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ABSTRACT

This topical report summarizes the results of an updated Technical & Economic Feasibility Study (T&EFS) which was conducted in Budget Period 3 of the project to evaluate the performance and cost of the Electrochemical Membrane (ECM)-based CO_2 capture system. The ECM technology is derived from commercially available inorganic membranes; the same used in FuelCell Energy's commercial fuel cell power plants and sold under the trade name Direct FuelCell® (DFC®). The ECM stacks are utilized in the Combined Electric Power (generation) And Carbon dioxide Separation (CEPACS) systems which can be deployed as add-ons to conventional power plants (Pulverized Coal, Combined Cycle, etc.) or industrial facilities to simultaneously produce power while capturing >90% of the CO_2 from the flue gas.

In this study, an ECM-based CEPACS plant was designed to capture and compress >90% of the CO_2 (for sequestration or beneficial use) from the flue gas of a reference 550 MW (nominal, net AC) Pulverized Coal (PC) Rankine Cycle (Subcritical steam) power plant. ECM performance was updated based on bench scale ECM stack test results. The system process simulations were performed to generate the CEPACS plant performance estimates. The performance assessment included estimation of the parasitic power consumption for CO_2 capture and compression, and the efficiency impact on the PC plant. While the ECM-based CEPACS system for the 550 MW PC plant captures 90% of CO_2 from the flue gas, it generates additional (net AC) power after compensating for the auxiliary power requirements of CO_2 capture and compression. An equipment list, ECM stacks packaging design, and CEPACS plant layout were developed to facilitate the economic analysis. Vendor quotes were also solicited. The economic feasibility study included estimation of CEPACS plant capital cost, cost of electricity (COE) analyses and estimation of cost per ton of CO_2 captured. The incremental COE for the ECM-based CO_2 capture is expected to meet U.S. DOE's target of 35%.

This study has indicated that CEPACS systems offer significant benefits with respect to cost, performance, water consumption and emissions to environment. The realization of these benefits will provide a single solution to carbon dioxide capture in addition to meeting the increasing demand for electricity.

TABLE OF CONTENTS

LIST OF FIGURES V
LIST OF TABLES VI
EXECUTIVE SUMMARY 1
EXPERIMENTAL METHODS 16
RESULTS AND DISCUSSIONS 17
1.0 CEPACS SYSTEM CONFIGURATION AND DESIGN 17
1.1 Design Basis 17
1.2 Overall Process 21
1.3 Major Subsystems 22
1.4 Equipment List 37
2.0 SYSTEM PERFORMANCE 40
2.1 Key System Assumptions 40
2.2 Performance Summary 41
2.3 Environmental Performance 42
2.4 Carbon Balance 43
2.5 Sulfur Balance 44
2.6 Energy Balance 44
2.7 Water Balance 46
3.0 ECONOMIC FEASIBILITY 48
3.1 Case 3 Capital Cost Estimate 48
3.2 Case 3 Cost of Electricity and Cost of CO_2 Capture Analysis 58
3.3 Case 3 Economic Sensitivity Studies 59
CONCLUSIONS 66
REFERENCES 67
LIST OF ACRONYMS 67

LIST OF FIGURES

Figure ES-1. Plant Electrical Efficiency (HHV) 4
Figure ES-2. Water Use 5
Figure ES-3. Plant Capital Costs 6
Figure ES-4. Cost of Electricity and Incremental COE 7
Figure ES-5. Cost of CO_2 Captured and Avoided 8
Figure ES-6. SO_2, NOx, and Particulate Emission Rates 9
Figure ES-7. Mercury Emission Rates 11
Figure ES-8. CO_2 Emission Rates 12
Figure I-1. Transport of CO_2 in the Electrochemical Membrane Cell: CO_2 is used at cathode as an oxidant and transferred to anode via carbonate ions 14
Figure I-2. CEPACS CO_2 Separation and Power System Concept: The system can be used with a variety of CO_2-containing greenhouse gases (GHG) 15
Figure 1-1. Boundary Limits of CEPACS System for CO_2 Capture (CC) from a 550 MW PC Plant 17
Figure 1-2: Capital Cost Levels and Their Elements [3] 20
Figure 1-3: Block Flow Diagram of CEPACS System Applied to a 550 MW Pulverized Coal Plant 21
Figure 1-4. Plan View of a 224-Stack ECM Enclosure 24
Figure 1-5. Cross-section of an ECM enclosure with stack being installed and power equipment external to the enclosure 25
Figure 1-6. General Arrangement of an ECM enclosure and associated “hot” BOP equipment. 26
Figure 1-7. General Arrangement of ECM enclosures, BOP equipment and piping 26
Figure 1-8. Direct FuelCell® commercial power plant products 27
Figure 1-9. (left) 14.9 MW Bridgeport, CT facility; and (right) 59 MW Hwasung City, South Korea facility 28
Figure 1-10. Cell Design and Materials 28
Figure 1-11. Product Cost Reduction of DFC Power Plants at Low/Moderate Production Volume 29
Figure 1-12. Global Manufacturing Facilities with an Ultimate Annual Production Capacity of 320 MW 29
Figure 1-13. ECM Performance Based on Bench-scale Testing 31
Figure 1-14. Electrical One-line Diagram for Power Generation Subsystem (CEPACS) 35
Figure 1-15. Electrical One-line Diagram for Auxiliary Power Subsystem (CEPACS) 36
Figure 2-1. Water Block Flow Diagram for the CEPACS System 47
Figure 3-1. Sensitivity of ECM Stack Cost to Production Rate, Normalized to Baseline Case ... 60
Figure 3-2. Sensitivity of Capital Cost for CEPACS-Equipped PC plant to ECM Stack Production Rate 61
Figure 3-3. Sensitivity of Cost of Electricity for CEPACS-Equipped PC plant to ECM Stack Production Rate 61

Figure 3-4. Cost of Electricity Breakdown for CEPACS-Equipped PC plant at Four Production Rates, Compared to a PC Plant without CCS and with an Amine Scrubber. 62
Figure 3-5. Historical Natural Gas Price for the Electric Power Sector ($/Mcf) 63
Figure 3-6. Sensitivity of Cost of Electricity for CEPACS-Equipped PC plant to NG Price 64
Figure 3-7. Sensitivity of Cost of CO_2 Captured and Avoided for CEPACS-Equipped PC plant to NG Price 64
Figure 3-8. Summary of Sensitivity Study Results: Effects of ECM production rate and NG Price on CEPACS-Equipped PC Plant Cost of Electricity 65

LIST OF TABLES

Table ES-1. Case Summary 2
Table ES-2. Cost and Performance Summary for All Cases 3
Table 1-1. PC Plant Flue Gas Specifications 18
Table 1-2. Pipeline Natural Gas Specification 19
Table 1-3. CO_2 Capture Requirement and Product Specification 19
Table 1-4. Economic Analysis Assumptions 20
Table 1-5. Expected System (Flue gas) Contaminant Levels Compared with Test Experience. 30
Table 1-6. CEPACS System Equipment List for Application to a 550 MW PC Power Plant 38
Table 2-1. Key System Assumptions 40
Table 2-2. PC Plant with CEPACS CO_2 Capture System: Performance Summary 41
Table 2-3. Air Emissions for Case 3: 550 MW PC Plant with CEPACS System 43
Table 2-4. Carbon Balance for CEPACS System 43
Table 2-5. Sulfur Balance for CEPACS Plant 44
Table 2-6. Overall Energy Balance for CEPACS System (25°C Reference) 45
Table 2-7. Water Balance for 550 MW PC Plant Equipped with CEPACS Plant 46
Table 3-1. Capital Cost Estimate for CEPACS System, 2014 USD 50
Table 3-2. Case 3 (PC + CEPACS) Capital Cost Estimate, 2007 USD 54
Table 3-3. Fixed Operating Costs for CEPACS System 58
Table 3-4. Variable Operating Costs for CEPACS System 58
Table 3-5. Case 3 (PC + CEPACS) COE and Cost of CO_2 Captured, ... 59

EXECUTIVE SUMMARY

This topical report presents the results of the final updated Technical & Economic Feasibility Study conducted (in Budget Period 3 of the project) to assess the performance and cost of FuelCell Energy's Electrochemical Membrane (ECM)-based CO_2 capture system. This Combined Electric Power (generation) And Carbon dioxide Separation (CEPACS) system employs FCE's Direct Fuel Cell technology which is commercialized for stationary power generation applications. A CEPACS plant utilizing ECM technology was designed to capture and compress >90% of CO_2 from the flue gas of a reference 550 MW (net AC) Pulverized Coal (PC) Subcritical Steam Cycle Plant. The PC plant design specified in "Case 9" of the U.S. Department of Energy - National Energy Technology Laboratory (DOE - NETL) report "*Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity, Revision 2a"* [5] *wa*s used as a reference.

The system configuration, simulations and analyses were performed using CHEMCAD process simulation software to guide the conceptual design of the CEPACS plant. Process simulations were updated based on ECM performance realized in bench-scale testing. In the CEPACS plant, ECM-separated CO_2-rich stream is cooled, compressed and chilled to liquefy CO_2 which can be easily pressurized for sequestration or beneficial use. Technical information provided by leading balance-of-plant (BOP) equipment manufacturers was utilized for system analyses. The performance assessment included estimation of the parasitic power consumption for >90% CO_2 capture and compression, and the efficiency impact on the PC plant. The updated CEPACS plant contains a total of 1,792 ECM stacks. An equipment list, ECM stacks packaging design, and CEPACS plant layout were developed to facilitate the economic analysis. Technical and cost quotations were solicited from leading vendors for key pieces of equipment. In addition to the process flow diagram and a stream table, electrical one-line diagrams were generated for the CEPACS plant. The economic feasibility study included estimation of CEPACS plant capital cost, cost of electricity (COE) analyses and, estimation of cost per tonne of CO_2 captured and cost per tonne of CO_2 avoided. The following two DOE-NETL documents were used as guidelines for the study/analysis:

- 'Scope and Reporting Requirements for NETL System Studies', dated May 2010 [4]
- 'Quality Guidelines for Energy System Studies: Cost Estimation Methodology for NETL Assessment of Power Plant Performance', dated April 2011, DOE/NETL-2011/1455 [3]

The study was conducted in accordance with the DOE–NETL reports mentioned above, and specifically focused on developing technical and economic comparisons to Cases 9 and 10 related to Subcritical PC plants.

The ECM-based CEPACS system applied to the 550 MW PC plant simultaneously generates additional (net AC) power (after compensating for the auxiliary power requirements of CO_2 capture and compression) while capturing >90% of CO_2 from the flue gas. The net electrical efficiency of the PC plant equipped with a CEPACS system (for CO_2 capture) was estimated to be 38.8% (based on higher heating values of coal and natural gas fuels used by PC plant and CEPACS plant, respectively). A list of the cases studied is presented in Table ES-1.

Table ES-1. Case Summary

Case ID	DOE/NETL-2010/1397 Case ID [2]	Unit Cycle	MW gross	MW net	Boiler Technology	Sulfur Removal/ Recovery	CO_2 Separation
1	9	PC	583	550	Subcritical PC	Wet Flue Gas Desulfurization (FGD)	--
2	10	PC + Amine	673	550	Subcritical PC	Wet FGD	Amine Absorber
3	--	PC + ECM	1016	901	Subcritical PC	Wet FGD	ECM-based CEPACS

Table ES-2 shows the cost, performance, and environmental profile summary for all cases. The results are discussed below in the following order:

- Performance (efficiency and raw water consumption)
- Cost (plant capital costs, COE, and cost per ton of CO_2 captured)
- Environmental profile (CO_2 and other emissions)

Table ES-2. Cost and Performance Summary for All Cases

	Case 1 PC w/o CO_2 capture	PC w/ Amine CO_2 Cap	PC + CEPACS
PERFORMANCE			
CO_2 Capture	0%	90%	92.8%
Gross Power Output (kWe)	582,600	672,700	1,016,064
Auxiliary Power Requirement (kWe)	32,580	122,740	115,239
Net Power Output (kWe)	550,020	549,960	900,825
Coal Flow rate (lb/hr)	437,378	614,994	437,378
Natural Gas Flow rate (lb/hr)	N/A	N/A	124,763
HHV Thermal Input (kWth)	1,495,379	2,102,643	2,321,943
Net Plant HHV Efficiency (%)	36.8%	26.2%	38.8%
Net Plant HHV Heat Rate (Btu/kWh)	9,277	13,046	8,795
Raw Water Withdrawal (gpm/MWnet)	10.7	20.4	8.1
Process Water Discharge (gpm/MWnet)	2.2	4.7	1.9
Raw Water Consumption (gpm/MWnet)	8.5	15.7	6.2
CO_2 Emissions (lb/MMBtu)	204	20	13
CO_2 Emissions (lb/MWhgross)	1,783	217	98
CO_2 Emissions (lb/MWhnet)	1,888	266	111
SO_2 Emissions (lb/MMBtu)	0.0858	0.0017	0.0006
SO_2 Emissions (lb/MWhgross)	0.7515	0.0176	0.0047
NOx Emissions (lb/MMBtu)	0.07	0.07	0.0155
NOx Emissions (lb/MWhgross)	0.613	0.747	0.1205
PM Emissions (lb/MMBtu)	0.013	0.013	0.0042
PM Emissions (lb/MWhgross)	0.114	0.139	0.0329
Hg Emissions (lb/TBtu)	1.143	1.143	0.7360
Hg Emissions (lb/MWhgross)	1.00E-05	1.22E-05	5.74E-06
COST			
Total Plant Cost (2007$/kW)	1,622	2,942	1,881
Total Overnight Cost (2007$/kW)	1,996	3,610	2,297
Bare Erected Cost (2007$/kW)	1,317	2,255	1,480
Home Office Expenses (2007$/kW)	124	213	139
Project Contingency (2007$/kW)	182	369	227
Process Contingency (2007$/kW)	0	105	35
Owner's Costs (2007$/kW)	374	667	416
Total Overnight Cost (2007$ x 1,000)	1,098,124	1,985,432	2,068,815
Total As Spent Capital (2007$/kW)	2,264	4,115	2,618
CO2 TS&M Costs (mills/kWh, 2007$)	0.0	5.8	2.3
Fuel Costs (mills/kWh, 2007$)	15.2	21.3	29.8
Variable Costs (mills/kWh, 2007$)	5.1	9.2	5.5
Fixed Costs (mills/kWh, 2007$)	7.8	13.1	5.1
Capital Costs (mills/kWh, 2007$)	31.2	60.2	38.3
COE (mills/kWh, 2007$)	**59.4**	**109.6**	**80.9**
Incremental COE, Case 1 Basis	0	84.3%	36.2%
LCOE (mills/kWh, 2007$)	75.3	139.0	102.6
Cost of CO_2 Captured ($/ton - 2007)	--	$ 41.89	$ 30.52
Cost of CO_2 Avoided ($/ton - 2007)	--	$ 60.94	$ 24.20
Cost of CO_2 Captured ($/tonne - 2007)	--	$ 46.17	$ 33.63
Cost of CO_2 Avoided ($/tonne - 2007)	--	$ 67.15	$ 26.67

Performance

The plant net efficiency (HHV basis) for all cases is presented in Figure ES-1. The key conclusions that can be drawn are:

- The CEPACS-equipped PC plant (Case 3) has the highest net electrical efficiency at 38.8%.
- The net electrical efficiency of the CEPACS-equipped (for CO_2 capture) PC plant (Case 3) is 5.4% higher than that of the baseline PC plant without CO_2 capture (Case 1).

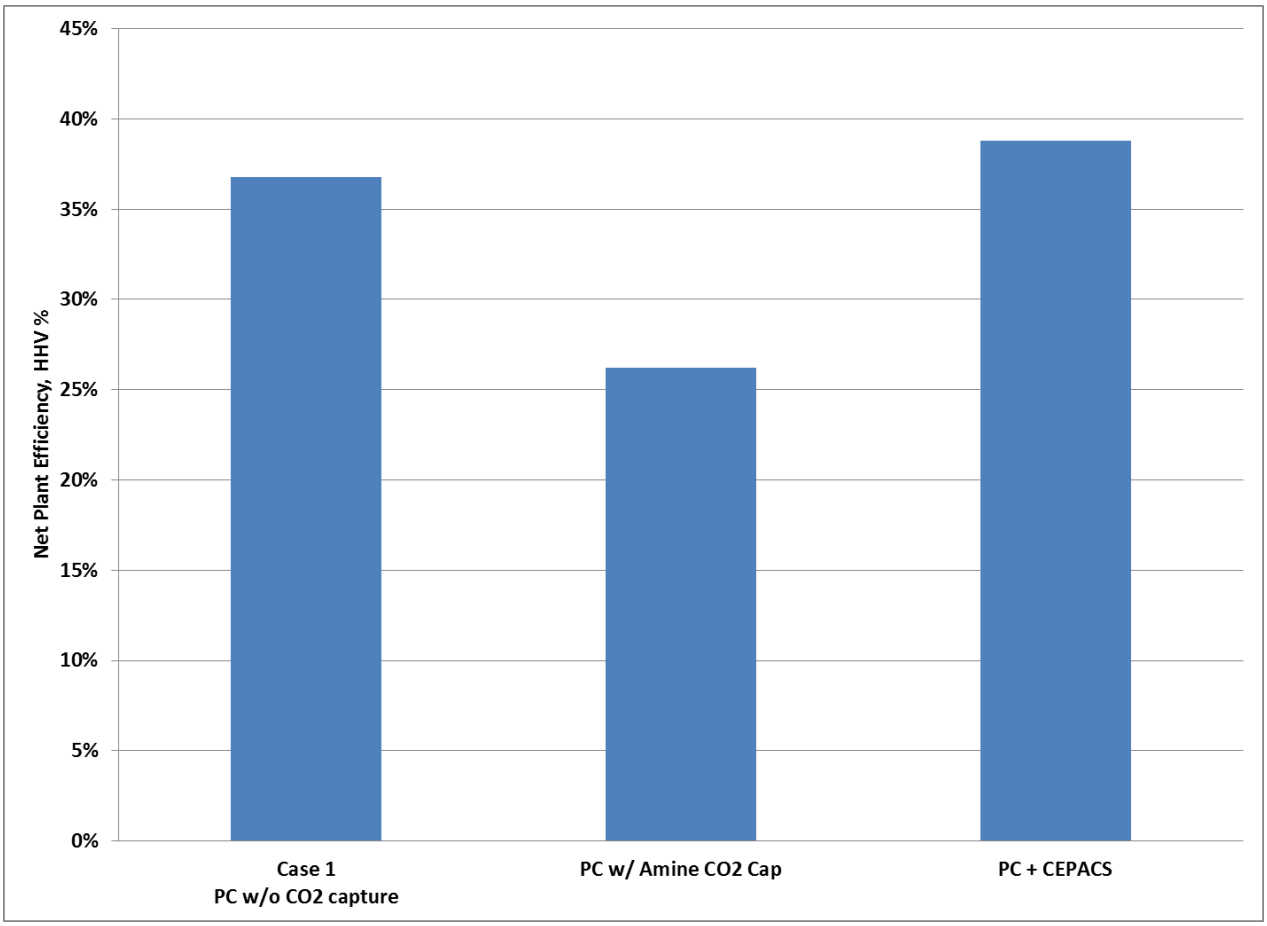

Figure ES-1. Plant Electrical Efficiency (HHV)

A comparison of water use is presented in Figure ES-2. Three categories of water use, normalized by plant net power output, are shown: water withdrawal, discharge, and consumption. Water withdrawal is the amount of water removed from the ground or other supply source for the process. Water consumption is the amount of water that is consumed within the process (i.e.: evaporated, transpired, or incorporated into products). Water discharge is water that is treated and discharged to the environment. The primary conclusions that can be drawn are:

- The CEPACS-equipped PC plant (Case 3) has the lowest water use (withdrawal) requirements of all cases, including Case 1. Case 3 normalized water withdrawal is 24.3% less than that for Case 1 (no CO_2 capture). This is partially due to the fact that water is generated within the ECM stacks as a byproduct of the electrochemical reactions.
- The PC plant with Econamine-based CO_2 capture process (Case 2) requires 151.9% more water withdrawal than the PC plant with CEPACS-based CO_2 capture process (Case 3).

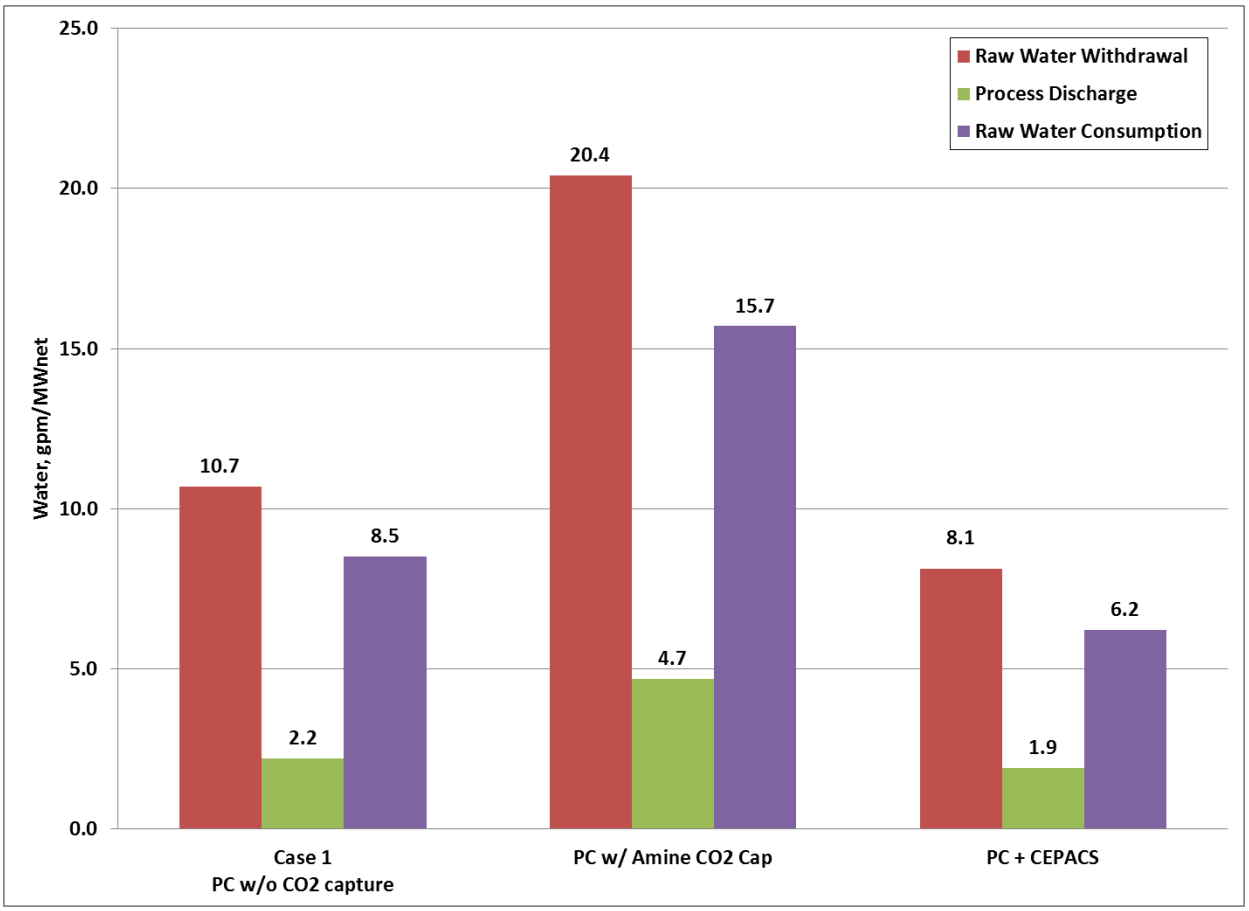

Figure ES-2. Water Use

Plant Capital Cost

The Total Overnight Cost (TOC) was estimated for each plant by adding owner's costs to the Total Plant Cost (TPC). The TPC for the CEPACS case was estimated by AECOM (formerly URS Corporation) based on a combination of vendor quotations and in-house cost databases. The TPC and TOC estimates for Cases 1 and 2 were based on the reported values in the referenced DOE/NETL Baseline Bituminous report [2].

The normalized TOC (with breakdown by component) and Total As-Spent Capital (TASC) for each case are shown in Figure ES-3. The following key conclusions can be drawn:

- Case 3 (PC + CEPACS) has the lowest TOC of the two cases with carbon capture, at $2,297/kW (2007 USD).
- The TOC for Case 3 is only 15.1% higher than the TOC for Case 1. This is because the additional costs of the CEPACS system are partially offset by the additional power generated by the system.
- The TOC of the Econamine-based system (Case 2) is 80.9% higher than the TOC for Case 1.

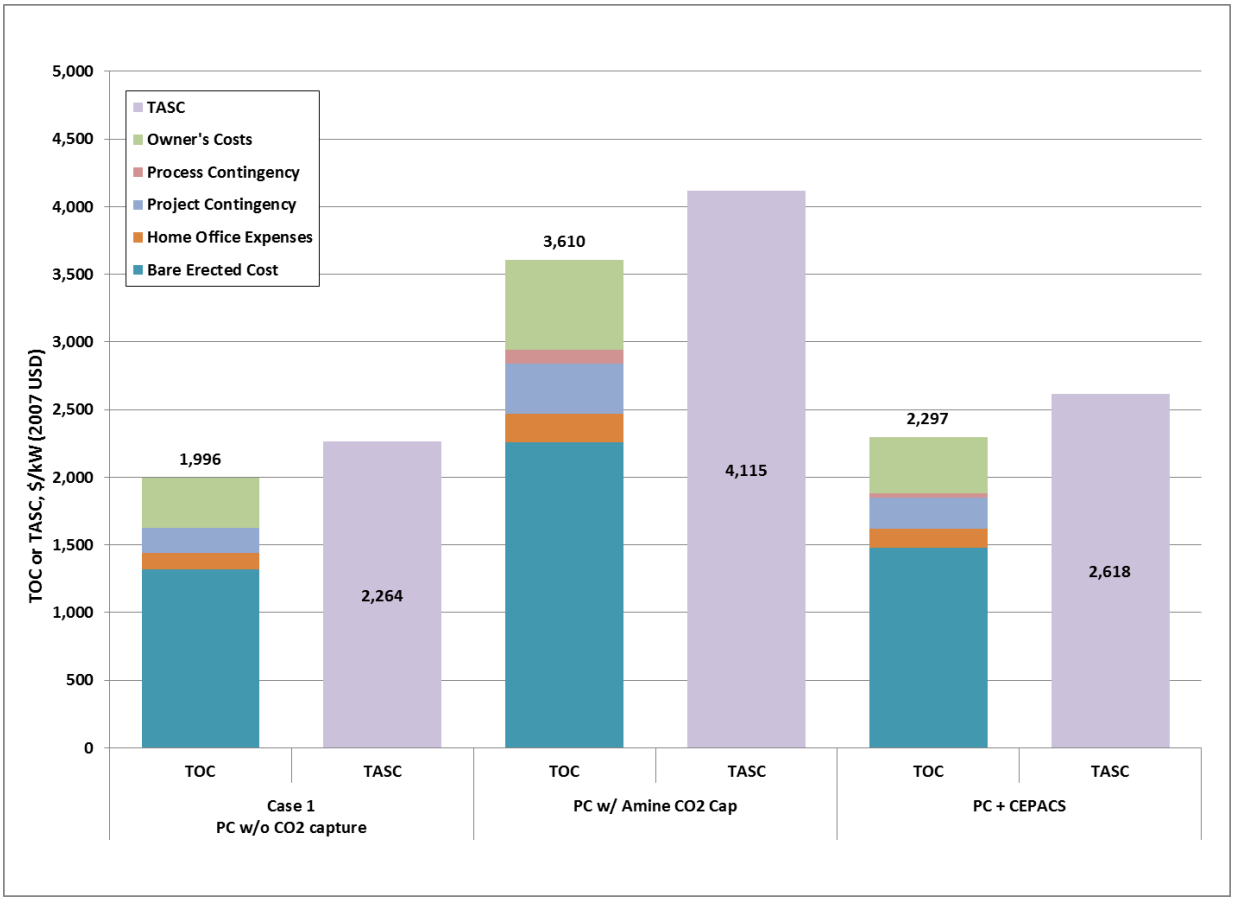

Figure ES-3. Plant Capital Costs

Cost of Electricity and CO_2 Captured

Figure ES-4 shows the Cost of Electricity (COE) with component breakdown and Incremental COE (Case 1 as basis) calculated for each case. The following key conclusion can be drawn:

- Case 3 (PC + CEPACS) offers the lowest COE of all cases with carbon capture at 80.9 mills/kWh. The incremental COE for Case 3 is 36.2%.

