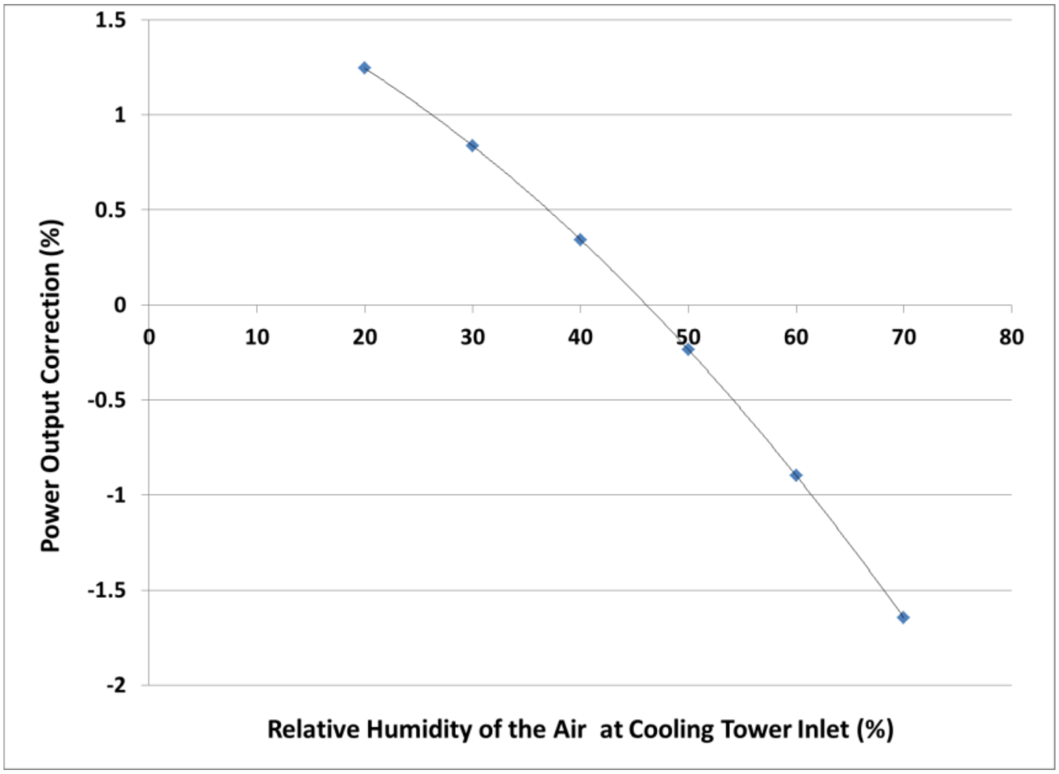


**Figure 6-2**
**The Impact of Relative Humidity on Overall Plant Thermal Efficiency at 90°F dry bulb temperature (Correction Curve was obtained from PTC Code for Steam Turbine)**

In a boiler system, the air preheater is typically the last means of extracting energy from the combustion flue gas prior to discharge to the stack. The design flue gas exit temperature from the air preheater can range from 280 °F to 350 °F, depending on the acid dew point temperature of the flue gas, which is dependent on the concentration of sulfur trioxide and moisture. If the plant is equipped with a wet flue gas desulfurization system, the flue gas is further cooled to approximately 125 °F in direct contact with the flue gas desulfurization reagent slurry. The heat removed from the flue gas between the air preheater outlet and the FGD is generally lost to the atmosphere. However, it is possible to recover some of this energy in the flue gas that would otherwise be lost, and return it to the water/steam cycle. Hitachi has developed such a heat exchanger, the Clean Energy Recuperator (CER), which was derived from Hitachi's patented high dust Gas-Gas-Heater (GGH) technology, which has been used successfully on five large supercritical coal-fired power plants in Japan.

The CER is a finned tube heat exchanger with the flue gas flowing over the tubes and the cooling medium within them. Located downstream of the air preheater and upstream of dust collecting and $SO_2$ removal equipment, it cools the flue gas, recovers a large amount of low grade energy and, due to its operation in high ash environment and the deep cooling of flue gas, removes almost all $SO_3$ in the flue gas.

By transferring the energy recovered from the above-described heat recovery process to the heat-integrated cooling tower system for liquid desiccant regeneration, UKRF has estimated that approximately 50% of the boiler dry flue gas heat loss can be recovered (approximately 3% of overall boiler heat input), which is equivalent to 47 MWt , based on the DOE Reference Case 9.

## 6.2 *Warm-weather Sensitivity Analysis for the Liquid Desiccant Drying System*

The design objective of the proposed liquid desiccant system is to recover low-quality heat from the CCS plant and flue gas such that the air supplied to an evaporative cooling system may be dried to effectively lower the operating wet bulb temperature. This in turn will have the effect of lowering the cooling water temperature supplied to the steam plant condenser. This operation will allow for increased efficiency in warm-weather months that are typical throughout the eastern and mid-western United States. The key to the effectiveness of such a massive drying system will be the availability of waste heat from various sources within power plant equipped with CCS. Additionally, the cost of increased fan and pump power should be minimized to make the additional efficiency savings both feasible and cost-effective.

A sensitivity study was performed using an Aspen Plus® process simulation to estimate degree of the ambient wet-bulb temperature depression possible and the corresponding power requirements for additional fan/pump power along with waste heat requirements to drive the thermal regeneration of the brine. The design basis of the study included an evaporative cooling tower system connected to a 2000 MMBtu/hr steam condenser that is in line with the DOE base case. For the purpose of the study, the ambient design basis was modified to use 90 $^{o}$F (32.2$^{o}$C) ambient air instead of the 59 $^{o}$F (15 $^{o}$C) DOE test case to gauge the feasible efficiency improvements during the warm-weather seasons.

As previously stated, the proposed desiccant system will consist of a dehydration tower for the drying of incoming air destined for the main evaporative cooling tower and a water-rich brine regenerator tower to remove excess moisture from a the brine. The brine mixture used for this study was a 50wt% (with a maximum of 55% wt) $CaCl_2$ water solution. The brine is contacted with moist ambient air in the dehydration tower. The resulting water-rich brine will have a higher temperature than that of the incoming brine as a result of the latent heat of the water vapor removed. In the simulation, the water-rich brine collected in the dehydration tower is pumped to a series of heat exchangers representing heat loads from various parts of the CCS plant and possibly flue gas heat recovered past the recuperative air heater.

As the water-rich brine gains additional waste heat enthalpy, its temperature rises accordingly, reaching a range of 120 (48.9 $^{o}$C) to 180 $^{o}$F (82.2 $^{o}$C), depending on the temperature of the waste heat sources available. With this increased brine temperature, the water vapor pressure is increased. Consequently, the water-rich brine may be regenerated in a separate tower by contacting it with ambient air. The excess water vapor is released at the exhaust of the tower where a portion is ducted to the air-stripping unit in the CSS process. Air, in excess of the air stripping requirements, is vented to the atmosphere. The parasitic electric load for the desiccant system will be from the two pumps required to move the brine solution between the two towers and the fan power for the blower used in the dehydration tower. Additional fan energy will be required to overcome the increased pressure drop in the main evaporative cooling tower connected in series with the dehydration tower. In order to minimize parasitic energy requirements for the proposed air drying system, the air flow rate supplied to the brine regeneration system should be kept well below that used for the main evaporative cooling tower. Likewise, brine liquid flows should be kept low enough only to allow a favorable equilibrium between moisture absorption at low temperature and evaporation at regenerator temperatures. Obviously, the waste heat needed to drive the desiccant regeneration process needs to be within the inventory of available waste heat available in the CCS plant and from the flue gas.

EPRI's initial model of the dehydration system was modified for the current sensitivity study. The thermodynamics were based on the NRTL/Electrolyte model. Airflow through the main evaporative cooling tower was kept as a constant 2.0419E+8 lbs/hr. The $CaCl_2$ desiccant solution (at 50 wt% aqueous mixture) was fixed at 9.118E+7 lbs/hr. Therefore, the L/G ratio in the dehydration was fixed at 0.45 lbs desiccant per lb of air treated. Since the desiccant solution flow rate was held constant, the pumping power for the two pumps was fixed at 1.8MWe. All of the unit operations involving mass transfer calculations were based on vapor liquid equilibrium models.

### 6.2.1 Effect of Ambient Air Relative Humidity

As previously mentioned, the original design basis of the DOE was modified to investigate the effectiveness of the desiccant drying system over warm weather periods experienced in most areas of the United States. For the purposes of this sensitivity study, the ambient dry bulb temperature was fixed at 90 $^{o}$F (32.2 $^{o}$C) with the relative humidity varied from 40 to 66% that translates to a variation in wet-bulb temperature from about 73 to 80$^{o}$F, respectively. The airflow rate to the regenerator was fixed at 6.0E+7 lbs/hr (or 30% of the mass of air treated in the dehydration tower) over the range of RH studied. A thermal chiller load of 10 MWth was extracted from the incoming lean-brine to help the model converge.

As shown in Figure 6-3, with increasing relative humidity, the equilibrium water vapor pressure over the desiccant will increase accordingly. Thus, to maximize the wet-bulb depression, the quantity of waste heat required for keeping the system in balance increases proportionately from 40 to 340 MWth. The model indicates that the wet bulb depression (or the difference between the ambient and dried-air wet bulb temperatures) was between 6 to 7 $^{o}$F over range of 40-66% RH, respectively, that will result in additional 13.1 to 15.1MWe electricity output at the generator terminal if the backpressure is originally run with 4" Hg (abs).

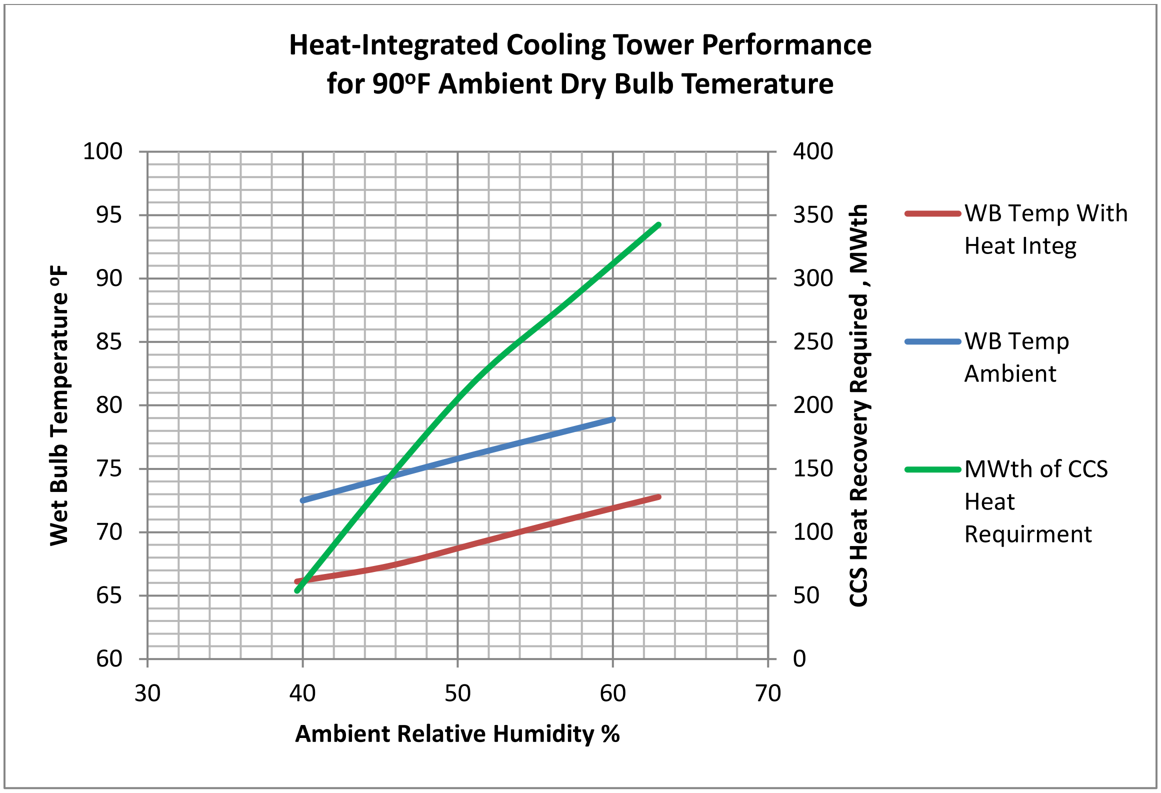


**Figure 6-3**
**Aspen Plus® model results showing the effect of ambient relative humidity at a constant dry-bulb temperature of 90 °F on dried gas wet-bulb and dehydration energy requirements**

### 6.2.2 Sensitivity of Brine Regenerator Air Flow to Wet-bulb Depression and Waste Heat Recovery

One of the key design variables for the desiccant drying system will be the quantity of airflow required to regenerate the moisture-laden desiccant. Effectively, the power source to drive this regeneration will be from the low quality heat recovered from various sources within the CCS plant and the flue gas. However, additional ambient air must be provided via a blower to reach equilibrium with the desiccant at higher temperature to vaporize moisture. Hopefully, this quantity of airflow will be substantially less than that of the air being dried for the main evaporative cooling system

For the above-mentioned model constants, the airflow to the desiccant regenerator was varied from 4.00E+7 to 1.00E+8 lbs/hr, which is approximately 20% to 50% of the total air, treated in the dehydration tower, respectively. The fan power for this range of airflow varied from 0.5 to 1.4 MWe, respectively. Additionally, a chiller load of 5 MWth was included to lower the incoming lean-desiccant temperature to the dehydration tower. The model was iterated to solve for the amount of waste energy required to equalize both the temperature and the exiting $CaCl_2$ concentration with that of the incoming brine (water-lean desiccant) entering the dehydration tower over the range of airflow considered. In theory, more regenerator airflow will result in more favorable water equilibrium in the vapor phase requiring less energy for driving the dehydration process at the expense of fan power.

The results of the model iterations in terms of the wet bulb temperature depression achieved in the evaporative cooling tower and waste heat required over the range of regenerator airflow are shown in Figure 6-4. The ambient wet bulb for the ambient condition considered (90 °F dry bulb temperature at 60% RH) was 79 °F (26.1 °C). As expected, the wet-bulb depression increased proportionately with the regenerator airflow while the required waste recovery to drive the desiccant regeneration varied inversely with airflow. Toward the low end of the regenerator airflow, the model had difficulty converging and became unstable. To remedy this, the convergence criterion was initially lowered for the first point to start the calculations. This is likely why power curve slope tends to flatten in the low end of the airflow range.

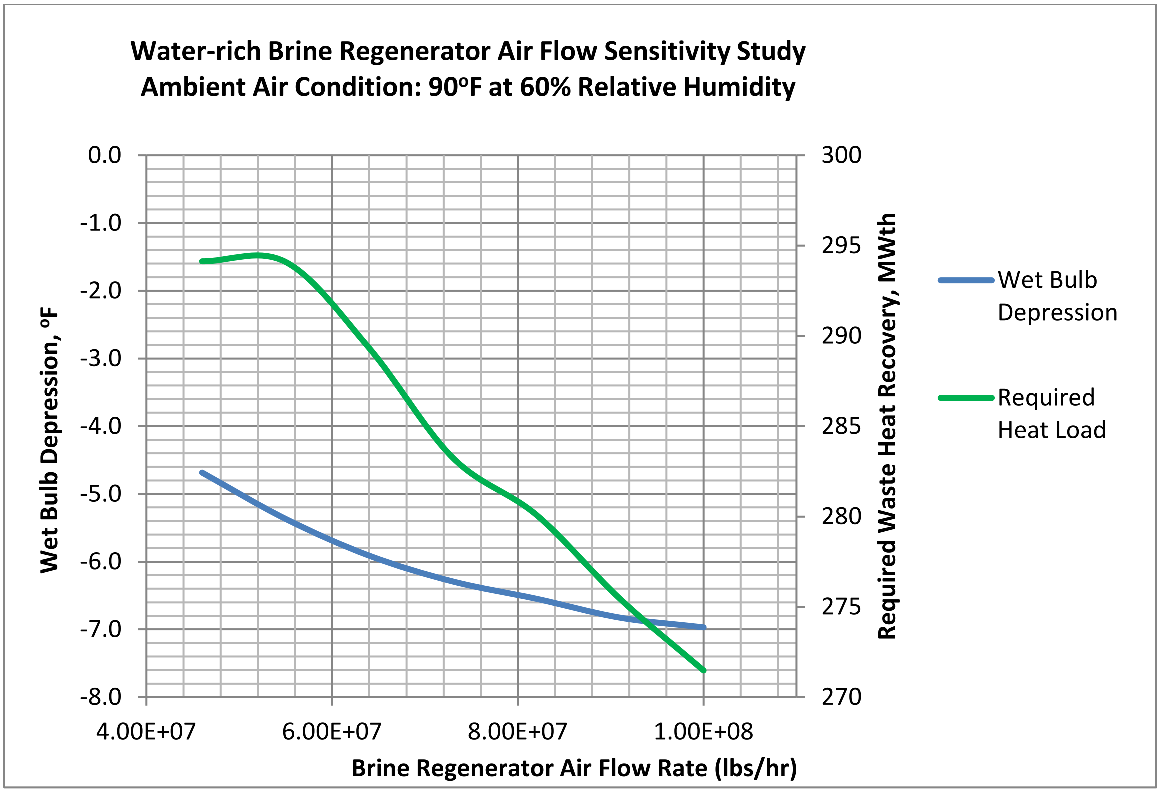


**Figure 6-4**
**Air Flow Rate to the Brine Regenerator Tower (30% to 50% of the main cooling tower air flow)**

# A APPENDICES

## A.1 The selection of flue gas extraction location for slipstream facility

During the kick-off meeting at NETL in October 2011, the flue gas extraction for the slipstream facility was discussed. Initially the UKRF team proposed to extract flue gas from the location prior to WFGD (where the water vapor is approximately 8% vol) to decrease water balance concerns and potentially reduce the slipstream facility complexity because the water removal from the saturated flue gas stream at WFGD (the water vapor is approximately 18%) was thought to be commercially available at present. In that plan, the makeup water for water wash at the top section of $CO_2$ absorber and air stripper would be collected and sent to the flue gas pre-treatment tower for flue gas direct cooling and $SO_2$ removal.  However, extracting flue gas after the WFGD is more realistic since most units will be equipped with desulfurization units when $CO_2$ capture regulation is applied in the future, and one of the slipstream demonstration project objectives is to obtain first-hand experience for future system design and operation. Consequently, UKRF has selected to extract flue gas at the WFGD scrubber exit and return the processed gas stream to the inlet of WFGD to eliminate the potential concern of emissions from the carbon capture facility.

For the slipstream facility several measures have been evaluated to address the water balance issue caused by water content in the stream entering the CCS block (approximately 18% vol) and leaving the CCS block (approximately 8% vol), which include chilling the flue gas to 30$^{o}$C, immersed EHX with glycol chilling cycle, direct cooling using cooling water, and direct cooling with external EHX using a glycol chilling unit. In order to increase the flexibility of the slipstream facility and handle flue gas constituents at various concentrations, the approach of direct cooling with external EHX using a glycol chilling unit is selected to cool the flue gas to 30$^{o}$C and polish the $SO_2$ concentration to below 10 ppm. The water condensed here will be sent to the WFGD blow-down loop for treatment.

Of course, as expected, this process modification has resulted in higher capital cost than originally estimated for the slipstream facility.

## A.2 Corrosion and Steel Selection

The materials of construction are critical for amine acid gas treating plants with corrosion being a significant concern in the selection. The selection of carbon steel for the bulk of the plant design here was based on extensive electrochemical tests, and traditional coupon tests on carbon steel A106 have been carried out in the aqueous environment at our UK CAER research facility. For instance, using MEA (no corrosion inhibitor) as a generic solvent, the effect of solution temperature, and $CO_2$ loading in MEA without the use of corrosion inhibitors on steel corrosion was investigated. The corrosion rate of carbon steel A106 increases at higher temperature because both anodic and cathodic reactions proceed faster due to the fact that molecules have higher thermal energy at 80 °C. This is reflected in a higher calculated corrosion rate of 0.62 vs. 0.04 mmpy, as indicated in Table A-1.