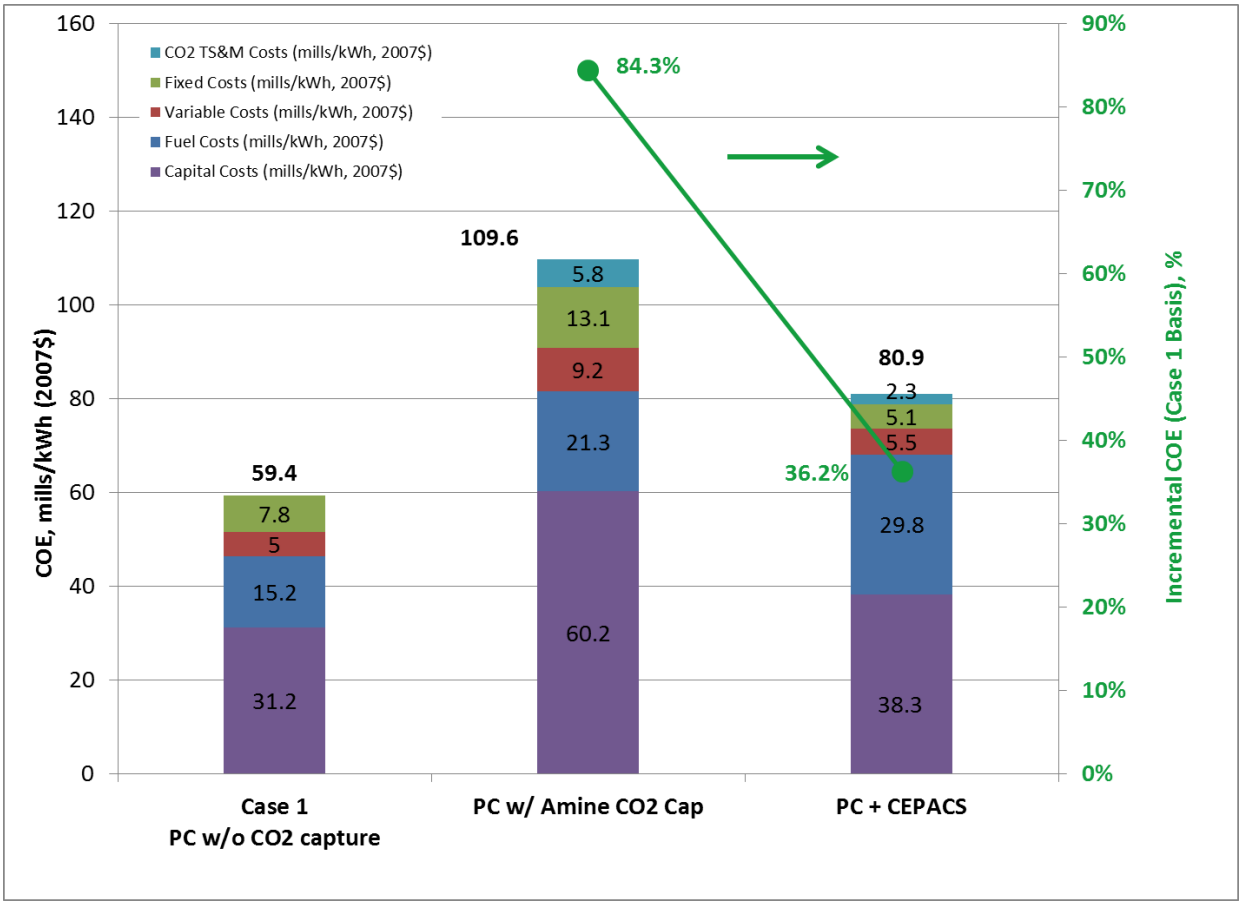

Figure ES-4. Cost of Electricity and Incremental COE

Figure ES-5 shows the cost of CO_2 captured (Case 1 as basis) calculated for the two CO_2 capture cases. The costs are shown in year 2007 US dollars and per metric ton of CO_2, for consistency with the T&EFS basis. The following key conclusion can be drawn:

- The CEPACS system cost of CO_2 captured is $33.63/tonne (2007 USD), which compares favorably with the DOE target of less than $40/tonne (2011 USD).
- The cost of CO_2 captured for the CEPACS-based process (Case 3) is 27.2% lower than that for the Econamine-based process (Case 2).
- The cost of CO_2 avoided for Case 3 is 60.3% lower than that for Case 2, due to the extra power generation of the CEPACS plant which results in significantly lower CO_2 emissions (lb/MWh) than Case 2, at a fixed 90% CO_2 capture rate.

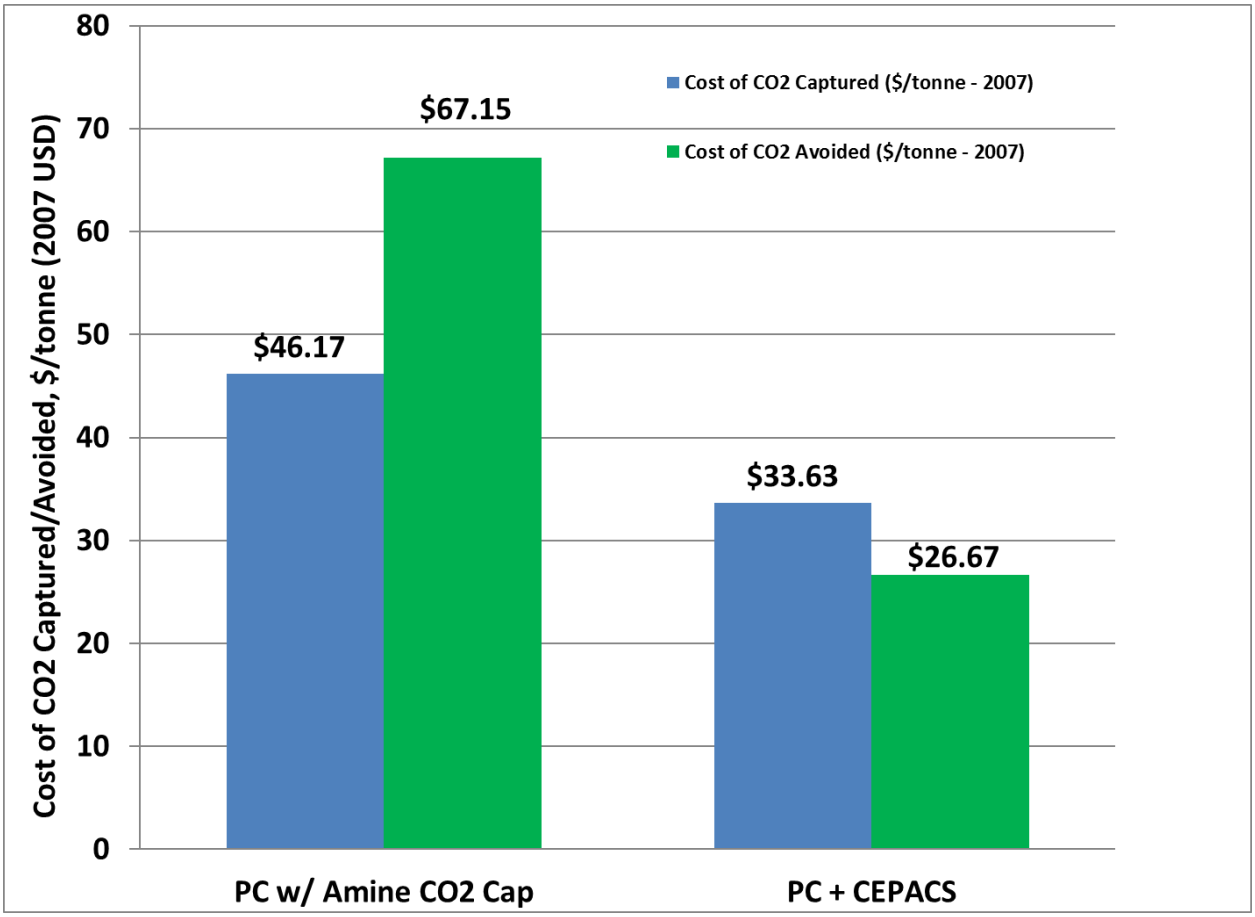

Figure ES-5. Cost of CO_2 Captured and Avoided

Environmental Performance

Figure ES-6 shows the normalized emission rates of NOx, SO_2, and particulate matter (PM) calculated for each case. Emission limits from the US EPA new source performance standards (NSPS) Mercury and Air Toxics Standards (MATS) are also shown in the Figure. The following key conclusions can be drawn:

- Cases with carbon capture (Cases 2 and 3) require SO_2 polishing equipment added to the baseline PC plant and, as such, they have very low SO_2 emissions.
- Case 3 has the lowest emission rates of SO_2, NOx, and PM of all the cases studied.
- Case 3 has significantly lower emissions of SO_2, NOx, and PM than required by the NSPS MATS rules. Emissions of NOx and PM for Case 2 exceed the MATS requirements.

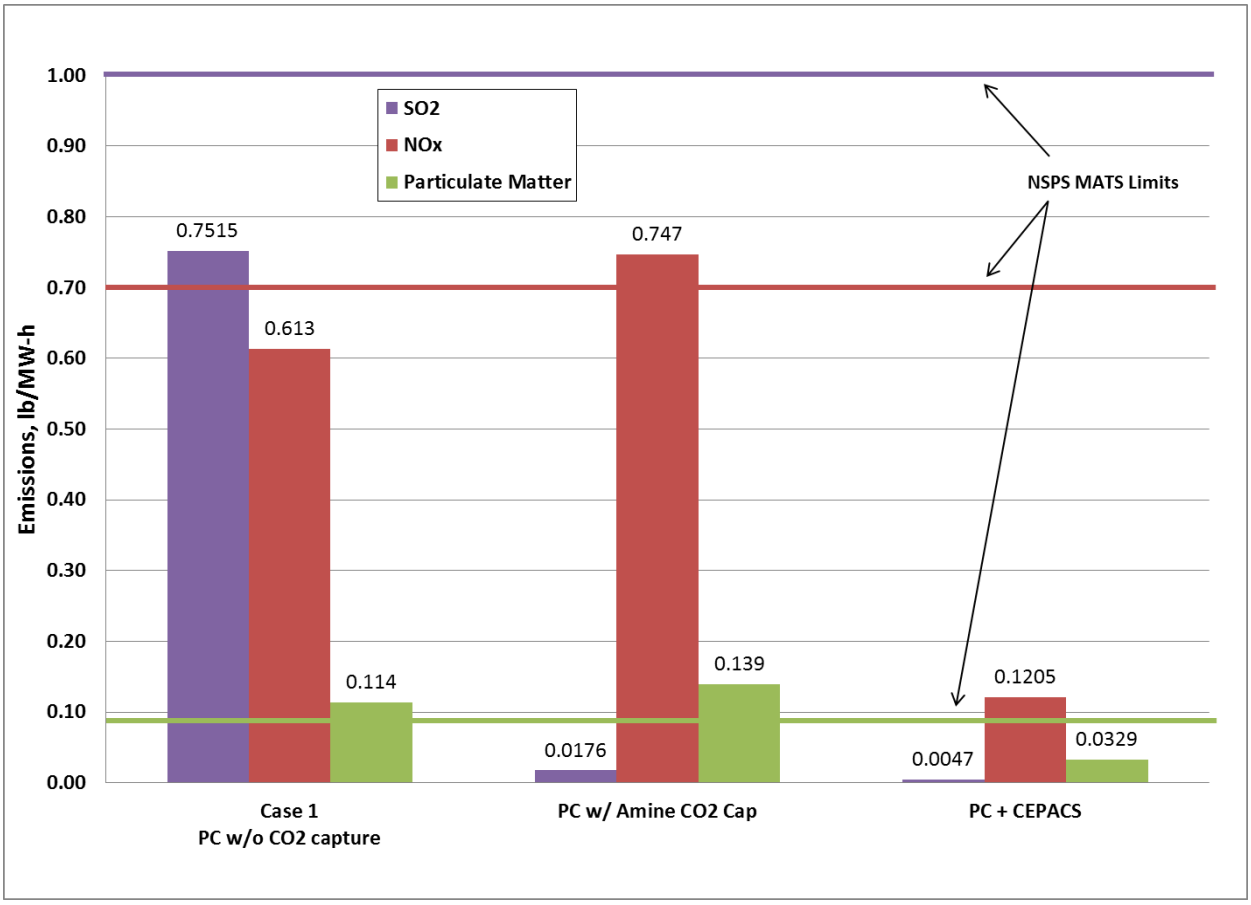

Figure ES-6. SO_2, NOx, and Particulate Emission Rates

Figure ES-7 shows the normalized emission rates of mercury calculated for each case. The following key conclusion can be drawn:

- Case 3 has lower Hg emissions than Cases 1 and 2 because a portion of the net power generation is fueled by natural gas, which contains negligible amounts of Hg. No additional Hg removal from the flue gas (due to the CEPACS system) was assumed for Case 3.

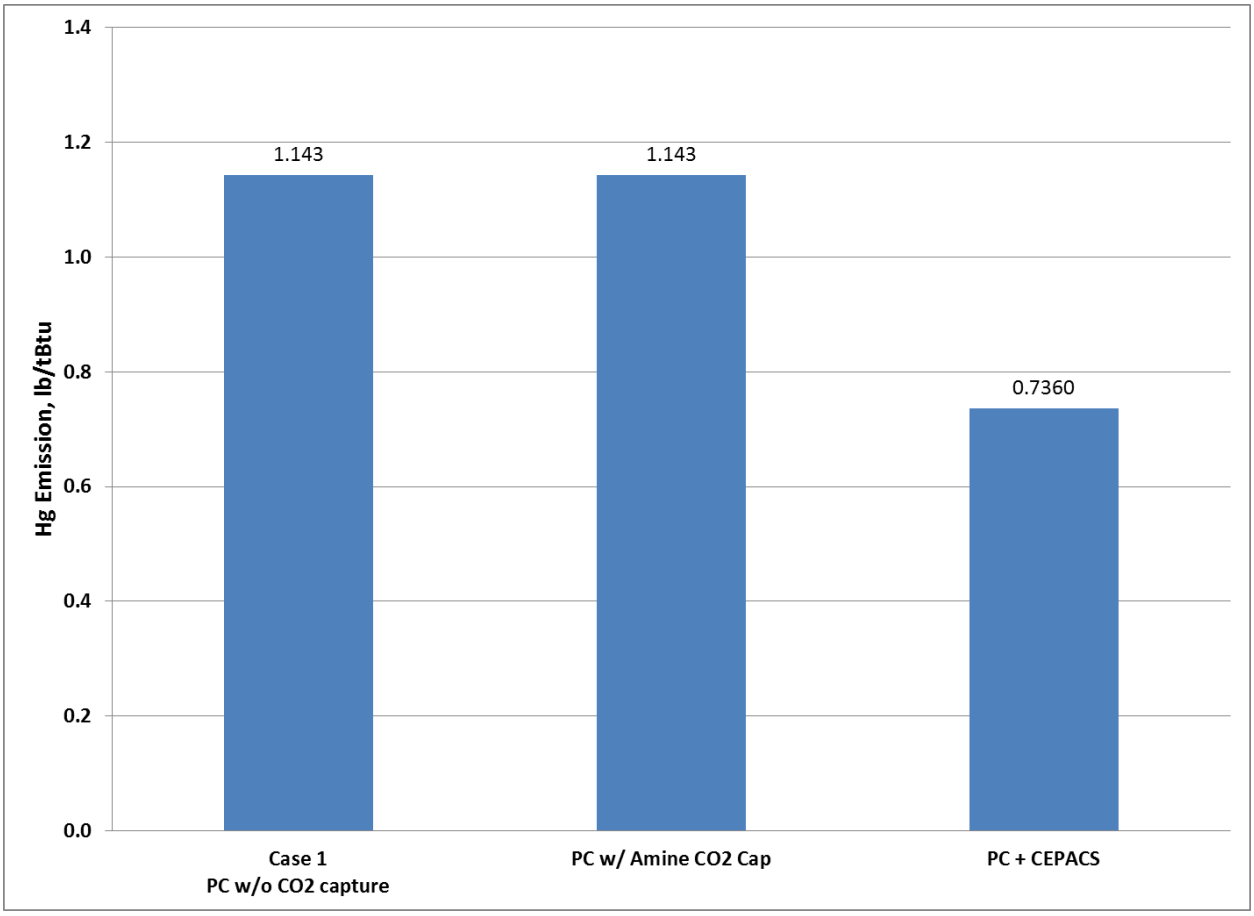

Figure ES-7. Mercury Emission Rates

Figure ES-8 shows the normalized emission rates of CO_2 calculated for each case. The following key conclusion can be drawn:

- Case 3 (PC + CEPACS) has the lowest CO_2 emissions of all the cases. This is due to the design criteria to capture 90% of the carbon which enters the CEPACS system. Since the CEPACS system generates additional power, the CO_2 emissions (normalized by total plant net output) are 58.3% lower than for Case 2.

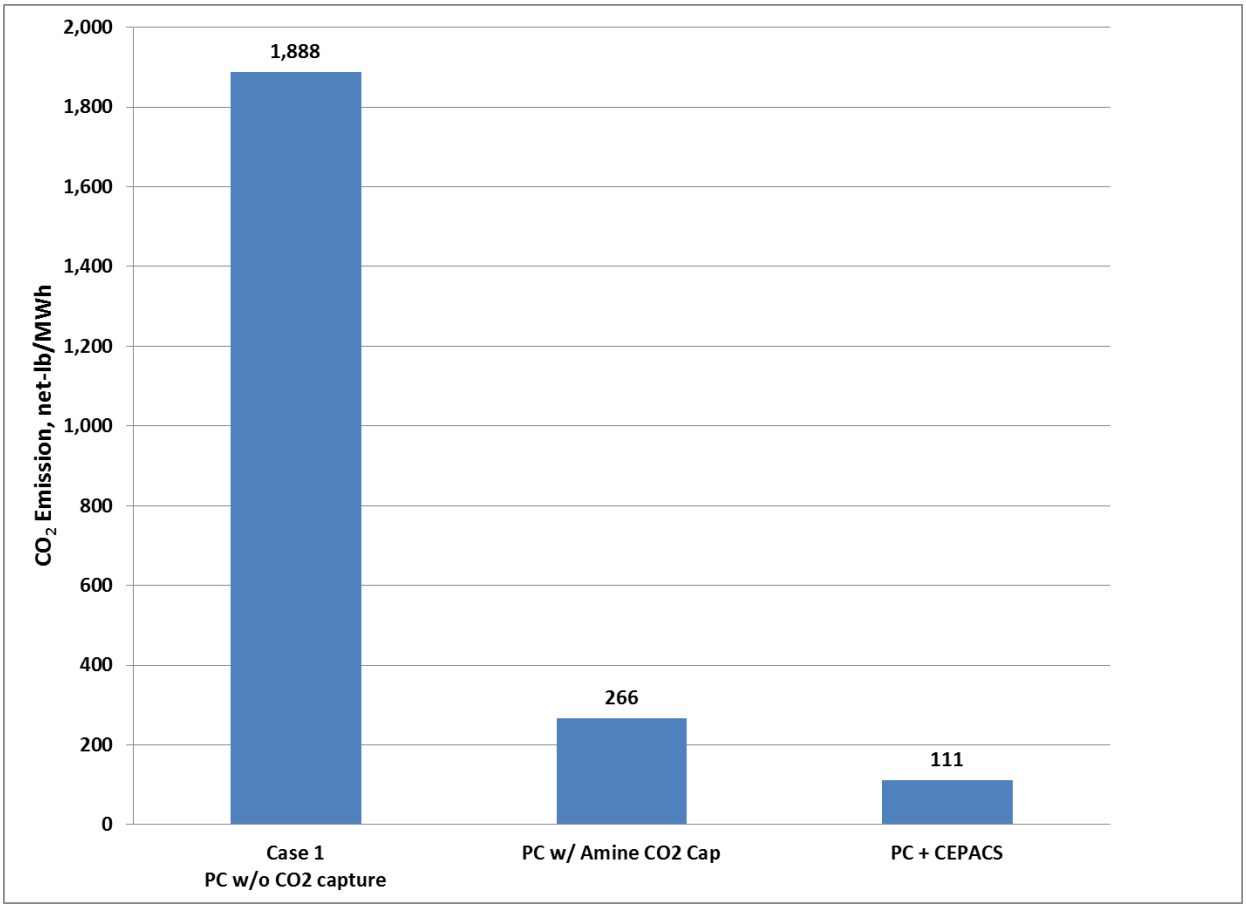

Figure ES-8. CO_2 Emission Rates

Overall, the CEPACS-based CO_2 capture process is more attractive technically and economically than the amine-based process. The CEPACS based process meets the DOE target for incremental COE and has considerable potential to meet the DOE cost/tonne of CO_2 captured target on an equivalent dollar-year basis.

INTRODUCTION AND OBJECTIVES

FuelCell Energy, Inc. (FCE), in collaboration with Pacific Northwest National Laboratory (PNNL) and AECOM (formerly URS Corporation), is developing a novel Combined Electric Power and Carbon-dioxide Separation (CEPACS) system [1]. The CEPACS system is based on electrochemical membrane (ECM) technology derived from FCE's carbonate fuel cell products featuring internal (methane steam) reforming and carrying the trade name of Direct FuelCell® (DFC®). The unique chemistry of carbonate fuel cells offers an innovative approach for separation of CO_2 from existing fossil-fuel power plant exhaust streams (flue gases). The ECM-based CEPACS system has the potential to become a transformational CO_2-separation technology by working as two devices in one: it separates the CO_2 from the exhaust of other plants such as an existing coal-fired plant and simultaneously produces clean electric power at high efficiency using a supplementary fuel. Additional information including the operational principle of ECM cell and the process concept for CEPACS system is provided later in this section, for reference.

The development effort is being carried out under the U.S. Department of Energy (DOE) contract DE-FE0007634. The overall objective of this project is to verify that FCE's ECM-based CEPACS system technology can achieve at least ≥ 90% CO_2 capture from Pulverized Coal (PC) power plant flue gas with 95% CO_2 purity at a Transportation, Storage and Disposal (TS&M) cost below $40/tonne. In addition, a key objective is to show, through this Technical and Economic Feasibility Study (T&EFS) that the ECM-based CO_2 capture technology has an economic advantage over the existing CO_2 capture technology and it has a path forward to reducing the incremental cost of electricity (COE) for post-combustion CO_2 capture to meet DOE's cost target.

The project was scheduled to be performed in three budget periods. FCE has just completed Budget Period 3 (BP3). The specific objectives for BP3 are to perform bench scale testing of an 11.7m^2 ECM CO_2 capture, purification and compression system and update (as final) the Technical and Economic Feasibility Study (T&EFS) for the ECM-based CEPACS plant.

This topical report presents the results of the updated T&EFS. The Updated BP3 T&EFS Topical Report satisfies Task 2 (2.2) Deliverable specified in the Statement of Project Objectives (SOPO). The study was based on the carbon capture system size suitable for a reference 550 MW PC power plant.

Electrochemical Membrane Technology - Operating Principle

The operating principle of the ECM cell, including the mechanism for transport of CO_2 (by migration of carbonate ions through electrolyte) from the cathode to the anode of the cell, is shown in Figure I-1, along with the appropriate electrochemical reactions.

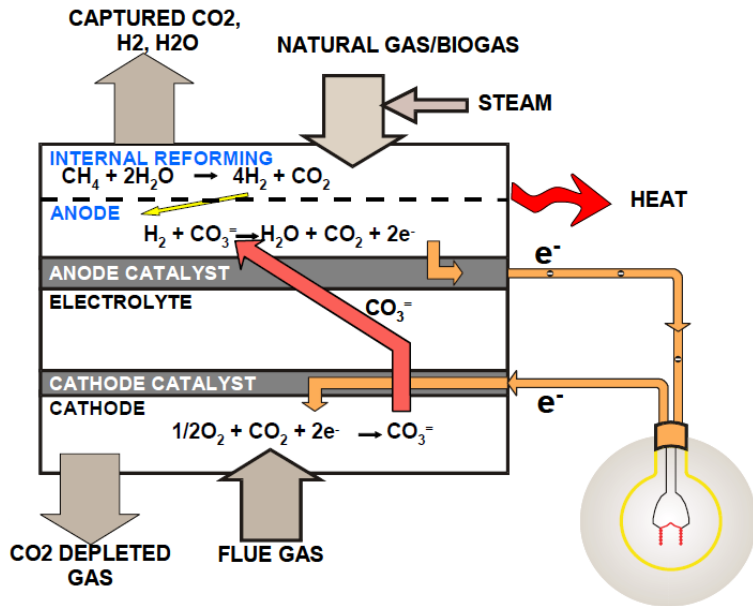

Figure I-1. Transport of CO_2 in the Electrochemical Membrane Cell: CO_2 is used at cathode as an oxidant and transferred to anode via carbonate ions

The flue gas from an existing power plant, containing CO_2, is fed to the cathode side of the cell. A supplemental fuel is supplied to the anode side of the cell. The ECM technology is compatible with numerous methane-containing fuels such as: coal and biomass derived syngas, natural gas (NG), and biogas (e.g. anaerobic digester gas). Natural gas has been assumed as the supplemental fuel source for this study. Due to the internal reforming capability of the ECM cell, methane in the fuel is converted (steam reformed) into hydrogen according to the following reaction:

$$CH_4 + 2H_2O \rightarrow CO_2 + 4H_2 \tag{1}$$

Hydrogen is used as a reactant at the anode. Carbon dioxide and oxygen present in the flue gas are used as reactants at the cathode. The electrochemical reaction at ECM cell cathode (Figure 1) involves the formation of carbonate ions (CO_3^{2-}) by combination of O_2, CO_2 and two electrons. Carbonate ions produced at the cathode migrate to the anode side via the electrolyte in the cell. At anode, the reaction of carbonate ion with H_2 produces H_2O, CO_2 and two electrons. The internal transport of carbonate ions in ECM cell and the flow of electrons in the external circuit results in power generation as a consequence of the CO_2 separation process. DC power produced is converted to AC power using an inverter.

Overall, the operating mechanism of the ECM cell results in the separation (from flue gas) and transfer of CO_2 into the anode exhaust stream which has a much reduced volumetric flow (resulting in a CO_2-rich stream) compared to the flue gas stream. The CO_2-rich anode exhaust gas is further processed in the ECM-based CEPACS system to purify the CO_2 for sequestration, as described in the CEPACS system process concept section that follows.

The ECM cell operates at 550 - 650°C and atmospheric pressure. Unlike conventional membrane technologies that rely on pressure (partial pressure) differentials and permeability properties, ECM separates CO_2 at a rate dependent on the electrical current drawn. The flue gas does not need to be pressurized and vacuum operation is not required on the permeate side. Because of fast electrode kinetics, the ECM cell does not require high CO_2 concentration

in the flue gas feed. Planar geometry and large gas flow channels of the ECM cell enable processing of large volumetric flow of flue gas feed without significant back pressure. The ECM membrane is fabricated from inexpensive organic materials.

CEPACS System – Process Concept: FCE has developed the Combined Electric Power and Carbon-dioxide Separation system concept (US Patent 7,396,603 B2) as a novel solution for greenhouse gas emission reduction. The CEPACS system employs ECM technology derived from the Company's well established Direct FuelCell® products. A simplified diagram of the CEPACS system concept is shown in Figure I-2.

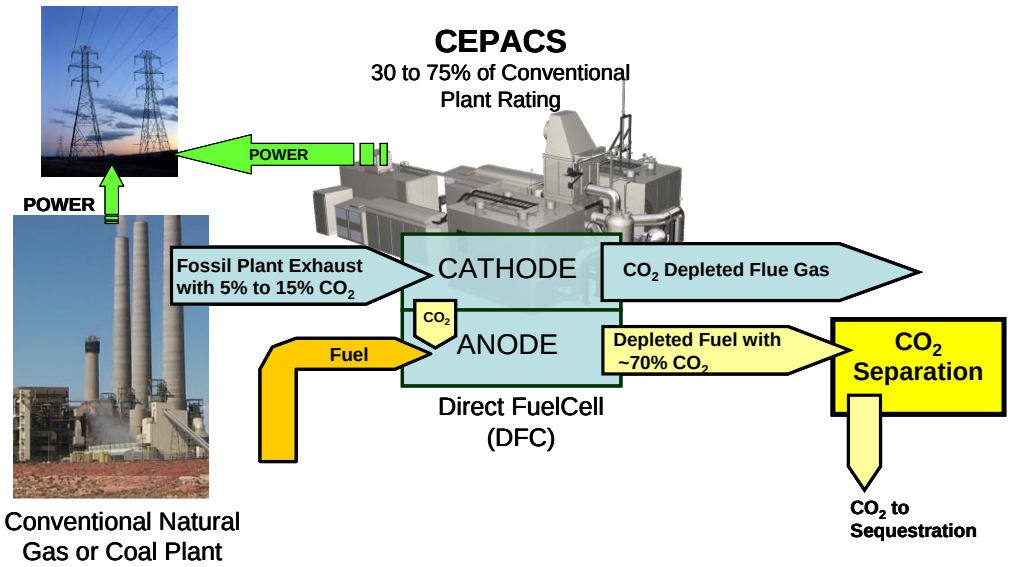

Figure I-2. CEPACS CO_2 Separation and Power System Concept:
The system can be used with a variety of CO_2-containing greenhouse gases (GHG)

CO_2-containing flue gas from a coal-fired (combustion-based) power plant, such as the exhaust from a PC power plant or other industrial source, is utilized as the oxidant for the ECM cathode. The key feature (as explained in the operating principle of ECM above) is that the ECM utilizes the CO_2 of the flue gas as a reactant for the electrochemical reaction to produce power, while synergistically transferring CO_2 from the flue gas to the anode exhaust stream. A supplementary fuel such as natural gas or biogas (from a digester) is internally reformed in the fuel cell to provide the hydrogen needed to complete the electrochemical power generation cycle.

The CO_2-rich anode exhaust gas is processed (post-processing) in the ECM-based CEPACS system to further concentrate and compress the CO_2 for sequestration. The H_2O (product of ECM anode-side electrochemical reaction) is removed by simple condensation during downstream processing. There is also some unused fuel (mainly H_2) in the CO_2-rich anode exhaust stream. This remaining H_2 is separated by liquefaction of the CO_2. After the water has been condensed out and the H_2 removed, the resulting CO_2-capture stream is ready for compression (pumping of supercritical fluid) and sequestration.

The CO_2-lean cathode exhaust (flue gas after CO_2 removal) is vented to atmosphere after recovering the heat for process use (e. g. preheating of feed streams, steam generation). Water condensed during post-processing of the CO_2-rich anode exhaust stream is used to provide water (steam) needed for internal reforming of CH_4 in supplementary fuel, eliminating the need for external process water. H_2 separated during post-processing of CO_2-rich anode exhaust

stream is recycled to provide additional preheat in the system and as part of the supplementary fuel (thereby reducing NG fuel needed).

The key difference between the ECM-based CEPACS system technology, and existing membrane and amine scrubbing technologies (competing technologies) is that electric power is produced during the CO_2 separation process in the ECM-based system. This synergistic coupling of the separation of CO_2 from flue gas of an existing plant and the production of clean electric power is unlike any other carbon capture technology, all of which consume energy.

EXPERIMENTAL METHODS

This topical report summarizes the results of the Technical and Economic Feasibility Study which utilizes the experimental testing results gathered from other tasks in the project. Experimental work was involved in contaminant effect evaluation, performance testing of small-area ECM cells (performed during BP2 of the project) and in bench-scale ECM stack-system demonstration testing (performed during BP3). The experimental methods used and the testing approach taken are briefly discussed below.

Button cells were used to evaluate the tolerance of ECM membrane to coal-fired power plant flue gas contaminants. The testing was performed by Pacific Northwest National Laboratory (PNNL) utilizing membranes provided by FuelCell Energy. Simulated flue gas was supplied to the cathode, and simulated reformed natural gas fuel was used on the anode side. Before introduction of specific impurity/impurities, cells were pre-conditioned at 650°C in clean gas at 0.8-0.9 V for 50-200 hours to obtain a stable baseline, and then were switched to a constant current operational mode. After that, the impurity gases from cylinders were added to flue gas near the cell inlet using calibrated electronic flow controllers, downstream of the water bubbler.

Long-term exposure tests were performed at a constant current density (constant CO_2 flux) in the range from 50 to 160 mA/cm^2, while monitoring the cell voltage. Each test condition was replicated at least once to confirm reproducibility. This approach allowed elimination of occasional artifacts. Electrochemical impedance spectra were obtained at regular time intervals to separate ohmic and electrodic (anodic and cathodic) losses of cells. Post-test electrode characterization was performed using scanning electron microscopy (SEM) and energy dispersive spectroscopy (EDS).

Bench-scale demonstration testing of the ECM system utilized a 14-cell ECM stack with a total area of 11.7m^2 available for CO_2 separation. An existing 10 kW-scale test facility was modified to conduct the bench scale testing. The modified facility accommodated, in addition to the ECM stack module, a CEPACS skid containing equipment for CO_2 (product) stream post processing. ECM stack conditioning, performance, validation and parametric testing was conducted during the initial 600 hours of operation before initiating the steady-state long-term testing. During the demonstration testing, the CO_2 flux remained constant at 116 cc/s/m^2.

Gas chromatography measurements of the ECM stack inlet and outlet streams were performed to estimate and monitor %CO_2 transfer (capture) throughout the testing. DC Power output and power degradation rates were monitored during the steady-state testing. Additional parametric testing was conducted after the conclusion of steady-state testing. The parametric testing included operation at various carbon capture percentage levels, anode fuel compositions, stack temperatures and current densities. Thermal cycling was also performed.

Additional experimental details are provided along with relevant test results under ‘Results and Discussion’ section of the report.

The methodologies used for the system study and for plant capital cost estimation and the cost of electricity analysis are referenced here. The following two U.S. Department of Energy-

National Energy Technology Laboratory (DOE - NETL) documents were used as guidelines for the study/analysis:

- 'Scope and Reporting Requirements for NETL System Studies' , dated May 2010 [4]
- 'Quality Guidelines for Energy System Studies: Cost Estimation Methodology for NETL Assessment of Power Plant Performance', dated April 2011, DOE/NETL-2011/1455 [3]

In addition, the study was conducted in accordance with the U.S. DOE – NETL report entitled 'Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity, Revision 2a' [5], and was specifically focused on developing technical and economic comparisons to Cases 9 and 10 of the referenced report. The analysis also followed economic updates from the report "Updated Costs (June 2011 Basis) for selected Bituminous Baseline Cases" [6].

The system simulations were performed using CHEMCAD, a process design software suite from Chemstations, Inc. The heat and mass balances for the system cases were derived from CHEMCAD simulation results. The plant performance estimates are based on CHEMCAD's rigorous thermodynamic models and property (physical, thermodynamic) values/databases.

Additional descriptions of the methodologies used are included in relevant sections of this report.

RESULTS AND DISCUSSIONS

1.0 CEPACS SYSTEM CONFIGURATION AND DESIGN

1.1 Design Basis

The design basis used in the design of the CEPACS plant is summarized in this section.

Site Location: The generic site location is in the U.S. It is assumed that the battery limits of the CEPACS plant are adjacent to the existing PC plant flue gas desulfurization (FGD) scrubber.

CEPACS System Boundary Limits: Figure 1-1 shows the boundary limits of the ECM-based CEPACS system for design and costing.

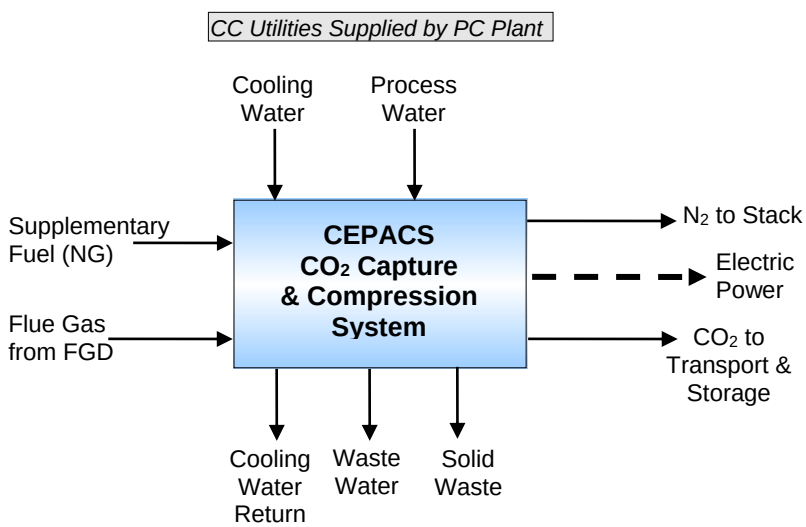

Figure 1-1. Boundary Limits of CEPACS System for CO_2 Capture (CC) from a 550 MW PC Plant

Design Life: For the purpose of developing the T&EFS, a 30-year design life for the CEPACS system is assumed. The ECM stacks have a lifetime of 10 years, after which they are replaced. The used stacks are returned to FCE.

Turndown Requirements: The CEPACS plant (facility) shall be capable of processing inlet gas (flue gas) on a stable and continuous basis up to the Design Capacity conditions. The plant will have eight (8) parallel trains (sections) of ECM stacks. Each process train can be shut down independently for maintenance and/or capacity reduction, if required.

Availability: The facility shall be designed for a 93% availability factor. Loss of availability includes unscheduled shutdowns and scheduled downtime to perform inspection, maintenance, etc. The availability factor of 93% allows for the following typical average downtimes:

ACTIVITY	DOWNTIME
Unscheduled Shutdowns	12 days/year
Blowers / Compressor Maintenance	Annual, 9 days/year
3 year Maintenance	15 days
6 year Maintenance	27 days
10 year Maintenance (ECM Stack Replacement)	20 days (Staged in 224-stack groups)

Sparing Philosophy: The general sparing philosophy is 1 x 100% sparing for each section of ECM stacks since the plant has eight (8) separate sections which can be shut down independently. Individual equipment sparing was selected by URS based on experience.

Flue Gas Feed and Related Specifications: Table 1-1 presents the flue gas composition and conditions per the Statement of Project Objectives that were used for the T&EFS. The flue gas flow rate is based on a 550 MW (net AC) PC power plant.

Table 1-1. PC Plant Flue Gas Specifications

Flowrate (mass)	5,118,399 lb/h (2,321,705 kg/h)
Pressure	14.7 psia (101.3 kPa abs)
Temperature	135 °F (57 °C)
Composition (volume %)	
CO_2	13.17
H_2O	17.25
N_2	66.44
O_2	2.34
Ar	0.8
SO_X	42 ppmv
NO_X	74 ppmv

Pipeline natural gas is used as the supplementary fuel for the ECM stacks in the CEPACS system. The natural gas specification is shown in Table 1-2.

Table 1-2. Pipeline Natural Gas Specification

Component		Volume %
Methane	CH_4	93.1
Ethane	C_2H_6	3.2
Propane	C_3H_8	0.7
n-Butane	C_4H_{10}	0.4
Carbon Dioxide	CO_2	1.0
Nitrogen	N_2	1.6
	Total	100.0
Total Sulfur		3.0 ppmv
	LHV	**HHV**
kJ/kg MJ/scm	47,454 34.71	52,581 38.46
Btu/lb Btu/scf	20,410 932	22,600 1,032

CO_2 Product and Other Specifications: Table 1-3 lists the CO_2 capture requirement and product specification.

Table 1-3. CO_2 Capture Requirement and Product Specification

CO_2 Removal from Flue Gas	Greater than 90%
CO_2 Purity	Greater than 95 vol%
CO_2 Delivery Pressure	2,215 psia (15.3 MPa abs)
CO_2 Delivery Temperature	124°F (51°C)

The conditions for cooling water were assumed to be the feed at 60°F (15.6°C), the return at ≤80°F (26.7°C) and the minimum approach ΔT of 30°F (16.7°C).

Cost Estimation: The NETL cost estimation methodology guideline document (mentioned under the 'Experimental Methods' section) was used as a main reference to generate costing. The capital cost levels and their elements are shown in Figure 1-2. Cost estimates for all major process equipment and subsystems were generated from vendor contacts and URS's historical cost databases. The cost estimate includes the cost of consumables and vendor-quoted costs for key process equipment items.

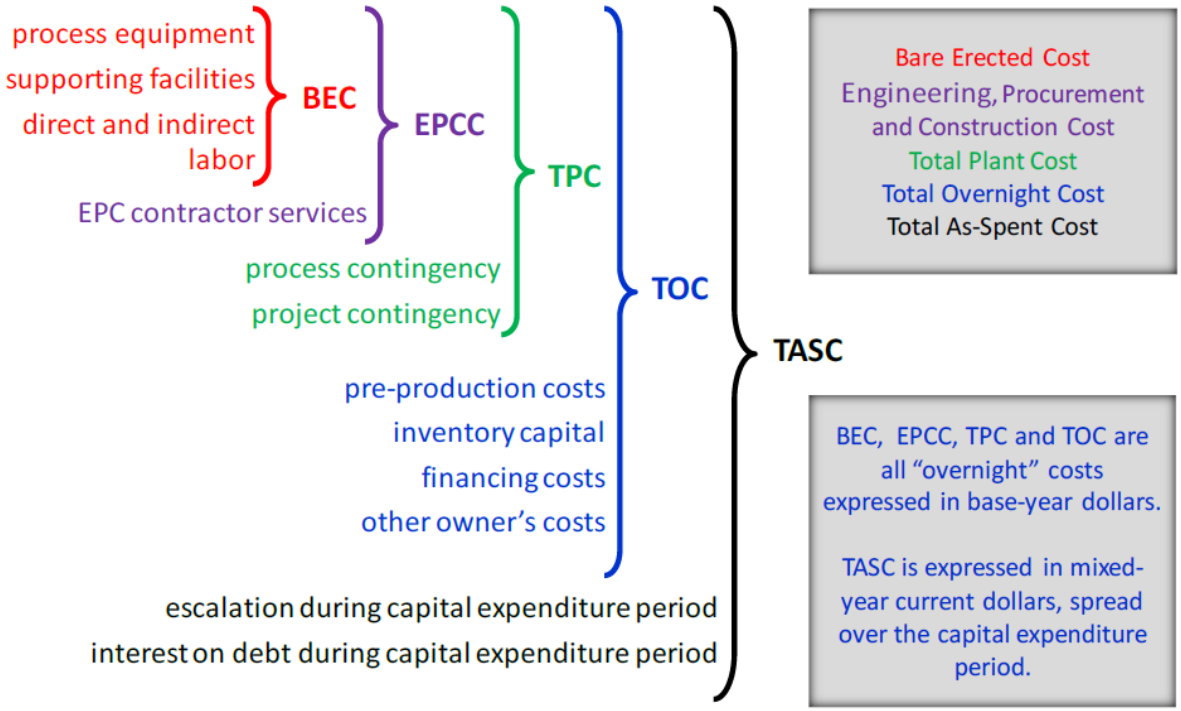

Figure 1-2: Capital Cost Levels and Their Elements [3]

The economic analysis assumptions are listed in Table 1-4. The economic assumptions were taken from three sources: 1) NETL Cost Estimation Methodology [3], 2) Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity – Revision 2a, DOE – NETL report [5], and 3) FuelCell Energy's Statement of Project Objectives for this project. A primary goal was to develop the cost estimates on an equal basis to those reported in the referenced Baseline Bituminous Coal report [2, 5], allowing for a fair and accurate comparison between the cases.

Table 1-4. Economic Analysis Assumptions

Parameter	Value	Basis (see notes)
Levelized-Cost of Process Make-up Water, $/1000 lbs	0.07	1
Levelized Cost of Solid-Waste Disposal, $/ton	17.87	1
Levelized-Cost of Toxic-Waste Disposal, $/ton	89.36	1
Levelized Cost of CO_2 Transportation, Storage, & Monitoring, $/ton CO_2	4.05	1
Plant On-Stream (Capacity) Factor, days/y (%)	310.25 (85%)	1, 2, 3
Natural Gas Price, $/MMBtu	6.55	3
Coal Price, $/Ton	38.18	3
Plant Location	Generic site, Mid-west	1, 2, 3
Dollar-Year Reporting Basis	2007	1, 2, 3
Total Fixed O&M Levelized-Costs, $/calendar day	995	1
Maintenance-Material Costs (% of initial equip cost)	2	1, 2, 3

Parameter	Value	Basis (see notes)
Capital Expenditure Period	5 years	2, 3
Capital Charge Factor, %/yr	12.4 (IOU, high-risk)	2, 3
Levelization Factor (IOU @ 12% IRROE)	1.268	2, 3
TASC/TOC Multiplier	1.140 (IOU, high-risk)	2, 3

1) FCE Project SOPO
2) NETL Cost Estimation Methodology (DOE/NETL-2011/1455) [3]
3) Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity – Revision 2, 2010 (DOE/NETL-2010/1397) [2]

1.2 Overall Process

This section describes the overall process for an ECM-based CEPACS system to process the flue gas from a 550 MW pulverized coal fired Rankine cycle plant. The design for the subcritical PC plant given in "Case 9" of the DOE - NETL report [5] was used as the reference. A simplified block flow diagram of the CEPACS system is shown in Figure 1-3. Detailed system modeling was performed using CHEMCAD process simulation software. Process design, development of a process flow diagram, and heat and material balances were completed using process simulation software, although are not included in this report as the information is proprietary to FCE. Descriptions and key features of major subsystems are presented in Section 1.3 that follows.

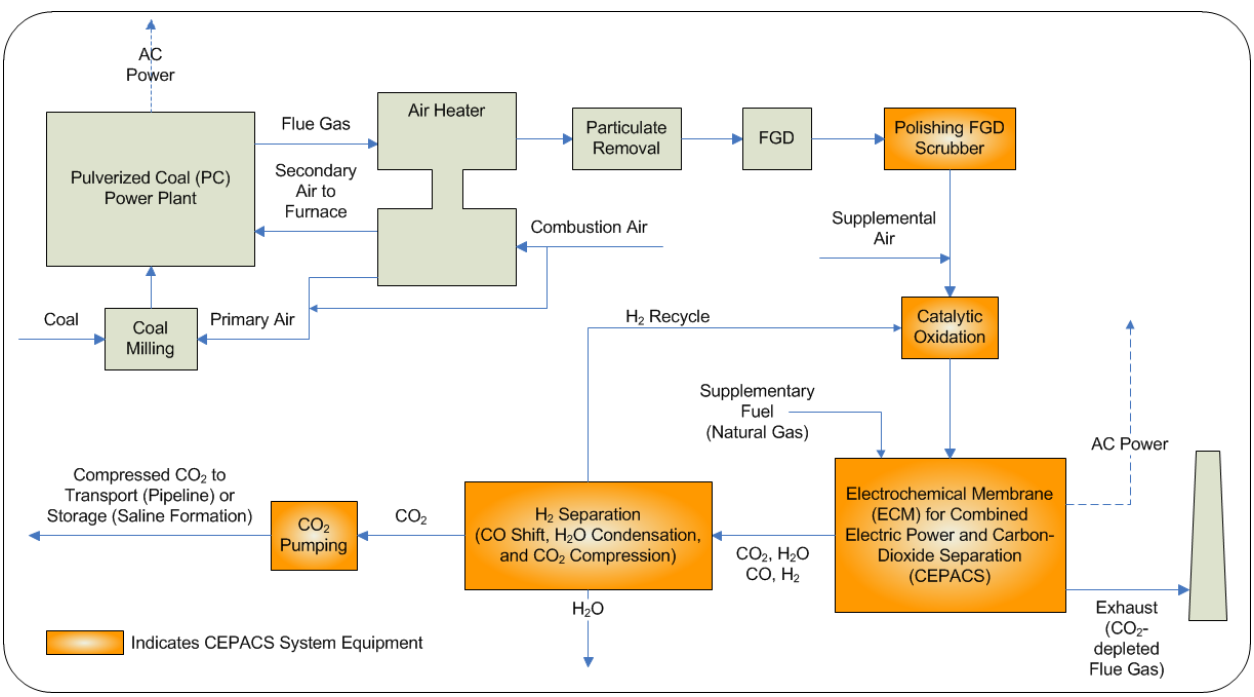

Figure 1-3: Block Flow Diagram of CEPACS System Applied to a 550 MW Pulverized Coal Plant

1.3 Major Subsystems

1.3.1 Flue Gas Processing Sub-system

Flue Gas Clean-up: The flue gas in the 550 MW PC Power Plant is filtered using a baghouse (part of the PC plant) to remove ash and particulates. Based on discussions with one vendor it is possible to achieve up to 99.999% removal of particulate matter in a bag house filter. However, the maximum achievable removal efficiency will depend on the site-specific characteristics of the particulate matter. The stream is then processed in a wet limestone scrubber, referred to as the Flue Gas Desulfurization (FGD) unit (also part of the PC plant), to reduce the SOx (Sulfur) content to 42 ppmV. The flue gas exiting the PC plant requires further sulfur removal to the level of <0.4 ppmV total sulfur to make it suitable for feed to the ECM stacks in the CEPACS plant. The additional desulfurization is performed by the Polishing FGD scrubber. A Raw Flue Gas Blower is located upstream of the Polishing FGD to boost the pressure of the flue gas and facilitate its flow through the scrubber unit.

The polishing FGD is a wet scrubber with a design SO_2 removal of >99%. In a wet FGD system, flue gas enters the absorber and is sprayed with wet slurry. SO_2 in the flue gas is absorbed into the sprayed slurry, which is then collected in the reaction tank. In the reaction tank, the absorbed SO_2 combines with an alkaline reagent of limestone to produce gypsum. In order to maintain the pH in the reaction tank, limestone is continuously fed to the tank. The slurry that is collected in the reaction tank is recycled to the spray levels via recycle pumps. A bleed stream of slurry is removed from the reaction tank to control density. Oxidation air is produced by the oxidation air blowers (two operating and one standby) and supplied to the absorber via lances installed in the absorber. The oxidation air blowers are equipped with inlet butterfly dampers which make it possible to adjust the flow. The air from the oxidation air blowers is cooled by water to avoid plugging of the oxidation air lances. The bleed slurry is sent to a dewatering system where the solids are directed to the same location as the gypsum produced in the primary FGD. The “cleaned” flue gas passes through a mist eliminator (ME), which removes large slurry droplets entrained in the gas stream, before entering the Flue Gas Blower.

In order to achieve >99% SO_2 removal in a scrubber, the latest design technologies within the absorber tower are employed, including a dense, overlapping spray header/nozzle design, double hollow cone spray nozzles, wall baffles to prevent gas sneak-age and sieve trays. Several commercial installations are currently demonstrating this level of performance including Gorgas and Hammond (both owned by Southern Company).

The power consumption for the system is estimated to be 4,500 kVA, based on the following assumptions:

- Limestone feed system not included (assuming limestone is fed from primary FGD system)
- Process water pumps included
- Instrument air compressor included
- Gypsum dewatering not included (assuming gypsum is transferred to same location as the primary FGD – polishing system adds very small quantities relative to bulk scrubber)
- Oxidation air blowers included

The water consumption is estimated to be 500 gpm, based on the following assumptions:

- No quenching of oxidation air required
- Limestone feed water included (assuming 30wt% limestone slurry)
- Water consumption for gypsum dewatering not included – assuming water consumption for the system is included in primary FGD system design

- ME wash included
- There is no evaporation in the polishing FGD since it is located downstream of primary FGD and the flue gas leaving the primary FGD is saturated with water.

The water discharge from the absorber is assumed to be the same as the water consumption. Since there is no evaporation (due to flue gas saturation), all water added to the absorber is discharged. Most of the water will leave the absorber with the gypsum slurry and the water will therefore be discharged where the gypsum is dewatered.