**Table A-1**
**Summary of electrochemical parameters and corrosion rate of carbon steel A106 in MEA-$H_2O$-$CO_2$ systems**

| No. | $CO_2$ loading (mol/mol MEA) | Temper-ature (°C) | $O_2$ percentage (%) | $I_{corr}$ (μA) | $E_{corr}$ (mV vs. SCE) | Corrosion Rate (mmpy) | $\beta_a$ (mV/ decade) | $i_{crit}$ (μA/cm$^2$) | $i_{pass}$ (μA/cm$^2$) | $E_b$ (mV) |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 0.2 | 40 | 0 | 18.2 | -885.3 | 0.04 | 146.8 | -18.7 | -0.9 | 544 |
| 2 | 0.2 | 80 | 0 | 227.2 | -880.3 | 0.53 | 99.5 | -281.7 | -1.5 | 456 |
| 3 | 0.5 | 40 | 0 | 79.1 | -810.1 | 0.18 | - | -18.3 | -1.9 | 715 |
| 4 | 0.5 | 80 | 0 | 359.1 | -853.3 | 0.83 | 110.2 | -778.9 | -3.4 | 623 |

The effects of $CO_2$ loading in solution show that the polarization curve obtained from the electrochemical run with $\alpha = 0.5$ shifts towards the right with higher measured current density at both 40 °C and 80 °C. The current density of the curves is the total cell current density, which was contributed by both the anodic and the cathodic currents. Therefore, higher iron dissolution and cathodic reduction rate with higher $CO_2$ loading can be expected. This indicated that the carbon steel corrodes faster with higher $CO_2$ loading. From Figure A-1, it can be seen that the corrosion rate increases from 0.02 to 0.06 mmpy and 0.62 to 0.83 mmpy when $CO_2$ loading is raised from 0.2 to 0.5 at 40 °C and 80 °C, respectively.

The increase in corrosion rate in rich MEA solution is due to the rise in oxidizer concentration. Bicarbonate ion is a primary oxidizing agent in aqueous amine-$CO_2$ systems and the reduction of bicarbonate ion is as in the equation of $2HCO_3^- + 2e^- \leftrightarrow 2CO_3^{2-} + H_2$ (g). According to Veawab et al., $HCO_3^-$ plays a significant role in corrosion due to its high rate of reduction while $H_3O^+$ contributes less to corrosion because of its extremely low concentration in amine solutions. Higher $CO_2$ loading increase results in an increase of oxidizer $HCO_3^-$concentration considering the basic environment of MEA.

Data was collected from UK CAER's electrochemistry corrosion cell at given conditions, as listed in Table A-2. For the representative carbon steel, the H3-1 solvent exhibits a dramatically lower corrosion rate (greater than one order of mag\nitude) compared to MEA regardless of the temperature measured. When considering a representative stainless steel, H3-1 exhibits similar corrosion rate at low temperature but approximately half the corrosion rate at high temperature. It should be noted that the above corrosion data was obtained through short duration tests. Therefore, the values, especially at low corrosion rate, may include significant measurement uncertainties.

**Table A-2**
**Comparative corrosion data as measure using electrochemical method for Hitachi H3-1 and 30 wt% MEA measured at rich conditions (0.5 mol C/mol N).**

| Solvent | Temperature (ºC) | Corrosion rate (mmpy) | |
|---|---|---|---|
| | | H3-1 | 5M MEA |
| Carbon steel A106 | 40 | 0.029 | 0.79 |
| | 90 | 0.350 | 4.97 |
| Stainless steel 304 | 40 | 0.037 | 0.033 |
| | 90 | 0.104 | 0.187 |

Overall, the potential for significant corrosion will occur at high temperature and high carbon loading spots, e.g. the hot end of L/R Heat Exchanger and the top of stripper. As result, high corrosion resistance metal such as stainless steel is selected for high carbon loading and high temperature areas of the plant while remaining parts utilize carbon steel.

## *A.3 Commercial deployment/technology transfer for UK CAER heat integrated system*

If we are to continue using coal while simultaneously addressing climate change, international cooperation to develop new, environmentally sound coal-based technologies that are deployable in both developing and industrialized countries must be addressed. In response to this urgent need, in November 2009, President Barack Obama and President Hu Jintao announced the establishment of the Clean Energy Research Center (CERC). On November 17,2009, U.S. Secretary of Energy Steven Chu, Chinese Minister of Science and Technology Wan Gang, and Chinese National Energy Administrator Zhang Guobao signed the U.S.-China CERC Protocol, launching the CERC. The primary purpose of the CERC is to facilitate joint research, development, and commercialization of clean energy technologies between U.S. and China.

Within the three current CERC programs, the Clean Coal, including Carbon Capture and Sequestration (CCS), program addresses technology and practices for clean coal utilization and carbon capture, utilization, and storage.  In 2010, US DOE selected the West Virginia University (WVU) –led consortium, including University of Kentucky Center for Energy Research as one of the few main partners, under DOE award DE- PI0000017. In the Consortia, Dr. Kunlei Liu is the PI for Task 5 – Novel $CO_2$ Capture covering pre-, post- and oxyfuel combustion.

Using the exchange platform established through US-China CERC, a working relationship has built between UK CAER and China Huaneng Clean Energy Research Institute, and between UK CAER and Sinopec Shengli Oil Field Company.  Huaneng Clean Energy Research Institute, as PI, has constructed a 160,000 ton/year post-combustion $CO_2$ capture demonstration plant at Shanghai Shidongkou Power Plant in 2009 which has been successfully run for over a few thousands of hours.

The Sinopec Shengli Oil Field Company has built a 40ton/day post-combustion $CO_2$ capture plant in one of its power plants located at Dongyin, Shandong province, and is currently in the process of selecting a technology to build a 1Mton/year post-combustion $CO_2$ capture plant for its EOR operation in 2015. UK CAER has been informed that this company has very strong interests in the heat-integrated process UKy is currently developing under this slipstream project. A delegation from Shengli Oil Field Company has scheduled to visit UK CAER for discussion of collaboration in January, 2013. If successful, this international cooperation could potentially lead to a technology transfer to Asia and maintain US as the leading technology provider.

## *A.4 Auxillary Boiler and Backpressure Steam Turbine for Existing Plant Retrofit*

The heat integration of the UK CAER process is a scheme in which the heat integration does not impact the main turbine steam cycle. For example there is no waste heat from the CCS block used to heat steam for the turbine cycle in this intial TEA report. Doing so has too large of an impact on the steam extraction point as described below.

An auxillary boiler with back pressure turbine to provide steam for solvent regeneration. To maintain a 575 MWe net power output for external grid demand, for UKRF Heat-integrated process with 30% MEA as solvent, an extra 34% coal compared to DOE Reference Case 9 will be burned to generate steam for (a) 75.7 MWe electricity production which will off-set the $CO_2$ capture auxiliaries consumption; and (b) 1694 MBtu/hr low pressure (LP) stream (78 psia and 551$^o$F) for solvent regeneration in the reboiler which is equivalent to approximately 50% of steam flowing into the low pressure steam turbine. With the capacity factor for a selected carbon capture process between 80-85%, absence of 40% low pressure steam extraction demanded by CCS after retrofitted could force the main plant to shut-down which will potentially drag the overall plant capacity factor down to 70%; (2) the routine cyclic loading change for any giving power generation unit. The $CO_2$ capture process requires minimum steam pressures to regenerate the solvent effectively. Initially, the location of the steam extraction can be determined by the pressure profile across the steam turbine. However, as the steam turbine load is decreased, the pressure at a selected extraction point decreases, and will post a tremendous challenge for retrofitting because of significant changes in steam thermodynamics at the low pressure turbine after approximately 40% steam is extracted for solvent regeneration requirements. Therefore, to maintain a constant extraction steam pressure will require multiple locations that will increase the cost and system complexity; (3) for a typical subcritical steam cycle, the pressure of cross-over steam between IP and LP turbine is in the range of 73-78 psia with an enthalpy of 1313.3 Btu/lb steam . On the other hand, the steam pressure required for the reboiler is only between 45-50 psia with enthalpy 1290 Btu/lb steam. In order to take advantage of the difference between those two steam parameters, a lay-down turbine has been suggested by others to generate approximately 10.5MWe which could improve the overall plant efficiency by 0.5 percentage points. However, the variation of LP steam due to external load changes will make the realization of this benefit much more difficult.

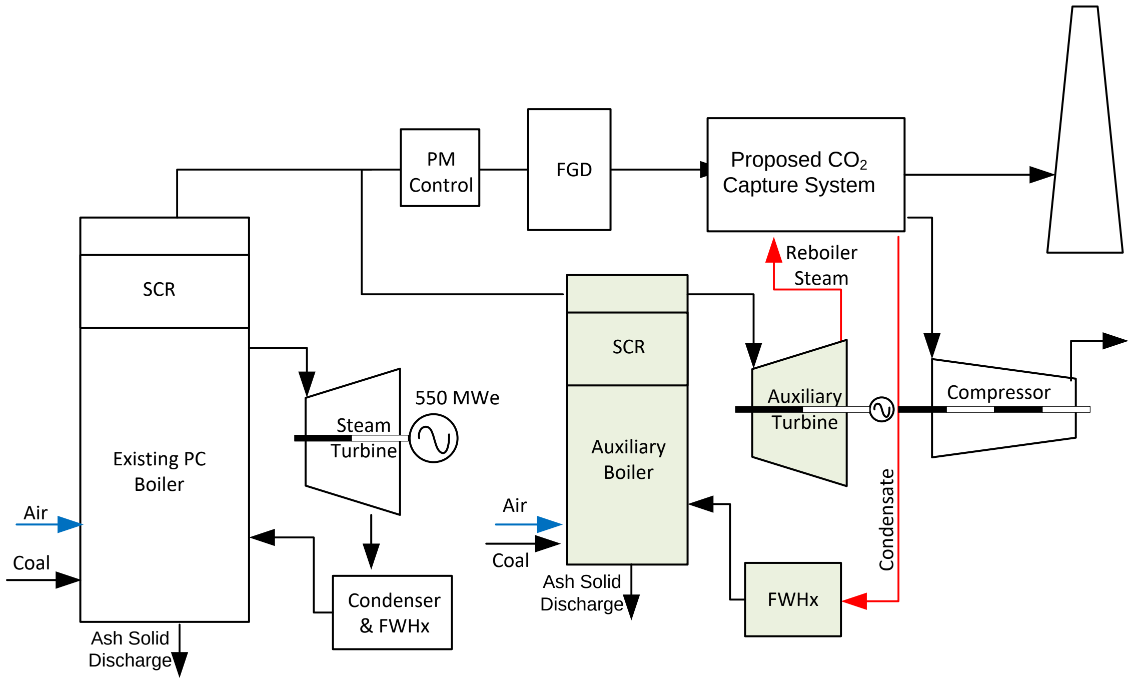


**Figure A-1**
**The flowchart of auxiliary unit for $CO_2$ capture process**

Instead of extracting steam from existing steam turbines, an alternative approach to shortcut the challenges for retrofitting mentioned above is utilized – constructing a stand-alone intermediate-pressure boiler with the back-pressure steam for single-unit power plant or retrofitting one power train with back-pressure steam turbine for the multi-unit power plant, as illustrated in Figure A-1. The power produced will be make-up power for the extra auxiliaries and compression train. The application of a back-pressure steam turbine will eliminate the need for a condenser and guarantee the overall thermal efficiency of a newly-constructed unit to be above 80% which is at least 20 points higher than natural gas combined cycle (NGCC). A carbon-neutral biomass fuel, or even natural gas (NG) could be the feedstock for the make-up boiler. On the other hand, the makeup boiler will only be equipped with SCR for NOx reduction if needed. The exhaust flue gas stream after the SCR will combine with main flue gas stream prior to the in-duct cooling section in the proposed $CO_2$ capture process. $SO_2$ in the flue gas stream from the makeup boiler will be removed by aqueous ammonia solution in the pre-treatment tower. This alternative approach will also give more flexibility to operate both units.

## *A.5 Updated DOE Cases 9 and 10 Results*

**Table A-3**
**Summary of Updated Capital Costs for DOE Bituminous Coal Baseline Case 9**

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Client:** | EPRI | | | | | | | | **Report Date:** | 2012-Aug-23 | | |
| **Project:** | Post-Combustion CO2 Capture | | | | | | | | | | | |
| | **TOTAL PLANT COST SUMMARY** | | | | | | | | | | | |
| **Case:** | Baseline Case 9 - 1x550 MWnet SubCritical PC | | | | | | | | | | | |
| **Plant Size:** | 550.1 MW,net | | **Estimate Type:** Conceptual | | | | **Cost Base (Jan)** | | 2012 | ($x1000) | | |

| Acct No. | Item/Description | Equipment Cost | Material Cost | Labor Direct | Labor Indirect | Sales Tax | Bare Erected Cost $ | Eng'g CM H.O.& Fee | Contingencies Process | Contingencies Project | TOTAL PLANT COST $ | TOTAL PLANT COST $/kW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | COAL & SORBENT HANDLING | $21,020 | $5,351 | $12,487 | $0 | $0 | **$38,858** | $3,405 | $0 | $6,339 | **$48,603** | $88 |
| 2 | COAL & SORBENT PREP & FEED | $14,155 | $782 | $3,560 | $0 | $0 | **$18,497** | $1,572 | $0 | $3,010 | **$23,079** | $42 |
| 3 | FEEDWATER & MISC. BOP SYSTEMS | $49,628 | $0 | $23,266 | $0 | $0 | **$72,894** | $6,414 | $0 | $12,997 | **$92,305** | $168 |
| 4 | PC BOILER | | | | | | | | | | | |
| 4.1 | PC Boiler & Accessories | $165,013 | $0 | $105,843 | $0 | $0 | **$270,856** | $25,677 | $0 | $29,653 | **$326,186** | $593 |
| 4.2 | SCR (w/4.1) | $0 | $0 | $0 | $0 | $0 | **$0** | $0 | $0 | $0 | **$0** | $0 |
| 4.3 | Open | $0 | $0 | $0 | $0 | $0 | **$0** | $0 | $0 | $0 | **$0** | $0 |
| 4.4-4.9 | Boiler BoP (w/ ID Fans) | $0 | $0 | $0 | $0 | $0 | **$0** | $0 | $0 | $0 | **$0** | $0 |
| | **SUBTOTAL 4** | **$165,013** | **$0** | **$105,843** | **$0** | **$0** | **$270,856** | **$25,677** | **$0** | **$29,653** | **$326,186** | **$593** |
| 5 | FLUE GAS CLEANUP | $104,340 | $0 | $34,777 | $0 | $0 | **$139,117** | $12,787 | $0 | $15,190 | **$167,094** | $304 |
| 5B | $CO_2$ REMOVAL & COMPRESSION | $0 | $0 | $0 | $0 | $0 | **$0** | $0 | $0 | $0 | **$0** | $0 |
| 6 | COMBUSTION TURBINE/ACCESSORIES | | | | | | | | | | | |
| 6.1 | Combustion Turbine Generator | N/A | $0 | N/A | $0 | $0 | **$0** | $0 | $0 | $0 | **$0** | $0 |
| 6.2-6.9 | Combustion Turbine Other | $0 | $0 | $0 | $0 | $0 | **$0** | $0 | $0 | $0 | **$0** | $0 |
| | **SUBTOTAL 6** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** |
| 7 | HRSG, DUCTING & STACK | | | | | | | | | | | |
| 7.1 | Heat Recovery Steam Generator | N/A | $0 | N/A | $0 | $0 | **$0** | $0 | $0 | $0 | **$0** | $0 |
| 7.2-7.9 | HRSG Accessories, Ductwork and Stack | $22,521 | $1,217 | $15,123 | $0 | $0 | **$38,861** | $3,460 | $0 | $5,515 | **$47,836** | $87 |
| | **SUBTOTAL 7** | **$22,521** | **$1,217** | **$15,123** | **$0** | **$0** | **$38,861** | **$3,460** | **$0** | **$5,515** | **$47,836** | **$87** |
| 8 | STEAM TURBINE GENERATOR | | | | | | | | | | | |
| 8.1 | Steam TG & Accessories | $66,000 | $0 | $7,620 | $0 | $0 | **$73,620** | $6,401 | $0 | $8,002 | **$88,024** | $160 |
| 8.2-8.9 | Turbine Plant Auxiliaries and Steam Piping | $31,679 | $1,267 | $15,451 | $0 | $0 | **$48,397** | $3,919 | $0 | $7,313 | **$59,629** | $108 |
| | **SUBTOTAL 8** | **$97,679** | **$1,267** | **$23,072** | **$0** | **$0** | **$122,017** | **$10,321** | **$0** | **$15,315** | **$147,653** | **$268** |
| 9 | COOLING WATER SYSTEM | $16,363 | $8,446 | $14,954 | $0 | $0 | **$39,763** | $3,605 | $0 | $5,882 | **$49,250** | $90 |
| 10 | ASH/SPENT SORBENT HANDLING SYS | $5,814 | $169 | $7,464 | $0 | $0 | **$13,446** | $1,239 | $0 | $1,510 | **$16,195** | $29 |
| 11 | ACCESSORY ELECTRIC PLANT | $21,183 | $8,327 | $22,619 | $0 | $0 | **$52,130** | $4,482 | $0 | $7,032 | **$63,644** | $116 |
| 12 | INSTRUMENTATION & CONTROL | $10,641 | $0 | $10,726 | $0 | $0 | **$21,367** | $1,883 | $0 | $2,868 | **$26,117** | $47 |
| 13 | IMPROVEMENTS TO SITE | $3,413 | $1,962 | $7,318 | $0 | $0 | **$12,692** | $1,254 | $0 | $2,789 | **$16,735** | $30 |
| 14 | BUILDINGS & STRUCTURES | $0 | $28,314 | $27,159 | $0 | $0 | **$55,473** | $4,908 | $0 | $15,095 | **$75,476** | $137 |
| | **TOTAL COST** | **$531,770** | **$55,835** | **$308,367** | **$0** | **$0** | **$895,972** | **$81,005** | **$0** | **$123,197** | **$1,100,174** | **$2,000** |