The polishing FGD also removes other contaminants, such as chlorine, mercury and selenium, present in the PC plant flue gas. The concentration levels of sulfur and these contaminants in the flue gas (FG) after the polishing FGD unit were estimated and compared with ECM cell tolerance levels determined based on Contaminant Evaluation Study test results. The contaminant (effect) evaluation and comparison with CEPACS plant flue gas polishing system output showed that the ECM tolerance levels are well above the contaminant (impurity) levels expected in the ECM cathode feed gas (treated flue gas). The contaminant testing and the results are further discussed under ECM Stacks section of this report.

Pre-heating (Heat Exchangers, Catalytic Oxidizer) and Supplemental Air Introduction: The clean flue gas is heated by passing the stream through the Flue Gas Heater which uses the hot cathode exhaust gas from the ECM stacks as the heat source. The Flue Gas Heater is a seam-welded, parallel plate heat unit integrated with other heat exchangers (Fuel Preheater, Boiler in the CEPACS plant), forming a series arrangement of three seam-welded parallel plate heat exchangers using a single pass of hot cathode exhaust gas.

The PC plant flue gas is lean in oxygen. As oxygen from the flue gas is also used as a reactant at ECM cathodes (in the CO_2 capture process), supplemental air is added to the clean flue gas for proper operation of the ECM stacks downstream. The supplemental air is preheated to over 900°F (482°C) before it is blended into the hot flue gas. The hot anode exhaust gas from the ECM stacks provides the preheat. Some of the heat generated by the Low Temperature Shift Converter (LTSC) is also utilized for preheating of the supplemental air. This is described separately under the CO_2 Post-processing section (Sec 1.3.3).

Further preheating of the air-supplemented clean flue gas is carried out in the catalytic oxidizer. Part of the H_2 recycle stream (in the CEPACS plant) is directed to the oxidizer to provide the combustion heat (from exothermic catalytic oxidation) required for the preheating of the flue gas. About 42% of the hydrogen-containing stream remaining after liquefying and separating out CO_2 from the CO_2-rich anode exhaust (ECM) gas is utilized for this purpose. The H_2 recycle stream also contains CO_2 which helps to boost the CO_2 concentration of the flue gas for improved ECM performance. Some flue gas is bypassed around the oxidizer to minimize the size of the parallel oxidizer beds while achieving the maximum exit temperature. The effluent stream from the oxidizer (after the bypass) – clean, air-supplemented, pre-heated flue gas - is now at the required temperature and suitable for feed to the ECM cathodes. During start-up of the plant, a duct burner fed with NG fuel and located upstream of the catalytic oxidizer is used to provide the heat needed.

1.3.2 ECM Stacks (for CO_2 Separation)

ECM Enclosures: The CEPACS system for separating CO_2 from the flue gas of a 550 MW PC power plant employs 1,792 ECM stacks divided into 8 sections. For large-scale applications of the CEPACS system, grouping the stacks into larger enclosures reduces the overall capital costs by eliminating smaller module enclosures and their associated piping, facilitates the replacement of individual stacks (compared to replacing complete modules) and provides

economies of scale that are not possible with 448 separate 1 MW (nominal), 4-stack modules (BP1 stack packaging concept).

In each section, 224 ECM stacks are located in an enclosure. The enclosure is 70' wide, 178' long and 50' high, sitting on a concrete pad 108' wide and 181' long. The ECM stacks are located in 8 rows with 28 ECM stacks per row as shown in Figure 1-4. The ECM stacks are supported in the enclosure on concrete and stainless steel supports. The enclosure has concrete walls and steel trusses mounted above the ECM stacks. Thermal insulation supported by the trusses, and on the walls and lower floor of the enclosure, completely surrounds the 224 stacks. A cross section of the enclosure is shown in Figure 1-5.

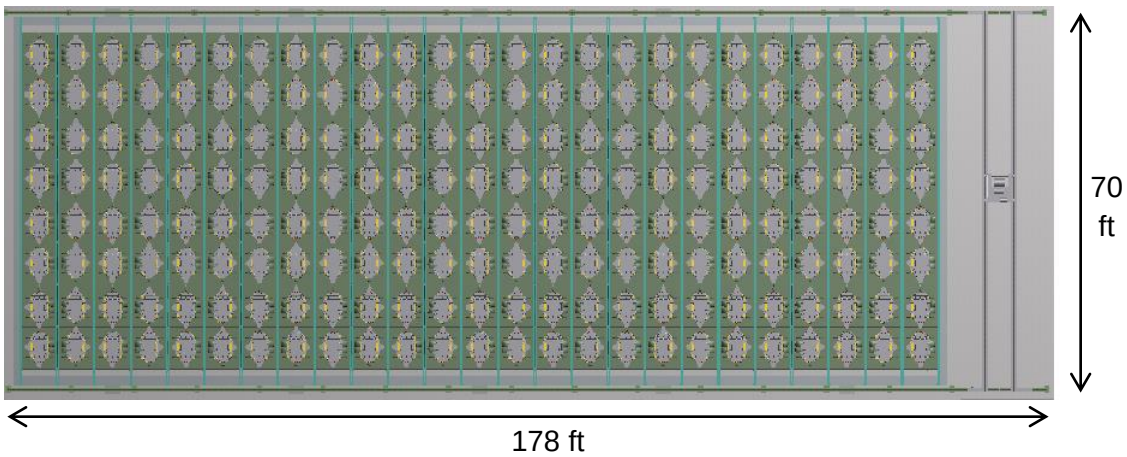

Figure 1-4. Plan View of a 224-Stack ECM Enclosure

A region in the lower part of the building is open for PC plant flue gas and air to enter the building and distribute upward to each of the ECM stack cathodes. The cathode exhaust is collected in eight 30" x 50" ducts, located below the ECM stacks, and flows to the end of the enclosure where it is collected and flows to fuel superheaters located outside the enclosure. Fuel gas from the superheaters enters the enclosure and is distributed in four 26"x 18" ducts in the lower part of the enclosure. The fuel gas flows upward from the ducts, in distributor tubes, to the ECM stack anodes. The CO_2-rich anode exhaust gas, carrying the CO_2 separated from the ECM cathodes, exits the ECM stacks and flows downward in collector tubes to two 24" x 17" ducts and three 32" x 28" ducts located in the lower part of the enclosure. The anode exhaust gas flows in the five ducts to the end of the enclosure where it is collected and routed outside the enclosure. The ducting for gas distribution in the enclosure is made from 316SS, and has expansion joints to accommodate thermal expansion.

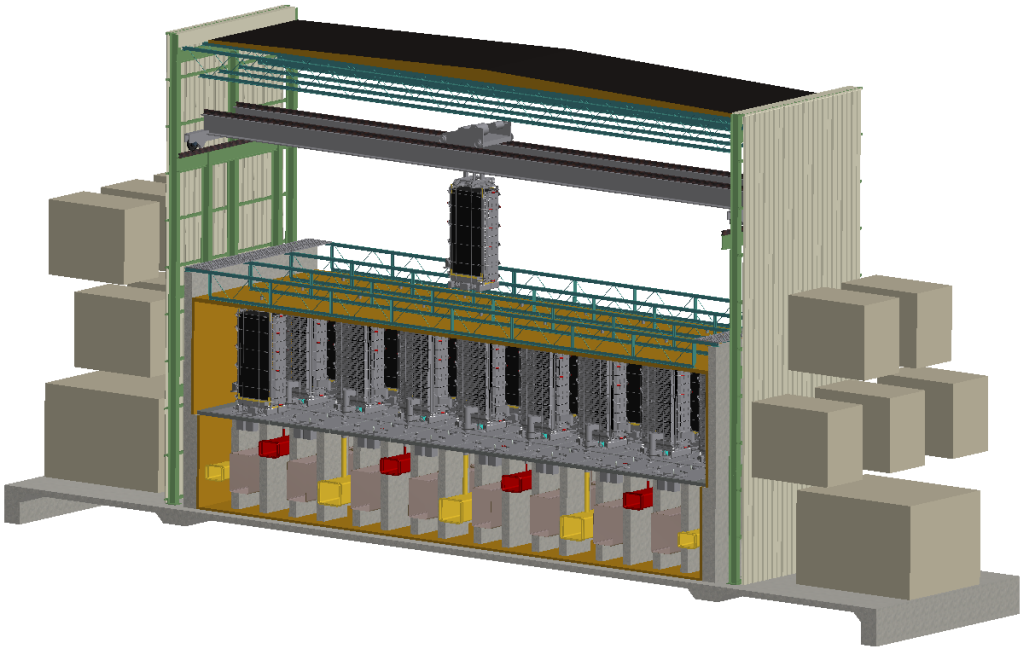

Figure 1-5. Cross-section of an ECM enclosure with stack being installed and power equipment external to the enclosure

The space above the trusses is a cool region. Bus-bars that transfer the DC current from the ECM stacks to the power conditioning equipment are located in this cool region. The power conditioning choppers and inverters are located outside and adjacent to the enclosure. Access to each of the ECM stacks is provided by removable sections of the upper insulation. A traveling crane is located in the building for placement of and access to each of the ECM stacks. The enclosure has sheet metal siding and sheet metal roofing supported on roof trusses.

CEPACS Plant Layout: The layout of the CEPACS system was designed to minimize capital costs. Specifically, the “hot” balance-of-plant equipment was de-centralized into 8 separate sections with one section located proximate to each of the 8 ECM enclosures as shown in Figure 1-6. These “hot” sections comprise such major BOP equipment as the flue gas blower, the flue gas heater, the boiler, the fuel preheater, the air blower, the air preheater, the duct burner and oxidizers, the anode exhaust cooler and the low-temperature shift converter. This modular design minimizes the lengths of “hot” piping and the quantities of fittings, significantly reducing capital costs while simplifying the sparing of parts and potentially increasing the capacity factor.

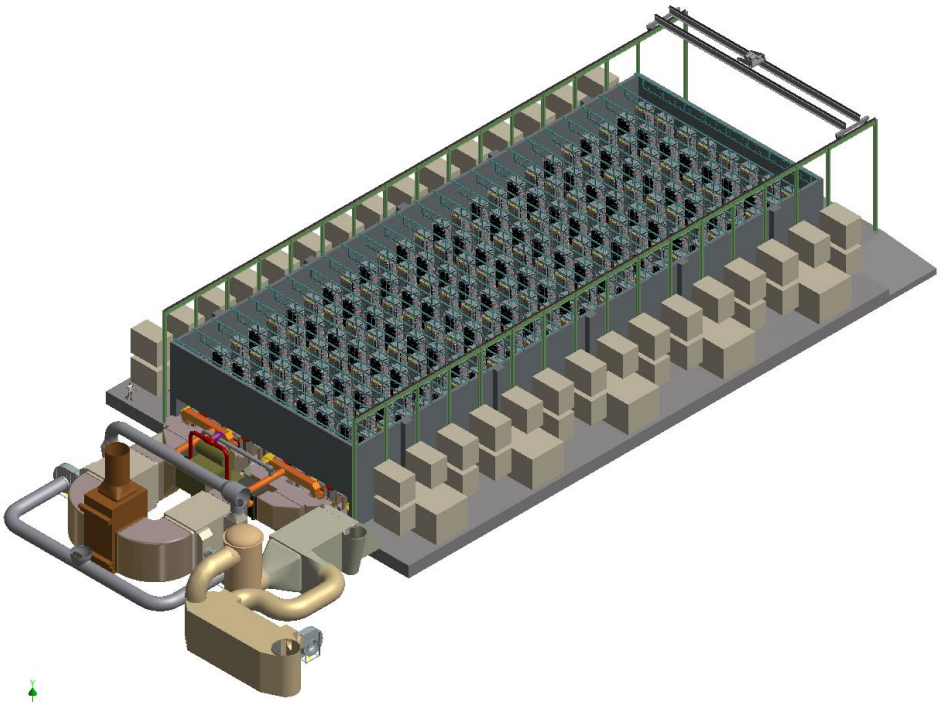

Figure 1-6. General Arrangement of an ECM enclosure and associated "hot" BOP equipment

The general arrangement of the ECM enclosures and associated "hot" BOP equipment is shown in Figure 1-7, along with the piping for the distribution of coal plant flue gas to the 8 sections and collection of the CO_2-rich anode exhaust gas from the 8 sections. The remainder of the balance-of-plant equipment such as the compressors and chillers has been centralized and located in an area to the side of the 8 ECM enclosures and opposite to the FGD unit (not-shown). Including access ways and the centralized equipment, the CEPACS system sized for 90% CO_2 capture from a 550 MW PC plant is estimated to require ~12 acres.

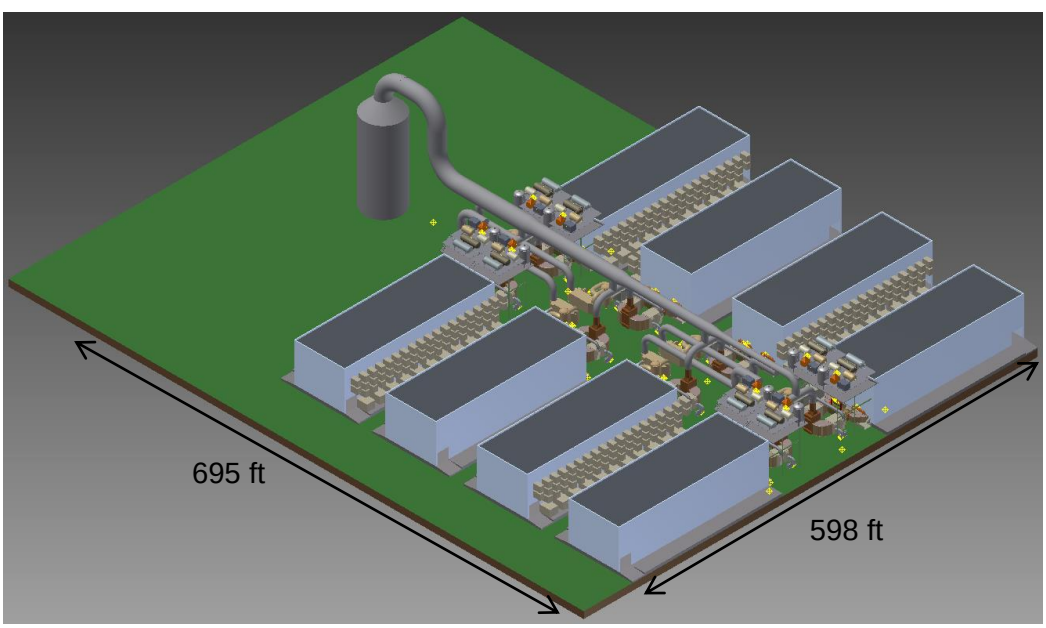

Figure 1-7. General Arrangement of ECM enclosures, BOP equipment and piping

DFC® Operational Experience: FuelCell Energy, Inc. is a global leader in the design, manufacture, operation, and service of ultra-clean, efficient, and reliable megawatt-class stationary molten carbonate fuel cell power plants. FCE began manufacturing MCFC stacks at its production facility in Torrington, Connecticut in 2001. Since then, FCE has been expanding globally. Starting in 2007, through its partnership with POSCO Energy, FCE has been able to target markets in Southeast Asia, particularly South Korea. A European manufacturing, sales, and service presence was also established in 2012, with German-based FuelCell Energy Solutions, GmbH.

FCE's MCFC-based products are trademarked as Direct FuelCell® (DFC®) because of their capabilities for direct internal reforming of methane and other hydrocarbons. FCE has three commercial DFC® power plant products: DFC300 (300 kW), DFC1500 (1.4 MW), and DFC3000® (2.8 MW), as shown in Figure 1-8. FCE's DFC® power plants have been installed in more than 50 locations, throughout 9 countries, and have generated over 2.4 billion kilowatt hours of electricity.

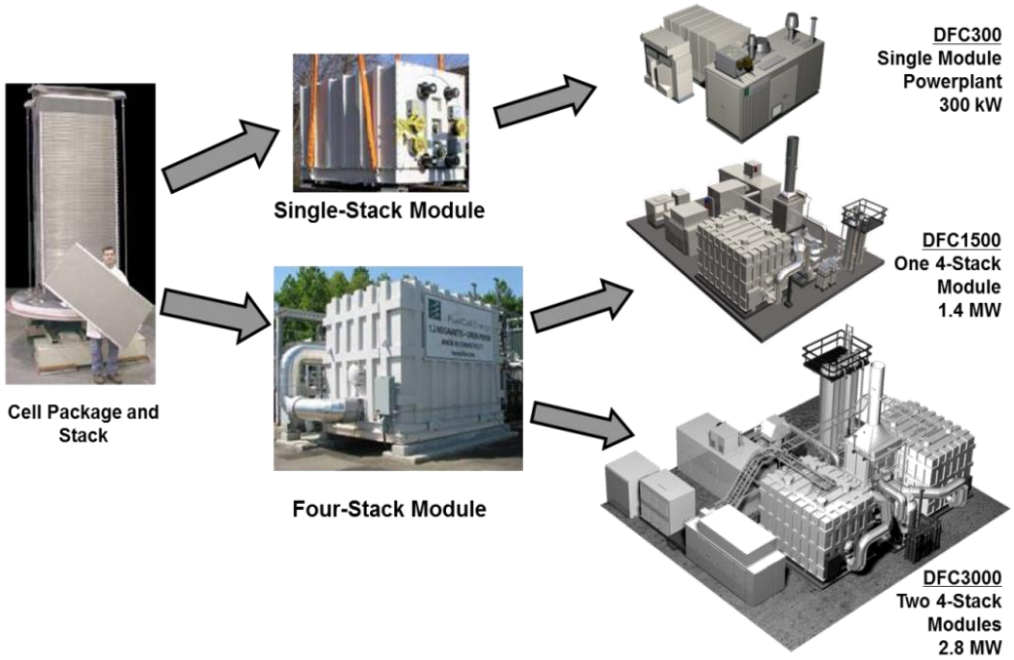

Figure 1-8. Direct FuelCell® commercial power plant products

The DFC® power plants are fuel flexible and can operate using a range of fuels from natural gas (NG) to renewable biogas (Anaerobic Digester Gas, ADG). DFC® field installations include 14.9 MW of total capacity in Bridgeport, Connecticut, and 59 MW of total capacity in Hwasung City, South Korea, representing the largest fuel cell power plants in North America and the world, respectively. Figure 1-9 shows the pictures of these two power plants.

- The installation in Bridgeport, CT comprises five DFC3000® plants and is owned by Dominion, a leading electric utility company. The electricity generated will be sold under a 15-year purchase agreement to Connecticut Light and Power. This facility, shown in Figure 1-9 (left), was fully designed and constructed in 12 months.

- The 59 MW facility in South Korea, shown in Figure 1-9 (right) was completed in 13 months and comprises 21 DFC3000® plants.

Figure 1-9. (left) 14.9 MW Bridgeport, CT facility; and (right) 59 MW Hwasung City, South Korea facility

The DFC® power plants are comprised of 401-cell stacks. The sub-MW power plant (DFC300), has a single-stack module, while the MW-class power plants (DFC1500 and DFC3000®) utilize modules containing 4 stacks each. The stacks operate at an average temperature of 650°C, which enables the cathode exhaust to be used for co-generation heat recovery. A schematic of a cell (including anode, electrolyte matrix, cathode and Interconnect) is shown in Figure 1-10. No barrier layer is used in DFC®. Fuel and air flow paths in DFC® are in a cross-flow configuration. The ECM cell and stack technology is identical to the DFC® design. The naming convention (ECM vs. DFC®) simply indicates re-application of the technology in the CEPACS system for carbon capture from flue gases.

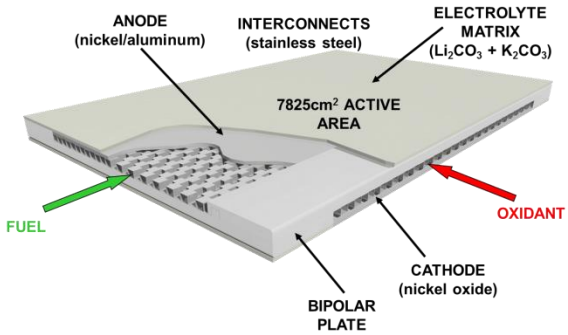

Figure 1-10. Cell Design and Materials

As of 2014, a fleet of over 100 DFC300, DFC1500, and DFC3000® units has been deployed and is operational. DFC3000® fleet availability for the twelve months ending in March 2014 exceeded 95%.

FCE has been continuously working to reduce the product capital cost. In the past decade, the cost per kW has decreased by nearly 75% to around 2,600 $/kW as shown in Figure 1-11.

Further reduction in cost is expected with increased global production volume and product enhancement. The annual production capacity reached 100 MW in North America by the end of 2013.

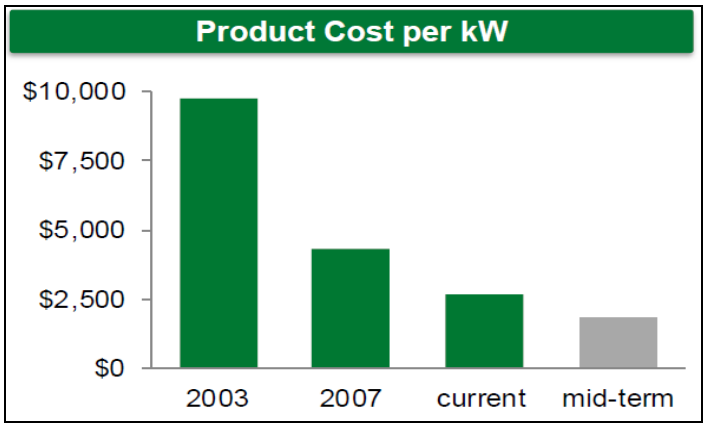

Figure 1-11. Product Cost Reduction of DFC Power Plants at Low/Moderate Production Volume

The global manufacturing facilities in place have the capacity to exceed the milestone of 210 MW of annual production. Manufacturing in Asia is performed by POSCO Energy at a manufacturing facility in Pohang, South Korea under a licensing agreement with FCE. This facility is being configured with initial capability for an annual production of 100 MW with the ability to ramp up to 200 MW in the future. Europe is served by a 20,000 ft^2 manufacturing facility in Ottobrun, Germany that has the capability to produce up to 20 MW per year of sub-MW DFC® power plants. This facility produced its first fuel cell stack in 2013. All of these facilities are shown in Figure 1-12, and cumulatively provide an ultimate annual production capacity of 320 MW.

Figure 1-12. Global Manufacturing Facilities with an Ultimate Annual Production Capacity of 320 MW

ECM Contaminant Tolerance Testing and Analysis: A comprehensive contaminant evaluation study was performed to address possible interactions of the impurities that may be present in flue gas, with ECM cell, which could result in reduced performance. Pacific Northwest National Laboratory performed the analysis and testing using ECM cells provided by FCE. Four main flue gas impurities were considered – sulfur, chlorine, mercury and selenium. The study included thermochemical modeling to predict the possible impurity-membrane interactions, and bench-scale experimental work to assess the extent of the interactions, if any. Prevalent forms of S, Cl, Hg, and Se which can be present in flue gas were identified and included in the evaluation tests. Effect of these contaminants on ECM cell performance and endurance was studied. Based on the experimental results, contaminant tolerance levels for the ECM were identified. The contaminant levels expected from the flue gas clean-up (polishing FGD) subsystem were estimated and compared with the ECM tolerance levels. Table 1-5 provides a summary of the comparison. The contaminant (effect) evaluation and comparison with CEPACS plant flue gas polishing system output showed that the ECM tolerance levels were well above the contaminant levels expected in the ECM cathode feed gas (treated flue gas). Also the testing showed that CO_2 flux (carbon capture rate) remained constant during the tests.

Table 1-5. Expected System (Flue gas) Contaminant Levels Compared with Test Experience

Contam-inant	Concentration in Cathode Inlet Gas After Polishing FGD, Estimated by URS		Highest Concentration Tested by PNNL with low/no power degradation		Notes
SO_2	0.18	ppmv	1	ppmv	Performance losses due to short-term SO_2 exposure up to 40 ppm were fully reversible
Se	0.30	ppbv	10	ppbv	No apparent degradation over 860 h
Hg	0.08	ppbv	250	ppbv	Expected form is predominantly elemental Hg. No apparent degradation over 1100 h
HCl	12.7	ppbv	200	ppbv	No apparent degradation over 915 h.

ECM Performance Testing and Analysis: In conventional power generation applications, the carbonate fuel cells are operated at high power level and ~70% of the CO_2 in the cathode stream is transferred to the anode side. Carbonate fuel cell performance is influenced by the partial pressures of the CO_2 and O_2 (reactants) in the feed stream and utilization levels of the reactants (e.g. % of the CO_2 in the cathode stream that is transferred through the membrane to the anode side) in the cell. For CO_2 separation application (carbonate fuel cell as ECM), the reactant conditions in the cell result in slightly lower electrochemical performance (and hence the power output which is a byproduct) because of the higher than normal utilization required to achieve greater than 90% CO_2 capture.

ECM single-cell testing (operation in a CO_2 transfer mode) using simulated flue gas was conducted to verify ECM performance. The lab-scale testing was conducted using 250 cm^2 area cells. Parametric testing was performed to evaluate the effects of auxiliary air flow (air

supplementation of flue gas), cathode feed gas water vapor concentration, current density, CO_2 transfer rate, fuel utilization, and cell temperature. Testing determined that the optimal cell performance is achieved with an auxiliary air flow that results in 8.25-8.5% oxygen concentration in (supplemented) flue gas (cathode feed gas), with a water vapor concentration of ~12.5%. The optimal system efficiency, determined through a combination of single-cell testing and system simulations, is achieved when operating at a fuel utilization of 75%, a CO_2 utilization of 92.5%, and a CO_2 flux of 128 scc/s/m^2 (corresponds to current density of 110 mA/cm^2). The CO_2 utilization is defined as the % of CO_2 transferred (to the anode side) as the stream passes through the cathode side of the cell. Cell voltage was measured as a function of the CO_2 transfer rate (or flux) for a carbon dioxide utilization of 92.5%. At the design condition of 128 scc/s/m², the cell voltage was 739 mV.

In BP3 of the project, bench-scale demonstration of the ECM-based CEPACS system was conducted in FCE's Danbury, CT test facility. The testing utilized FCE's ECM stack containing 14 full-area cells, providing a total membrane area of 11.7 m^2. The cell packages were manufactured in FCE's commercial production facility located in Torrington, CT. The testing was performed using simulated flue gas (ECM cathode side). The test facility included a CEPACS system skid for post-processing the anode exhaust stream to produce high-purity CO_2 product. The testing included 9 months of steady-state testing, in addition to the parametric and optimization tests. The total test period of 15,715 h highlighted 100 tons/year CO_2 capture capability and 10 kW peak power production. The CO_2 flux remained constant at 116 cc/s/m^2 during the steady state testing (meeting the project milestone of verifying CO_2 flux of 100 cc/s/m^2). Capability of the ECM stack for operation at 20% higher CO_2 flux (139 cc/s/m^2) was also verified in the parametric tests. Average cell voltage based on test results as a function of the CO_2 transfer rate (or flux) for a carbon dioxide utilization range of 50 to 92% is shown in Figure 1-13. At the design condition of 128 scc/s/m², the cell voltage is ~725 mV. Adjusting for cell performance degradation, this cell voltage is equivalent to 730 mV, which was used as the basis for the design of the CEPACS system.