**Table A-4**
**Detailed Updated Capital Costs for DOE Bituminous Coal Baseline Case 9**

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Client:** | EPRI | | | | | **Report Date:** | 2012-Aug-23 |
| **Project:** | Post-Combustion CO2 Capture | | | | | | |
| | **TOTAL PLANT COST SUMMARY** | | | | | | |
| **Case:** | Baseline Case 9 - 1x550 MWnet SubCritical PC | | | | | | |
| **Plant Size:** | 550.1 MW,net | **Estimate Type:** | Conceptual | **Cost Base (Jan)** | 2012 | ($x1000) | |

| Acct | | Equipment | Material | Labor | | Sales | Bare Erected | Eng'g CM | Contingencies | | TOTAL PLANT COST | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| No. | Item/Description | Cost | Cost | Direct | Indirect | Tax | Cost $ | H.O.& Fee | Process | Project | $ | $/kW |
| 1 | COAL & SORBENT HANDLING | | | | | | | | | | | |
| 1.1 | Coal Receive & Unload | $4,320 | $0 | $1,956 | $0 | $0 | $6,276 | $543 | $0 | $1,023 | $7,842 | $14 |
| 1.2 | Coal Stackout & Reclaim | $5,583 | $0 | $1,254 | $0 | $0 | $6,837 | $579 | $0 | $1,112 | $8,528 | $16 |
| 1.3 | Coal Conveyors | $5,191 | $0 | $1,241 | $0 | $0 | $6,432 | $545 | $0 | $1,047 | $8,024 | $15 |
| 1.4 | Other Coal Handling | $1,358 | $0 | $287 | $0 | $0 | $1,645 | $139 | $0 | $268 | $2,052 | $4 |
| 1.5 | Sorbent Receive & Unload | $173 | $0 | $52 | $0 | $0 | $225 | $19 | $0 | $37 | $281 | $1 |
| 1.6 | Sorbent Stackout & Reclaim | $2,795 | $0 | $508 | $0 | $0 | $3,302 | $278 | $0 | $537 | $4,118 | $7 |
| 1.7 | Sorbent Conveyors | $997 | $214 | $242 | $0 | $0 | $1,454 | $122 | $0 | $236 | $1,812 | $3 |
| 1.8 | Other Sorbent Handling | $602 | $140 | $313 | $0 | $0 | $1,056 | $90 | $0 | $172 | $1,318 | $2 |
| 1.9 | Coal & Sorbent Hnd.Foundations | $0 | $4,997 | $6,635 | $0 | $0 | $11,631 | $1,089 | $0 | $1,908 | $14,628 | $27 |
| | **SUBTOTAL 1.** | **$21,020** | **$5,351** | **$12,487** | **$0** | **$0** | **$38,858** | **$3,405** | **$0** | **$6,339** | **$48,603** | **$88** |
| 2 | COAL & SORBENT PREP & FEED | | | | | | | | | | | |
| 2.1 | Coal Crushing & Drying | $2,481 | $0 | $479 | $0 | $0 | $2,960 | $250 | $0 | $481 | $3,691 | $7 |
| 2.2 | Coal Conveyor to Storage | $6,352 | $0 | $1,374 | $0 | $0 | $7,726 | $653 | $0 | $1,257 | $9,637 | $18 |
| 2.3 | Coal Injection System | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 2.4 | Misc.Coal Prep & Feed | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 2.5 | Sorbent Prep Equipment | $4,750 | $204 | $978 | $0 | $0 | $5,931 | $500 | $0 | $965 | $7,395 | $13 |
| 2.6 | Sorbent Storage & Feed | $572 | $0 | $217 | $0 | $0 | $790 | $68 | $0 | $129 | $986 | $2 |
| 2.7 | Sorbent Injection System | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 2.8 | Booster Air Supply System | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 2.9 | Coal & Sorbent Feed Foundation | $0 | $578 | $511 | $0 | $0 | $1,090 | $101 | $0 | $179 | $1,369 | $2 |
| | **SUBTOTAL 2.** | **$14,155** | **$782** | **$3,560** | **$0** | **$0** | **$18,497** | **$1,572** | **$0** | **$3,010** | **$23,079** | **$42** |
| 3 | FEEDWATER & MISC. BOP SYSTEMS | | | | | | | | | | | |
| 3.1 | Feedwater System | $20,016 | $0 | $6,850 | $0 | $0 | $26,866 | $2,279 | $0 | $4,372 | $33,517 | $61 |
| 3.2 | Water Makeup & Pretreating | $5,982 | $0 | $1,867 | $0 | $0 | $7,848 | $707 | $0 | $1,711 | $10,266 | $19 |
| 3.3 | Other Feedwater Subsystems | $6,790 | $0 | $2,744 | $0 | $0 | $9,534 | $806 | $0 | $1,551 | $11,891 | $22 |
| 3.4 | Service Water Systems | $1,194 | $0 | $619 | $0 | $0 | $1,813 | $161 | $0 | $395 | $2,369 | $4 |
| 3.5 | Other Boiler Plant Systems | $8,060 | $0 | $7,543 | $0 | $0 | $15,603 | $1,406 | $0 | $2,551 | $19,560 | $36 |
| 3.6 | FO Supply Sys & Nat Gas | $337 | $0 | $390 | $0 | $0 | $727 | $65 | $0 | $119 | $911 | $2 |
| 3.7 | Waste Treatment Equipment | $3,942 | $0 | $2,241 | $0 | $0 | $6,183 | $586 | $0 | $1,354 | $8,123 | $15 |
| 3.8 | Misc. Equip.(cranes,AirComp.,Comm.) | $3,306 | $0 | $1,012 | $0 | $0 | $4,319 | $405 | $0 | $945 | $5,669 | $10 |
| | **SUBTOTAL 3.** | **$49,628** | **$0** | **$23,266** | **$0** | **$0** | **$72,894** | **$6,414** | **$0** | **$12,997** | **$92,305** | **$168** |
| 4 | PC BOILER & ACCESSORIES | | | | | | | | | | | |
| 4.1 | PC Boiler & Accessories | $165,013 | $0 | $105,843 | $0 | $0 | $270,856 | $25,677 | $0 | $29,653 | $326,186 | $593 |
| 4.2 | SCR (w/4.1) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 4.3 | Open | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 4.4 | Boiler BoP (w/ ID Fans) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 4.5 | Primary Air System | w/4.1 | $0 | w/4.1 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 4.6 | Secondary Air System | w/4.1 | $0 | w/4.1 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 4.8 | Major Component Rigging | $0 | w/4.1 | w/4.1 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 4.9 | Boiler Foundations | $0 | w/14.1 | w/14.1 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | **SUBTOTAL 4.** | **$165,013** | **$0** | **$105,843** | **$0** | **$0** | **$270,856** | **$25,677** | **$0** | **$29,653** | **$326,186** | **$593** |
| 5 | FLUE GAS CLEANUP | | | | | | | | | | | |
| 5.1 | Absorber Vessels & Accessories | $72,668 | $0 | $15,337 | $0 | $0 | $88,005 | $8,045 | $0 | $9,605 | $105,655 | $192 |
| 5.2 | Other FGD | $3,792 | $0 | $4,213 | $0 | $0 | $8,005 | $750 | $0 | $876 | $9,631 | $18 |
| 5.3 | Bag House & Accessories | $20,535 | $0 | $12,777 | $0 | $0 | $33,312 | $3,091 | $0 | $3,640 | $40,044 | $73 |
| 5.4 | Other Particulate Removal Materials | $1,390 | $0 | $1,458 | $0 | $0 | $2,848 | $267 | $0 | $311 | $3,426 | $6 |
| 5.5 | Gypsum Dewatering System | $5,955 | $0 | $992 | $0 | $0 | $6,947 | $634 | $0 | $758 | $8,339 | $15 |
| 5.6 | Mercury Removal System | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 5.9 | Open | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | **SUBTOTAL 5.** | **$104,340** | **$0** | **$34,777** | **$0** | **$0** | **$139,117** | **$12,787** | **$0** | **$15,190** | **$167,094** | **$304** |

| | | | | | |
|---|---|---|---|---|---|
| **Client:** | EPRI | | | **Report Date:** | 2012-Aug-23 |
| **Project:** | Post-Combustion CO2 Capture | | | | |

## TOTAL PLANT COST SUMMARY

| | | | | | | |
|---|---|---|---|---|---|---|
| **Case:** | Baseline Case 9 - 1x550 MWnet SubCritical PC | | | | | |
| **Plant Size:** | 550.1 MW,net | **Estimate Type:** Conceptual | **Cost Base (Jan)** | 2012 | ($x1000) | |

| Acct | | Equipment | Material | Labor | | Sales | Bare Erected | Eng'g CM | Contingencies | | TOTAL PLANT COST | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| No. | Item/Description | Cost | Cost | Direct | Indirect | Tax | Cost $ | H.O.& Fee | Process | Project | $ | $/kW |
| 11 | ACCESSORY ELECTRIC PLANT | | | | | | | | | | | |
| 11.1 | Generator Equipment | $1,966 | $0 | $317 | $0 | $0 | $2,284 | $205 | $0 | $187 | $2,676 | $5 |
| 11.2 | Station Service Equipment | $3,440 | $0 | $1,165 | $0 | $0 | $4,605 | $429 | $0 | $378 | $5,412 | $10 |
| 11.3 | Switchgear & Motor Control | $3,949 | $0 | $693 | $0 | $0 | $4,641 | $431 | $0 | $507 | $5,579 | $10 |
| 11.4 | Conduit & Cable Tray | $0 | $2,758 | $8,835 | $0 | $0 | $11,593 | $1,075 | $0 | $1,900 | $14,568 | $26 |
| 11.5 | Wire & Cable | $0 | $5,205 | $9,308 | $0 | $0 | $14,513 | $1,160 | $0 | $2,351 | $18,024 | $33 |
| 11.6 | Protective Equipment | $320 | $0 | $1,121 | $0 | $0 | $1,441 | $138 | $0 | $158 | $1,736 | $3 |
| 11.7 | Standby Equipment | $1,515 | $0 | $36 | $0 | $0 | $1,551 | $143 | $0 | $169 | $1,863 | $3 |
| 11.8 | Main Power Transformers | $9,993 | $0 | $210 | $0 | $0 | $10,204 | $779 | $0 | $1,098 | $12,081 | $22 |
| 11.9 | Electrical Foundations | $0 | $364 | $934 | $0 | $0 | $1,298 | $122 | $0 | $284 | $1,704 | $3 |
| | **SUBTOTAL 11.** | **$21,183** | **$8,327** | **$22,619** | **$0** | **$0** | **$52,130** | **$4,482** | **$0** | **$7,032** | **$63,644** | **$116** |
| 12 | INSTRUMENTATION & CONTROL | | | | | | | | | | | |
| 12.1 | PC Control Equipment | w/12.7 | $0 | w/12.7 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 12.2 | Combustion Turbine Control | N/A | $0 | N/A | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 12.3 | Steam Turbine Control | w/8.1 | $0 | w/8.1 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 12.4 | Other Major Component Control | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 12.5 | Signal Processing Equipment | w/12.7 | $0 | w/12.7 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 12.6 | Control Boards,Panels & Racks | $528 | $0 | $326 | $0 | $0 | $855 | $80 | $0 | $140 | $1,075 | $2 |
| 12.7 | Distributed Control System Equipment | $5,336 | $0 | $961 | $0 | $0 | $6,296 | $584 | $0 | $688 | $7,568 | $14 |
| 12.8 | Instrument Wiring & Tubing | $3,269 | $0 | $5,913 | $0 | $0 | $9,182 | $739 | $0 | $1,488 | $11,409 | $21 |
| 12.9 | Other I & C Equipment | $1,508 | $0 | $3,526 | $0 | $0 | $5,034 | $480 | $0 | $551 | $6,065 | $11 |
| | **SUBTOTAL 12.** | **$10,641** | **$0** | **$10,726** | **$0** | **$0** | **$21,367** | **$1,883** | **$0** | **$2,868** | **$26,117** | **$47** |
| 13 | IMPROVEMENTS TO SITE | | | | | | | | | | | |
| 13.1 | Site Preparation | $0 | $57 | $1,221 | $0 | $0 | $1,278 | $124 | $0 | $280 | $1,682 | $3 |
| 13.2 | Site Improvements | $0 | $1,904 | $2,517 | $0 | $0 | $4,421 | $437 | $0 | $972 | $5,829 | $11 |
| 13.3 | Site Facilities | $3,413 | $0 | $3,581 | $0 | $0 | $6,994 | $693 | $0 | $1,537 | $9,224 | $17 |
| | **SUBTOTAL 13.** | **$3,413** | **$1,962** | **$7,318** | **$0** | **$0** | **$12,692** | **$1,254** | **$0** | **$2,789** | **$16,735** | **$30** |
| 14 | BUILDINGS & STRUCTURES | | | | | | | | | | | |
| 14.1 | Boiler Building | $0 | $10,273 | $9,145 | $0 | $0 | $19,418 | $1,712 | $0 | $5,282 | $26,412 | $48 |
| 14.2 | Turbine Building | $0 | $14,845 | $14,006 | $0 | $0 | $28,851 | $2,551 | $0 | $7,850 | $39,252 | $71 |
| 14.3 | Administration Building | $0 | $708 | $758 | $0 | $0 | $1,466 | $130 | $0 | $399 | $1,995 | $4 |
| 14.4 | Circulation Water Pumphouse | $0 | $203 | $163 | $0 | $0 | $366 | $32 | $0 | $100 | $498 | $1 |
| 14.5 | Water Treatment Buildings | $0 | $727 | $671 | $0 | $0 | $1,397 | $123 | $0 | $380 | $1,901 | $3 |
| 14.6 | Machine Shop | $0 | $474 | $322 | $0 | $0 | $796 | $69 | $0 | $216 | $1,081 | $2 |
| 14.7 | Warehouse | $0 | $321 | $326 | $0 | $0 | $647 | $57 | $0 | $176 | $880 | $2 |
| 14.8 | Other Buildings & Structures | $0 | $262 | $226 | $0 | $0 | $488 | $43 | $0 | $133 | $664 | $1 |
| 14.9 | Waste Treating Building & Str. | $0 | $502 | $1,542 | $0 | $0 | $2,044 | $190 | $0 | $559 | $2,793 | $5 |
| | **SUBTOTAL 14.** | **$0** | **$28,314** | **$27,159** | **$0** | **$0** | **$55,473** | **$4,908** | **$0** | **$15,095** | **$75,476** | **$137** |
| | **TOTAL COST** | **$531,770** | **$55,835** | **$308,367** | **$0** | **$0** | **$895,972** | **$81,005** | **$0** | **$123,197** | **$1,100,174** | **$2,000** |

**Client:** EPRI **Report Date:** 2012-Aug-23

**Project:** Post-Combustion CO2 Capture

## TOTAL PLANT COST SUMMARY

**Case:** Baseline Case 9 - 1x550 MWnet SubCritical PC

**Plant Size:** 550.1 MW,net **Estimate Type:** Conceptual **Cost Base (Jan)** 2012 ($x1000)

| Acct No. | Item/Description | Equipment Cost | Material Cost | Labor Direct | Labor Indirect | Sales Tax | Bare Erected Cost $ | Eng'g CM H.O.& Fee | Contingencies Process | Contingencies Project | TOTAL PLANT COST $ | TOTAL PLANT COST $/kW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 11 | ACCESSORY ELECTRIC PLANT | | | | | | | | | | | |
| 11.1 | Generator Equipment | $1,966 | $0 | $317 | $0 | $0 | $2,284 | $205 | $0 | $187 | $2,676 | $5 |
| 11.2 | Station Service Equipment | $3,440 | $0 | $1,165 | $0 | $0 | $4,605 | $429 | $0 | $378 | $5,412 | $10 |
| 11.3 | Switchgear & Motor Control | $3,949 | $0 | $693 | $0 | $0 | $4,641 | $431 | $0 | $507 | $5,579 | $10 |
| 11.4 | Conduit & Cable Tray | $0 | $2,758 | $8,835 | $0 | $0 | $11,593 | $1,075 | $0 | $1,900 | $14,568 | $26 |
| 11.5 | Wire & Cable | $0 | $5,205 | $9,308 | $0 | $0 | $14,513 | $1,160 | $0 | $2,351 | $18,024 | $33 |
| 11.6 | Protective Equipment | $320 | $0 | $1,121 | $0 | $0 | $1,441 | $138 | $0 | $158 | $1,736 | $3 |
| 11.7 | Standby Equipment | $1,515 | $0 | $36 | $0 | $0 | $1,551 | $143 | $0 | $169 | $1,863 | $3 |
| 11.8 | Main Power Transformers | $9,993 | $0 | $210 | $0 | $0 | $10,204 | $779 | $0 | $1,098 | $12,081 | $22 |
| 11.9 | Electrical Foundations | $0 | $364 | $934 | $0 | $0 | $1,298 | $122 | $0 | $284 | $1,704 | $3 |
| | **SUBTOTAL 11.** | **$21,183** | **$8,327** | **$22,619** | **$0** | **$0** | **$52,130** | **$4,482** | **$0** | **$7,032** | **$63,644** | **$116** |
| 12 | INSTRUMENTATION & CONTROL | | | | | | | | | | | |
| 12.1 | PC Control Equipment | w/12.7 | $0 | w/12.7 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 12.2 | Combustion Turbine Control | N/A | $0 | N/A | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 12.3 | Steam Turbine Control | w/8.1 | $0 | w/8.1 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 12.4 | Other Major Component Control | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 12.5 | Signal Processing Equipment | w/12.7 | $0 | w/12.7 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 12.6 | Control Boards,Panels & Racks | $528 | $0 | $326 | $0 | $0 | $855 | $80 | $0 | $140 | $1,075 | $2 |
| 12.7 | Distributed Control System Equipment | $5,336 | $0 | $961 | $0 | $0 | $6,296 | $584 | $0 | $688 | $7,568 | $14 |
| 12.8 | Instrument Wiring & Tubing | $3,269 | $0 | $5,913 | $0 | $0 | $9,182 | $739 | $0 | $1,488 | $11,409 | $21 |
| 12.9 | Other I & C Equipment | $1,508 | $0 | $3,526 | $0 | $0 | $5,034 | $480 | $0 | $551 | $6,065 | $11 |
| | **SUBTOTAL 12.** | **$10,641** | **$0** | **$10,726** | **$0** | **$0** | **$21,367** | **$1,883** | **$0** | **$2,868** | **$26,117** | **$47** |
| 13 | IMPROVEMENTS TO SITE | | | | | | | | | | | |
| 13.1 | Site Preparation | $0 | $57 | $1,221 | $0 | $0 | $1,278 | $124 | $0 | $280 | $1,682 | $3 |
| 13.2 | Site Improvements | $0 | $1,904 | $2,517 | $0 | $0 | $4,421 | $437 | $0 | $972 | $5,829 | $11 |
| 13.3 | Site Facilities | $3,413 | $0 | $3,581 | $0 | $0 | $6,994 | $693 | $0 | $1,537 | $9,224 | $17 |
| | **SUBTOTAL 13.** | **$3,413** | **$1,962** | **$7,318** | **$0** | **$0** | **$12,692** | **$1,254** | **$0** | **$2,789** | **$16,735** | **$30** |
| 14 | BUILDINGS & STRUCTURES | | | | | | | | | | | |
| 14.1 | Boiler Building | $0 | $10,273 | $9,145 | $0 | $0 | $19,418 | $1,712 | $0 | $5,282 | $26,412 | $48 |
| 14.2 | Turbine Building | $0 | $14,845 | $14,006 | $0 | $0 | $28,851 | $2,551 | $0 | $7,850 | $39,252 | $71 |
| 14.3 | Administration Building | $0 | $708 | $758 | $0 | $0 | $1,466 | $130 | $0 | $399 | $1,995 | $4 |
| 14.4 | Circulation Water Pumphouse | $0 | $203 | $163 | $0 | $0 | $366 | $32 | $0 | $100 | $498 | $1 |
| 14.5 | Water Treatment Buildings | $0 | $727 | $671 | $0 | $0 | $1,397 | $123 | $0 | $380 | $1,901 | $3 |
| 14.6 | Machine Shop | $0 | $474 | $322 | $0 | $0 | $796 | $69 | $0 | $216 | $1,081 | $2 |
| 14.7 | Warehouse | $0 | $321 | $326 | $0 | $0 | $647 | $57 | $0 | $176 | $880 | $2 |
| 14.8 | Other Buildings & Structures | $0 | $262 | $226 | $0 | $0 | $488 | $43 | $0 | $133 | $664 | $1 |
| 14.9 | Waste Treating Building & Str. | $0 | $502 | $1,542 | $0 | $0 | $2,044 | $190 | $0 | $559 | $2,793 | $5 |
| | **SUBTOTAL 14.** | **$0** | **$28,314** | **$27,159** | **$0** | **$0** | **$55,473** | **$4,908** | **$0** | **$15,095** | **$75,476** | **$137** |
| | **TOTAL COST** | **$531,770** | **$55,835** | **$308,367** | **$0** | **$0** | **$895,972** | **$81,005** | **$0** | **$123,197** | **$1,100,174** | **$2,000** |