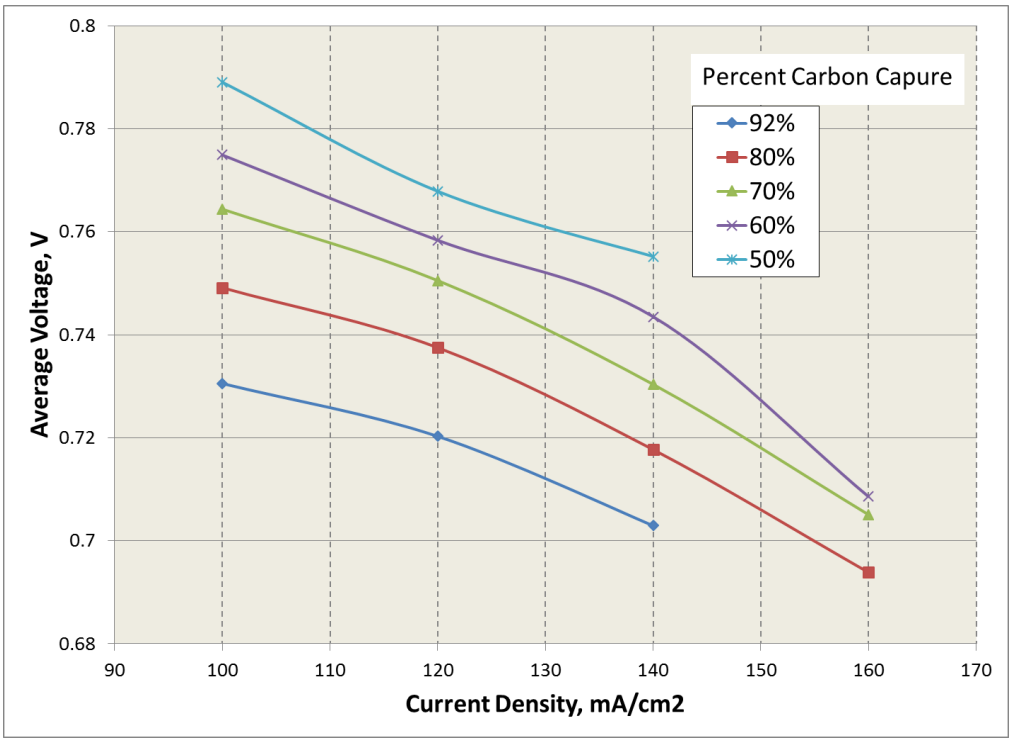

Figure 1-13. ECM Performance Based on Bench-scale Testing

1.3.3 CO_2 Product Post-processing

Water Gas Shift (Low Temperature Shift Converter) and Water Removal (Cooler, Condenser): The anode gas exiting the ECM stacks is CO_2–rich and also contains unused fuel (mostly H_2 and some CO) and product water vapor. It is processed in a Low Temperature Shift Converter (LTSC) to maximize its CO_2 content prior to CO_2 capture steps. Prior to processing in LTSC, the stream is cooled to provide preheat to the supplemental air stream (as mentioned earlier). After additional cooling by water injection (condensate recycled within the CEPACS plant), the gas is now at the desired temperature to maximize CO shift and is fed to the LTSC where most of the CO is shifted to CO_2, consuming water and generating additional hydrogen (required for its exothermic heat at the oxidizer and recycle to the anode).

The shifted anode gas (from LTSC) is then processed to remove most of the water prior to CO_2 capture steps. The gas is cooled in the Air Preheater to provide pre-heat to the supplemental air. Some of the heat generated by the exothermic shift reaction is utilized here for air pre-heating (as mentioned earlier). The shifted gas is cooled further in the CO_2 (product liquid) Reheater and in the Condenser (using cooling water). This provides substantial condensation and water removal prior to the compression stages employed for CO_2 capture (described separately below).

Compression and CO_2 Liquefaction: The cooled, shifted anode gas stream contains about 79% CO_2, 18% H_2, and 2.5% H_2O upon exiting the Condenser. It is then chilled and compressed in a series of stages to reduce its water content and liquefy CO_2. Pre- and interstage-cooling, using cooling water and chilled refrigerant, is used to further condense and remove water as well as reducing the power consumption of the compressors. The Stage 1 and 2 Chillers provide two levels of refrigeration. The initial stage provides moderate cooling and the last stage cools to lower temperature to liquefy the CO_2. The existing PC Plant cooling tower water loop provides 60°F (16°C) water to each compression stage pre-cooler and the chiller units (condenser heat loads). The final stage results in a stream that allows for a flash separation of near pure CO_2.

The CO_2-rich anode gas stream is compressed using a two-stage, intercooled compressor suitable for hydrogen environments. Such compressors are commercially available and are used in a wide range of industrial applications, including: industrial gases, petrochemicals, hydrocarbons, power generation, furnace gas recovery (FGR), ammonia, etc. Many large, globally-known OEMs such as Siemens, GE Oil & Gas, MAN Diesel & Turbo, Elliott Group (Ebara Corporation) and Dresser-Rand manufacture a wide range of state-of-the-art compressors spanning the operating conditions of the CEPACS system. These compressors are typically either multi-stage centrifugal compressors, or two-stage axial / centrifugal compressor systems. All of these compressors are available with electric motors and variable speed drives.

Product Carbon Dioxide Delivery: High purity CO_2 is flashed as a liquid from the refrigerated and compressed anode gas stream. The off-gas (after the flash operation) containing mostly H_2 and CO_2 is recycled back to the catalytic oxidizer and ECM stack. The separation of CO_2 (as supercritical fluid) represents about 93% capture of the carbon input to the CEPACS system. The CO_2 liquid is continuously pumped to 2215 psia (15.3 MPa abs) and heated to the required product stream temperature.

1.3.4 Supplemental Fuel Processing Sub-system

The CEPACS system for the CO_2 capture from the 550 MW PC plant flue gas utilizes pipeline natural gas as a supplemental fuel. The natural gas is delivered at a relatively low pressure of about 6 psig (145 kPa abs), as the ECM stacks operate at near atmospheric pressure. As it contains ~3 ppmv of total sulfur compounds, the natural gas is desulfurized in a two bed

subsystem featuring lead/lag arrangement flexibility. The natural gas flow is switched to the second bed after about 9000 hrs. The sorbent in the first bed is replaced and it becomes the second bed in the series flow configuration to guard against preliminary sulfur break-through. Each of the two vessels is about 10 ft (3.05 m) in diameter and 20 ft (6.1 m) high.

The desulfurized natural gas is then mixed with steam which is provided from a low pressure boiler. The water is supplied with water recovered within the CEPACS plant. The humidified natural gas then passes through a fuel preheater which raises its temperature to about 700 °F (371 °C). The fuel preheater and the boiler heat duties are provided by the CO_2-depleted stream leaving the ECM cathodes (as it contains the waste heat generated in the ECM stacks). Before distribution to the 8 ECM stack enclosures (containing 224 stacks each), the humidified natural gas is mixed with a hydrogen recycle stream. About 58% of the hydrogen-containing stream remaining after liquefying and separating out CO_2 from the CO_2-rich ECM anode exhaust gas is recycled back to the ECM anodes. The mixed fuel stream to the ECM cell stacks contains ~16% hydrogen. The recycle of hydrogen provides a per-pass fuel utilization in the cells of 75%, which serves to reduce the natural gas fuel consumption.

1.3.5 Water Sub-systems

Process Water (Water Recovery and Recycle within the CEPACS system): This water category refers to high quality water generated and consumed within the CEPACS plant. The anode exhaust gas from the ECM stacks contains about 38% water vapor as water is generated as a product of the electrochemical reactions occurring in the stacks. A small fraction is consumed in the water gas shift reaction. The remaining water is condensed and separated from the anode stream after the Condenser and the initial Chiller stages. All condensate is collected in a central tank. Some of this water is used for quenching the anode exhaust stream (from the ECM stacks) upstream of LTSC (as mentioned earlier). About 55% (by mass) of the condensate water is pumped to the CEPACS Boiler to generate steam required for ECM fuel feed. The remaining condensate flow is net excess process water generated by the CEPACS system and is provided to the PC plant for process requirements.

Cooling Water (Addition to PC Plant Cooling Tower): This water category refers to a portion of the PC Plant Cooling tower water which is circulated through the CEPACS heat exchangers, and does not contact the process gas. This is treated water and normal cooling tower losses are assumed. Supply water is fed at 60°F (16°C) and returned at $\leq$80°F (27°C). Two cooling water loops are provided. One loop supplies water to the Condenser and pre-coolers upstream of the chiller units and requires about 40% of the total cooling water (used for CEPACS). The balance at about 60% of the water is supplied to the Chiller units.

1.3.6 Electrical Sub-systems

The CEPACS system for the 550 MW coal plant includes two electrical subsystems: a Power Generation subsystem and an Auxiliary Power subsystem. The Power Generation subsystem includes the 1792 ECM stacks that generate DC power in the process of separating CO_2 from the coal plant flue gas. The plant is divided into eight (8) sections. Each ECM enclosure containing 224 stacks and the associated balance of plant components constitutes a section. The electrical 1-line diagram is shown in Figure 1-14. Within each section, the 224 ECM stacks are arranged electrically in 8 groups of 28 stacks each. Each group includes seven sub-groups of four stacks each. The stacks within a sub-group are electrically connected in series and grounded in center (two stacks on each side of ground connection). Each sub-group is connected to a 400 Hz square wave chopper, high frequency transformer and rectifier. The output of 7 sub-groups (28 ECM stacks total) is combined and flows to an inverter that converts the power to 3-phase 60 Hz at 4.16 kV. The inverted output from each group pair (56 ECM stacks total) is combined and transformed to 54 kV and fed on the section bus. The 54 kV

output from each section is combined and transformed to 345 kV before directing it to the main switch yard. The final result is the CEPACS 350 MVA AC output.

The Auxiliary Power subsystem takes power from the coal plant's 345 kV switchyard. The electrical 1-line diagram is shown in Figure 1-15. A 100 MVA transformer delivers 3-phase 60 Hz power at 54 kV. Auxiliary power for each of the 8 sections, as well as the central balance-of-plant equipment, is transformed to 4.16 KV required to operate the compressors, blowers, pumps, and flue gas desulfurizer. Power is further transformed to 460 V for smaller pumps, the chillers and the system controls and auxiliary loads. Power is also delivered at 3-phase 60 Hz 277 V for various single phase loads.

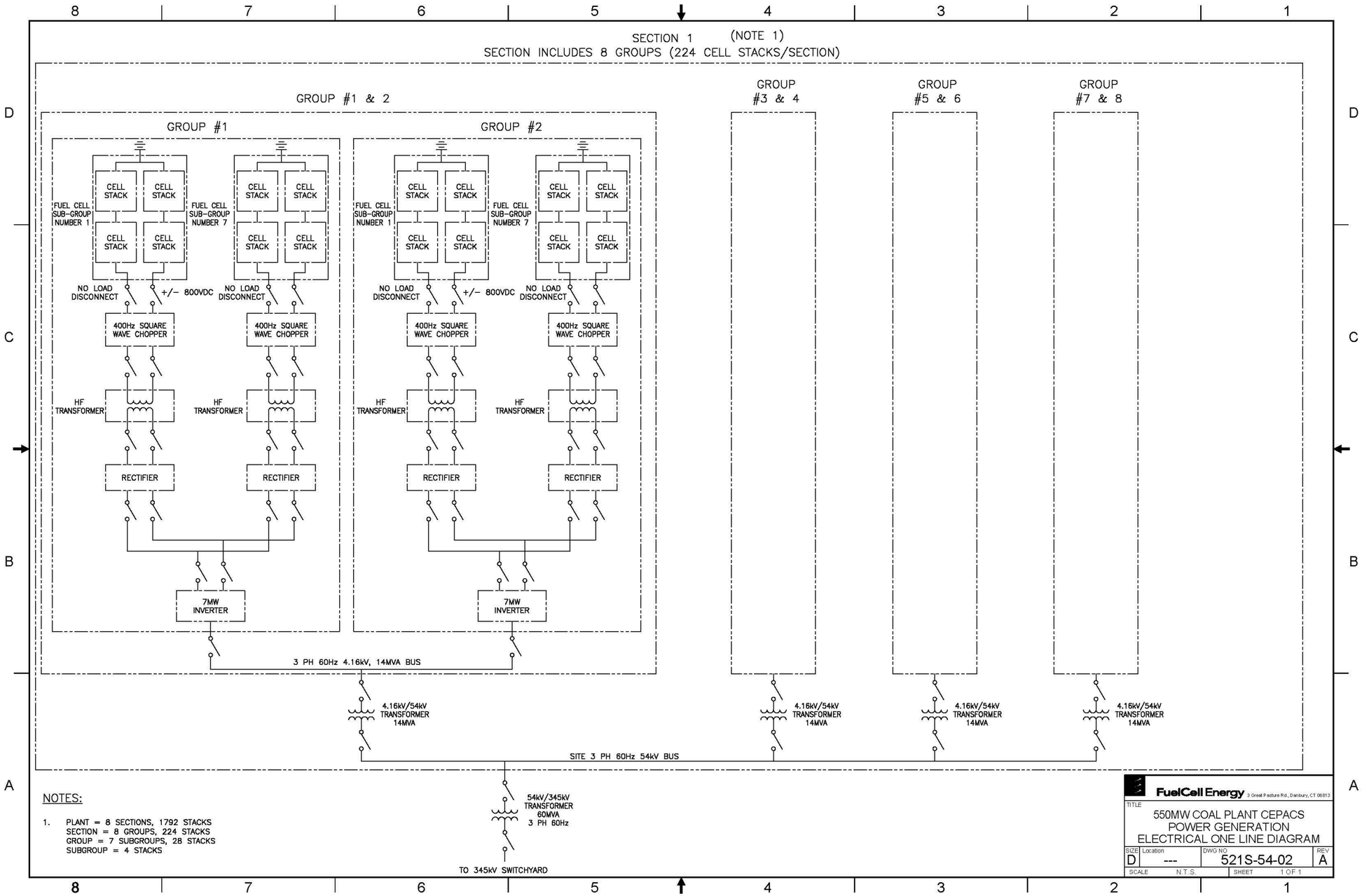

Figure 1-14. Electrical One-line Diagram for Power Generation Subsystem (CEPACS)

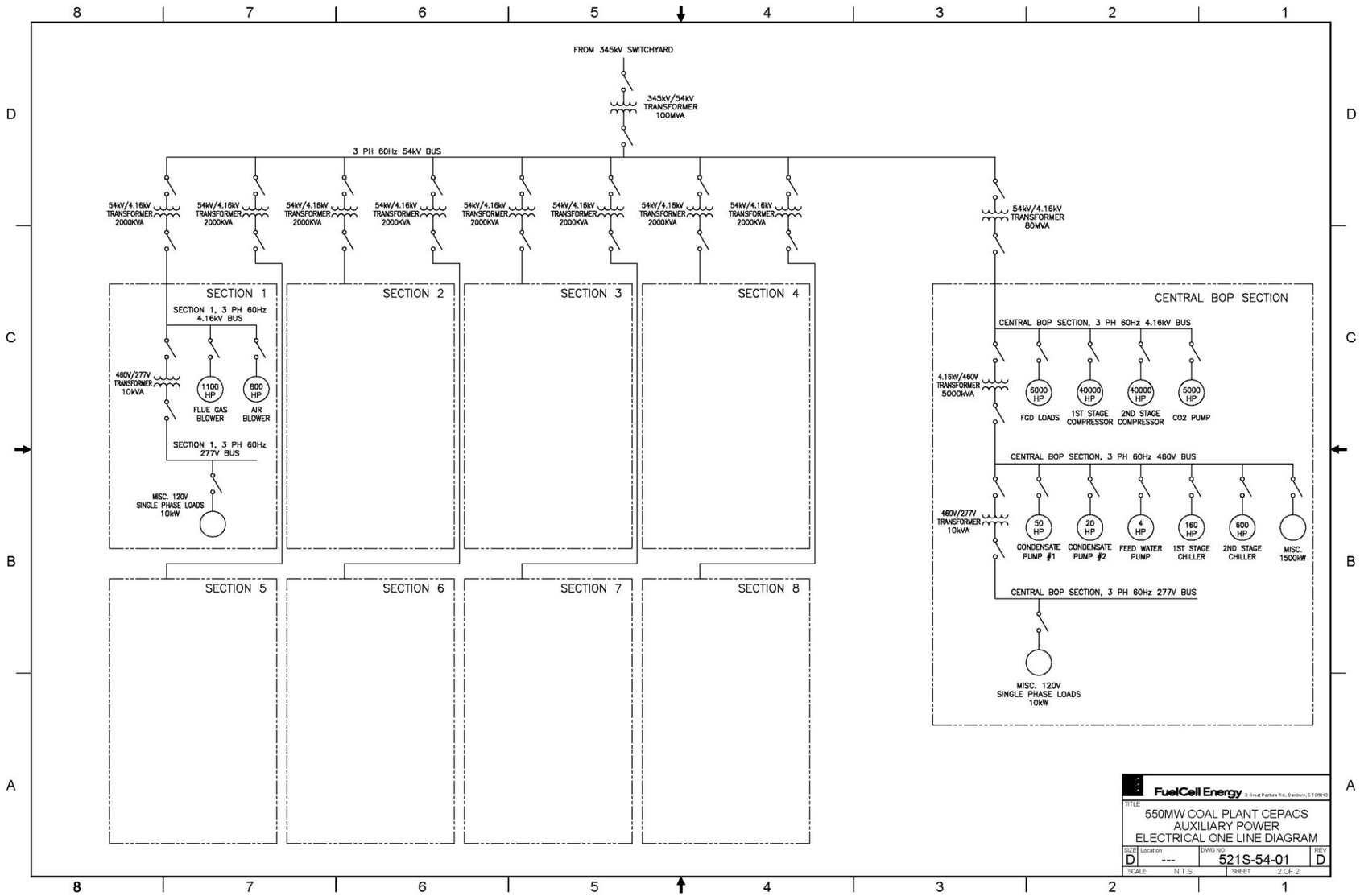

Figure 1-15. Electrical One-line Diagram for Auxiliary Power Subsystem (CEPACS)

1.4 Equipment List

The equipment list for the CEPCAS system designed for integration with a 550 MW PC plant is shown in Table 1-5. Information such as equipment description and type, design conditions, and operating unit and spare counts was developed.

The CEPACS plant consists of 1,792 ECM Stacks which are arranged in 8 sections of 224 stacks each. A “hot” balance-of-plant train services each section, for a total of 8 “hot” BOP trains. These “hot” sections comprise such major BOP equipment as the flue gas blower, the flue gas heater, the boiler, the fuel preheater, the air blower, the air preheater, the duct burner and oxidizers, the anode exhaust cooler and the low-temperature shift converter. This approach was chosen based on available equipment capacities and also to limit the gas ducting sizes. The remainder of the balance-of-plant equipment such as the compressors and chillers have been centralized and located in a centralized area. A plot plan for the ECM stack sections was prepared (presented in Section 1.3.2 of this report) to facilitate the economic analysis.

Table 1-6. CEPACS System Equipment List for Application to a 550 MW PC Power Plant

Equipment Description	Equipment Tag #	Type	Total Operating Qty.	Capacity Related to Plant
Boiler	100-HX-102	Heat Exchanger, Tube-Fin	8	12.5%
Natural Gas Desulfurizer Vessel	200-RR-101/2	Vertical Bed	1	100%
Natural Gas Desulfurizer Sorbent	-	Pelletized	1	100%
Fuel Preheater	200-HX-104	Heat Exchanger, Seam welded Parallel Plate	16	6.25%
Electrochemical Membrane (ECM) Stack Enclosures	200-ECM-106	Molten carbonate -based planar, cross flow membrane	8	12.5%
Flue Gas Blower	300-BL-103	Blower, Centrifugal	16	6.25%
Flue Gas Heater	300-HX-105	Heat Exchanger, Seam welded Parallel Plate	16	6.25%
Start-up Duct Burner	300-HE-106	Duct Burner	8	12.5%
FG Oxidizer	300-RR-108A/B	Reactor	16	6.25%
Oxidizer Catalyst	-	Catalyst, Wash Coated Monolith	16	6.25%
Low-Temp. Shift Converter (LTSC)	400-RR-101	Reactor	8	12.5%
LTSC Catalyst	-	Catalyst, Pellet, Vertical Flow Bed	8	12.5%
Condenser	400-HX-109	Heat Exchanger, Tube-Fin	1	100%
Air Filter	500-FL-101	Replaceable elements	8	12.5%
Air Blower	500-BL-101	Blower, Centrifugal	8	12.5%
Anode Exit Cooler (Air Preheater II)	500-HX-101	Heat Exchanger, Seam welded Parallel Plate	8	12.5%
Air Preheater	500-HX-102	Heat Exchanger, Seam welded Parallel Plate	8	12.5%

Table 1-6. CEPACS System Equipment List for Application to a 550 MW PC Power Plant (continued)

Equipment Description	Equipment Tag #	Type	Total Operating Qty.	Capacity Related to Plant
Condensate Pump #1	100-PU-101	Pump, Centrifugal	1	100%
Condensate Pump #2	100-PU-102	Pump, Centrifugal	1	100%
Feedwater Pump	100-PU-103	Pump, Centrifugal	1	100%
Water Collection Tank	100-TK-106	Vessel, Vertical	1	100%
Raw Flue Gas Blower	300-BL-100	Blower, Centrifugal	1	100%
Polishing FGD	300-RR-101	Wet Absorber	1	100%
Chiller - Stage 1	400-HX-101	Heat Exchanger, Tube-Fin	1	100%
Inter-stage Precooler	400-HX-102	Heat Exchanger, Tube-Fin	1	100%
CO_2 Recycle Heater	400-HX-104	Heat Exchanger, Tube-Fin	1	100%
Chiller Precooler	400-HX-105	Heat Exchanger, Tube-Fin	1	100%
Chiller Inlet Cooler	400-HX-106	Heat Exchanger, Tube-Fin	1	100%
Chiller - Stage 2	400-HX-107	Heat Exchanger, Tube-Fin	1	100%
CO_2 Reheater	400-HX-108	Heat Exchanger, Tube-Fin	1	100%
Water Separator #1	400-SP-101	Vessel, Vertical	1	100%
Water Separator #2	400-SP-102	Vessel, Vertical	1	100%
Water Separator #3	400-SP-103	Vessel, Vertical	1	100%
1st Stage Compressor	400-CR-101	Compressor, Centrifugal	1	100%
2nd Stage Compressor	400-CR-102	Compressor, Centrifugal	1	100%
CO_2 Separator	400-SP-109	Vessel, Vertical	1	100%
CO_2 Pump	400-PU-120	Pump, Piston	1	100%

2.0 SYSTEM PERFORMANCE

2.1 Key System Assumptions

Assumptions made regarding the key operational and performance parameters for major subsystems or system components are listed in Table 2-1.

Table 2-1. Key System Assumptions

Case ID	1	2	3
Description	**Subcritical PC**	**Subcritical PC w/ CO_2 Capture (Amine)**	**Subcritical PC w/ CO_2 Capture (CEPACS)**
DOE/NETL-2010/1397 Case ID	9	10	--
Steam Cycle, MPa/°C/°C (psig/°F/°F)	16.5/566/566 (2400/1050/1050)		
Coal	Illinois No. 6		
Condenser pressure, mm Hg (in Hg)	50.8 (2)		
Boiler Efficiency, %	88		
Cooling water to condensers, °C (ºF)	16 (60)		
Cooling water from condensers, °C (ºF)	27 (80)		
Stack temperature, °C (°F)	57 (135)	32 (89)	90 (194)
SO_2 Control	Wet Limestone, Forced Oxidation		
FGD Efficiency, % (A)	98	98 (B)	Bulk: 98 Polishing: 99 (C)
NOx Control	LNB w/OFA and SCR	LNB w/OFA and SCR	LNB w/OFA, SCR, and ECM
SCR Efficiency, % (A)	86	86	86
ECM NOx Removal Efficiency, %	--	--	70
Particulate Control	Fabric Filter	Fabric Filter	Fabric Filters
Fabric Filter efficiency, % (A)	99.8	99.8	99.9
Ash Distribution, Fly/Bottom	80% / 20%	80% / 20%	80% / 20%
Mercury Control	Co-benefit Capture	Co-benefit Capture	Co-benefit Capture
Mercury removal efficiency, % (A)	90	90	90
CO_2 Control	N/A	Econamine	ECM-based CEPACS
Overall CO_2 Capture (D)	N/A	90.2%	93.0%
CO_2 Sequestration	N/A	Off-site Saline Formation	Off-site Saline Formation

A. Removal efficiencies are based on the FG content

B. An SO_2 polishing step is included to meet more stringent SO_x content limits in the FG (< 10 ppmv) to reduce formation of amine HSS (Heat Stable Salts) during the CO_2 absorption process. SO_2 exiting the post-FGD polishing step is absorbed in the CO_2 capture process making stack emissions negligible.

C. Based on remaining SO_2 in FG after bulk polishing

D. Defined as: 1-[(Stack Gas Carbon-Air Carbon)/(Total Carbon In-Air Carbon)] and expressed as percentage.

2.2 Performance Summary

Based on system simulation results, the CEPACS system performance was estimated. In the process of capturing CO_2, the CEPACS system produces additional net AC output of 351 MWe at a plant efficiency of 42.4% (NG HHV basis). The ECM performance was based upon testing results at CEPACS operating conditions (as described in Section 1.3.2). The overall performance for the CEPACS plant, as applied to a 550 MW PC plant (from Case 9 of the referenced DOE/NETL report [5]), is summarized in Table 2-2, which includes auxiliary power requirements (including CO_2 compression).