**Table A-5**
**Updated O&M Costs for DOE Bituminous Coal Baseline Case 9**

| | | | | | | |
|---|---|---|---|---|---|---|
| INITIAL & ANNUAL O&M EXPENSES | | | | | Cost Base (Jan): | 2012 |
| Baseline Case 9 - 1x550 MWnet SubCritical PC | | | | | Heat Rate-net (Btu/kWh): | 9,276 |
| | | | | | MWe-net: | 550 |
| | | | | | Capacity Factor (%): | 85 |
| OPERATING & MAINTENANCE LABOR | | | | | | |
| Operating Labor | | | | | | |
| Operating Labor Rate (base): | 40.30 | $/hour | | | | |
| Operating Labor Burden: | 30.00 | % of base | | | | |
| Labor O-H Charge Rate: | 25.00 | % of labor | | | | |
| | | | Total | | | |
| Skilled Operator | 2.0 | | 2.0 | | | |
| Operator | 9.0 | | 9.0 | | | |
| Foreman | 1.0 | | 1.0 | | | |
| Lab Tech's, etc. | 2.0 | | 2.0 | | | |
| TOTAL-O.J.'s | 14.0 | | 14.0 | | | |
| | | | | | Annual Cost<br>$ | Annual Unit Cost<br>$/kW-net |
| Annual Operating Labor Cost | | | | | $6,425,110 | $11.681 |
| Maintenance Labor Cost | | | | | $7,203,494 | $13.096 |
| Administrative & Support Labor | | | | | $3,407,151 | $6.194 |
| Property Taxes and Insurance | | | | | $22,003,483 | $40.003 |
| **TOTAL FIXED OPERATING COSTS** | | | | | **$39,039,238** | **$70.974** |
| VARIABLE OPERATING COSTS | | | | | | |
| | | | | | | $/kWh-net |
| **Maintenance Material Cost** | | | | | **$10,805,241** | **$0.00264** |
| Consumables | Consumption<br>Initial Fill | /Day | Unit<br>Cost | Initial Fill<br>Cost | | |
| **Water (/1000 gallons)** | 0 | 4,245 | 1.51 | **$0** | **$1,992,367** | **$0.00049** |
| **Chemicals** | | | | | | |
| MU & WT Chem.(lbs) | 0 | 20,549 | 0.24 | $0 | $1,543,093 | $0.00038 |
| Limestone (ton) | 0 | 521 | 30.26 | $0 | $4,889,653 | $0.00119 |
| Carbon (Mercury Removal) (lb) | 0 | 0 | 1.47 | $0 | $0 | $0.00000 |
| MEA Solvent (ton) | 0 | 0.00 | 3,146.52 | $0 | $0 | $0.00000 |
| NaOH (tons) | 0 | 0.00 | 606.51 | $0 | $0 | $0.00000 |
| H2SO4 (tons) | 0 | 0.00 | 194.09 | $0 | $0 | $0.00000 |
| Corrosion Inhibitor | 0 | 0 | 0.00 | $0 | $0 | $0.00000 |
| Activated Carbon (lb) | 0 | 0 | 1.47 | $0 | $0 | $0.00000 |
| Ammonia (19% NH3) ton | 0 | 78 | 298.21 | $0 | $7,205,519 | $0.00176 |
| **Subtotal Chemicals** | | | | **$0** | **$13,638,264** | **$0.00333** |
| **Other** | | | | | | |
| Supplemental Fuel (MBtu) | 0 | 0 | 0.00 | $0 | $0 | $0.00000 |
| SCR Catalyst (m3) | w/equip. | 0.33 | 8,077.80 | $0 | $828,824 | $0.00020 |
| Emission Penalties | 0 | 0 | 0.00 | $0 | $0 | $0.00000 |
| **Subtotal Other** | | | | **$0** | **$828,824** | **$0.00020** |
| **Waste Disposal** | | | | | | |
| Fly Ash (ton) | 0 | 407 | 25.11 | $0 | $3,171,856 | $0.00077 |
| Bottom Ash (ton) | 0 | 102 | 25.11 | $0 | $792,964 | $0.00019 |
| **Subtotal-Waste Disposal** | | | | **$0** | **$3,964,820** | **$0.00097** |
| **By-products & Emissions** | | | | | | |
| Gypsum (tons) | 0 | 811 | 0.00 | $0 | $0 | $0.00000 |
| **Subtotal By-Products** | | | | **$0** | **$0** | **$0.00000** |
| **TOTAL VARIABLE OPERATING COSTS** | | | | **$0** | **$31,229,517** | **$0.00763** |
| **Fuel (ton)** | 0 | 5,248 | 69.00 | **$0** | **$112,352,584** | **$0.02743** |

**Table A-6**
**Summary of Updated Capital Costs for DOE Bituminous Coal Baseline Case 10**

**Client:** EPRI
**Project:** Post-Combustion CO2 Capture
**Report Date:** 2012-Aug-23

## TOTAL PLANT COST SUMMARY

**Case:** Baseline Case 10 - 1x550 MWnet SubCritical PC w/ CO2 Capture
**Plant Size:** 550.0 MW,net **Estimate Type:** Conceptual **Cost Base (Jan)** 2012 ($x1000)

| Acct No. | Item/Description | Equipment Cost | Material Cost | Labor Direct | Labor Indirect | Sales Tax | Bare Erected Cost $ | Eng'g CM H.O.& Fee | Contingencies Process | Contingencies Project | TOTAL PLANT COST $ | TOTAL PLANT COST $/kW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | COAL & SORBENT HANDLING | $26,098 | $6,621 | $15,458 | $0 | $0 | **$48,176** | $4,221 | $0 | $7,860 | **$60,256** | $110 |
| 2 | COAL & SORBENT PREP & FEED | $17,814 | $992 | $4,486 | $0 | $0 | **$23,293** | $1,979 | $0 | $3,791 | **$29,063** | $53 |
| 3 | FEEDWATER & MISC. BOP SYSTEMS | $65,942 | $0 | $30,904 | $0 | $0 | **$96,846** | $8,535 | $0 | $17,430 | **$122,812** | $223 |
| 4 | PC BOILER & ACCESSORIES | | | | | | | | | | | |
| 4.1 | PC Boiler & Accessories | $209,298 | $0 | $134,249 | $0 | $0 | **$343,547** | $32,568 | $0 | $37,612 | **$413,727** | $752 |
| 4.2 | SCR (w/4.1) | $0 | $0 | $0 | $0 | $0 | **$0** | $0 | $0 | $0 | **$0** | $0 |
| 4.3 | Open | $0 | $0 | $0 | $0 | $0 | **$0** | $0 | $0 | $0 | **$0** | $0 |
| 4.4-4.9 | Boiler BoP (w/ ID Fans) | $0 | $0 | $0 | $0 | $0 | **$0** | $0 | $0 | $0 | **$0** | $0 |
| | **SUBTOTAL 4** | **$209,298** | **$0** | **$134,249** | **$0** | **$0** | **$343,547** | **$32,568** | **$0** | **$37,612** | **$413,727** | **$752** |
| 5 | FLUE GAS CLEANUP | $133,952 | $0 | $44,885 | $0 | $0 | **$178,837** | $16,438 | $0 | $19,528 | **$214,803** | $391 |
| 5B | CO2 REMOVAL & COMPRESSION | $324,867 | $0 | $99,921 | $0 | $0 | **$424,788** | $39,002 | $70,598 | $106,878 | **$641,265** | $1,166 |
| 6 | COMBUSTION TURBINE/ACCESSORIES | | | | | | | | | | | |
| 6.1 | Combustion Turbine Generator | N/A | $0 | N/A | $0 | $0 | **$0** | $0 | $0 | $0 | **$0** | $0 |
| 6.2-6.9 | Combustion Turbine Accessories | $0 | $0 | $0 | $0 | $0 | **$0** | $0 | $0 | $0 | **$0** | $0 |
| | **SUBTOTAL 6** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** |
| 7 | HRSG, DUCTING & STACK | | | | | | | | | | | |
| 7.1 | Heat Recovery Steam Generator | N/A | $0 | N/A | $0 | $0 | **$0** | $0 | $0 | $0 | **$0** | $0 |
| 7.2-7.9 | HRSG Accessories, Ductwork and Stack | $24,075 | $1,239 | $16,131 | $0 | $0 | **$41,446** | $3,683 | $0 | $5,921 | **$51,049** | $93 |
| | **SUBTOTAL 7** | **$24,075** | **$1,239** | **$16,131** | **$0** | **$0** | **$41,446** | **$3,683** | **$0** | **$5,921** | **$51,049** | **$93** |
| 8 | STEAM TURBINE GENERATOR | | | | | | | | | | | |
| 8.1 | Steam TG & Accessories | $73,004 | $0 | $8,429 | $0 | $0 | **$81,433** | $7,081 | $0 | $8,851 | **$97,365** | $177 |
| 8.2-8.9 | Turbine Plant Auxiliaries and Steam Piping | $36,323 | $1,407 | $18,681 | $0 | $0 | **$56,411** | $4,516 | $0 | $8,674 | **$69,601** | $127 |
| | **SUBTOTAL 8** | **$109,328** | **$1,407** | **$27,110** | **$0** | **$0** | **$137,844** | **$11,597** | **$0** | **$17,525** | **$166,967** | **$304** |
| 9 | COOLING WATER SYSTEM | $27,590 | $13,342 | $24,066 | $0 | $0 | **$64,998** | $5,893 | $0 | $9,521 | **$80,413** | $146 |
| 10 | ASH/SPENT SORBENT HANDLING SYS | $7,024 | $204 | $9,018 | $0 | $0 | **$16,246** | $1,497 | $0 | $1,824 | **$19,568** | $36 |
| 11 | ACCESSORY ELECTRIC PLANT | $30,957 | $14,518 | $38,223 | $0 | $0 | **$83,698** | $7,204 | $0 | $11,468 | **$102,370** | $186 |
| 12 | INSTRUMENTATION & CONTROL | $12,210 | $0 | $12,307 | $0 | $0 | **$24,517** | $2,160 | $1,226 | $3,442 | **$31,345** | $57 |
| 13 | IMPROVEMENTS TO SITE | $3,837 | $2,206 | $8,227 | $0 | $0 | **$14,269** | $1,409 | $0 | $3,136 | **$18,814** | $34 |
| 14 | BUILDINGS & STRUCTURES | $0 | $31,083 | $29,825 | $0 | $0 | **$60,908** | $5,389 | $0 | $9,944 | **$76,241** | $139 |
| | **TOTAL COST** | **$992,992** | **$71,611** | **$494,810** | **$0** | **$0** | **$1,559,412** | **$141,576** | **$71,823** | **$255,880** | **$2,028,692** | **$3,688** |

**Table A-7**
**Detailed Updated Capital Costs for DOE Bituminous Coal Baseline Case 10**

| | | | |
|---|---|---|---|
| **Client:** | EPRI | **Report Date:** | 2012-Aug-23 |
| **Project:** | Post-Combustion CO2 Capture | | |
| | **TOTAL PLANT COST SUMMARY** | | |
| **Case:** | Baseline Case 10 - 1x550 MWnet SubCritical PC w/ CO2 Capture | | |
| **Plant Size:** | 550.0 MW,net **Estimate Type:** Conceptual | **Cost Base (Jan)** 2012 | ($x1000) |

| Acct No. | Item/Description | Equipment Cost | Material Cost | Labor Direct | Labor Indirect | Sales Tax | Bare Erected Cost $ | Eng'g CM H.O.& Fee | Contingencies Process | Contingencies Project | TOTAL PLANT COST $ | TOTAL PLANT COST $/kW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | COAL & SORBENT HANDLING | | | | | | | | | | | |
| 1.1 | Coal Receive & Unload | $5,337 | $0 | $2,416 | $0 | $0 | $7,753 | $671 | $0 | $1,264 | $9,688 | $18 |
| 1.2 | Coal Stackout & Reclaim | $6,897 | $0 | $1,549 | $0 | $0 | $8,446 | $715 | $0 | $1,374 | $10,535 | $19 |
| 1.3 | Coal Conveyors | $6,412 | $0 | $1,533 | $0 | $0 | $7,945 | $674 | $0 | $1,293 | $9,911 | $18 |
| 1.4 | Other Coal Handling | $1,678 | $0 | $355 | $0 | $0 | $2,032 | $172 | $0 | $331 | $2,535 | $5 |
| 1.5 | Sorbent Receive & Unload | $219 | $0 | $65 | $0 | $0 | $284 | $24 | $0 | $46 | $355 | $1 |
| 1.6 | Sorbent Stackout & Reclaim | $3,533 | $0 | $642 | $0 | $0 | $4,175 | $352 | $0 | $679 | $5,206 | $9 |
| 1.7 | Sorbent Conveyors | $1,261 | $271 | $306 | $0 | $0 | $1,838 | $154 | $0 | $299 | $2,291 | $4 |
| 1.8 | Other Sorbent Handling | $761 | $177 | $396 | $0 | $0 | $1,335 | $114 | $0 | $217 | $1,667 | $3 |
| 1.9 | Coal & Sorbent Hnd.Foundations | $0 | $6,172 | $8,196 | $0 | $0 | $14,368 | $1,345 | $0 | $2,357 | $18,070 | $33 |
| | **SUBTOTAL 1.** | **$26,098** | **$6,621** | **$15,458** | **$0** | **$0** | **$48,176** | **$4,221** | **$0** | **$7,860** | **$60,256** | **$110** |
| 2 | COAL & SORBENT PREP & FEED | | | | | | | | | | | |
| 2.1 | Coal Crushing & Drying | $3,107 | $0 | $600 | $0 | $0 | $3,707 | $313 | $0 | $603 | $4,622 | $8 |
| 2.2 | Coal Conveyor to Storage | $7,954 | $0 | $1,721 | $0 | $0 | $9,675 | $818 | $0 | $1,574 | $12,068 | $22 |
| 2.3 | Coal Injection System | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 2.4 | Misc.Coal Prep & Feed | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 2.5 | Sorbent Prep Equipment | $6,027 | $258 | $1,241 | $0 | $0 | $7,526 | $634 | $0 | $1,224 | $9,384 | $17 |
| 2.6 | Sorbent Storage & Feed | $726 | $0 | $276 | $0 | $0 | $1,002 | $86 | $0 | $163 | $1,251 | $2 |
| 2.7 | Sorbent Injection System | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 2.8 | Booster Air Supply System | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 2.9 | Coal & Sorbent Feed Foundation | $0 | $734 | $649 | $0 | $0 | $1,383 | $128 | $0 | $227 | $1,738 | $3 |
| | **SUBTOTAL 2.** | **$17,814** | **$992** | **$4,486** | **$0** | **$0** | **$23,293** | **$1,979** | **$0** | **$3,791** | **$29,063** | **$53** |
| 3 | FEEDWATER & MISC. BOP SYSTEMS | | | | | | | | | | | |
| 3.1 | Feedwater System | $25,393 | $0 | $8,691 | $0 | $0 | $34,084 | $2,891 | $0 | $5,546 | $42,521 | $77 |
| 3.2 | Water Makeup & Pretreating | $9,448 | $0 | $2,948 | $0 | $0 | $12,396 | $1,116 | $0 | $2,702 | $16,215 | $29 |
| 3.3 | Other Feedwater Subsystems | $8,614 | $0 | $3,481 | $0 | $0 | $12,095 | $1,023 | $0 | $1,968 | $15,086 | $27 |
| 3.4 | Service Water Systems | $1,887 | $0 | $977 | $0 | $0 | $2,864 | $254 | $0 | $624 | $3,741 | $7 |
| 3.5 | Other Boiler Plant Systems | $10,408 | $0 | $9,740 | $0 | $0 | $20,148 | $1,815 | $0 | $3,294 | $25,257 | $46 |
| 3.6 | FO Supply Sys & Nat Gas | $367 | $0 | $425 | $0 | $0 | $792 | $70 | $0 | $129 | $991 | $2 |
| 3.7 | Waste Treatment Equipment | $6,226 | $0 | $3,540 | $0 | $0 | $9,766 | $925 | $0 | $2,138 | $12,829 | $23 |
| 3.8 | Misc. Equip.(cranes,AirComp.,Comm.) | $3,599 | $0 | $1,102 | $0 | $0 | $4,701 | $441 | $0 | $1,028 | $6,171 | $11 |
| | **SUBTOTAL 3.** | **$65,942** | **$0** | **$30,904** | **$0** | **$0** | **$96,846** | **$8,535** | **$0** | **$17,430** | **$122,812** | **$223** |
| 4 | PC BOILER & ACCESSORIES | | | | | | | | | | | |
| 4.1 | PC Boiler & Accessories | $209,298 | $0 | $134,249 | $0 | $0 | $343,547 | $32,568 | $0 | $37,612 | $413,727 | $752 |
| 4.2 | SCR (w/4.1) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 4.3 | Open | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 4.4 | Boiler BoP (w/ ID Fans) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 4.5 | Primary Air System | w/4.1 | $0 | w/4.1 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 4.6 | Secondary Air System | w/4.1 | $0 | w/4.1 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 4.8 | Major Component Rigging | $0 | w/4.1 | w/4.1 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 4.9 | Boiler Foundations | $0 | w/14.1 | w/14.1 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | **SUBTOTAL 4.** | **$209,298** | **$0** | **$134,249** | **$0** | **$0** | **$343,547** | **$32,568** | **$0** | **$37,612** | **$413,727** | **$752** |
| 5 | FLUE GAS CLEANUP | | | | | | | | | | | |
| 5.1 | Absorber Vessels & Accessories | $93,027 | $0 | $19,635 | $0 | $0 | $112,662 | $10,299 | $0 | $12,296 | $135,257 | $246 |
| 5.2 | Other FGD | $4,855 | $0 | $5,394 | $0 | $0 | $10,248 | $960 | $0 | $1,121 | $12,329 | $22 |
| 5.3 | Bag House & Accessories | $26,873 | $0 | $16,720 | $0 | $0 | $43,593 | $4,045 | $0 | $4,764 | $52,401 | $95 |
| 5.4 | Other Particulate Removal Materials | $1,819 | $0 | $1,908 | $0 | $0 | $3,726 | $349 | $0 | $408 | $4,483 | $8 |
| 5.5 | Gypsum Dewatering System | $7,379 | $0 | $1,229 | $0 | $0 | $8,608 | $785 | $0 | $939 | $10,332 | $19 |
| 5.6 | Mercury Removal System | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 5.9 | Open | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | **SUBTOTAL 5.** | **$133,952** | **$0** | **$44,885** | **$0** | **$0** | **$178,837** | **$16,438** | **$0** | **$19,528** | **$214,803** | **$391** |
| 5B | CO2 REMOVAL & COMPRESSION | | | | | | | | | | | |
| 5B.1 | CO2 Removal System | $272,013 | $0 | $80,975 | $0 | $0 | $352,988 | $32,396 | $70,598 | $91,196 | $547,178 | $995 |
| 5B.2 | CO2 Compression & Drying | $52,854 | $0 | $18,946 | $0 | $0 | $71,800 | $6,606 | $0 | $15,681 | $94,087 | $171 |
| | **SUBTOTAL 5B.** | **$324,867** | **$0** | **$99,921** | **$0** | **$0** | **$424,788** | **$39,002** | **$70,598** | **$106,878** | **$641,265** | **$1,166** |

| | | | | | | |
|---|---|---|---|---|---|---|
| **Client:** | EPRI | | | | **Report Date:** | 2012-Aug-23 |
| **Project:** | Post-Combustion CO2 Capture | | | | | |
| | **TOTAL PLANT COST SUMMARY** | | | | | |
| **Case:** | Baseline Case 10 - 1x550 MWnet SubCritical PC w/ CO2 Capture | | | | | |
| **Plant Size:** | 550.0 MW,net | **Estimate Type:** Conceptual | | **Cost Base (Jan)** | 2012 | ($x1000) |

| Acct | | Equipment | Material | Labor | | Sales | Bare Erected | Eng'g CM | Contingencies | | TOTAL PLANT COST | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **No.** | **Item/Description** | **Cost** | **Cost** | **Direct** | **Indirect** | **Tax** | **Cost $** | **H.O.& Fee** | **Process** | **Project** | **$** | **$/kW** |
| 6 | COMBUSTION TURBINE/ACCESSORIES | | | | | | | | | | | |
| 6.1 | Combustion Turbine Generator | N/A | $0 | N/A | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 6.2 | Open | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 6.3 | Compressed Air Piping | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 6.9 | Combustion Turbine Foundations | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | **SUBTOTAL 6.** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** |
| 7 | HRSG, DUCTING & STACK | | | | | | | | | | | |
| 7.1 | Heat Recovery Steam Generator | N/A | $0 | N/A | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 7.2 | HRSG Accessories | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 7.3 | Ductwork | $12,476 | $0 | $7,995 | $0 | $0 | $20,471 | $1,737 | $0 | $3,331 | $25,539 | $46 |
| 7.4 | Stack | $11,599 | $0 | $6,654 | $0 | $0 | $18,253 | $1,691 | $0 | $1,994 | $21,939 | $40 |
| 7.9 | Duct & Stack Foundations | $0 | $1,239 | $1,482 | $0 | $0 | $2,721 | $254 | $0 | $595 | $3,571 | $6 |
| | **SUBTOTAL 7.** | **$24,075** | **$1,239** | **$16,131** | **$0** | **$0** | **$41,446** | **$3,683** | **$0** | **$5,921** | **$51,049** | **$93** |
| 8 | STEAM TURBINE GENERATOR | | | | | | | | | | | |
| 8.1 | Steam TG & Accessories | $73,004 | $0 | $8,429 | $0 | $0 | $81,433 | $7,081 | $0 | $8,851 | $97,365 | $177 |
| 8.2 | Turbine Plant Auxiliaries | $481 | $0 | $1,011 | $0 | $0 | $1,492 | $141 | $0 | $163 | $1,797 | $3 |
| 8.3 | Condenser & Auxiliaries | $7,662 | $0 | $3,111 | $0 | $0 | $10,773 | $993 | $0 | $1,177 | $12,943 | $24 |
| 8.4 | Steam Piping | $28,180 | $0 | $12,219 | $0 | $0 | $40,399 | $3,030 | $0 | $6,514 | $49,943 | $91 |
| 8.9 | TG Foundations | $0 | $1,407 | $2,340 | $0 | $0 | $3,747 | $352 | $0 | $820 | $4,919 | $9 |
| | **SUBTOTAL 8.** | **$109,328** | **$1,407** | **$27,110** | **$0** | **$0** | **$137,844** | **$11,597** | **$0** | **$17,525** | **$166,967** | **$304** |
| 9 | COOLING WATER SYSTEM | | | | | | | | | | | |
| 9.1 | Cooling Towers | $20,745 | $0 | $6,334 | $0 | $0 | $27,079 | $2,486 | $0 | $2,957 | $32,522 | $59 |
| 9.2 | Circulating Water Pumps | $4,077 | $0 | $318 | $0 | $0 | $4,395 | $375 | $0 | $477 | $5,247 | $10 |
| 9.3 | Circ.Water System Auxiliaries | $1,045 | $0 | $137 | $0 | $0 | $1,181 | $108 | $0 | $129 | $1,418 | $3 |
| 9.4 | Circ.Water Piping | $0 | $8,766 | $7,871 | $0 | $0 | $16,637 | $1,459 | $0 | $2,714 | $20,811 | $38 |
| 9.5 | Make-up Water System | $872 | $0 | $1,109 | $0 | $0 | $1,982 | $181 | $0 | $324 | $2,487 | $5 |
| 9.6 | Component Cooling Water Sys | $850 | $0 | $646 | $0 | $0 | $1,496 | $135 | $0 | $245 | $1,875 | $3 |
| 9.9 | Circ.Water System Foundations& Structures | $0 | $4,576 | $7,652 | $0 | $0 | $12,228 | $1,150 | $0 | $2,676 | $16,054 | $29 |
| | **SUBTOTAL 9.** | **$27,590** | **$13,342** | **$24,066** | **$0** | **$0** | **$64,998** | **$5,893** | **$0** | **$9,521** | **$80,413** | **$146** |
| 10 | ASH/SPENT SORBENT HANDLING SYS | | | | | | | | | | | |
| 10.1 | Ash Coolers | N/A | $0 | N/A | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 10.2 | Cyclone Ash Letdown | N/A | $0 | N/A | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 10.3 | HGCU Ash Letdown | N/A | $0 | N/A | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 10.4 | High Temperature Ash Piping | N/A | $0 | N/A | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 10.5 | Other Ash Recovery Equipment | N/A | $0 | N/A | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 10.6 | Ash Storage Silos | $921 | $0 | $2,781 | $0 | $0 | $3,701 | $352 | $0 | $405 | $4,459 | $8 |
| 10.7 | Ash Transport & Feed Equipment | $6,104 | $0 | $5,985 | $0 | $0 | $12,088 | $1,102 | $0 | $1,319 | $14,510 | $26 |
| 10.8 | Misc. Ash Handling Equipment | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 10.9 | Ash/Spent Sorbent Foundation | $0 | $204 | $253 | $0 | $0 | $456 | $43 | $0 | $100 | $599 | $1 |
| | **SUBTOTAL 10.** | **$7,024** | **$204** | **$9,018** | **$0** | **$0** | **$16,246** | **$1,497** | **$0** | **$1,824** | **$19,568** | **$36** |

| | | | |
|---|---|---|---|
| **Client:** | EPRI | **Report Date:** | 2012-Aug-23 |
| **Project:** | Post-Combustion CO2 Capture | | |

## TOTAL PLANT COST SUMMARY

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Case:** | Baseline Case 10 - 1x550 MWnet SubCritical PC w/ CO2 Capture | | | | | | |
| **Plant Size:** | 550.0 MW,net | **Estimate Type:** | Conceptual | **Cost Base (Jan)** | 2012 | ($x1000) | |

| Acct No. | Item/Description | Equipment Cost | Material Cost | Labor Direct | Labor Indirect | Sales Tax | Bare Erected Cost $ | Eng'g CM H.O.& Fee | Contingencies Process | Contingencies Project | TOTAL PLANT COST $ | TOTAL PLANT COST $/kW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 11 | ACCESSORY ELECTRIC PLANT | | | | | | | | | | | |
| 11.1 | Generator Equipment | $2,139 | $0 | $345 | $0 | $0 | $2,484 | $223 | $0 | $203 | $2,911 | $5 |
| 11.2 | Station Service Equipment | $6,098 | $0 | $2,065 | $0 | $0 | $8,163 | $761 | $0 | $669 | $9,592 | $17 |
| 11.3 | Switchgear & Motor Control | $6,999 | $0 | $1,228 | $0 | $0 | $8,227 | $764 | $0 | $899 | $9,890 | $18 |
| 11.4 | Conduit & Cable Tray | $0 | $4,889 | $15,662 | $0 | $0 | $20,550 | $1,905 | $0 | $3,368 | $25,824 | $47 |
| 11.5 | Wire & Cable | $0 | $9,227 | $16,499 | $0 | $0 | $25,726 | $2,057 | $0 | $4,167 | $31,950 | $58 |
| 11.6 | Protective Equipment | $320 | $0 | $1,121 | $0 | $0 | $1,441 | $138 | $0 | $158 | $1,736 | $3 |
| 11.7 | Standby Equipment | $1,622 | $0 | $38 | $0 | $0 | $1,661 | $153 | $0 | $181 | $1,995 | $4 |
| 11.8 | Main Power Transformers | $13,779 | $0 | $233 | $0 | $0 | $14,011 | $1,068 | $0 | $1,508 | $16,587 | $30 |
| 11.9 | Electrical Foundations | $0 | $403 | $1,033 | $0 | $0 | $1,435 | $135 | $0 | $314 | $1,885 | $3 |
| | **SUBTOTAL 11.** | **$30,957** | **$14,518** | **$38,223** | **$0** | **$0** | **$83,698** | **$7,204** | **$0** | **$11,468** | **$102,370** | **$186** |
| 12 | INSTRUMENTATION & CONTROL | | | | | | | | | | | |
| 12.1 | PC Control Equipment | w/12.7 | $0 | w/12.7 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 12.2 | Combustion Turbine Control | N/A | $0 | N/A | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 12.3 | Steam Turbine Control | w/8.1 | $0 | w/8.1 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 12.4 | Other Major Component Control | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 12.5 | Signal Processing Equipment | w/12.7 | $0 | w/12.7 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 12.6 | Control Boards,Panels & Racks | $606 | $0 | $374 | $0 | $0 | $981 | $92 | $49 | $168 | $1,290 | $2 |
| 12.7 | Distributed Control System Equipment | $6,122 | $0 | $1,103 | $0 | $0 | $7,225 | $670 | $361 | $826 | $9,081 | $17 |
| 12.8 | Instrument Wiring & Tubing | $3,751 | $0 | $6,785 | $0 | $0 | $10,536 | $848 | $527 | $1,787 | $13,697 | $25 |
| 12.9 | Other I & C Equipment | $1,730 | $0 | $4,046 | $0 | $0 | $5,776 | $551 | $289 | $662 | $7,277 | $13 |
| | **SUBTOTAL 12.** | **$12,210** | **$0** | **$12,307** | **$0** | **$0** | **$24,517** | **$2,160** | **$1,226** | **$3,442** | **$31,345** | **$57** |
| 13 | IMPROVEMENTS TO SITE | | | | | | | | | | | |
| 13.1 | Site Preparation | $0 | $65 | $1,372 | $0 | $0 | $1,437 | $139 | $0 | $315 | $1,891 | $3 |
| 13.2 | Site Improvements | $0 | $2,141 | $2,829 | $0 | $0 | $4,970 | $491 | $0 | $1,092 | $6,553 | $12 |
| 13.3 | Site Facilities | $3,837 | $0 | $4,026 | $0 | $0 | $7,862 | $779 | $0 | $1,728 | $10,369 | $19 |
| | **SUBTOTAL 13.** | **$3,837** | **$2,206** | **$8,227** | **$0** | **$0** | **$14,269** | **$1,409** | **$0** | **$3,136** | **$18,814** | **$34** |
| 14 | BUILDINGS & STRUCTURES | | | | | | | | | | | |
| 14.1 | Boiler Building | $0 | $11,044 | $9,832 | $0 | $0 | $20,876 | $1,841 | $0 | $3,407 | $26,124 | $47 |
| 14.2 | Turbine Building | $0 | $16,183 | $15,268 | $0 | $0 | $31,451 | $2,780 | $0 | $5,135 | $39,366 | $72 |
| 14.3 | Administration Building | $0 | $780 | $834 | $0 | $0 | $1,614 | $144 | $0 | $264 | $2,021 | $4 |
| 14.4 | Circulation Water Pumphouse | $0 | $213 | $171 | $0 | $0 | $384 | $34 | $0 | $63 | $480 | $1 |
| 14.5 | Water Treatment Buildings | $0 | $1,148 | $1,059 | $0 | $0 | $2,207 | $195 | $0 | $360 | $2,762 | $5 |
| 14.6 | Machine Shop | $0 | $521 | $355 | $0 | $0 | $876 | $76 | $0 | $143 | $1,095 | $2 |
| 14.7 | Warehouse | $0 | $353 | $359 | $0 | $0 | $712 | $63 | $0 | $116 | $892 | $2 |
| 14.8 | Other Buildings & Structures | $0 | $289 | $249 | $0 | $0 | $537 | $47 | $0 | $88 | $673 | $1 |
| 14.9 | Waste Treating Building & Str. | $0 | $553 | $1,698 | $0 | $0 | $2,251 | $209 | $0 | $369 | $2,829 | $5 |
| | **SUBTOTAL 14.** | **$0** | **$31,083** | **$29,825** | **$0** | **$0** | **$60,908** | **$5,389** | **$0** | **$9,944** | **$76,241** | **$139** |
| | **TOTAL COST** | **$992,992** | **$71,611** | **$494,810** | **$0** | **$0** | **$1,559,412** | **$141,576** | **$71,823** | **$255,880** | **$2,028,692** | **$3,688** |

**Table A-8**
**Updated O&M Costs for DOE Bituminous Coal Baseline Case 10**

| INITIAL & ANNUAL O&M EXPENSES | | | | | | |
|---|---|---|---|---|---|---|
| Baseline Case 10 - 1x550 MWnet SubCritical PC w/ CO2 Capture | | | | | Cost Base (Jan): | 2012 |
| | | | | | Heat Rate-net (Btu/kWh): | 13,044 |
| | | | | | MWe-net: | 550 |
| | | | | | Capacity Factor (%): | 85 |
| OPERATING & MAINTENANCE LABOR | | | | | | |
| Operating Labor | | | | | | |
| Operating Labor Rate (base): | 40.30 | $/hour | | | | |
| Operating Labor Burden: | 30.00 | % of base | | | | |
| Labor O-H Charge Rate: | 25.00 | % of labor | | | | |
| | | | Total | | | |
| Skilled Operator | 2.0 | | 2.0 | | | |
| Operator | 11.3 | | 11.3 | | | |
| Foreman | 1.0 | | 1.0 | | | |
| Lab Tech's, etc. | 2.0 | | 2.0 | | | |
| TOTAL-O.J.'s | 16.3 | | 16.3 | | | |
| | | | | | Annual Cost $ | Annual Unit Cost $/kW-net |
| Annual Operating Labor Cost | | | | | $7,495,808 | $13.628 |
| Maintenance Labor Cost | | | | | $13,055,660 | $23.737 |
| Administrative & Support Labor | | | | | $5,137,867 | $9.341 |
| Property Taxes and Insurance | | | | | $40,573,838 | $73.769 |
| **TOTAL FIXED OPERATING COSTS** | | | | | **$66,263,173** | **$120.476** |
| VARIABLE OPERATING COSTS | | | | | | |
| | | | | | | $/kWh-net |
| **Maintenance Material Cost** | | | | | **$19,583,490** | **$0.00478** |
| Consumables | Consumption Initial Fill | Consumption /Day | Unit Cost | Initial Fill Cost | | |
| **Water (/1000 gallons)** | 0 | 8,081 | 1.51 | **$0** | **$3,792,796** | **$0.00093** |
| **Chemicals** | | | | | | |
| MU & WT Chem.(lbs) | 0 | 39,119 | 0.24 | $0 | $2,937,530 | $0.00072 |
| Limestone (ton) | 0 | 751 | 30.26 | $0 | $7,053,251 | $0.00172 |
| Carbon (Mercury Removal) (lb) | 0 | 0 | 1.47 | $0 | $0 | $0.00000 |
| MEA Solvent (ton) | 1,117 | 1.58 | 3,146.52 | $3,514,864 | $1,546,159 | $0.00038 |
| NaOH (tons) | 79 | 7.89 | 606.51 | $47,859 | $1,484,821 | $0.00036 |
| H2SO4 (tons) | 75 | 7.53 | 194.09 | $14,615 | $453,426 | $0.00011 |
| Corrosion Inhibitor | 0 | 0 | 0.00 | $206,727 | $9,844 | $0.00000 |
| Activated Carbon (lb) | 0 | 1,892 | 1.47 | $0 | $862,097 | $0.00021 |
| Ammonia (19% NH3) ton | 0 | 110 | 298.21 | $0 | $10,215,405 | $0.00249 |
| **Subtotal Chemicals** | | | | **$3,784,064** | **$24,562,533** | **$0.00600** |
| **Other** | | | | | | |
| Supplemental Fuel (MBtu) | 0 | 0 | 0.00 | $0 | $0 | $0.00000 |
| SCR Catalyst (m3) | w/equip. | 0.46 | 8,077.80 | $0 | $1,162,897 | $0.00028 |
| Emission Penalties | 0 | 0 | 0.00 | $0 | $0 | $0.00000 |
| **Subtotal Other** | | | | **$0** | **$1,162,897** | **$0.00028** |
| **Waste Disposal** | | | | | | |
| Fly Ash (ton) | 0 | 572 | 25.11 | $0 | $4,459,927 | $0.00109 |
| Bottom Ash (ton) | 0 | 143 | 25.11 | $0 | $1,114,982 | $0.00027 |
| **Subtotal-Waste Disposal** | | | | **$0** | **$5,574,909** | **$0.00136** |
| **By-products & Emissions** | | | | | | |
| Gypsum (tons) | 0 | 1,159 | 0.00 | $0 | $0 | $0.00000 |
| **Subtotal By-Products** | | | | **$0** | **$0** | **$0.00000** |
| **TOTAL VARIABLE OPERATING COSTS** | | | | **$3,784,064** | **$54,676,626** | **$0.01335** |
| **Fuel (ton)** | 0 | 7,380 | 69.00 | **$0** | **$157,979,789** | **$0.03858** |

**Table A-9**
**Summary of Capital Costs for UK CAER + MEA Case**

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Client:** | EPRI | | | | | | | | | | |
| | **Project:** | University of Kentucky Post-Combustion CO2 Capture Study | | | | | | | | **Report Date:** 2020-March-30 | | |
| | | | | | | **TOTAL PLANT COST SUMMARY** | | | | | | |
| | **Case:** | SubCritical PC w/ CO2 Capture - MEA | | | | | | | | | | |
| | **Plant Size:** | 580.9 | MW, net | | | | **Estimate Type:** Conceptual | | | **Cost Base (Jan)** | 2012 | ($x1000) |
| **Acct No.** | **Item/Description** | **Equipment Cost** | **Material Cost** | **Labor** | | **Sale Tax** | **Bare Erected Cost $** | **Eng'g CM H.O. & Fee** | **Contingencies** | | **TOTAL PLANT COST** | |
| | | | | **Direct** | **Indirect** | | | | **Process** | **Project** | **$** | **$/kW** |
| 1 | COAL & SORBENT HANDLING | $26,077 | $6,619 | $15,454 | $0 | $0 | **$48,150** | $4,218 | $0 | $7,856 | **$60,224** | $104 |
| 2 | COAL & SORBENT PREP & FEED | $17,787 | $988 | $4,478 | $0 | $0 | **$23,253** | $1,976 | $0 | $3,786 | **$29,015** | $50 |
| 3 | FEEDWATER & MISC. BOP SYSTEM | $65,205 | $0 | $30,624 | $0 | $0 | **$95,829** | $8,445 | $0 | $17,247 | **$121,521** | $209 |
| 4 | PC BOILER & ACCESSORIES | | | | | | | | | | | |
| 4.1 | PC Boiler & Accessories | $209,298 | $0 | $134,249 | $0 | $0 | **$343,547** | $32,568 | $0 | $37,612 | **$413,727** | $712 |
| 4.2 | SCR (w/ 4.1) | $0 | $0 | $0 | $0 | $0 | **$0** | $0 | $0 | $0 | **$0** | $0 |
| 4.3 | Open | $0 | $0 | $0 | $0 | $0 | **$0** | $0 | $0 | $0 | **$0** | $0 |
| 4.4-4.9 | Boiler BoP (w/ID Fans) | $0 | $0 | $0 | $0 | $0 | **$0** | $0 | $0 | $0 | **$0** | $0 |
| | **SUBTOTAL 4** | **$209,298** | **$0** | **$134,249** | **$0** | **$0** | $343,547 | **$32,568** | **$0** | **$37,612** | $413,727 | **$712** |
| 5 | FLUE GAS CLEANUP | $117,815 | $0 | $39,245 | $0 | $0 | **$157,060** | $14,436 | $0 | $17,150 | **$188,646** ` | |
| 5B | CO2 REMOVAL & COMPRESSION | $221,689 | $0 | $140,032 | $0 | $0 | **$361,721** | $33,572 | $58,006 | $90,660 | **$543,959** | $936 |
| 6 | COMBUSTION TURBINE/ACCESSORIES | | | | | | | | | | | |
| 6.1 | Combustion Turbine Generator | $0 | $0 | $0 | $0 | $0 | **$0** | $0 | $0 | $0 | **$0** | $0 |
| 6.2-6.9 | Combustion Turbine Other | $0 | $0 | $0 | $0 | $0 | **$0** | $0 | $0 | $0 | **$0** | $0 |
| | **SUBTOTAL 6** | **$0** | **$0** | **$0** | **$0** | **$0** | $0 | **$0** | **$0** | **$0** | $0 | **$0** |
| 7 | HRSG, DUCTING & STACK | | | | | | | | | | | |
| 7.1 | Heat recovery Steam Generator | $0 | $0 | $0 | $0 | $0 | **$0** | $0 | $0 | $0 | **$0** | $0 |
| 7.2-7.9 | HRSG Accessories, Ductwork and Stack | $24,955 | $1,285 | $16,720 | $0 | $0 | **$42,960** | $3,817 | $0 | $6,137 | **$52,914** | $91 |
| | **SUBTOTAL 7** | **$24,955** | **$1,285** | **$16,720** | **$0** | **$0** | $42,960 | **$3,817** | **$0** | **$6,137** | $52,914 | **$91** |
| 8 | STEM TURBINE GENERATOR | | | | | | | | | | | |
| 8.1 | Steam TG and Accessories | $74,990 | $0 | $8,658 | $0 | $0 | **$83,649** | $7,274 | $0 | $9,092 | **$100,014** | $172 |
| 8.2-8.9 | Turbine Plant Auxiliaries and Steam Piping | $36,283 | $1,446 | $18,835 | $0 | $0 | **$56,564** | $4,531 | $0 | $8,702 | **$69,797** | $120 |
| | **SUBTOTAL 8** | **$111,273** | **$1,446** | **$27,493** | **$0** | **$0** | $140,213 | **$11,804** | **$0** | **$17,794** | $169,811 | **$292** |
| 9 | COOLING WATER SYSTEM | $21,813 | $10,808 | $19,483 | $0 | $0 | **$52,104** | $4,724 | $0 | $7,672 | **$64,500** | $111 |
| 10 | ASH/SPENT SORBENT HANDLING SYS | $7,025 | $204 | $9,019 | $0 | $0 | **$16,248** | $1,497 | $0 | $1,824 | **$19,569** | $34 |
| 11 | ACCESSORY ELECTRIC PLANT | $30,653 | $14,300 | $37,668 | $0 | $0 | **$82,621** | $7,112 | $0 | $11,315 | **$101,048** | $174 |
| 12 | INSTRUMENTATION & CONTROL | $12,149 | $0 | $12,247 | $0 | $0 | **$24,396** | $2,150 | $1,327 | $3,426 | **$31,299** | $54 |
| 13 | IMPROVEMENTS TO SITE | $3,886 | $2,233 | $8,332 | $0 | $0 | **$14,451** | $1,427 | $0 | $3,175 | **$19,053** | $33 |
| 14 | BUILDINGS & STRUCTURE | $0 | $31,504 | $30,224 | $0 | $0 | **$61,728** | $5,463 | $0 | $10,078 | **$77,269** | $133 |
| | **TOTAL COST** | **$869,625** | **$69,387** | **$525,269** | **$0** | **$0** | **$1,464,280** | **$133,209** | **$59,333** | **$235,732** | **$1,892,555** | **$3,258** |