Table 2-2. PC Plant with CEPACS CO_2 Capture System: Performance Summary

Plant Performance Summary - Case 3 - PC + ECM-based CEPACS	
CEPACS System (ECM Stack) Power, Gross AC kWe[1]	433,464
CEPACS System Auxiliary Load Summary, kWe	
Flue Gas Blower	8,126
Supplemental Air Blower	5,964
Polishing FGD	4,500
Anode Exit Compressor - Stage 1	27,369
Anode Exit Compressor - Stage 2	27,860
Chillers	397
CO_2 Liquid Pump	5,565
Water Pumps	23
Miscellaneous Balance of Plant[2]	1,500
Transformer Losses	1,355
TOTAL CEPACS AUXILIARIES, kWe	**82,659**
CEPACS NET POWER, kWe	**350,805**
CEPACS Net Plant Efficiency (HHV Natural Gas)	42.4%
CEPACS Net Plant Heat Rate, kJ/kWh	8,482
PULVERIZED COAL PLANT NET POWER, AC kWe[3]	**550,020**
TOTAL (PC + CEPACS) NET POWER w/ CO_2 capture, kWe	**900,825**
Net Plant Efficiency w/ CO_2 Capture[4]	38.8%
Net Plant Heat Rate w/ CO_2 Capture, kJ/kWh[4]	9,279
CONSUMABLES	
As-Received Coal Feed, kg/hr	198,391
Coal Thermal Input, kWt[5]	1,495,379
Natural Gas Feed, kg/hr	56,591
Natural Gas Thermal Input, kWt[6]	826,564

1. ECM Stack power includes DC-AC losses, assuming 96% conversion efficiency
2. Includes plant control systems, lighting, HVAC, and misc. low voltage loads
3. Net power from Case 9 of referenced DOE report
4. Basis: HHV Coal + HHV Natural Gas
5. HHV of As-Received Illinois No. 6 coal is 27,135 kJ/kg
6. HHV of Natural Gas is 52,581 kJ/kg

In the process of capturing 90% of the CO_2 from the PC plant flue gas, the ECM-based CEPACS system for the 550 MW (net AC) PC plant simultaneously generates additional (net AC) power after compensating for the auxiliary power requirements of CO_2 capture and compression. The net electrical efficiency of the CEPACS-equipped PC plant (with CO_2 capture) was estimated to be 38.8% (based on higher heating values of coal and natural gas fuels used by PC plant and CEPACS system, respectively).

2.3 Environmental Performance

The environmental performance was estimated for the PC plant (Case 9 of DOE-NETL Report) combined with the CEPACS system based on a gross power of 1,016 MW and is presented in Table 2-3. The reported emissions include the individual pollutants as SO_2, NO_x, Hg and Particulates. Carbon dioxide emitted with the plant exhaust (ECM cathode side) represents CO_2 in the flue gas which is not captured by the ECM stacks. This is reported as a mass flow per net power. The percentage of CO_2 captured exceeds the 90% capture level minimum.

The primary and the final polishing SO_2 scrubber units reduce the SO_2 level to 0.3 ppmV in the flue gas (fed to the ECM cathode). The SO_2 which is not removed by the primary (1st) Wet Limestone Scrubber and the CEPACS Polishing Wet Limestone scrubber (2nd) is emitted to the environment. All sulfur is reported as SO_2. Sulfur in the natural gas fuel (supplementary fuel for ECM anodes) is adsorbed and captured by the fuel desulfurizer sorbent.

The NOx emissions correspond to the flue gas NO_2 and NO content which is not removed/converted by the ECM stacks. During normal power operation ECM testing results have shown that >70% of the flue gas NO_x content is transferred across the membrane to the anode and reduced. No NOx emissions are created within the CEPACS system. The overall emissions specific flow rate of 0.055 kg/MWh is ~17% of the MATS limit of 0.32 kg/MWh.

Mercury (Hg) emissions represent the mercury content in the PC Plant flue gas which is not scrubbed out by the Primary wet lime scrubber unit. This primary scrubber removes 90% of the Hg in the flue gas feed by wet lime impingement and conversion. No credit is taken for Hg removal in the downstream polishing scrubber. The mercury passes through the ECM cathode side, as verified by ECM contaminant evaluation testing.

Particulate emissions account for the PC Plant flue gas particulate matter not removed by a combination of the PC plant baghouse and the two Wet Lime scrubbers in series. These solids are removed at 99.8% removal efficiency. The remaining particulates exit with the CEPACS plant exhaust stream. The emission level is <37% of the MATS limit of 0.041 kg/MWh.

Table 2-3. Air Emissions for Case 3: 550 MW PC Plant with CEPACS System

	kg/GJ (lb/MMBtu)		Tonne/year (ton/year) 85% CF		kg/MWh (lb/MWh)	
SO_2	0.0003	(0.0006)	16	(18)	0.002	(0.005)
NO_x	0.007	(0.015)	414	(456)	0.055	(0.121)
Particulates	0.002	(0.004)	113	(124)	0.015	(0.033)
Hg	0.0000	(0.00)	0.020	(0.022)	2.60E-06	(5.74E-06)
CO_2	5.4	(12.6)	337,109	(371,595)	45	(98)
CO_2[1]					50	(111)

[1] CO_2 Emissions Based on Net Plant Output

Table 2-3.1. US EPA NSPS Air Toxics Standards (MATS) Limits

Constituent	lb/MWh	kg/MWh
SO_2	1.0	0.45
NOx	0.7	0.32
PM	0.09	0.04

2.4 Carbon Balance

Table 2-4 shows the carbon balance for the CEPACS system. The CEPACS system is designed to capture at least 90% of the carbon from the coal plant flue gas. The total carbon captured exceeds 93%.

Table 2-4. Carbon Balance for CEPACS System

Carbon In, kg/hr		Carbon Out, kg/hr	
Flue Gas from PC Plant	128,401	Plant Exhaust	12,345
Natural Gas	40,837	CO_2 Product	157,089
Supplemental Air	196		
Total	**169,434**	**Total**	**169,434**
Carbon Capture Percentage (of total C Entering CEPACS)			**92.82%**
Carbon Capture Percentage (of C in Flue Gas)			**90.39%**

2.5 Sulfur Balance

Table 2-5 shows the sulfur balance for the CEPACS plant. Sulfur input comes from the sulfur (present as SO_2) in the PC plant flue gas fed to ECM cathodes and from the sulfur (present as inorganic and organic compounds) in the pipeline natural gas (supplementary fuel) fed to the ECM anodes. Sulfur output includes the sulfur recovered from the Polishing FGD as gypsum, sulfur adsorbed by (and disposed of with) the sorbent in the natural gas desulfurizer vessels, and sulfur emitted in the plant exhaust.

Table 2-5. Sulfur Balance for CEPACS Plant

Sulfur In, kg/hr		Sulfur Out, kg/hr	
Flue Gas from PC Plant	218.5	Polishing FGD Product	217.0
Natural Gas	2.6	Plant Exhaust	1.6
		Removal in NG Desulfurizers	2.6
Total	**221.1**	**Total**	**221.1**

2.6 Energy Balance

The overall CEPACS plant energy balance based on the CHEMCAD system simulations is shown in Table 2-6. The auxiliary or parasitic power consumed by the CEPACS plant is supplied from the power generated by the ECM stacks in the process of separating CO_2 from the PC plant flue gas. The other (miscellaneous) process losses are negligible. These may relate to losses such as motor losses for the fluid transport equipment.

Table 2-6. Overall Energy Balance for CEPACS System (25°C Reference)

	HHV		Heat Content: Sensible + Latent		Power		Total	
	GJ/hr	MMBtu/hr	GJ/hr	MMBtu/hr	GJ/hr	MMBtu/hr	GJ/hr	MMBtu/hr
Energy In								
Natural Gas Feed	2972.7	2818.8	(1.2)	(1.2)			2,971.5	2,817.7
Flue Gas Feed			696.1	660.1			696.1	660.1
Air Feed			7.4	7.0			7.4	7.0
Cooling Water Supply			(1,271.9)	(1,206.0)			(1,271.9)	(1,206.0)
Total Energy In	**2,972.7**	**2,818.8**	**(569.6)**	**(540.1)**	**-**	**-**	**2,403.2**	**2,278.7**
Energy Out								
CO_2 Product			(30.5)	(28.9)			(30.5)	(28.9)
Plant Exhaust			966.5	916.5			966.5	916.5
Cooling Water Return			(23.2)	(22.0)			(23.2)	(22.0)
Excess Water to PC Plant			(3.6)	(3.4)			(3.6)	(3.4)
Power (net AC output)					1,262.4	1,197.0	1,262.4	1,197.0
Inverter & Transformer Losses					69.9	66.2	69.9	66.2
Auxiliary power load (non-process)					5.4	5.1	5.4	5.1
Heat Losses from Piping & Equip			134.7	127.77			134.7	127.8
Other Process Losses*			21.7	20.5			21.7	20.5
Total Energy Out	**-**	**-**	**1,065.5**	**1,010.4**	**1,337.6**	**1,268.4**	**2,403.2**	**2,278.7**

* Includes losses such as motor losses for the fluid transport equipment

2.7 Water Balance

Figure 2-1 shows the water block flow diagram: ECM-Based CEPACS System Water Balance (Dwg No. 521S-31-04). The focal point of the balance is the PC Plant Cooling Tower. The Tower and the PC Plant existing loops are depicted as one block. Because the CEPACS system (including the Polishing FGD) will be processing the PC plant flue gas, the circulation heat duty /size of this cooling tower will be increased (only the CEPACS system-specific water requirements are shown in the block diagram).

The CEPACS system is a net producer of clean process water which is sent to the PC plant for process requirements. CEPACS internal water consumption-throughput is shown as a recycle stream which includes boiler water (steam) required for ECM fuel feed and quench water used upstream of the shift converter (LTSC).

The cooling water loops designated as “Anode Exhaust Gas Precoolers / Condensers” and “Chillers” represent the cooling water used in CEPACS heat exchangers and chillers. These are closed loops with no consumption. The PC Plant cooling tower inlet is shown as makeup water only. The cooling tower evaporation and drift losses are shown as an outlet stream.

The primary exit water from the PC Plant Cooling Tower is the additional blowdown water proportioned to the above-mentioned CEPACS heat exchanger cooling water loops. A large fraction of the cooling tower blowdown water (500 gpm) is utilized as feed water to the Polishing FGD scrubber. This feature serves to reduce the net water withdrawal of the CEPACS system. Most of the scrubber feed water is consumed in making slurry and gypsum. A small fraction of the cooling tower feed water goes to the Waste Water clarifier. The rest is evaporation and losses (with solids).

Table 2-7 shows the overall water balance for the CEPACS system applied to a 550 MW PC plant (Case 3), including the water usage of the base PC plant.

Table 2-7. Water Balance for 550 MW PC Plant Equipped with CEPACS Plant

	Raw Water Withdrawal, m^3/min (gpm)	Process Water Discharge, m^3/min (gpm)	Raw Water Consumption, m^3/min (gpm)
Primary FGD Makeup	3.9 (1,017)	0.0 (0) Note 1	3.9 (1,017)
BFW Makeup	0.3 (74)	0.0 (0)	0.3 (74)
CEPACS Process	-1.5 (-386) Note 2	0.0 (0)	-1.5 (-386)
Cooling Tower & Polishing FGD	25.0 (6,610)	6.5 (1,715) Note 1	18.5 (4,895)
Totals	**27.7 (7,317)**	**6.5 (1,715)**	**21.2 (5,602)**

Note 1: Polishing FGD utilizes blowdown from the cooling tower as feed water; no raw-source water is used. See CEPACS system water block diagram.
Note 2: Negative numbers designate water exported from (or produced by) the system.

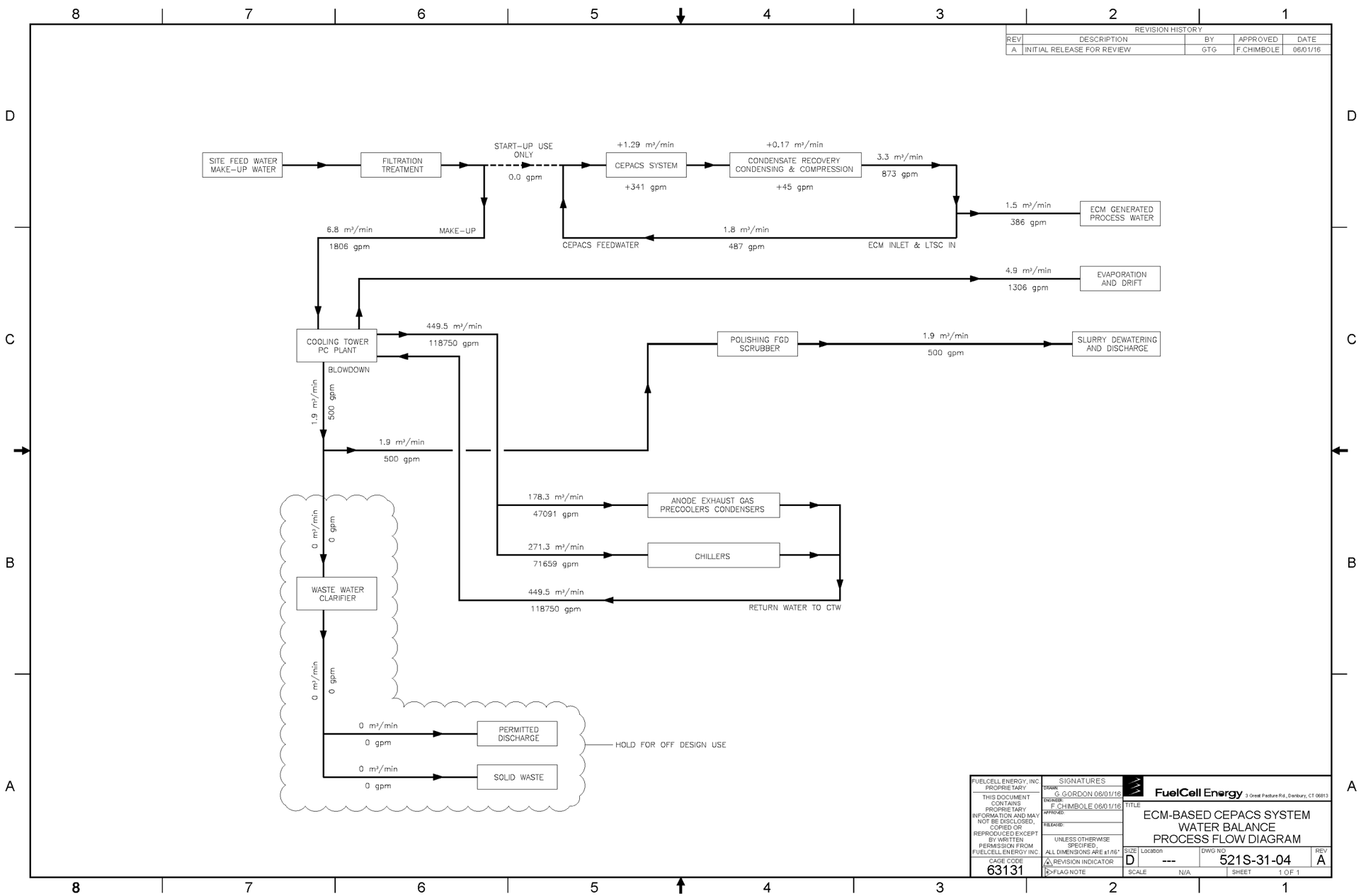

Figure 2-1. Water Block Flow Diagram for the CEPACS System

3.0 ECONOMIC FEASIBILITY

The cost estimate for the CO_2 capture system was generated utilizing the guidelines set forth in the DOE - NETL document mentioned under 'Experimental Methods' section of this report. The approach taken, and the assumptions used, in the economic feasibility study have been summarized in the Design Basis section (Section 1.1). Cost estimates for all major process equipment and systems were generated from a combination of vendor contacts and URS's historical cost databases. Additional information such as piping and ductwork cost estimation methodology is presented under Section 3.1.

3.1 Case 3 Capital Cost Estimate

Piping and ductwork cost methodology

The piping and ductwork cost estimate was developed utilizing the pipe sizes estimated. Each pipe run was evaluated individually according to the design pressure and temperature to determine the appropriate pipe schedule and materials. In most cases, standard weight pipe was used. For pipe sizes less than 14 inches (35.6 cm) in diameter, the wall thickness is equivalent to Schedule 40. For the larger pipe sizes, standard weight is equivalent to Schedule 20.

When design conditions allowed and wherever possible, ducts were selected in lieu of piping to reduce costs. In every case, the duct was estimated to be 3/16 inch (0.48 cm) wall carbon steel plate with stiffeners spaced every 36 inches (91 cm), a configuration that is quite common for ductwork in power plants. The use of stiffened carbon steel plate in lieu of piping was also viewed to be a lower overall cost approach to accommodate the fairly significant temperatures. The ASME B31.3 pipe code cautions against the use of carbon steel at temperatures above 800°F (427°C), citing an increased likelihood of inter-granular phase transformation and the potential for graphitization of the carbon steel. If this occurs, the material becomes weakened and in some cases more brittle, requiring additional reinforcement, such as external stiffeners. As an alternative, ASME B31.3 recommends utilizing higher grade materials such as stainless or other alloys. Given the increased cost associated with these materials, URS elected to estimate these duct runs utilizing the carbon steel and external stiffener configuration.

Several assumptions/good design practices were employed to determine the cross sectional area of the ductwork and estimate the material costs. Velocities in the ductwork were assumed to be limited to 60 ft/sec (18.3 m/s). This velocity is typical for FGD ductwork systems, as well as compressed air piping, to stay below acoustic velocity limits and avoid excessive noise generation in the ductwork and/or pipes. Wherever possible, factory-fabricated ducting (spiral wound round or rectangular) was utilized. In cases where factory-fabricated ducting was not large enough to accommodate the gas flows, multiple ducts were selected rather than using a single field-erected duct. This methodology was developed as a cost reduction measure based on design guidance and quotations from ducting suppliers. As fittings add significantly to the ducting costs, effort was taken to maximize the use of straight runs.

Case 3 Capital Cost

The capital cost for Case 3 (PC + CEPACS-based CO_2 capture) includes two components: the CEPACS system cost and the PC plant cost. The PC plant cost estimate was taken directly from the Case 9 estimate as reported in the DOE Baseline Bituminous report [5]. Table 3-1 shows the capital cost estimate for the CEPACS plant which was developed by URS in 2013/14 dollars. The TOC (total overnight cost) was then de-escalated to 2007

dollars. Table 3-2 shows the complete Case 3 plant capital cost summary (PC + CEPACS) organized by detailed cost accounts along with owner's costs, TOC, and TASC (total as-spent cost). Cost savings of approximately $20 million were estimated based on redundancy of equipment and utilities when combining the cost estimate for the CEPACS Plant (layout described in Section 1.3.2) with Case 9 of the DOE report. These estimated savings are primarily attributed to synergies that can be realized by centrally locating redundant equipment systems such as Limestone Feeders/Conveyors/Day Bins, Ball Mills, Dewatering equipment, electrical distribution and plant utilities. These cost savings were deducted from the combined cost estimate. The values in Table 3-2 are presented in 2007 dollars. The estimated TOC of the subcritical PC power plant with the CEPACS system for CO_2 capture is $2,297/kW.

Table 3-1. Capital Cost Estimate for CEPACS System, 2014 USD

Tag No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost, $	Eng'g CM H.O. & Fee	Contingencies Process	Contingencies oject	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
100-HX-10	Boiler Equipment	$479,566	$0	$7,957	$9,341	$496,865	$46,705	$24,843.23	15%	$85,262	$653,675	$0.73
	Boiler Civil	$0	$13,477	$17,946	$21,067	$52,489	$4,934	$2,624	15%	$9,007	$69,054	$0.08
	Boiler Piping	$0	$571,540	$254,615	$298,895	$1,125,050	$105,755	$56,253	15%	$193,059	$1,480,116	$1.64
	SUBTOTAL 1.	**$479,566**	**$585,017**	**$280,518**	**$329,303**	**$1,674,404**	**$157,394**	**$83,720**		**$287,328**	**$2,202,846**	**$2**
200-RR-10	Natural Gas Vessel (with d	$152,326	$0	$227,341	$266,879	$646,546	$60,775	$32,327.31	15%	$110,947	$850,596	$0.94
	Natural Gas Vessel Civil	$0	$29,087	$40,685	$47,760	$117,532	$11,048	$5,877	15%	$20,168	$154,625	$0.17
	SUBTOTAL 2.	**$152,326**	**$29,087**	**$268,026**	**$314,639**	**$764,078**	**$71,823**	**$38,204**		**$131,116**	**$1,005,221**	**$1**
200-HX-10	Fuel Preheater	$5,405,186	$0	$51,343	$60,272	$5,516,800	$518,579	$275,840.01	15%	$946,683	$7,257,902	$8.06
	Fuel Preheater Civil		$47,175	$83,002	$97,438	$227,615	$21,396	$11,381	15%	$39,059	$299,450	$0.33
	Fuel Preheater Electrical		$0	$0	$0	$0	$0	$0	15%	$0	$0	$0.00
	SUBTOTAL 3.	**$5,405,186**	**$47,175**	**$134,345**	**$157,710**	**$5,744,415**	**$539,975**	**$287,221**		**$985,742**	**$7,557,353**	**$8**
200-ECM-1	Electrochemical Module, I	$227,520,872	$21,565,291	$4,431,904	$5,202,670	$258,720,737	$24,319,749	$12,936,037	15%	$44,396,478	$340,373,001	$377.85
			$0	$0	$0	$0	$0	$0	15%	$0	$0	$0.00
		$0	$0	$0	$0	$0	$0	$0	15%	$0	$0	$0.00
	SUBTOTAL 4.	**$227,520,872**	**$21,565,291**	**$4,431,904**	**$5,202,670**	**$258,720,737**	**$24,319,749**	**$12,936,037**		**$44,396,478**	**$340,373,001**	**$378**
300-BL-103	Flue Gas Blower	$2,400,000	$0	$964,399	$1,132,121	$4,496,521	$422,673	$224,826.03	15%	$771,603	$5,915,622	$6.57
	Flue Gas Blower Civil		$220,651	$320,522	$376,265	$917,438	$86,239	$45,872	15%	$157,432	$1,206,981	$1.34
	Flue Gas Blower Electrical		$174,088	$305,877	$359,073	$839,039	$78,870	$41,952	15%	$143,979	$1,103,840	$1.23
	SUBTOTAL 5.	**$2,400,000**	**$394,740**	**$1,590,799**	**$1,867,459**	**$6,252,998**	**$587,782**	**$312,650**		**$1,073,014**	**$8,226,444**	**$9**
300-HX-10	Flue Gas Heater	$11,417,140	$0	$191,164	$224,410	$11,832,715	$1,112,275	$591,635.73	15%	$2,030,494	$15,567,119	$17.28
	Flue Gas Heater Civil		$47,175	$83,002	$97,438	$227,615	$21,396	$11,381	15%	$39,059	$299,450	$0.33
	Flue Gas Heater Electrical		$0	$0	$0	$0	$0	$0	15%	$0	$0	$0.00
	SUBTOTAL 6.	**$11,417,140**	**$47,175**	**$274,167**	**$321,848**	**$12,060,329**	**$1,133,671**	**$603,016**		**$2,069,553**	**$15,866,569**	**$18**
300-HE-10	Start Up Duct Burner	$166,593	$0	$77,581	$91,073	$335,247	$31,513	$16,762.36	15%	$57,528	$441,051	$0.49
	SUBTOTAL 7.	**$166,593**	**$0**	**$77,581**	**$91,073**	**$335,247**	**$31,513**	**$16,762**		**$57,528**	**$441,051**	**$0**
300-RR-10	Oxidizer (including catalys	$349,399	$0	$2,394	$2,810	$354,603	$33,333	$17,730.15	15%	$60,850	$466,516	$0.52
	Oxidizer Civil		$13,309	$21,300	$25,005	$59,614	$5,604	$2,981	15%	$10,230	$78,428	$0.09
	Oxidizer Electrical		$0	$0	$0	$0	$0	$0	15%	$0	$0	$0.00
	SUBTOTAL 8.	**$349,399**	**$13,309**	**$23,694**	**$27,815**	**$414,217**	**$38,936**	**$20,711**		**$71,080**	**$544,944**	**$1**
400-RR-10	LTSC (including catalyst)	$18,361,145	$0	$71,538	$83,980	$18,516,663	$1,740,566	$925,833.14	15%	$3,177,459	$24,360,522	$27.04
	LTSC Civil	$0	$69,231	$121,516	$142,649	$333,396	$31,339	$16,670	15%	$57,211	$438,616	$0.49
	LTSC Piping	$0	$0	$0	$0	$0	$0	$0	15%	$0	$0	$0.00
	SUBTOTAL 9.	**$18,361,145**	**$69,231**	**$193,054**	**$226,629**	**$18,850,059**	**$1,771,906**	**$942,503**		**$3,234,670**	**$24,799,137**	**$28**
400-HX-10	Condenser	$1,511,449	$0	$5,134	$6,027	$1,522,611	$143,125	$76,130.53	15%	$261,280	$2,003,147	$2.22
	Condenser Civil		$4,717	$8,300	$9,744	$22,762	$2,140	$1,138	15%	$3,906	$29,945	$0.03
	Condenser Electrical		$0	$0	$0	$0						
	SUBTOTAL 10.	**$1,511,449**	**$4,717**	**$13,435**	**$15,771**	**$1,545,372**	**$145,265**	**$77,269**		**$265,186**	**$2,033,092**	**$2**
500-FL-101	Air Filter	$1,396,528	$0	$314,303	$368,965	$2,079,796	$195,501	$103,989.78	15%	$356,893	$2,736,179	$3.04
	Air Filter Civil	$0	$10,762	$17,514	$20,559	$48,835	$4,590	$2,442	15%	$8,380	$64,247	$0.07
	Air Filter Steel	$0	$156,643	$72,440	$85,039	$314,122	$29,527	$15,706	15%	$53,903	$413,259	$0.46
	SUBTOTAL 11.	**$1,396,528**	**$167,405**	**$404,257**	**$474,563**	**$2,442,752**	**$229,619**	**$122,138**		**$419,176**	**$3,213,685**	**$4**
500-BL-101	Air Blower	$5,143,220	$0	$411,342	$482,880	$6,037,443	$567,520	$301,872.13	15%	$1,036,025	$7,942,860	$8.82
	Air Blower Civil		$82,093	$129,408	$151,914	$363,416	$34,161	$18,171	15%	$62,362	$478,110	$0.53
	Air Blower Electrical		$87,044	$152,939	$179,537	$419,520	$39,435	$20,976	15%	$71,990	$551,920	$0.61
	SUBTOTAL 12.	**$5,143,220**	**$169,137**	**$693,690**	**$814,331**	**$6,820,378**	**$641,116**	**$341,019**		**$1,170,377**	**$8,972,889**	**$10**

Table 3-1. Capital Cost Estimate for CEPACS System, 2014 USD (continued)

Tag No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost, $	Eng'g CM H.O. & Fee	Contingencies Process	oject	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
500-HX-10	Anode Exit Cooler	$12,340,643	$0	$51,343	$60,272	$12,452,258	$1,170,512	$622,612.90	15%	$2,136,807	$16,382,191	$18.19
	Anode Exit Cooler Civil		$47,175	$83,002	$97,438	$227,615	$21,396	$11,381	15%	$39,059	$299,450	$0.33
	Anode Exit Electrical		$0	$0	$0	$0	$0	$0	15%	$0	$0	$0.00
	SUBTOTAL 13.	**$12,340,643**	**$47,175**	**$134,345**	**$157,710**	**$12,679,873**	**$1,191,908**	**$633,994**		**$2,175,866**	**$16,681,641**	**$19**
500-HX-10	Air Preheater	$16,920,000	$0	$51,343	$60,272	$17,031,615	$1,600,972	$851,580.73	15%	$2,922,625	$22,406,792	$24.87
	Air Preheater Civil		$47,175	$83,002	$97,438	$227,615	$21,396	$11,381	15%	$39,059	$299,450	$0.33
	Air Preheater Electrical		$0									
	SUBTOTAL 14.	**$16,920,000**	**$47,175**	**$134,345**	**$157,710**	**$17,259,229**	**$1,622,368**	**$862,961**		**$2,961,684**	**$22,706,242**	**$25**
100-PU-10	Condensate Pump #1	$113,772	$0	$7,586	$8,905	$130,263	$12,245	$6,513.14	15%	$22,353	$171,374	$0.19
	Condensate Pump #1 Civil	$0	$829	$3,106	$3,646	$7,581	$713	$379	15%	$1,301	$9,973	$0.01
	Condensate #1 Electrical	$0	$7,859	$32,080	$37,659	$77,598	$7,294	$3,880	15%	$13,316	$102,088	$0.11
	SUBTOTAL 15.	**$113,772**	**$8,689**	**$42,771**	**$50,209**	**$215,441**	**$20,251**	**$10,772**		**$36,970**	**$283,435**	**$0**
100-PU-10	Condensate Pump #2	$117,334	$0	$5,372	$6,306	$129,013	$12,127	$6,450.64	15%	$22,139	$169,729	$0.19
	Condensate Pump #2 Civil	$0	$472	$2,174	$2,553	$5,199	$489	$260	15%	$892	$6,839	$0.01
	Condensate #2 Electrical	$0	$7,859	$32,080	$37,659	$77,598	$7,294	$3,880	15%	$13,316	$102,088	$0.11
	SUBTOTAL 16.	**$117,334**	**$8,331**	**$39,626**	**$46,518**	**$211,809**	**$19,910**	**$10,590**		**$36,346**	**$278,656**	**$0**
100-PU-10	Feedwater Pumps Equipm	$116,465	$0	$8,122	$9,534	$134,121	$12,607	$6,706.04	15%	$23,015	$176,449	$0.20
	Feedwater Pumps Civil	$0	$913	$3,305	$3,880	$8,098	$761	$405	15%	$1,390	$10,654	$0.01
	Feedwater Pumps Electric	$0	$7,859	$32,080	$37,659	$77,598	$7,294	$3,880	15%	$13,316	$102,088	$0.11
	SUBTOTAL 17.	**$116,465**	**$8,773**	**$43,506**	**$51,073**	**$219,817**	**$20,663**	**$10,991**		**$37,721**	**$289,191**	**$0**
100-TK-10	Water Collection Tank	$80,710	$0	$7,123	$8,362	$96,196	$9,042	$4,810	15%	$16,507	$126,555	$0.14
	Water Collection Civil	$0	$8,654	$15,189	$17,831	$41,674	$3,917	$2,084	15%	$7,151	$54,827	$0.06
	Water Collection Piping	$0	$494,444	$120,697	$141,688	$756,829	$71,142	$37,841	15%	$129,872	$995,684	$1.11
	SUBTOTAL 18.	**$80,710**	**$503,098**	**$143,010**	**$167,881**	**$894,699**	**$84,102**	**$44,735**		**$153,530**	**$1,177,066**	**$1**
300-BL-10	FD Fan	$1,086,937	$0	$13,486	$15,832	$1,116,255	$104,928	$55,812.77	15%	$191,549	$1,468,546	$1.63
	FD Fan Civil		$20,708	$24,530	$28,796	$74,033	$6,959	$3,702	15%	$12,704	$97,398	$0.11
	FD Fan Electrical		$8,704	$15,294	$17,954	$41,952	$3,943	$2,098	15%	$7,199	$55,192	$0.06
	SUBTOTAL 19.	**$1,086,937**	**$29,412**	**$53,310**	**$62,581**	**$1,232,240**	**$115,831**	**$61,612**		**$211,452**	**$1,621,135**	**$2**
300-RR-10	Polishing FGD	$76,074,655	$0	$5,593,234	$6,565,971	$88,233,860	$8,293,983	$4,411,693	15%	$15,140,930	$116,080,466	$128.86
	SUBTOTAL 20.	**$76,074,655**	**$0**	**$5,593,234**	**$6,565,971**	**$88,233,860**	**$8,293,983**	**$4,411,693**		**$15,140,930**	**$116,080,466**	**$129**
400-HX-10	Absorbtion Chiller stage I	$2,327,776	$0	$13,096	$15,373	$2,356,244	$221,487	$117,812.22	15%	$404,332	$3,099,875	$3.44
	Absorbtion Chiller Stage I Civil		$15,592	$20,391	$23,937	$59,921	$5,633	$2,996	15%	$10,282	$78,832	$0.09
	Absorbtion Chiller Stage I Electrical		$0	$0	$0	$0	$0	$0	15%	$0	$0	$0.00
	SUBTOTAL 21.	**$2,327,776**	**$15,592**	**$33,487**	**$39,311**	**$2,416,165**	**$227,120**	**$120,808**		**$414,614**	**$3,178,707**	**$4**
400-HX-10	Interstage Precooler	$2,386,163	$0	$13,096	$15,373	$2,414,632	$226,975	$120,731.58	15%	$414,351	$3,176,689	$3.53
	Interstage Precooler Civil		$15,592	$20,391	$23,937	$59,921	$5,633	$2,996	15%	$10,282	$78,832	$0.09
	Interstage Precooler Electrical		$0									
	SUBTOTAL 22.	**$2,386,163**	**$15,592**	**$33,487**	**$39,311**	**$2,474,552**	**$232,608**	**$123,728**		**$424,633**	**$3,255,521**	**$4**
400-HX-10	CO2 Recycle Heater	$1,471,832	$0	$13,096	$15,373	$1,500,300	$141,028	$75,015.02	15%	$257,452	$1,973,795	$2.19
	CO2 Recycle Heater Civil		$15,592	$20,391	$23,937	$59,921	$5,633	$2,996	15%	$10,282	$78,832	$0.09
	CO2 Recycle Electrical		$0	$0	$0	$0	$0	$0	15%	$0	$0	$0.00
	SUBTOTAL 23.	**$1,471,832**	**$15,592**	**$33,487**	**$39,311**	**$1,560,221**	**$146,661**	**$78,011**		**$267,734**	**$2,052,627**	**$2**
400-HX-10	Chiller Precooler	$2,444,475	$0	$13,096	$15,373	$2,472,944	$232,457	$123,647.21	15%	$424,357	$3,253,405	$3.61
	Chiller Precooler Civil		$15,592	$20,391	$23,937	$59,921	$5,633	$2,996	15%	$10,282	$78,832	$0.09
	Chiller Precooler Electrical		$0	$0	$0	$0	$0	$0	15%	$0	$0	$0.00
	SUBTOTAL 24.	**$2,444,475**	**$15,592**	**$33,487**	**$39,311**	**$2,532,865**	**$238,089**	**$126,643**		**$434,640**	**$3,332,237**	**$4**

Table 3-1. Capital Cost Estimate for CEPACS System, 2014 USD (continued)

Tag		Equipment	Material	Labor		Bare Erected	Eng'g CM	Contingencies			TOTAL PLANT COST	
No.	Item/Description	Cost	Cost	Direct	Indirect	Cost, $	H.O. & Fee	Process	oject	Project	$	$/kW
400-HX-10(	Chiller Inlet Cooler	$892,680	$0	$13,096	$15,373	$921,148	$86,588	$46,057.42	15%	$158,069	$1,211,863	$1.35
	Chiller Inlet Cooler Civil		$15,592	$20,391	$23,937	$59,921	$5,633	$2,996	15%	$10,282	$78,832	$0.09
	Chiller Inlet Cooler Electrical		$0	$0	$0	$0	$0	$0	15%	$0	$0	$0.00
	SUBTOTAL 25.	**$892,680**	**$15,592**	**$33,487**	**$39,311**	**$981,069**	**$92,221**	**$49,053**		**$168,351**	**$1,290,695**	**$1**
400-HX-10	Absorbtion Chiller Stage 2	$32,588,858	$0	$731,165	$858,324	$34,178,348	$3,212,765	$1,708,917.40	15%	$5,865,005	$44,965,035	$49.92
	Absorbtion Chiller Stage 2 Civil		$610,376	$738,913	$867,420	$2,216,708	$208,371	$110,835	15%	$380,387	$2,916,302	$3.24
	Absorbtion Chiller Stage 2 Electrical		$0	$0	$0	$0	$0	$0	15%	$0	$0	$0.00
	SUBTOTAL 26.	**$32,588,858**	**$610,376**	**$1,470,078**	**$1,725,744**	**$36,395,056**	**$3,421,135**	**$1,819,753**		**$6,245,392**	**$47,881,336**	**$53**
400-HX-10	CO2 Reheater	$2,344,727	$0	$13,096	$15,373	$2,373,196	$223,080	$118,659.81	15%	$407,240	$3,122,177	$3.47
	CO2 Reheater Civil		$15,592	$20,391	$23,937	$59,921	$5,633	$2,996	15%	$10,282	$78,832	$0.09
	CO2 Reheater Electrical		$0									
	SUBTOTAL 27.	**$2,344,727**	**$15,592**	**$33,487**	**$39,311**	**$2,433,117**	**$228,713**	**$121,656**		**$417,523**	**$3,201,009**	**$4**
400-SP-101	Water Separator #1	$289,601	$0	$239,090	$280,671	$809,363	$76,080	$40,468.13	15%	$138,887	$1,064,797	$1.18
	Water Separator #1 Civil	$0	$20,568	$30,178	$35,426	$86,172	$8,100	$4,309	15%	$14,787	$113,369	$0.13
	SUBTOTAL 28.	**$289,601**	**$20,568**	**$269,269**	**$316,098**	**$895,535**	**$84,180**	**$44,777**		**$153,674**	**$1,178,166**	**$1**
400-SP-102	Water Seperator #2	$237,525	$0	$196,599	$230,791	$664,914	$62,502	$33,245.72	15%	$114,099	$874,761	$0.97
	Water seperator #2 Civil	$0	$18,404	$27,439	$32,211	$78,054	$7,337	$3,903	15%	$13,394	$102,688	$0.11
	SUBTOTAL 29.	**$237,525**	**$18,404**	**$224,038**	**$263,001**	**$742,968**	**$69,839**	**$37,148**		**$127,493**	**$977,449**	**$1**
400-SP-103	Water Separator #3	$253,136	$0	$65,533	$76,930	$395,599	$37,186	$19,779.97	15%	$67,885	$520,451	$0.58
	Water Separator #3 Civil	$0	$18,404	$27,439	$32,211	$78,054	$7,337	$3,903	15%	$13,394	$102,688	$0.11
	SUBTOTAL 30.	**$253,136**	**$18,404**	**$92,972**	**$109,141**	**$473,653**	**$44,523**	**$23,683**		**$81,279**	**$623,138**	**$1**
400-CR-10	Compressor	$27,523,639	$0	$278,224	$326,611	$28,128,473	$2,644,077	$1,406,423.67	15%	$4,826,846	$37,005,820	$41.08
	Compressor Civil		$207,141	$204,745	$240,353	$652,240	$61,311	$32,612	15%	$111,924	$858,087	$0.95
	Compressor Electrical		$60,820	$65,995	$77,472	$204,287	$19,203	$10,214	15%	$35,056	$268,760	$0.30
	SUBTOTAL 31.	**$27,523,639**	**$267,962**	**$548,964**	**$644,436**	**$28,985,000**	**$2,724,590**	**$1,449,250**		**$4,973,826**	**$38,132,666**	**$42**
400-SP-109	CO2 seperator	$335,618	$0	$37,584	$44,120	$417,322	$39,228	$20,866.11	15%	$71,612	$549,029	$0.61
	CO2 Seperator Civil	$0	$8,654	$15,189	$17,831	$41,674	$3,917	$2,084	15%	$7,151	$54,827	$0.06
	SUBTOTAL 32.	**$335,618**	**$8,654**	**$52,773**	**$61,951**	**$458,997**	**$43,146**	**$22,950**		**$78,764**	**$603,856**	**$1**
400-PU-12(	CO2 Pump	$1,726,725	$0	$64,651	$75,894	$1,867,271	$175,523	$93,363.54	15%	$320,424	$2,456,581	$2.73
	CO2 Pump Civil	$0	$1,270	$3,327	$3,906	$8,502	$799	$425	15%	$1,459	$11,186	$0.01
	CO2 Pump Electrical	$0	$7,859	$32,080	$37,659	$77,598	$7,294	$3,880	15%	$13,316	$102,088	$0.11
	SUBTOTAL 33.	**$1,726,725**	**$9,129**	**$100,058**	**$117,459**	**$1,953,371**	**$183,617**	**$97,669**		**$335,198**	**$2,569,855**	**$3**
HVRG-1	HVRG 1	Included with 400-HX-107		$0	$0	$0	$0	$0.00	15%	$0	$0	$0.00
	HVRG 1 Civil			$0	$0	$0	$0	$0	15%	$0	$0	$0.00
	HVRG 1 Electrical			$0	$0	$0	$0	$0	15%	$0	$0	$0.00
	SUBTOTAL 34.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**		**$0**	**$0**	**$0**
HVRG-2	HVRG 2	Included with 400-HX-107		$0	$0	$0	$0	$0	15%	$0	$0	$0.00
	HVRG 2 Civil			$0	$0	$0	$0	$0	15%	$0	$0	$0.00
	HVRG 2 Electrical			$0	$0	$0	$0	$0	15%	$0	$0	$0.00
	SUBTOTAL 35.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**		**$0**	**$0**	**$0**

Table 3-1. Capital Cost Estimate for CEPACS System, 2014 USD (continued)

Tag No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost, $	Eng'g CM H.O. & Fee	Contingencies Process	Contingencies oject	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
Common	Bus Duct	$0	$1,207,222	$148,041	$173,787	$1,529,050	$143,731	$76,452	15%	$262,385	$2,011,618	$2.23
	Piping and Ductwork (see	$0	$50,091,441	$42,698,650	$50,124,502	$142,914,593	$13,433,972	$7,145,730	15%	$24,524,144	$188,018,438	$208.72
	Coatings	$0	$18,895	$32,605	$38,276	$89,776	$8,439	$4,489	15%	$15,406	$118,109	$0.13
	DCS	$0	$3,500,000	$0	$0	$3,500,000	$329,000	$175,000	15%	$600,600	$4,604,600	$5.11
	Ductbank	$0	Incl Elsewhere			$0	$0	$0	15%	$0	$0	$0.00
	Electrical building	$0	$283,341	$293,759	$344,848	$921,949	$86,663	$46,097	15%	$158,206	$1,212,916	$1.35
	Grounding	$0	Incl Elsewhere			$0	$0	$0	15%	$0	$0	$0.00
	Instrumentation	$0	$1,458,366	$350,610	$411,585	$2,220,561	$208,733	$111,028	15%	$381,048	$2,921,370	$3.24
	Insulation	$0	Incl Elsewhere			$0	$0	$0	15%	$0	$0	$0.00
	Lighting/Recepticals	$0	$1,877,952	$3,594,320	$4,219,419	$9,691,690	$911,019	$484,585	15%	$1,663,094	$12,750,388	$14.15
	MCC	$0	$1,100,118	$293,250	$344,250	$1,737,618	$163,336	$86,881	15%	$298,175	$2,286,010	$2.54
	PipeRack	$0	$5,162,935	$2,091,212	$2,454,901	$9,709,048	$912,650	$485,452	15%	$1,666,073	$12,773,223	$14.18
	SiteWork	$0	$4,416,151	$1,455,402	$1,708,516	$7,580,069	$712,526	$379,003	15%	$1,300,740	$9,972,338	$11.07
	Switchgear/Inverters	$0	$7,300,000	$328,440	$385,560	$8,014,000	$753,316	$400,700	15%	$1,375,202	$10,543,218	$11.70
	Transformers	$0	$14,266,065	$1,195,142	$1,402,993	$16,864,201	$1,585,235	$843,210	15%	$2,893,897	$22,186,543	$24.63
	Deep Foundations	$0	$9,689,861	$5,333,251	$6,260,772	$21,283,884	$2,000,685	$1,064,194	15%	$3,652,314	$28,001,078	$31.08
	BOP Piping and Testing	$0	$6,941,622	$17,970,999	$21,096,390	$46,009,010	$4,324,847	$2,300,451	15%	$7,895,146	$60,529,454	$67.19
	Drainage Pipe	$0	$234,115	$206,780	$242,742	$683,637	$64,262	$34,182	15%	$117,312	$899,393	$1.00
	Platforms	$0	$1,218,395	$953,936	$1,119,838	$3,292,169	$309,464	$164,608	15%	$564,936	$4,331,178	$4.81
	SUBTOTAL 36.	**$0**	**$108,766,479**	**$76,946,397**	**$90,328,379**	**$276,041,255**	**$25,947,878**	**$13,802,063**		**$47,368,679**	**$363,159,875**	**$403**
	TOTAL COST	**$455,976,695**	**$133,558,466**	**$94,475,085**	**$110,905,535**	**$794,915,782**	**$74,722,084**	**$39,745,789**		**$136,407,548**	**$1,045,791,203**	**$1,161**
	Owner's Costs											
	Preproduction Costs											
	6 Months All Labor										$1,124,500	$1
	1 Month Maintenance Materials										$982,559	$1
	1 Month Non-fuel Consumables										$10,000	$0
	1 Month Waste Disposal										$0	$0
	aining/Plant Personel Project Support										$93,600	$0
	5% of 1 Months Fuel Cost at 100% CF										$4,022,742	$4
	2% of TPC										$20,915,824	$23
	Total										**$27,149,224**	**$30**
	Inventory Capital											
	y of fuel and consumables at 100% CF										$20,000	$0
	0.5% of TPC (spare parts)										$5,228,956	$6
	Total										**$5,248,956**	**$6**
	Initial Cost for Catalyst and Chemicals										$2,231,309	$2
	Land										$54,720	$0
	Other Owner's Costs										$156,868,680	$174
	Financing										$28,236,362	$31
	Total Overnight Costs (TOC)										**$1,265,580,455**	**$1,405**
	TOC De-escalation							Deescalation 18% or 3.6 per year			(277,547,407)	($308.10)
	TOC 2007 Dollars										**$988,033,048**	**$1,097**
	TASC Multiplier							(IOU, high-risk, 35 year)			1.140	
	Total As-Spent Cost (TASC)										**$1,126,357,675**	**$1,250**

Table 3-2. Case 3 (PC + CEPACS) Capital Cost Estimate, 2007 USD

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	$3,508,000	$0	$1,602,000	$0		$5,110,000	$480,340	$0	$838,551	$6,428,891	$7
1.2	Coal Stackout & Reclaim	$4,533,000	$0	$1,027,000	$0		$5,560,000	$522,640	$0	$912,396	$6,995,036	$8
1.3	Coal Conveyors	$4,215,000	$0	$1,016,000	$0		$5,231,000	$491,714	$0	$858,407	$6,581,121	$7
1.4	Other Coal Handling	$1,103,000	$0	$235,000	$0		$1,338,000	$125,772	$0	$219,566	$1,683,338	$2
1.5	Sorbent Receive & Unload	$140,000	$0	$42,000	$0		$182,000	$17,108	$0	$29,866	$228,974	$0
1.6	Sorbent Stackout & Reclaim	$1,469,000	$0	$269,327	$0		$1,738,327	$163,403	$0	$440,609	$2,342,339	$3
1.7	Sorbent Conveyors	$510,000	$110,185	$125,296	$0		$745,481	$70,075	$0	$194,294	$1,009,851	$1
1.8	Other Sorbent Handling	$239,000	$56,207	$125,609	$0		$420,816	$39,557	$0	$141,290	$601,663	$1
1.9	Coal & Sorbent Hnd.Foundations	$0	$2,058,000	$2,596,386	$0		$4,654,386	$437,512	$0	$1,598,826	$6,690,724	$7
	SUBTOTAL 1.	**$15,717,000**	**$2,224,392**	**$7,038,619**	**$0**	**$0**	**$24,980,011**	**$2,348,121**	**$0**	**$5,233,805**	**$32,561,937**	**$36**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	$2,014,000	$0	$393,000	$0		$2,407,000	$226,258	$0	$394,989	$3,028,247	$3
2.2	Coal Conveyor to Storage	$5,158,000	$0	$1,126,000	$0		$6,284,000	$590,696	$0	$1,031,204	$7,905,900	$9
2.3	Coal Injection System	$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
2.5	Sorbent Prep Equipment	$2,657,000	$114,354	$551,791	$0		$3,323,144	$312,376	$0	$791,618	$4,427,138	$5
2.6	Sorbent Storage & Feed	$438,929	$6,198	$116,768	$12,953		$574,848	$54,036	$16,237	$161,243	$806,363	$1
2.7	Sorbent Injection System	$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
2.9	Coal & Sorbent Feed Foundation	$0	$299,000	$251,064	$0		$550,064	$51,706	$0	$150,644	$752,414	$1
	SUBTOTAL 2.	**$10,267,929**	**$419,552**	**$2,438,622**	**$12,953**	**$0**	**$13,139,056**	**$1,235,071**	**$16,237**	**$2,529,698**	**$16,920,063**	**$19**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	Feedwater System	$13,029,496	$15,940	$4,500,719	$91,339		$17,637,494	$1,657,924	$25,365	$3,675,631	$22,996,415	$26
3.2	Water Makeup & Pretreating	$3,814,277	$312,500	$1,300,234	$104,279		$5,531,290	$519,941	$35,072	$1,494,179	$7,580,482	$8
3.3	Other Feedwater Subsystems	$5,318,000	$0	$2,248,000	$0		$7,566,000	$711,204	$0	$1,241,699	$9,518,903	$11
3.4	Service Water Systems	$931,000	$0	$507,000	$0		$1,438,000	$135,172	$0	$314,634	$1,887,806	$2
3.5	Other Boiler Plant Systems	$6,634,980	$458,653	$6,398,926	$258,174		$13,750,733	$1,292,569	$65,637	$2,266,418	$17,375,356	$19
3.6	FO Supply Sys & Nat Gas	$4,613,089	$59,789	$635,459	$370,322		$5,678,658	$533,794	$255,133	$970,368	$7,437,953	$8
3.7	Waste Treatment Equipment	$3,221,000	$0	$1,836,000	$0		$5,057,000	$475,358	$0	$1,106,598	$6,638,956	$7
3.8	Misc. Equip.(cranes, AirComp., Comm.)	$1,965,000	$0	$599,994	$0		$2,564,994	$241,109	$0	$775,611	$3,581,715	$4
	SUBTOTAL 3.	**$39,526,842**	**$846,882**	**$18,026,332**	**$824,114**	**$0**	**$59,224,170**	**$5,567,072**	**$381,207**	**$11,845,138**	**$77,017,587**	**$85**
4	PC BOILER & ACCESSORIES											
4.1	PC Boiler & Accessories	$134,824,000	$0	$86,704,000	$0		$221,528,000	$20,823,632	$0	$24,235,163	$266,586,795	$296
4.2	SCR (w/4.1)	$0	$0	$0	$0		$0	$0	$0	$0	$0	$0
4.3	Open	$0	$0	$0	$0		$0	$0	$0	$0	$0	$0
4.4	Boiler BoP (w/ ID Fans)	$130,609	$0	$60,824	$71,402		$262,834	$24,706	$13,142	$45,102	$345,784	$0
4.5	Primary Air System	w/4.1	$0	w/4.1	$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
4.8	Major Component Rigging		w/4.1	w/4.1	$0		$0	$0	$0	$0	$0	$0
4.9	Boiler Foundations		w/14.1	w/14.1	$0		$0	$0	$0	$0	$0	$0
	SUBTOTAL 4.	**$134,954,609**	**$0**	**$86,764,824**	**$71,402**	**$0**	**$221,790,834**	**$20,848,338**	**$13,142**	**$24,280,265**	**$266,932,579**	**$296**

Table 3-2. Case 3 (PC + CEPACS) Capital Cost Estimate, 2007 USD (continued)