**Table A-10**
**Detailed Capital Costs for UK CAER + MEA Case**

| | |
|---|---|
| **Client:** | EPRI |
| **Project:** | University of Kentucky Post-Combustion CO2 Capture Study — Report Date: 2020-March-30 |
| | **TOTAL PLANT COST SUMMARY** |
| **Case:** | SubCritical PC w/ CO2 Capture - MEA |
| **Plant Size:** | 580.9 MW, net — **Estimate Type:** Conceptual — Cost Base (Jan) 2012 — ($x1000) |

| Acct No. | Item/Description | Equipment Cost | Material Cost | Labor Direct | Labor Indirect | Sale Tax | Bare Erected Cost $ | Eng'g CM H.O. & Fee | Contingencies Process | Contingencies Project | TOTAL PLANT COST $ | TOTAL PLANT COST $/kW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **1** | **COAL & SORBENT HANDLING** | | | | | | | | | | | |
| 1.1 | Coal Receive and Unload | $5,337 | $0 | $2,416 | $0 | $0 | $7,753 | $671 | $0 | $1,264 | $9,688 | $16.7 |
| 1.2 | Coal Stack out and Reclaim | $6,897 | $0 | $1,549 | $0 | $0 | $8,446 | $715 | $0 | $1,374 | $10,535 | $18.1 |
| 1.3 | Coal Conveyors | $6,412 | $0 | $1,533 | $0 | $0 | $7,945 | $674 | $0 | $1,293 | $9,912 | $17.1 |
| 1.4 | Other Coal Handling | $1,678 | $0 | $355 | $0 | $0 | $2,033 | $172 | $0 | $331 | $2,536 | $4.4 |
| 1.5 | Sorbent Receive and Unload | $219 | $0 | $65 | $0 | $0 | $284 | $24 | $0 | $46 | $354 | $0.6 |
| 1.6 | Sorbent stack out and Reclaim | $3,519 | $0 | $639 | $0 | $0 | $4,158 | $350 | $0 | $676 | $5,184 | $8.9 |
| 1.7 | Sorbent Conveyors | $1,256 | $270 | $305 | $0 | $0 | $1,831 | $153 | $0 | $298 | $2,282 | $3.9 |
| 1.8 | Other Sorbent Handling | $759 | $177 | $396 | $0 | $0 | $1,332 | $114 | $0 | $217 | $1,663 | $2.9 |
| 1.9 | Coal and Sorbent Handling Foundations | $0 | $6,172 | $8,196 | $0 | $0 | $14,368 | $1,345 | $0 | $2,357 | $18,070 | $31.1 |
| | **Subtotal 1.** | **$26,077** | **$6,619** | **$15,454** | **$0** | **$0** | **$48,150** | **$4,218** | **$0** | **$7,856** | **$60,224** | **$104** |
| **2** | **COAL & SORBENT PREP & FEED** | | | | | | | | | | | |
| 2.1 | Coal Crushing and Drying | $3,107 | $0 | $600 | $0 | $0 | $3,707 | $313 | $0 | $603 | $4,623 | $8.0 |
| 2.2 | Coal Conveyor to Storage | $7,954 | $0 | $1,721 | $0 | $0 | $9,675 | $818 | $0 | $1,574 | $12,067 | $20.8 |
| 2.3 | Coal Injection System | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 2.4 | Misc. Coal Prep & Feed | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 2.5 | Sorbent Prep Equipment | $6,003 | $257 | $1,236 | $0 | $0 | $7,496 | $631 | $0 | $1,219 | $9,346 | $16.1 |
| 2.6 | Sorbent Storage and Feed | $723 | $0 | $275 | $0 | $0 | $998 | $86 | $0 | $163 | $1,247 | $2.1 |
| 2.7 | Sorbent Injection System | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 2.8 | Booster Air Supply System | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 2.9 | Coal and Sorbent Feed Foundation | $0 | $731 | $646 | $0 | $0 | $1,377 | $128 | $0 | $227 | $1,732 | $3.0 |
| | **Subtotal 2.** | **$17,787** | **$988** | **$4,478** | **$0** | **$0** | **$23,253** | **$1,976** | **$0** | **$3,786** | **$29,015** | **$50** |
| **3** | **FEEDWATER & MISC. BOP SYSTEM** | | | | | | | | | | | |
| 3.1 | Feedwater System | $25,001 | $0 | $8,556 | $0 | $0 | $33,557 | $2,846 | $0 | $5,461 | $41,864 | $72.1 |
| 3.2 | Water Makeup and Pretreating | $9,300 | $0 | $2,902 | $0 | $0 | $12,202 | $1,098 | $0 | $2,660 | $15,960 | $27.5 |
| 3.3 | Other Feedwater Subsystems | $8,481 | $0 | $3,427 | $0 | $0 | $11,908 | $1,007 | $0 | $1,937 | $14,852 | $25.6 |
| 3.4 | Service Water Systems | $1,857 | $0 | $962 | $0 | $0 | $2,819 | $250 | $0 | $614 | $3,683 | $6.3 |
| 3.5 | Other Boiler Plant Systems | $10,408 | $0 | $9,740 | $0 | $0 | $20,148 | $1,815 | $0 | $3,294 | $25,257 | $43.5 |
| 3.6 | FO Supply System and Natural Gas | $373 | $0 | $432 | $0 | $0 | $805 | $71 | $0 | $131 | $1,007 | $1.7 |
| 3.7 | Waste Treatment Equipment | $6,129 | $0 | $3,485 | $0 | $0 | $9,614 | $910 | $0 | $2,105 | $12,629 | $21.7 |
| 3.8 | Misc. Equip. (Cranes, air comp, comm.) | $3,656 | $0 | $1,120 | $0 | $0 | $4,776 | $448 | $0 | $1,045 | $6,269 | $10.8 |
| | **Subtotal 3.** | **$65,205** | **$0** | **$30,624** | **$0** | **$0** | **$95,829** | **$8,445** | **$0** | **$17,247** | **$121,521** | **$209** |
| **4** | **PC BOILER & ACCESSORIES** | | | | | | | | | | | |
| 4.1 | PC Boiler & Accessories | $209,298 | $0 | $134,249 | $0 | $0 | $343,547 | $32,568 | $0 | $37,612 | $413,727 | $712.3 |
| 4.2 | SCR (w/ 4.1) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 4.3 | Open | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 4.4 | Boiler BoP (w/ ID Fans) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 4.5 | Primary Air System | w/4.1 | $0 | w/4.1 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 4.6 | Secondary Air System | w/4.1 | $0 | w/4.1 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 4.8 | Major Component Rigging | $0 | w/4.1 | w/4.1 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 4.9 | Boiler Foundations | $0 | w/4.1 | w/4.1 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| | **Subtotal 4.** | **$209,298** | **$0** | **$134,249** | **$0** | **$0** | **$343,547** | **$32,568** | **$0** | **$37,612** | **$413,727** | **$712** |

**Client:** EPRI
**Project:** University of Kentucky Post-Combustion CO2 Capture Study — Report Date: 2020-March-30

## TOTAL PLANT COST SUMMARY

**Case:** SubCritical PC w/ CO2 Capture - MEA
**Plant Size:** 580.9 MW, net — **Estimate Type:** Conceptual — Cost Base (Jan) 2012 ($x1000)

| Acct No. | Item/Description | Equipment Cost | Material Cost | Labor | | Sale Tax | Bare Erected Cost $ | Eng'g CM H.O. & Fee | Contingencies | | TOTAL PLANT COST | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Direct | Indirect | | | | Process | Project | $ | $/kW |
| **5** | **FLUE GAS CLEANUP** | | | | | | | | | | | |
| 5.1 | Absorber Vessel and Accessories | $81,343 | $0 | $17,168 | $0 | $0 | $98,511 | $9,006 | $0 | $10,752 | $118,269 | $203.6 |
| 5.2 | Other FGD | $4,245 | $0 | $4,716 | $0 | $0 | $8,961 | $840 | $0 | $980 | $10,781 | $18.6 |
| 5.3 | Bag House and Accessories | $23,273 | $0 | $14,480 | $0 | $0 | $37,753 | $3,503 | $0 | $4,126 | $45,382 | $78.1 |
| 5.4 | Oter Particulate Removal Materials | $1,575 | $0 | $1,652 | $0 | $0 | $3,227 | $302 | $0 | $353 | $3,882 | $6.7 |
| 5.5 | Gypsum Dewatering System | $7,379 | $0 | $1,229 | $0 | $0 | $8,608 | $785 | $0 | $939 | $10,332 | $17.8 |
| 5.6 | Mercury Removal System | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 5.9 | Open | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| | **Subtotal 5.** | **$117,815** | **$0** | **$39,245** | **$0** | **$0** | **$157,060** | **$14,436** | **$0** | **$17,150** | **$188,646** | **$325** |
| **5B** | **CO2 REMOVAL & COMPRESSION** | | | | | | | | | | | |
| 5B.1 | CO2 Removal System | $168,757 | $0 | $121,275 | $0 | $0 | $290,032 | $26,977 | $58,006 | $75,003 | $450,018 | $774.7 |
| 5B.2 | CO2 Compression & Drying | $52,932 | $0 | $18,757 | $0 | $0 | $71,689 | $6,595 | $0 | $15,657 | $93,941 | $161.7 |
| | **Subtotal 5B.** | **$221,689** | **$0** | **$140,032** | **$0** | **$0** | **$361,721** | **$33,572** | **$58,006** | **$90,660** | **$543,959** | **$936** |
| **6** | **COMBUSTION TURBINE/ACCESSORIES** | | | | | | | | | | | |
| 6.1 | Combustion Turbine Generator | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 6.2 | Open | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 6.3 | Compressed Air Piping | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 6.9 | Combustion Turbine Fundations | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| | **Subtotal 6.** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** |
| **7** | **HRSG, DUCTING & STACK** | | | | | | | | | | | |
| 7.1 | Heat recovery Steam Generator | $0 | $0 | $0 | $0 | $0 | $0 | $0.00 | $0 | $0 | $0 | $0.0 |
| 7.2 | HRSG Accessories | $0 | $0 | $0 | $0 | $0 | $0 | $0.00 | $0 | $0 | $0 | $0.0 |
| 7.3 | Ductwork | $12,932 | $0 | $8,287 | $0 | $0 | $21,219 | $1,800 | $0 | $3,453 | $26,472 | $45.6 |
| 7.4 | Stack | $12,023 | $0 | $6,897 | $0 | $0 | $18,920 | $1,753 | $0 | $2,067 | $22,740 | $39.1 |
| 7.9 | Duct and Stack Foundations | $0 | $1,285 | $1,536 | $0 | $0 | $2,821 | $264.00 | $0 | $617 | $3,702 | $6.4 |
| | **Subtotal 7.** | **$24,955** | **$1,285** | **$16,720** | **$0** | **$0** | **$42,960** | **$3,817** | **$0** | **$6,137** | **$52,914** | **$91** |
| **8** | **STEM TURBINE GENERATOR** | | | | | | | | | | | |
| 8.1 | Steam TG and Accessories | $74,990 | $0 | $8,658 | $0 | $0 | $83,649 | $7,273.67 | $0 | $9,092 | $100,014 | $172.2 |
| 8.2 | Turbine Plant Auxiliaries | $494 | $0 | $1,039 | $0 | $0 | $1,533 | $144.84 | $0 | $167 | $1,845 | $3.2 |
| 8.3 | Condenser & Auxiliaries | $7,609 | $0 | $3,173 | $0 | $0 | $10,782 | $994.00 | $0 | $1,178 | $12,954 | $22.3 |
| 8.4 | Steam Piping | $28,180 | $0 | $12,219 | $0 | $0 | $40,399 | $3,030.00 | $0 | $6,514 | $49,943 | $86.0 |
| 8.9 | TG Foundations | $0 | $1,446 | $2,405 | $0 | $0 | $3,850 | $361.72 | $0 | $843 | $5,055 | $8.7 |
| | **Subtotal 8.** | **$111,273** | **$1,446** | **$27,493** | **$0** | **$0** | **$140,213** | **$11,804** | **$0** | **$17,794** | **$169,811** | **$292** |
| **9** | **COOLING WATER SYSTEM** | | | | | | | | | | | |
| 9.1 | Cooling Towers | $16,227 | $0 | $4,954 | $0 | $0 | $21,181 | $1,945.00 | $0 | $2,313 | $25,439 | $43.8 |
| 9.2 | Circulating Water Pumps | $3,189 | $0 | $224 | $0 | $0 | $3,413 | $291.00 | $0 | $370 | $4,074 | $7.0 |
| 9.3 | CIrculating Water System Auxiliaries | $847 | $0 | $111 | $0 | $0 | $958 | $87.00 | $0 | $104 | $1,149 | $2.0 |
| 9.4 | Circualting Water Piping | $0 | $7,101 | $6,377 | $0 | $0 | $13,478 | $1,182.00 | $0 | $2,199 | $16,859 | $29.0 |
| 9.5 | Make-up Water System | $861 | $0 | $1,095 | $0 | $0 | $1,956 | $179.00 | $0 | $320 | $2,455 | $4.2 |
| 9.6 | Component Cooling Water System | $689 | $0 | $523 | $0 | $0 | $1,212 | $109.00 | $0 | $198 | $1,519 | $2.6 |
| 9.9 | CIrculating Water Foundations and Structures | $0 | $3,707 | $6,199 | $0 | $0 | $9,906 | $931.00 | $0 | $2,168 | $13,005 | $22.4 |
| | **Subtotal 9.** | **$21,813** | **$10,808** | **$19,483** | **$0** | **$0** | **$52,104** | **$4,724** | **$0** | **$7,672** | **$64,500** | **$111** |

**Client:** EPRI
**Project:** University of Kentucky Post-Combustion CO2 Capture Study — Report Date: 2020-March-30

## TOTAL PLANT COST SUMMARY

**Case:** SubCritical PC w/ CO2 Capture - MEA
**Plant Size:** 580.9 MW, net — **Estimate Type:** Conceptual — Cost Base (Jan) 2012 ($x1000)

| Acct No. | Item/Description | Equipment Cost | Material Cost | Labor | | Sale Tax | Bare Erected Cost $ | Eng'g CM H.O. & Fee | Contingencies | | TOTAL PLANT COST | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Direct | Indirect | | | | Process | Project | $ | $/kW |
| 10.2 | Cyclone ash Letdown | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 10.3 | HGCU Ash Letdown | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 10.4 | High Temperature Ash Piping | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 10.5 | Other Ash Revovery Equipment | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 10.6 | Ash Storage Silos | $921 | $0 | $2,781 | $0 | $0 | $3,702 | $352 | $0 | $405 | $4,459 | $7.7 |
| 10.7 | Ash Transport and Feed Equipment | $6,104 | $0 | $5,985 | $0 | $0 | $12,089 | $1,102 | $0 | $1,319 | $14,510 | $25.0 |
| 10.8 | Misc. Ash Handling Equipment | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 10.9 | Ash/Spent Sorbent Foundations | $0 | $204 | $253 | $0 | $0 | $457 | $43 | $0 | $100 | $600 | $1.0 |
| | **Subtotal 10.** | **$7,025** | **$204** | **$9,019** | **$0** | **$0** | **$16,248** | **$1,497** | **$0** | **$1,824** | **$19,569** | **$34** |
| **11** | **ACCESSORY ELECTRIC PLANT** | | | | | | | | | | | |
| 11.1 | Generator Equipment | $2,186 | $0 | $353 | $0 | $0 | $2,539 | $228 | $0 | $207 | $2,974 | $5.1 |
| 11.2 | Station Service Equipment | $5,999 | $0 | $2,031 | $0 | $0 | $8,030 | $749 | $0 | $658 | $9,437 | $16.2 |
| 11.3 | Switchgear and Motor Control | $6,885 | $0 | $1,208 | $0 | $0 | $8,093 | $752 | $0 | $884 | $9,729 | $16.7 |
| 11.4 | Conduit and Cable Tray | $0 | $4,809 | $15,407 | $0 | $0 | $20,216 | $1,874 | $0 | $3,313 | $25,403 | $43.7 |
| 11.5 | Wire and Cable | $0 | $9,077 | $16,230 | $0 | $0 | $25,307 | $2,024 | $0 | $4,099 | $31,430 | $54.1 |
| 11.6 | Protective Equipment | $315 | $0 | $1,103 | $0 | $0 | $1,418 | $136 | $0 | $155 | $1,709 | $2.9 |
| 11.7 | Standby Equipment | $1,651 | $0 | $39 | $0 | $0 | $1,690 | $156 | $0 | $184 | $2,029 | $3.5 |
| 11.8 | Main Power Transformers | $13,617 | $0 | $237 | $0 | $0 | $13,854 | $1,056 | $0 | $1,491 | $16,401 | $28.2 |
| 11.9 | Electrical Foundations | $0 | $414 | $1,061 | $0 | $0 | $1,475 | $139 | $0 | $322 | $1,936 | $3.3 |
| | **Subtotal 11.** | **$30,653** | **$14,300** | **$37,668** | **$0** | **$0** | **$82,621** | **$7,112** | **$0** | **$11,315** | **$101,048** | **$174** |
| **12** | **INSTRUMENTATION & CONTROL** | | | | | | | | | | | |
| 12.1 | PC Control Equipment | w 12.7 | $0 | w 12.7 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 12.2 | Combustion Turbine Control | NA | $0 | NA | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 12.3 | Steam Turbine Control | w 8.1 | $0 | w 8.1 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 12.4 | Other Major Component Control | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 12.5 | Signal Processing Equipment | w 12.7 | $0 | w 12.7 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 12.6 | Control Boards, Panels, and Racks | $603 | $0 | $372 | $0 | $0 | $975 | $92 | $53 | $167 | $1,287 | $2.2 |
| 12.7 | Distributed Control System Equipment | $6,092 | $0 | $1,098 | $0 | $0 | $7,189 | $667 | $393 | $822 | $9,071 | $15.6 |
| 12.8 | Instrument Wiring and Tubing | $3,732 | $0 | $6,751 | $0 | $0 | $10,484 | $844 | $566 | $1,778 | $13,672 | $23.5 |
| 12.9 | Other I&C Equipment | $1,721 | $0 | $4,026 | $0 | $0 | $5,747 | $548 | $315 | $659 | $7,269 | $12.5 |
| | **Subtotal 12.** | **$12,149** | **$0** | **$12,247** | **$0** | **$0** | **$24,396** | **$2,150** | **$1,327** | **$3,426** | **$31,299** | **$54** |
| **13** | **IMPROVEMENTS TO SITE** | | | | | | | | | | | |
| 13.1 | Site Preparation | $0 | $65 | $1,390 | $0 | $0 | $1,455 | $141 | $0 | $319 | $1,915 | $3.3 |
| 13.2 | Site Improvements | $0 | $2,168 | $2,865 | $0 | $0 | $5,033 | $497 | $0 | $1,106 | $6,636 | $11.4 |
| 13.3 | Site Facilities | $3,886 | $0 | $4,077 | $0 | $0 | $7,963 | $789 | $0 | $1,750 | $10,502 | $18.1 |
| | **Subtotal 13.** | **$3,886** | **$2,233** | **$8,332** | **$0** | **$0** | **$14,451** | **$1,427** | **$0** | **$3,175** | **$19,053** | **$33** |
| **14** | **BUILDINGS & STRUCTURE** | | | | | | | | | | | |
| 14.1 | Boiler Building | $0 | $11,195 | $9,966 | $0 | $0 | $21,161 | $1,866 | $0 | $3,454 | $26,481 | $45.6 |
| 14.2 | Turbine Building | $0 | $16,446 | $15,516 | $0 | $0 | $31,962 | $2,826 | $0 | $5,218 | $40,006 | $68.9 |
| 14.3 | Administration Building | $0 | $787 | $842 | $0 | $0 | $1,629 | $145 | $0 | $266 | $2,040 | $3.5 |
| 14.4 | Circulation Water Pumphouse | $0 | $215 | $173 | $0 | $0 | $388 | $34 | $0 | $63 | $485 | $0.8 |
| 14.5 | Water Treatment Buildings | $0 | $1,130 | $1,043 | $0 | $0 | $2,173 | $192 | $0 | $355 | $2,720 | $4.7 |
| 14.6 | Machine Shop | $0 | $526 | $358 | $0 | $0 | $884 | $77 | $0 | $144 | $1,105 | $1.9 |
| 14.7 | Warehouse | $0 | $356 | $362 | $0 | $0 | $718 | $64 | $0 | $117 | $899 | $1.5 |
| 14.8 | Other Buildings and Structures | $0 | $291 | $251 | $0 | $0 | $542 | $48 | $0 | $89 | $679 | $1.2 |
| 14.9 | Waste Treatming Building and Str. | $0 | $558 | $1,713 | $0 | $0 | $2,271 | $211 | $0 | $372 | $2,854 | $4.9 |
| | **Subtotal 14.** | **$0** | **$31,504** | **$30,224** | **$0** | **$0** | **$61,728** | **$5,463** | **$0** | **$10,078** | **$77,269** | **$133** |
| | **TOTAL COST** | **$869,625** | **$69,387** | **$525,269** | **$0** | **$0** | **$1,464,280** | **$133,209** | **$59,333** | **$235,732** | **$1,892,555** | **$3,258** |

**Table A-11**
**O&M Costs for UK CAER + MEA Case**

| | | | | | | |
|---|---|---|---|---|---|---|
| INITIAL & ANNUAL O&M EXPENSES | | | | | Cost Base (Jan): | 2012 |
| SubCritical PC w/ CO2 Capture - MEA | | | | | Heat Rate-net (Btu/kWh): | 12,352 |
| | | | | | MWe-net: | 581 |
| | | | | | Capacity Factor (%): | 85 |
| OPERATING & MAINTENANCE LABOR | | | | | | |
| Operating Labor | | | | | | |
| Operating Labor Rate (base): | | 40.30 | $/hr | | | |
| Operating Labor Burden: | | 30.00 | % of base | | | |
| Labor O-H Charge Rate: | | 25.00 | % of labor | | | |
| | | | | Total | | |
| Skilled Operator | | 2.0 | | 2.0 | | |
| Operator | | 11.3 | | 11.3 | | |
| Foreman | | 1.0 | | 1.0 | | |
| Lab Tech's, etc. | | 2.0 | | 2.0 | | |
| TOTAL-O.J.'s | | 16.3 | | 16.3 | | |
| | | | | | Annual Cost | Annual Unit Cost |
| | | | | | $ | $/kW-net |
| Annual Operating Labor Cost | | | | | $7,495,808 | $12.905 |
| Maintenance Labor Cost | | | | | $12,112,353 | $20.853 |
| Administrative & Support Labor | | | | | $4,902,040.14 | $8.439 |
| Property Taxes and Insurance | | | | | $37,851,102 | $65.164 |
| **TOTAL FIXED OPERATING COSTS** | | | | | **$62,361,303** | **$107.361** |
| VARIABLE OPERATING COSTS | | | | | | |
| | | | | | | $/kWh-net |
| **Maintenance Material Cost** | | | | | **$18,168,529** | **$0.00420** |
| Consumables | Consumption Initial Fill | /Day | Unit Cost | Initial Fill Cost | | |
| **Water (/1000 gallons)** | 0 | 7,904 | 1.51 | **$0** | **$3,709,409** | **$0.00086** |
| **Chemicals** | | | | | | |
| MU & WT Chem (lbs) | 0 | 38,259 | 0.24 | $0 | $2,872,946 | $0.00066 |
| Limestone (ton) | 0 | 747 | 30.26 | $0 | $7,010,117 | $0.00162 |
| Carbon (Mercury Removal) (lb) | 0 | 0 | 1.47 | $0 | $0 | $0.00000 |
| MEA Solvent (ton) | 1117.065 | 1.58 | 3146.52 | $3,514,867 | $1,546,159 | $0.00036 |
| NaOH (tons) | 79 | 7.89 | 606.51 | $47,914 | $1,484,821 | $0.00034 |
| H2SO4 | 75 | 7.53 | 194.09 | $14,615 | $453,426 | $0.00010 |
| Corrosion Inhibitor | 0 | 0 | 0.00 | $206,727 | $9,844 | $0.00000 |
| Activated Carbon (lb) | 0 | 1892 | 1.47 | $0 | $862,097 | $0.00020 |
| Ammonia (19% NH3) ton | 0 | 110 | 298.21 | $0 | $10,215,405 | $0.00236 |
| **Subtotal Chemicals** | | | | **$3,784,124** | **$24,454,815** | **$0.00565** |
| **Other** | | | | | | |
| Supplemental Fuel (Mbtu) | 0 | 0 | 0.00 | $0 | $0 | $0.00000 |
| SCR Catalyst (m3) | w/equip. | 0.46 | 8,077.80 | $0 | $1,162,897 | $0.00027 |
| Emission Penalties | 0 | 0 | 0.00 | $0 | $0 | $0.00000 |
| **Subtotal Other** | | | | **$0** | **$1,162,897** | **$0.00027** |
| **Waste Disposal** | | | | | | |
| Fly Ash (ton) | 0 | 572 | 25.11 | $0 | $4,459,927 | $0.00103 |
| Bottom Ash (Ton) | 0 | 143 | 25.11 | $0 | $1,114,982 | $0.00026 |
| **Subtotal-Waste Disposal** | | | | **$0** | **$5,574,909** | **$0.00129** |
| **By-Product & Emissions** | | | | | | $0.00000 |
| Gypsum (tons) | 0 | 1,159 | 0.00 | $0 | $0 | $0.00000 |
| **Subtotal By-Products** | | | | **$0** | **$0** | **$0.00000** |
| **TOTAL VARIABLE OPERATING COSTS** | | | | | **$53,070,559** | **$0.01227** |
| **Fuel (ton)** | 0 | 7,380 | 69.00 | **$0** | **$157,983,903** | **$0.03653** |

**Table A-12**
**Summary of Capital Costs for UK CAER + H3-1 Case**

**Client:** EPRI
**Project:** University of Kentucky Post-Combustion CO2 Capture Study — **Report Date:** 2020-March-30

**TOTAL PLANT COST SUMMARY**

**Case:** SubCritical PC w/ CO2 Capture - Hitachi 2020
**Plant Size:** 610.9 MW, net — **Estimate Type:** Conceptual — **Cost Base (Jan)** 2012 ($x1000)

| Acct No. | Item/Description | Equipment Cost | Material Cost | Labor | | Sale Tax | Bare Erected Cost $ | Eng'g CM H.O. & Fee | Contingencies | | TOTAL PLANT COST | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Direct | Indirect | | | | Process | Project | $ | $/kW |
| 1 | COAL & SORBENT HANDLING | $26,077 | $6,619 | $15,454 | $0 | $0 | **$48,150** | $4,218 | $0 | $7,856 | **$60,224** | $99 |
| 2 | COAL & SORBENT PREP & FEED | $17,787 | $988 | $4,478 | $0 | $0 | **$23,253** | $1,976 | $0 | $3,786 | **$29,015** | $47 |
| 3 | FEEDWATER & MISC. BOP SYSTEM | $73,948 | $0 | $33,954 | $0 | $0 | **$107,902** | $9,501 | $0 | $19,453 | **$136,855** | $224 |
| 4 | PC BOILER & ACCESSORIES | | | | | | | | | | | |
| 4.1 | PC Boiler & Accessories | $209,298 | $0 | $134,249 | $0 | $0 | **$343,547** | $32,568 | $0 | $37,612 | **$413,727** | $677 |
| 4.2 | SCR (w/ 4.1) | $0 | $0 | $0 | $0 | $0 | **$0** | $0 | $0 | $0 | **$0** | $0 |
| 4.3 | Open | $0 | $0 | $0 | $0 | $0 | **$0** | $0 | $0 | $0 | **$0** | $0 |
| 4.4-4.9 | Boiler BoP (w/ID Fans) | $0 | $0 | $0 | $0 | $0 | **$0** | $0 | $0 | $0 | **$0** | $0 |
| | **SUBTOTAL 4** | **$209,298** | **$0** | **$134,249** | **$0** | **$0** | **$343,547** | **$32,568** | **$0** | **$37,612** | **$413,727** | **$677** |
| 5 | FLUE GAS CLEANUP | $117,815 | $0 | $39,245 | $0 | $0 | **$157,060** | $14,436 | $0 | $17,150 | **$188,646** | $309 |
| 5B | CO2 REMOVAL & COMPRESSION | $162,649 | $0 | $99,643 | $0 | $0 | **$262,293** | $24,321 | $38,124 | $64,948 | **$389,686** | $638 |
| 6 | COMBUSTION TURBINE/ACCESSORIES | | | | | | | | | | | |
| 6.1 | Combustion Turbine Generator | $0 | $0 | $0 | $0 | $0 | **$0** | $0 | $0 | $0 | **$0** | $0 |
| 6.2-6.9 | Combustion Turbine Other | $0 | $0 | $0 | $0 | $0 | **$0** | $0 | $0 | $0 | **$0** | $0 |
| | **SUBTOTAL 6** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** |
| 7 | HRSG, DUCTING & STACK | | | | | | | | | | | |
| 7.1 | Heat recovery Steam Generator | $0 | $0 | $0 | $0 | $0 | **$0** | $0 | $0 | $0 | **$0** | $0 |
| 7.2-7.9 | HRSG Accessories, Ductwork and Stack | $24,955 | $1,285 | $16,720 | $0 | $0 | **$42,960** | $3,817 | $0 | $6,137 | **$52,914** | $87 |
| | **SUBTOTAL 7** | **$24,955** | **$1,285** | **$16,720** | **$0** | **$0** | **$42,960** | **$3,817** | **$0** | **$6,137** | **$52,914** | **$87** |
| 8 | STEM TURBINE GENERATOR | | | | | | | | | | | |
| 8.1 | Steam TG and Accessories | $76,865 | $0 | $8,875 | $0 | $0 | **$85,740** | $7,456 | $0 | $9,319 | **$102,515** | $168 |
| 8.2-8.9 | Turbine Plant Auxiliaries and Steam Piping | $37,581 | $1,503 | $19,060 | $0 | $0 | **$58,144** | $4,676 | $0 | $8,891 | **$71,711** | $117 |
| | **SUBTOTAL 8** | **$114,447** | **$1,503** | **$27,934** | **$0** | **$0** | **$143,884** | **$12,132** | **$0** | **$18,210** | **$174,226** | **$285** |
| 9 | COOLING WATER SYSTEM | $23,153 | $11,351 | $20,611 | $0 | $0 | **$55,115** | $4,998 | $0 | $8,111 | **$68,224** | $112 |
| 10 | ASH/SPENT SORBENT HANDLING SYS | $7,025 | $204 | $9,019 | $0 | $0 | **$16,248** | $1,497 | $0 | $1,824 | **$19,569** | $32 |
| 11 | ACCESSORY ELECTRIC PLANT | $31,150 | $14,398 | $37,937 | $0 | $0 | **$83,485** | $7,184 | $0 | $11,426 | **$102,095** | $167 |
| 12 | INSTRUMENTATION & CONTROL | $12,172 | $0 | $12,270 | $0 | $0 | **$24,442** | $2,253 | $1,278 | $3,591 | **$31,564** | $52 |
| 13 | IMPROVEMENTS TO SITE | $3,969 | $2,282 | $8,509 | $0 | $0 | **$14,760** | $1,458 | $0 | $3,243 | **$19,460** | $32 |
| 14 | BUILDINGS & STRUCTURE | $0 | $32,435 | $31,099 | $0 | $0 | **$63,534** | $5,623 | $0 | $10,373 | **$79,530** | $130 |
| | **TOTAL COST** | **$824,445** | **$71,064** | **$491,123** | **$0** | **$0** | **$1,386,633** | **$125,981** | **$39,402** | **$213,720** | **$1,765,736** | **$2,890** |

**Table A-13**
**Detailed Capital Costs for UK CAER + H3-1 Case**

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Client:** | EPRI | | | | | | | | | | | |
| | **Project:** | University of Kentucky Post-Combustion CO2 Capture Study | | | | | | | | Report Date: 2020-March-30 | | | |
| | | **TOTAL PLANT COST SUMMARY** | | | | | | | | | | | |
| | **Case:** | SubCritical PC w/ CO2 Capture - Hitachi 2020 | | | | | | | | | | | |
| | **Plant Size:** | 610.9 | MW, net | | | | **Estimate Type:** Conceptual | | | Cost Base (Jan) | | 2012 | ($x1000) |

| Acct No. | Item/Description | Equipment Cost | Material Cost | Labor Direct | Labor Indirect | Sale Tax | Bare Erected Cost $ | Eng'g CM H.O. & Fee | Contingencies Process | Contingencies Project | TOTAL PLANT COST $ | TOTAL PLANT COST $/kW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **1** | **COAL & SORBENT HANDLING** | | | | | | | | | | | |
| 1.1 | Coal Receive and Unload | $5,337 | $0 | $2,416 | $0 | $0 | $7,753 | $671 | $0 | $1,264 | $9,688 | $15.9 |
| 1.2 | Coal Stack out and Reclaim | $6,897 | $0 | $1,549 | $0 | $0 | $8,446 | $715 | $0 | $1,374 | $10,535 | $17.2 |
| 1.3 | Coal Conveyors | $6,412 | $0 | $1,533 | $0 | $0 | $7,945 | $674 | $0 | $1,293 | $9,912 | $16.2 |
| 1.4 | Other Coal Handling | $1,678 | $0 | $355 | $0 | $0 | $2,033 | $172 | $0 | $331 | $2,536 | $4.2 |
| 1.5 | Sorbent Receive and Unload | $219 | $0 | $65 | $0 | $0 | $284 | $24 | $0 | $46 | $354 | $0.6 |
| 1.6 | Sorbent stack out and Reclaim | $3,519 | $0 | $639 | $0 | $0 | $4,158 | $350 | $0 | $676 | $5,184 | $8.5 |
| 1.7 | Sorbent Conveyors | $1,256 | $270 | $305 | $0 | $0 | $1,831 | $153 | $0 | $298 | $2,282 | $3.7 |
| 1.8 | Other Sorbent Handling | $759 | $177 | $396 | $0 | $0 | $1,332 | $114 | $0 | $217 | $1,663 | $2.7 |
| 1.9 | Coal and Sorbent Handling Foundations | $0 | $6,172 | $8,196 | $0 | $0 | $14,368 | $1,345 | $0 | $2,357 | $18,070 | $29.6 |
| | **Subtotal 1.** | **$26,077** | **$6,619** | **$15,454** | **$0** | **$0** | **$48,150** | **$4,218** | **$0** | **$7,856** | **$60,224** | **$99** |
| **2** | **COAL & SORBENT PREP & FEED** | | | | | | | | | | | |
| 2.1 | Coal Crushing and Drying | $3,107 | $0 | $600 | $0 | $0 | $3,707 | $313 | $0 | $603 | $4,623 | $7.6 |
| 2.2 | Coal Conveyor to Storage | $7,954 | $0 | $1,721 | $0 | $0 | $9,675 | $818 | $0 | $1,574 | $12,067 | $19.8 |
| 2.3 | Coal Injection System | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 2.4 | Misc. Coal Prep & Feed | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 2.5 | Sorbent Prep Equipment | $6,003 | $257 | $1,236 | $0 | $0 | $7,496 | $631 | $0 | $1,219 | $9,346 | $15.3 |
| 2.6 | Sorbent Storage and Feed | $723 | $0 | $275 | $0 | $0 | $998 | $86 | $0 | $163 | $1,247 | $2.0 |
| 2.7 | Sorbent Injection System | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 2.8 | Booster Air Supply System | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 2.9 | Coal and Sorbent Feed Foundation | $0 | $731 | $646 | $0 | $0 | $1,377 | $128 | $0 | $227 | $1,732 | $2.8 |
| | **Subtotal 2.** | **$17,787** | **$988** | **$4,478** | **$0** | **$0** | **$23,253** | **$1,976** | **$0** | **$3,786** | **$29,015** | **$47** |
| **3** | **FEEDWATER & MISC. BOP SYSTEM** | | | | | | | | | | | |
| 3.1 | Feedwater System | $29,234 | $0 | $10,005 | $0 | $0 | $39,239 | $3,328 | $0 | $6,385 | $48,952 | $80.1 |
| 3.2 | Water Makeup and Pretreating | $10,896 | $0 | $3,400 | $0 | $0 | $14,296 | $1,287 | $0 | $3,116 | $18,699 | $30.6 |
| 3.3 | Other Feedwater Subsystems | $9,917 | $0 | $4,007 | $0 | $0 | $13,924 | $1,178 | $0 | $2,266 | $17,367 | $28.4 |
| 3.4 | Service Water Systems | $2,176 | $0 | $1,127 | $0 | $0 | $3,303 | $293 | $0 | $720 | $4,316 | $7.1 |
| 3.5 | Other Boiler Plant Systems | $10,408 | $0 | $9,740 | $0 | $0 | $20,148 | $1,815 | $0 | $3,294 | $25,257 | $41.3 |
| 3.6 | FO Supply System and Natural Gas | $383 | $0 | $443 | $0 | $0 | $826 | $73 | $0 | $135 | $1,034 | $1.7 |
| 3.7 | Waste Treatment Equipment | $7,181 | $0 | $4,083 | $0 | $0 | $11,264 | $1,067 | $0 | $2,466 | $14,797 | $24.2 |
| 3.8 | Misc. Equip. (Cranes, air comp, comm.) | $3,753 | $0 | $1,149 | $0 | $0 | $4,902 | $460 | $0 | $1,072 | $6,434 | $10.5 |
| | **Subtotal 3.** | **$73,948** | **$0** | **$33,954** | **$0** | **$0** | **$107,902** | **$9,501** | **$0** | **$19,453** | **$136,855** | **$224** |
| **4** | **PC BOILER & ACCESSORIES** | | | | | | | | | | | |
| 4.1 | PC Boiler & Accessories | $209,298 | $0 | $134,249 | $0 | $0 | $343,547 | $32,568 | $0 | $37,612 | $413,727 | $677.2 |
| 4.2 | SCR (w/ 4.1) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 4.3 | Open | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 4.4 | Boiler BoP (w/ ID Fans) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 4.5 | Primary Air System | w/4.1 | $0 | w/4.1 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 4.6 | Secondary Air System | w/4.1 | $0 | w/4.1 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 4.8 | Major Component Rigging | $0 | w/4.1 | w/4.1 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 4.9 | Boiler Foundations | $0 | w/4.1 | w/4.1 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| | **Subtotal 4.** | **$209,298** | **$0** | **$134,249** | **$0** | **$0** | **$343,547** | **$32,568** | **$0** | **$37,612** | **$413,727** | **$677** |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Client:** | EPRI | | | | | | | | | | | |
| | **Project:** | University of Kentucky Post-Combustion CO2 Capture Study | | | | | | | | Report Date: 2020-March-30 | | | |
| | | **TOTAL PLANT COST SUMMARY** | | | | | | | | | | | |
| | **Case:** | SubCritical PC w/ CO2 Capture - Hitachi 2020 | | | | | | | | | | | |
| | **Plant Size:** | 610.9 | MW, net | | | | **Estimate Type:** Conceptual | | Cost Base (Jan) | | 2012 | | ($x1000) |
| **Acct No.** | **Item/Description** | **Equipment Cost** | **Material Cost** | **Labor Direct** | **Labor Indirect** | **Sale Tax** | **Bare Erected Cost $** | **Eng'g CM H.O. & Fee** | **Contingencies Process** | **Contingencies Project** | **TOTAL PLANT COST $** | **TOTAL PLANT COST $/kW** | |
| **5** | **FLUE GAS CLEANUP** | | | | | | | | | | | | |
| 5.1 | Absorber Vessel and Accessories | $81,343 | $0 | $17,168 | $0 | $0 | $98,511 | $9,006 | $0 | $10,752 | $118,269 | $193.6 | |
| 5.2 | Other FGD | $4,245 | $0 | $4,716 | $0 | $0 | $8,961 | $840 | $0 | $980 | $10,781 | $17.6 | |
| 5.3 | Bag House and Accessories | $23,273 | $0 | $14,480 | $0 | $0 | $37,753 | $3,503 | $0 | $4,126 | $45,382 | $74.3 | |
| 5.4 | Oter Particulate Removal Materials | $1,575 | $0 | $1,652 | $0 | $0 | $3,227 | $302 | $0 | $353 | $3,882 | $6.4 | |
| 5.5 | Gypsum Dewatering System | $7,379 | $0 | $1,229 | $0 | $0 | $8,608 | $785 | $0 | $939 | $10,332 | $16.9 | |
| 5.6 | Mercury Removal System | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 | |
| 5.9 | Open | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 | |
| | **Subtotal 5.** | **$117,815** | **$0** | **$39,245** | **$0** | **$0** | **$157,060** | **$14,436** | **$0** | **$17,150** | **$188,646** | **$309** | |
| **5B** | **CO2 REMOVAL & COMPRESSION** | | | | | | | | | | | | |
| 5B.1 | CO2 Removal System | $109,717 | $0 | $80,886 | $0 | $0 | $190,604 | $17,726 | $38,124 | $49,291 | $295,745 | $484.1 | |
| 5B.2 | CO2 Compression & Drying | $52,932 | $0 | $18,757 | $0 | $0 | $71,689 | $6,595 | $0 | $15,657 | $93,941 | $153.8 | |
| | **Subtotal 5B.** | **$162,649** | **$0** | **$99,643** | **$0** | **$0** | **$262,293** | **$24,321** | **$38,124** | **$64,948** | **$389,686** | **$638** | |
| **6** | **COMBUSTION TURBINE/ACCESSORIES** | | | | | | | | | | | | |
| 6.1 | Combustion Turbine Generator | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 | |
| 6.2 | Open | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 | |
| 6.3 | Compressed Air Piping | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 | |
| 6.9 | Combustion Turbine Fundations | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 | |
| | **Subtotal 6.** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | |
| **7** | **HRSG, DUCTING & STACK** | | | | | | | | | | | | |
| 7.1 | Heat recovery Steam Generator | $0 | $0 | $0 | $0 | $0 | $0 | | $0 | $0 | $0 | $0.0 | |
| 7.2 | HRSG Accessories | $0 | $0 | $0 | $0 | $0 | $0 | | $0 | $0 | $0 | $0.0 | |
| 7.3 | Ductwork | $12,932 | $0 | $8,287 | $0 | $0 | $21,219 | $1,800 | $0 | $3,453 | $26,472 | $43.3 | |
| 7.4 | Stack | $12,023 | $0 | $6,897 | $0 | $0 | $18,920 | $1,753 | $0 | $2,067 | $22,740 | $37.2 | |
| 7.9 | Duct and Stack Foundations | $0 | $1,285 | $1,536 | $0 | $0 | $2,821 | $264.00 | $0 | $617 | $3,702 | $6.1 | |
| | **Subtotal 7.** | **$24,955** | **$1,285** | **$16,720** | **$0** | **$0** | **$42,960** | **$3,817** | **$0** | **$6,137** | **$52,914** | **$87** | |
| **8** | **STEM TURBINE GENERATOR** | | | | | | | | | | | | |
| 8.1 | Steam TG and Accessories | $76,865 | $0 | $8,875 | $0 | $0 | $85,740 | $7,455.53 | $0 | $9,319 | $102,515 | $167.8 | |
| 8.2 | Turbine Plant Auxiliaries | $506 | $0 | $1,064 | $0 | $0 | $1,571 | $148.46 | $0 | $172 | $1,891 | $3.1 | |
| 8.3 | Condenser & Auxiliaries | $8,895 | $0 | $3,277 | $0 | $0 | $12,172 | $1,121.95 | $0 | $1,330 | $14,624 | $23.9 | |
| 8.4 | Steam Piping | $28,180 | $0 | $12,219 | $0 | $0 | $40,399 | $3,030.00 | $0 | $6,514 | $49,943 | $81.8 | |
| 8.9 | TG Foundations | $0 | $1,503 | $2,499 | $0 | $0 | $4,002 | $375.93 | $0 | $876 | $5,253 | $8.6 | |
| | **Subtotal 8.** | **$114,447** | **$1,503** | **$27,934** | **$0** | **$0** | **$143,884** | **$12,132** | **$0** | **$18,210** | **$174,226** | **$285** | |
| **9** | **COOLING WATER SYSTEM** | | | | | | | | | | | | |
| 9.1 | Cooling Towers | $17,180 | $0 | $5,245 | $0 | $0 | $22,425 | $2,058.74 | $0 | $2,449 | $26,933 | $44.1 | |
| 9.2 | Circulating Water Pumps | $3,377 | $0 | $243 | $0 | $0 | $3,620 | $308.87 | $0 | $393 | $4,322 | $7.1 | |
| 9.3 | CIrculating Water System Auxiliaries | $889 | $0 | $116 | $0 | $0 | $1,005 | $91.83 | $0 | $110 | $1,207 | $2.0 | |
| 9.4 | Circualting Water Piping | $0 | $7,458 | $6,697 | $0 | $0 | $14,155 | $1,241.34 | $0 | $2,309 | $17,705 | $29.0 | |
| 9.5 | Make-up Water System | $984 | $0 | $1,251 | $0 | $0 | $2,235 | $204.21 | $0 | $366 | $2,805 | $4.6 | |
| 9.6 | Component Cooling Water System | $723 | $0 | $549 | $0 | $0 | $1,272 | $114.79 | $0 | $208 | $1,595 | $2.6 | |
| 9.9 | CIrculating Water Foundations and Structures | $0 | $3,893 | $6,510 | $0 | $0 | $10,403 | $978.37 | $0 | $2,277 | $13,658 | $22.4 | |
| | **Subtotal 9.** | **$23,153** | **$11,351** | **$20,611** | **$0** | **$0** | **$55,115** | **$4,998** | **$0** | **$8,111** | **$68,224** | **$112** | |

**Client:** EPRI
**Project:** University of Kentucky Post-Combustion CO2 Capture Study — Report Date: 2020-March-30

**TOTAL PLANT COST SUMMARY**

**Case:** SubCritical PC w/ CO2 Capture - Hitachi 2020
**Plant Size:** 610.9 MW, net — **Estimate Type:** Conceptual — Cost Base (Jan) 2012 — ($x1000)

| Acct No. | Item/Description | Equipment Cost | Material Cost | Labor Direct | Labor Indirect | Sale Tax | Bare Erected Cost $ | Eng'g CM H.O. & Fee | Contingencies Process | Contingencies Project | TOTAL PLANT COST $ | TOTAL PLANT COST $/kW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 10.2 | Cyclone ash Letdown | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 10.3 | HGCU Ash Letdown | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 10.4 | High Temperature Ash Piping | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 10.5 | Other Ash Revovery Equipment | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 10.6 | Ash Storage Silos | $921 | $0 | $2,781 | $0 | $0 | $3,702 | $352 | $0 | $405 | $4,459 | $7.3 |
| 10.7 | Ash Transport and Feed Equipment | $6,104 | $0 | $5,985 | $0 | $0 | $12,089 | $1,102 | $0 | $1,319 | $14,510 | $23.8 |
| 10.8 | Misc. Ash Handling Equipment | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 10.9 | Ash/Spent Sorbent Foundations | $0 | $204 | $253 | $0 | $0 | $457 | $43 | $0 | $100 | $600 | $1.0 |
| | **Subtotal 10.** | **$7,025** | **$204** | **$9,019** | **$0** | **$0** | **$16,248** | **$1,497** | **$0** | **$1,824** | **$19,569** | **$32** |
| **11** | **ACCESSORY ELECTRIC PLANT** | | | | | | | | | | | |
| 11.1 | Generator Equipment | $2,231 | $0 | $360 | $0 | $0 | $2,590 | $233 | $0 | $212 | $3,035 | $5.0 |
| 11.2 | Station Service Equipment | $6,037 | $0 | $2,044 | $0 | $0 | $8,081 | $753 | $0 | $662 | $9,496 | $15.5 |
| 11.3 | Switchgear and Motor Control | $6,928 | $0 | $1,216 | $0 | $0 | $8,144 | $756 | $0 | $890 | $9,790 | $16.0 |
| 11.4 | Conduit and Cable Tray | $0 | $4,840 | $15,504 | $0 | $0 | $20,344 | $1,886 | $0 | $3,334 | $25,564 | $41.8 |
| 11.5 | Wire and Cable | $0 | $9,134 | $16,333 | $0 | $0 | $25,467 | $2,036 | $0 | $4,125 | $31,628 | $51.8 |
| 11.6 | Protective Equipment | $317 | $0 | $1,110 | $0 | $0 | $1,426 | $137 | $0 | $156 | $1,719 | $2.8 |
| 11.7 | Standby Equipment | $1,678 | $0 | $39 | $0 | $0 | $1,717 | $158 | $0 | $187 | $2,063 | $3.4 |
| 11.8 | Main Power Transformers | $13,960 | $0 | $245 | $0 | $0 | $14,205 | $1,083 | $0 | $1,529 | $16,816 | $27.5 |
| 11.9 | Electrical Foundations | $0 | $424 | $1,087 | $0 | $0 | $1,511 | $142 | $0 | $330 | $1,983 | $3.2 |
| | **Subtotal 11.** | **$31,150** | **$14,398** | **$37,937** | **$0** | **$0** | **$83,485** | **$7,184** | **$0** | **$11,426** | **$102,095** | **$167** |
| **12** | **INSTRUMENTATION & CONTROL** | | | | | | | | | | | |
| 12.1 | PC Control Equipment | w 12.7 | $0 | w 12.7 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 12.2 | Combustion Turbine Control | NA | $0 | NA | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 12.3 | Steam Turbine Control | w 8.1 | $0 | w 8.1 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 12.4 | Other Major Component Control | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 12.5 | Signal Processing Equipment | w 12.7 | $0 | w 12.7 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.0 |
| 12.6 | Control Boards, Panels, and Racks | $604 | $0 | $373 | $0 | $0 | $977 | $96 | $51 | $176 | $1,300 | $2.1 |
| 12.7 | Distributed Control System Equipment | $6,103 | $0 | $1,100 | $0 | $0 | $7,203 | $699 | $377 | $861 | $9,140 | $15.0 |
| 12.8 | Instrument Wiring and Tubing | $3,740 | $0 | $6,764 | $0 | $0 | $10,504 | $884 | $549 | $1,864 | $13,801 | $22.6 |
| 12.9 | Other I&C Equipment | $1,725 | $0 | $4,034 | $0 | $0 | $5,758 | $574 | $301 | $690 | $7,323 | $12.0 |
| | **Subtotal 12.** | **$12,172** | **$0** | **$12,270** | **$0** | **$0** | **$24,442** | **$2,253** | **$1,278** | **$3,591** | **$31,564** | **$52** |
| **13** | **IMPROVEMENTS TO SITE** | | | | | | | | | | | |
| 13.1 | Site Preparation | $0 | $67 | $1,419 | $0 | $0 | $1,486 | $144 | $0 | $326 | $1,956 | $3.2 |
| 13.2 | Site Improvements | $0 | $2,215 | $2,926 | $0 | $0 | $5,141 | $508 | $0 | $1,130 | $6,778 | $11.1 |
| 13.3 | Site Facilities | $3,969 | $0 | $4,164 | $0 | $0 | $8,133 | $806 | $0 | $1,787 | $10,726 | $17.6 |
| | **Subtotal 13.** | **$3,969** | **$2,282** | **$8,509** | **$0** | **$0** | **$14,760** | **$1,458** | **$0** | **$3,243** | **$19,460** | **$32** |
| **14** | **BUILDINGS & STRUCTURE** | | | | | | | | | | | |
| 14.1 | Boiler Building | $0 | $11,448 | $10,191 | $0 | $0 | $21,639 | $1,908 | $0 | $3,532 | $27,079 | $44.3 |
| 14.2 | Turbine Building | $0 | $16,889 | $15,934 | $0 | $0 | $32,823 | $2,902 | $0 | $5,359 | $41,084 | $67.3 |
| 14.3 | Administration Building | $0 | $798 | $854 | $0 | $0 | $1,652 | $147 | $0 | $270 | $2,069 | $3.4 |
| 14.4 | Circulation Water Pumphouse | $0 | $218 | $175 | $0 | $0 | $393 | $35 | $0 | $64 | $492 | $0.8 |
| 14.5 | Water Treatment Buildings | $0 | $1,324 | $1,222 | $0 | $0 | $2,546 | $225 | $0 | $415 | $3,186 | $5.2 |
| 14.6 | Machine Shop | $0 | $534 | $363 | $0 | $0 | $897 | $78 | $0 | $146 | $1,121 | $1.8 |
| 14.7 | Warehouse | $0 | $362 | $367 | $0 | $0 | $729 | $65 | $0 | $119 | $913 | $1.5 |
| 14.8 | Other Buildings and Structures | $0 | $296 | $255 | $0 | $0 | $551 | $49 | $0 | $90 | $690 | $1.1 |
| 14.9 | Waste Treatming Building and Str. | $0 | $566 | $1,738 | $0 | $0 | $2,304 | $214 | $0 | $378 | $2,896 | $4.7 |
| | **Subtotal 14.** | **$0** | **$32,435** | **$31,099** | **$0** | **$0** | **$63,534** | **$5,623** | **$0** | **$10,373** | **$79,530** | **$130** |
| | **TOTAL COST** | **$824,445** | **$71,064** | **$491,123** | **$0** | **$0** | **$1,386,633** | **$125,981** | **$39,402** | **$213,720** | **$1,765,736** | **$2,890** |

**Table A-14**
**O&M Costs for UK CAER + H3-1 Case**

| | | |
|---|---|---|
| INITIAL & ANNUAL O&M EXPENSES | Cost Base (Jan): | 2012 |
| SubCritical PC w/ CO2 Capture - Hitachi 2020 | Heat Rate-net (Btu/kWh): | 11,744 |
| | MWe-net: | 611 |
| | Capacity Factor (%): | 85 |

OPERATING & MAINTENANCE LABOR

| Operating Labor | | | |
|---|---|---|---|
| Operating Labor Rate (base): | 40.30 | $/hr | |
| Operating Labor Burden: | 30.00 | % of base | |
| Labor O-H Charge Rate: | 25.00 | % of labor | |
| | | | Total |
| Skilled Operator | 2.0 | | 2.0 |
| Operator | 11.3 | | 11.3 |
| Foreman | 1.0 | | 1.0 |
| Lab Tech's, etc. | 2.0 | | 2.0 |
| TOTAL-O.J.'s | 16.3 | | 16.3 |

| | Annual Cost | Annual Unit Cost |
|---|---|---|
| | $ | $/kW-net |
| Annual Operating Labor Cost | $7,480,663 | $12.245 |
| Maintenance Labor Cost | $11,300,709 | $18.498 |
| Administrative & Support Labor | $4,695,343.02 | $7.686 |
| Property Taxes and Insurance | $35,314,715 | $57.807 |
| **TOTAL FIXED OPERATING COSTS** | **$58,791,430** | **$96.237** |

VARIABLE OPERATING COSTS

| | | | | | | $/kWh-net |
|---|---|---|---|---|---|---|
| **Maintenance Material Cost** | | | | | **$16,965,474** | **$0.00373** |
| Consumables | Consumption Initial Fill | /Day | Unit Cost | Initial Fill Cost | | |
| **Water (/1000 gallons)** | 0 | 9,880 | 1.51 | **$0** | **$4,628,558** | **$0.00102** |
| **Chemicals** | | | | | | |
| MU & WT Chem (lbs) | 0 | 47,823 | 0.24 | $0 | $3,560,901 | $0.00078 |
| Limestone (ton) | 0 | 747 | 30.26 | $0 | $7,010,117 | $0.00154 |
| Carbon (Mercury Removal) (lb) | 0 | 0 | 1.47 | $0 | $0 | $0.00000 |
| H3-1 Solvent (ton) | 0 | | | $10,333,699 | $1,700,602 | $0.00037 |
| NaOH (tons) | 79 | 7.89 | 606.51 | $47,914 | $1,484,821 | $0.00033 |
| H2SO4 | 75 | 7.53 | 194.09 | $14,615 | $453,426 | $0.00010 |
| Corrosion Inhibitor | 0 | 0 | 0.00 | $206,727 | $9,844 | $0.00000 |
| Activated Carbon (lb) | 0 | 1892 | 1.47 | $0 | $862,097 | $0.00019 |
| Ammonia (19% NH3) ton | 0 | 110 | 298.21 | $0 | $10,215,405 | $0.00225 |
| **Subtotal Chemicals** | | | | **$10,602,955** | **$25,297,213** | **$0.00556** |
| **Other** | | | | | | |
| Supplemental Fuel (Mbtu) | 0 | 0 | 0.00 | $0 | $0 | $0.00000 |
| SCR Catalyst (m3) | w/equip. | 0.46 | 8,077.80 | $0 | $1,162,897 | $0.00026 |
| Emission Penalties | 0 | 0 | 0.00 | $0 | $0 | $0.00000 |
| **Subtotal Other** | | | | **$0** | **$1,162,897** | **$0.00026** |
| **Waste Disposal** | | | | | | |
| Fly Ash (ton) | 0 | 572 | 25.11 | $0 | $4,459,927 | $0.00098 |
| Bottom Ash (Ton) | 0 | 143 | 25.11 | $0 | $1,114,982 | $0.00025 |
| **Subtotal-Waste Disposal** | | | | **$0** | **$5,574,909** | **$0.00123** |
| **By-Product & Emissions** | | | | | | |
| Gypsum (tons) | 0 | 1,159 | 0.00 | $0 | $0 | $0.00000 |
| **Subtotal By-Products** | | | | **$0** | **$0** | **$0.00000** |
| **TOTAL VARIABLE OPERATING COSTS** | | | | | **$53,614,640** | **$0.01179** |
| **Fuel (ton)** | 0 | 7,380 | 69.00 | **$0** | **$157,983,903** | **$0.03473** |