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
5	FLUE GAS CLEANUP											
5.1	Absorber Vessels & Accessories	$58,362,000	$0	$12,564,000	$0		$70,926,000	$6,667,044	$0	$7,759,304	$85,352,348	$95
5.2	Other FGD	$16,881,481	$192,648	$4,251,594	$939,828		$22,265,551	$2,092,962	$788,428	$3,416,655	$28,563,595	$32
5.3	Bag House & Accessories	$18,374,600	$309,476	$11,714,186	$1,464,088		$31,862,350	$2,995,061	$245,118	$3,790,667	$38,893,196	$43
5.4	Other Particulate Removal Materials	$2,210,878	$131,245	$1,510,937	$372,057		$4,225,118	$397,161	$95,756	$581,348	$5,299,383	$6
5.5	Gypsum Dewatering System	$2,532,000	$0	$429,942	$0		$2,961,942	$278,423	$0	$611,984	$3,852,348	$4
5.6	Mercury Removal System	$0	$0	$0	$0		$0	$0	$0	$0	$0	$0
5.7	Polishing FGD	$59,642,529	$0	$4,385,096	$5,147,721		$69,175,346	$6,502,483	$3,458,767	$11,870,489	$91,007,086	$101
5.9	Open	$0	$0	$0	$0		$0	$0	$0	$0	$0	$0
	SUBTOTAL 5.	**$158,003,488**	**$633,369**	**$34,855,756**	**$7,923,694**	**$0**	**$201,416,308**	**$18,933,133**	**$4,588,068**	**$28,030,448**	**$252,967,957**	**$281**
5B	CO_2 REMOVAL & COMPRESSION											
5B.1	CO_2 Removal System	$19,323,463	$87,600	$303,907	$356,760		$20,071,730	$1,886,743	$1,003,587	$3,444,309	$26,406,368	$29
5B.2	CO_2 Compression & Drying	$52,602,856	$770,273	$2,121,332	$2,490,260		$57,984,722	$5,450,564	$2,899,236	$9,950,178	$76,284,700	$85
	SUBTOTAL 5B.	**$71,926,320**	**$857,874**	**$2,425,239**	**$2,847,020**	**$0**	**$78,056,452**	**$7,337,306**	**$3,902,823**	**$13,394,487**	**$102,691,068**	**$114**
5C	Electrochemical Module											
5C.1	Electrochemical Module	$202,446,566	$16,907,188	$3,570,951	$4,191,986		$227,116,691	$21,348,969	$11,355,835	$38,973,224	$298,794,719	$332
5C.2	Electrochemical Module Civil	$0	$7,688,113	$4,341,611	$5,096,674		$17,126,397	$1,609,881	$856,320	$2,938,890	$22,531,489	$25
5C.3	Electrochemical Module Piping	$0	$0	$0	$0		$0	$0	$0	$0	$0	$0
	SUBTOTAL 5C	**$202,446,566**	**$24,595,301**	**$7,912,562**	**$9,288,660**	**$0**	**$244,243,089**	**$22,958,850**	**$12,212,154**	**$41,912,114**	**$321,326,208**	**$357**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	N/A		N/A			$0	$0	$0	$0	$0	$0
6.2	Open						$0	$0	$0	$0	$0	$0
6.3	Compressed Air Piping						$0	$0	$0	$0	$0	$0
6.4	Combustion Turbine Foundations						$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
7.2	HRSG System	$0	$0	$0	$0		$0	$0	$0	$0	$0	$0
7.3	Ductwork	$9,097,000	$0	$5,845,000	$0		$14,942,000	$1,404,548	$0	$2,451,982	$18,798,530	$21
7.4	Stack	$9,145,000	$0	$5,351,000	$0		$14,496,000	$1,362,624	$0	$1,585,862	$17,444,486	$19
7.9	Duct & Stack Foundations	$0	$1,049,000	$1,192,000	$0		$2,241,000	$210,654	$0	$489,938	$2,941,592	$3
	SUBTOTAL 7.	**$18,242,000**	**$1,049,000**	**$12,388,000**	**$0**	**$0**	**$31,679,000**	**$2,977,826**	**$0**	**$4,527,783**	**$39,184,609**	**$43**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$49,912,000	$0	$6,242,000	$0	$0	$56,154,000	$5,278,476	$0	$6,142,796	$67,575,272	$75
8.2	Turbine Plant Auxiliaries	$348,000	$0	$746,000	$0	$0	$1,094,000	$102,836	$0	$119,325	$1,316,161	$1
8.3	Condenser & Auxiliaries	$8,435,976	$3,699	$2,305,533	$12,364	$0	$10,757,572	$1,011,212	$60,579	$1,252,567	$13,081,929	$15
8.4	Steam Piping	$16,005,000	$0	$7,891,000	$0	$0	$23,896,000	$2,246,224	$0	$3,920,896	$30,063,120	$33
8.9	TG Foundations	$0	$1,092,000	$1,726,000	$0	$0	$2,818,000	$264,892	$0	$616,398	$3,699,290	$4
	SUBTOTAL 8.	**$74,700,976**	**$1,095,699**	**$18,910,533**	**$12,364**	**$0**	**$94,719,572**	**$8,903,640**	**$60,579**	**$12,051,982**	**$115,735,772**	**$128**

Table 3-2. Case 3 (PC + CEPACS) Capital Cost Estimate, 2007 USD (continued)

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
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$13,033,000	$0	$4,057,908	$0	$0	$17,090,908	$1,606,545	$0	$1,403,493	$20,100,946	$22
9.2	Circulating Water Pumps	$2,783,000	$0	$175,221	$0	$0	$2,958,221	$278,073	$0	$236,296	$3,472,590	$4
9.3	Circ.Water System Auxiliaries	$531,000	$0	$71,000	$0	$0	$602,000	$56,588	$0	$65,796	$724,384	$1
9.4	Circ.Water Piping	$0	$4,210,000	$4,080,000	$0	$0	$8,290,000	$779,260	$0	$1,360,357	$10,429,617	$12
9.5	Make-up Water System	$462,000	$0	$618,000	$0	$0	$1,080,000	$101,520	$0	$177,126	$1,358,646	$2
9.6	Component Cooling Water Sys	$421,000	$0	$335,000	$0	$0	$756,000	$71,064	$0	$124,028	$951,092	$1
9.9	Circ.Water System Foundations & Structures	$0	$2,500,000	$3,972,000	$0	$0	$6,472,000	$608,368	$0	$1,416,074	$8,496,442	$9
	SUBTOTAL 9.	**$17,230,000**	**$6,710,000**	**$13,309,129**	**$0**	**$0**	**$37,249,129**	**$3,501,418**	**$0**	**$4,783,170**	**$45,533,717**	**$51**
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	$612,000	$0	$1,885,000	$0	$0	$2,497,000	$234,718	$0	$273,172	$3,004,890	$3
10.7	Ash Transport & Feed Equipment	$3,961,000	$0	$4,058,000	$0	$0	$8,019,000	$753,786	$0	$877,279	$9,650,065	$11
10.8	Misc. Ash Handling Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.9	Ash/Spent Sorbent Foundation	$0	$0	$171,000	$0	$0	$171,000	$16,074	$0	$37,415	$224,489	$0
	SUBTOTAL 10.	**$4,573,000**	**$0**	**$6,114,000**	**$0**	**$0**	**$10,687,000**	**$1,004,578**	**$0**	**$1,187,865**	**$12,879,443**	**$14**
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$1,602,000	$0	$260,000	$0	$0	$1,862,000	$175,028	$0	$203,703	$2,240,731	$2
11.2	Station Service Equipment	$2,904,000	$0	$954,000	$0	$0	$3,858,000	$362,652	$0	$422,065	$4,642,717	$5
11.3	Switchgear & Motor Control	$3,339,000	$6,585,692	$1,054,405	$572,171	$0	$11,551,268	$1,085,819	$382,263	$1,739,470	$14,758,821	$16
11.4	Conduit & Cable Tray	$0	$3,039,462	$7,354,064	$136,249	$0	$10,529,775	$989,799	$59,939	$1,736,842	$13,316,355	$15
11.5	Wire & Cable	$0	$3,950,000	$7,625,000	$0	$0	$11,575,000	$1,088,050	$0	$1,899,514	$14,562,564	$16
11.6	Protective Equipment	$270,000	$0	$918,000	$0	$0	$1,188,000	$111,672	$0	$129,569	$1,429,241	$2
11.7	Standby Equipment	$1,279,000	$0	$29,000	$0	$0	$1,308,000	$122,952	$0	$143,189	$1,574,141	$2
11.8	Main Power Transformers	$8,414,000	$11,184,595	$1,108,992	$1,099,947	$0	$21,807,534	$2,049,908	$661,077	$3,208,348	$27,726,866	$31
11.9	Electrical Foundations	$0	$312,000	$765,000	$0	$0	$1,077,000	$101,238	$0	$235,648	$1,413,886	$2
	SUBTOTAL 11.	**$17,808,000**	**$25,071,749**	**$20,068,461**	**$1,808,367**	**$0**	**$64,756,577**	**$6,087,118**	**$1,103,279**	**$9,718,348**	**$81,665,322**	**$91**
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	$1,143,359	$274,878	$322,683	$0	$1,740,920	$163,646	$87,046	$298,742	$2,290,354	$3
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	$446,000	$0	$267,000	$0	$0	$713,000	$67,022	$0	$117,003	$897,025	$1
12.7	Distributed Control System Equipment	$4,504,000	$2,744,000	$787,000	$0	$0	$8,035,000	$755,290	$137,200	$1,049,706	$9,977,196	$11
12.8	Instrument Wiring & Tubing	$2,442,000	$0	$4,844,000	$0	$0	$7,286,000	$684,884	$0	$1,195,633	$9,166,517	$10
12.9	Other I & C Equipment	$1,273,000	$0	$2,888,000	$0	$0	$4,161,000	$391,134	$0	$455,213	$5,007,347	$6
	SUBTOTAL 12.	**$8,665,000**	**$3,887,359**	**$9,060,878**	**$322,683**	**$0**	**$21,935,920**	**$2,061,976**	**$224,246**	**$3,116,297**	**$27,338,439**	**$30**

Table 3-2. Case 3 (PC + CEPACS) Capital Cost Estimate, 2007 USD (continued)

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
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$3,512,262	$2,141,035	$1,339,476	$0	$6,992,774	$657,321	$297,139	$1,250,051	$9,197,285	$10
13.2	Site Improvements	$0	$3,330,674	$5,066,625	$3,528,342	$0	$11,925,641	$1,121,010	$410,232	$2,221,717	$15,678,601	$17
13.3	Site Facilities	$2,974,000	$0	$2,933,000	$0	$0	$5,907,000	$555,258	$0	$1,292,097	$7,754,355	$9
	SUBTOTAL 13.	**$2,974,000**	**$6,842,936**	**$10,140,660**	**$4,867,819**	**$0**	**$24,825,415**	**$2,333,589**	**$707,371**	**$4,763,866**	**$32,630,241**	**$36**
14	BUILDINGS & STRUCTURES											
14.1	Boiler Building	$0	$8,519,000	$7,491,000	$0	$0	$16,010,000	$1,504,940	$0	$3,502,988	$21,017,928	$23
14.2	Turbine Building	$0	$12,310,000	$11,473,000	$0	$0	$23,783,000	$2,235,602	$0	$5,203,720	$31,222,322	$35
14.3	Administration Building	$0	$587,000	$621,000	$0	$0	$1,208,000	$113,552	$0	$264,310	$1,585,862	$2
14.4	Circulation Water Pumphouse	$0	$168,000	$134,000	$0	$0	$302,000	$28,388	$0	$66,078	$396,466	$0
14.5	Water Treatment Buildings	$0	$603,000	$549,000	$0	$0	$1,152,000	$108,288	$0	$252,058	$1,512,346	$2
14.6	Machine Shop	$0	$393,000	$264,000	$0	$0	$657,000	$61,758	$0	$143,752	$862,510	$1
14.7	Warehouse	$0	$266,000	$267,000	$0	$0	$533,000	$50,102	$0	$116,620	$699,722	$1
14.8	Other Buildings & Structures	$0	$5,442,102	$2,802,704	$3,072,956	$0	$11,317,762	$1,063,870	$545,788	$1,961,102	$14,888,522	$17
14.9	Waste Treating Building & Str.	$0	$416,000	$1,263,000	$0	$0	$1,679,000	$157,826	$0	$367,365	$2,204,191	$2
	SUBTOTAL 14.	**$0**	**$28,704,102**	**$24,864,704**	**$3,072,956**	**$0**	**$56,641,762**	**$5,324,326**	**$545,788**	**$11,877,994**	**$74,389,869**	**$83**
15	Piping and Ductwork											
15.1	Piping and Ductwork	$0	$44,713,922	$47,565,004	$55,837,179	$0	$148,116,105	$13,922,914	$7,405,805	$25,416,724	$194,861,548	$216
	SUBTOTAL 15.	**$0**	**$44,713,922**	**$47,565,004**	**$55,837,179**	**$0**	**$148,116,105**	**$13,922,914**	**$7,405,805**	**$25,416,724**	**$194,861,548**	**$216**
	TOTAL COST	**$777,035,729**	**$147,652,136**	**$321,883,323**	**$86,889,211**	**$0**	**$1,333,460,399**	**$125,345,278**	**$31,160,699**	**$204,669,984**	**$1,694,636,359**	**$1,881**
	Owner's Costs											
	Preproduction Costs											
	6 Months All Labor										$7,985,608	$9
	1 Month Maintenance Materials										$1,629,326	$2
	1 Month Non-fuel Consumables										$963,840	$1
	1 Month Waste Disposal										$251,000	$0
	Operator Training/Plant Personel Project Support										$73,382	$0
	25% of 1 Months Fuel Cost at 100% CF										$4,677,830	$5
	2% of TPC										$33,892,727	$38
	Total										**$49,473,713**	**$55**
	Inventory Capital											
	60 day supply of fuel and consumables at 100% CF										$13,839,680	$15
	0.5% of TPC (spare parts)										$8,473,182	$9
	Total										**$22,312,862**	**$25**
	Initial Cost for Catalyst and Chemicals										$1,749,346	$2
	Land										$942,900	$1
	Other Owner's Costs										$254,195,454	$282
	Financing Costs										$45,755,182	$51
	Total Overnight Costs (TOC)										**$2,069,065,816**	**$2,297**
	TASC Multiplier										1.140	
	Total As-Spent Cost (TASC)										**$2,358,735,030**	**$2,618**

3.2 Case 3 Cost of Electricity and Cost of CO_2 Capture Analysis

The cost of electricity was estimated based on the NETL cost estimation methodology guidelines [3], incorporating capital and operating costs for the coal-fueled (non-CEPACS) portion of the system from Case 9 in the Baseline Bituminous Report, Rev 2a [5]. Tables 3-3 and 3-4 show the Fixed (OC_{FIX}) and Variable (OC_{VAR}) operating costs, respectively, for the CEPACS system. The estimates were developed by AECOM in a combination of 2012 and 2013/14 dollars and de-escalated to 2007 dollars. Dollar year basis for estimates are listed for each account (e.g.: fixed operating costs in 2012 USD, variable operating costs in 2014 USD, etc.). The rate of $65/h used for the Operating and Maintenance labor cost includes the Administrative and Support Costs (Overhead and G&A). All variable costs were estimated as a function of the capacity factor.

Table 3-3. Fixed Operating Costs for CEPACS System

Parameter	Annual Cost	Notes
Annual Operating Labor Cost/ Maintenance Labor Cost	$ 2,249,000	1 operator + 2 assistants for each shift. 4 maint. staff on day shift. Rate = 65$/h.
Property Taxes and Insurance	$ 363,175	$995 / calendar day
Total CEPACS Fixed Annual Operating Costs (OC_{FIX}) 2012 USD	**$ 2,612,175**	
Total CEPACS Plant OC_{FIX}, 2007 USD	$ 2,253,285	
Total PC Plant (Case 1) OC_{FIX}, 2007 USD	$ 32,056,744	
Total Case 3 (PC + CEPACS) OC_{FIX}, 2007 USD	**$ 34,310,029**	

Table 3-4. Variable Operating Costs for CEPACS System

Parameter	Initial Fill Cost	Operating Hours	Replacement Cost	Annual Cost
Maintenance Material Cost				$ 7,751,604
Consumables				
Consumables, Limestone				$ 114,750
Process Water (generation credit)				$ (101,493)
Others - Catalysts				
Sorbent - Desulfurizers	$ 2,394,855	9464 hrs	$ 1,197,427	$ 902,186
ECM Stack Replacement	$ 227,520,868	10 years	$ 352,657,345	$ 11,755,244.8
Total CEPACS Variable Annual Operating Costs (OC_{VAR}) 2014 USD				**$ 20,422,292**
Total CEPACS Plant OC_{VAR}, 2007 USD				**$ 15,943,593**
Total PC Plant (Case 1) OC_{VAR}, 2007 USD				**$ 21,078,354**
Total Case 3 (PC + CEPACS) OC_{VAR}, 2007 USD				**$ 37,021,947**

Table 3-5 shows the cost of electricity and cost of carbon dioxide captured and avoided for Case 3 (PC + CEPACS-based CO_2 capture) as compared to Case 1 (PC w/o CO_2 capture) and Case 2 (PC w/ Amine-based CO_2 capture). The estimated COE for Case 3 is 80.9 mills/kWh and the cost of CO_2 captured is $33.63/tonne (2007 USD basis). The cost of CO_2 avoided was estimated to be $26.67/tonne for Case 3.

The cost of coal used in this report is taken from the Bituminous Report [5] from

Table 3-5. Case 3 (PC + CEPACS) COE and Cost of CO_2 Captured, Compared to Cases 1 and 2

	Case 1 PC	Case 2 PC w/ Amine CO2 cap.	Case 3 PC + CEPACS
TOC	$ 1,098,124,000	$ 1,985,432,000	$ 2,069,065,816
Capital Charge Factor (CCF)	11.65%	12.40%	12.40%
OC_{FIX}	$ 32,056,744	$ 53,460,210	$ 34,310,029
OC_{VAR}	$ 21,078,354	$ 37,495,580	$ 37,021,947
Capacity Factor (CF)	85%	85%	85%
MW,net	550.020	549.960	900.825
Coal Usage, tons/day	5,248	7,380	5,248
Gas Usage, MMBTU/day	--	--	67,672
CO_2 TS&M, $/Ton	--	$ 3.194	$ 3.194
CO_2 Captured, tons/year	--	4,895,935	4,727,085
Cost of Electricity			
Capital	31.2	60.1	38.3
Fixed OCs	7.8	13.1	5.1
Variable OCs	5.1	9.2	5.5
Fuel Cost	15.2	21.3	29.8
CO_2 TS&M	0	5.8	2.3
COE, mills/kWh	**59.4**	**109.5**	**80.9**
Incremental COE (Case 1 Basis)	**--**	**84.3%**	**36.2%**
Levelized COE, mills/kWh	75.3	138.8	102.6
Cost of CO_2 Capture			
Cost per Ton of CO_2 captured, (2007$)		**$ 41.89**	**$ 30.52**
Cost per Ton of CO_2 avoided, (2007$)		**$ 60.94**	**$ 24.20**
Cost per tonne of CO_2 captured, (2007$)		**$ 46.17**	**$ 33.63**
Cost per tonne of CO_2 avoided, (2007$)		**$ 67.15**	**$ 26.67**

3.3 Case 3 Economic Sensitivity Studies

A sensitivity study was performed to determine the effect of ECM price and natural gas price on the CEPACS system capital cost and cost of electricity. Results are presented based on Case 3, described in the previous sections of this report.

The T&EFS described above utilized actual, present-day ECM costs scaled based on high-volume production (equivalent to ten 350.8 MW CEPACS plants produced per year), and de-escalated to year 2007 US Dollars. The sensitivity study examined the effect of ECM production volumes, from one to fifteen CEPACS plants per year, on the system economics. Figure 3-1 shows the normalized ECM cost as a function of CEPACS plant production volume. Each 350.8 MW CEPACS plant requires 1,792 ECM stacks. The ECM costs are normalized to the baseline case utilized to develop the T&EFS, which assumed 10 plants per year production. At low volume production rates, the ECM cost is 122% higher than for the high volume production case used in the T&EFS.

ECM stack costs impact the economic analysis in two ways: the plant capital cost and operating and maintenance (O&M) costs. In the baseline T&EFs, the ECM stack costs represent 12.2% of the Total Overnight Cost for the plant (PC + CEPACS). The ECM stacks are designed for 10 years of operation before requiring replacement. The stack replacement costs are included in the operating and maintenance (O&M) cost estimate. Therefore, the O&M costs will also vary with the ECM capital cost.

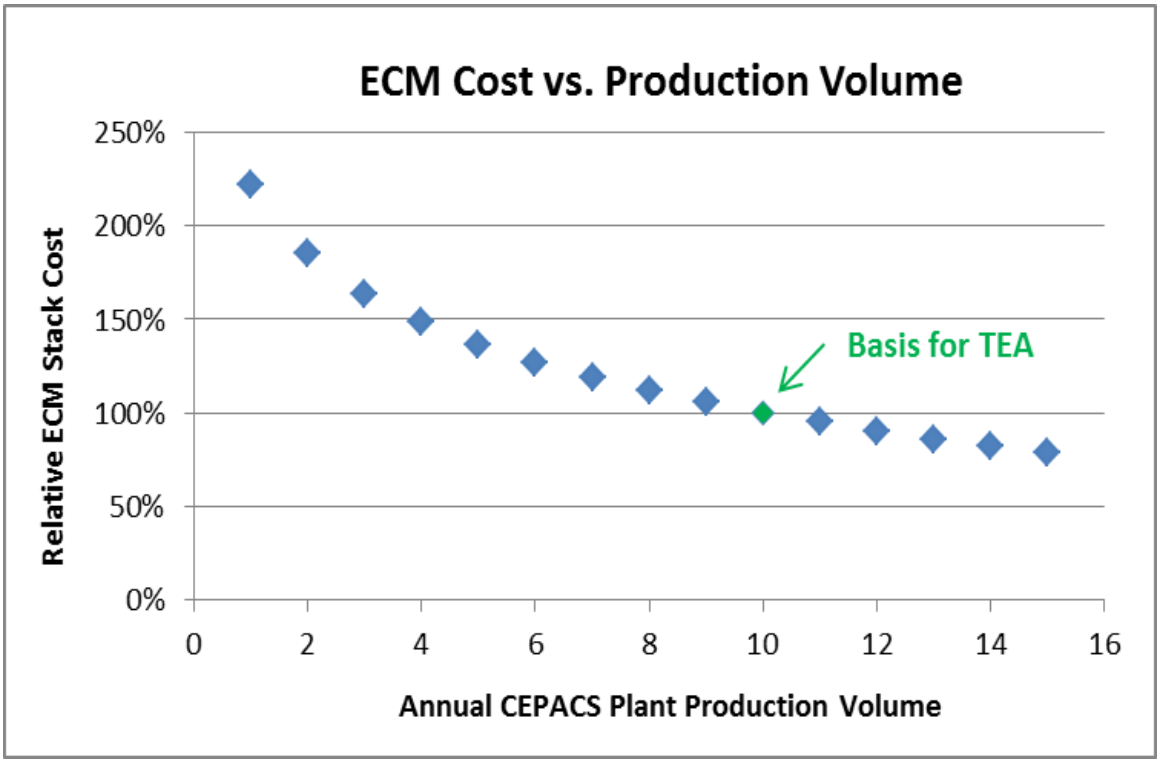

Figure 3-1. Sensitivity of ECM Stack Cost to Production Rate, Normalized to Baseline Case

Figure 3-2 shows the impact of ECM stack production rate (i.e. cost) on the Total Overnight Cost (TOC) for the 900.8 MW CEPACS-equipped PC plant. The results show a relatively weak relationship between ECM production volume and plant capital cost. At the low-volume ECM production rate of 1 plant/year (with 122% higher ECM costs compared to Baseline case), the TOC for the plant increased by 14.8%.

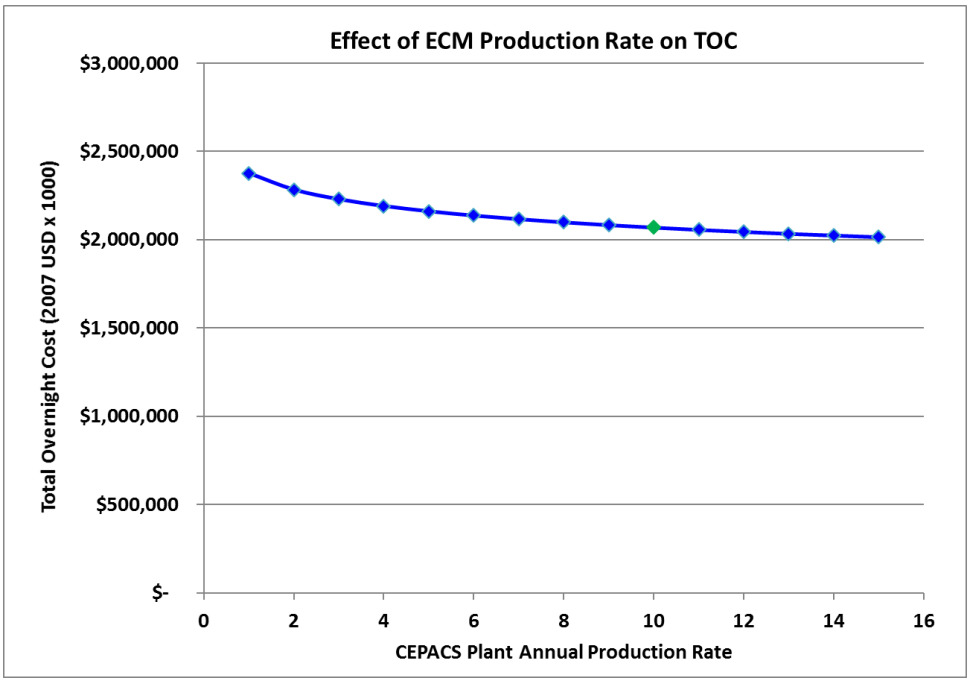

Figure 3-2. Sensitivity of Capital Cost for CEPACS-Equipped PC plant to ECM Stack Production Rate

Figure 3-3 shows the impact of ECM stack production rate on the cost of electricity (COE) for the 900.8 MW CEPACS-equipped PC plant. The COE at low volume production (1 plant/year), which includes contributions from both increased capital costs and O&M costs, is 9.0% higher than the baseline case (10 plants/year).

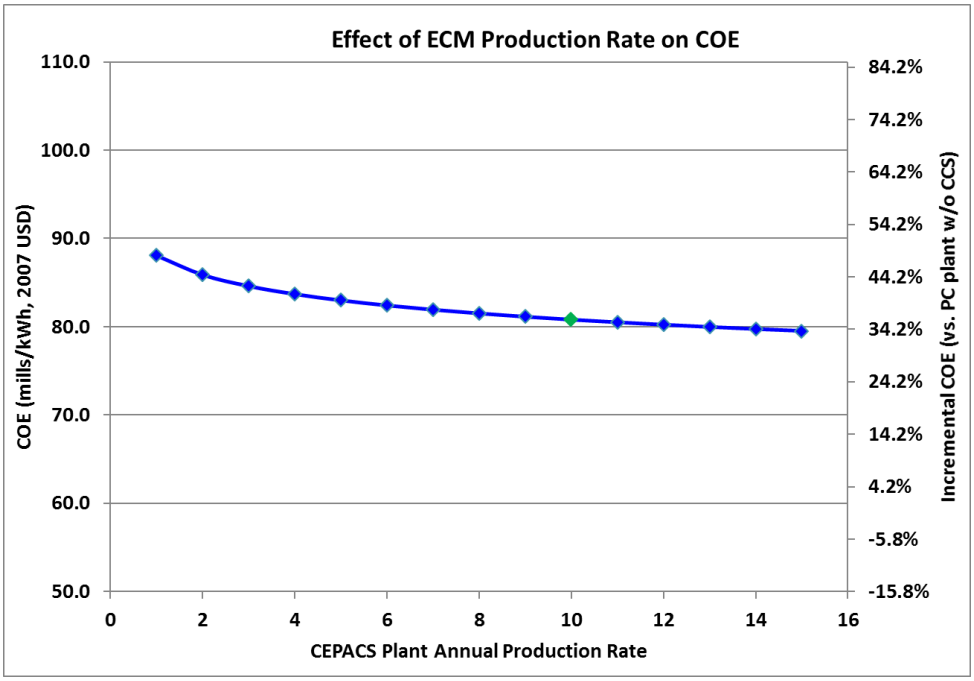

Figure 3-3. Sensitivity of Cost of Electricity for CEPACS-Equipped PC plant to ECM Stack Production Rate

Figure 3-4 shows the cost of electricity, broken down by contributing factors, for a CEPACS-equipped PC plant at annual production levels of 1, 5, 10 and 15 plants. The COE breakdown is shown in comparison to the baseline PC plant (without CCS), and an amine scrubber-equipped PC plant. As production levels increase, the CEPACS capital cost and O&M costs decrease due to reduced ECM capital/replacement costs. The incremental COE for the CEPACS-equipped PC plant ranges from 34.0% to 48.6% compared to the baseline PC plant without CCS, significantly lower than the 84.3% incremental COE of the PC plant equipped with amine scrubbing for CCS.

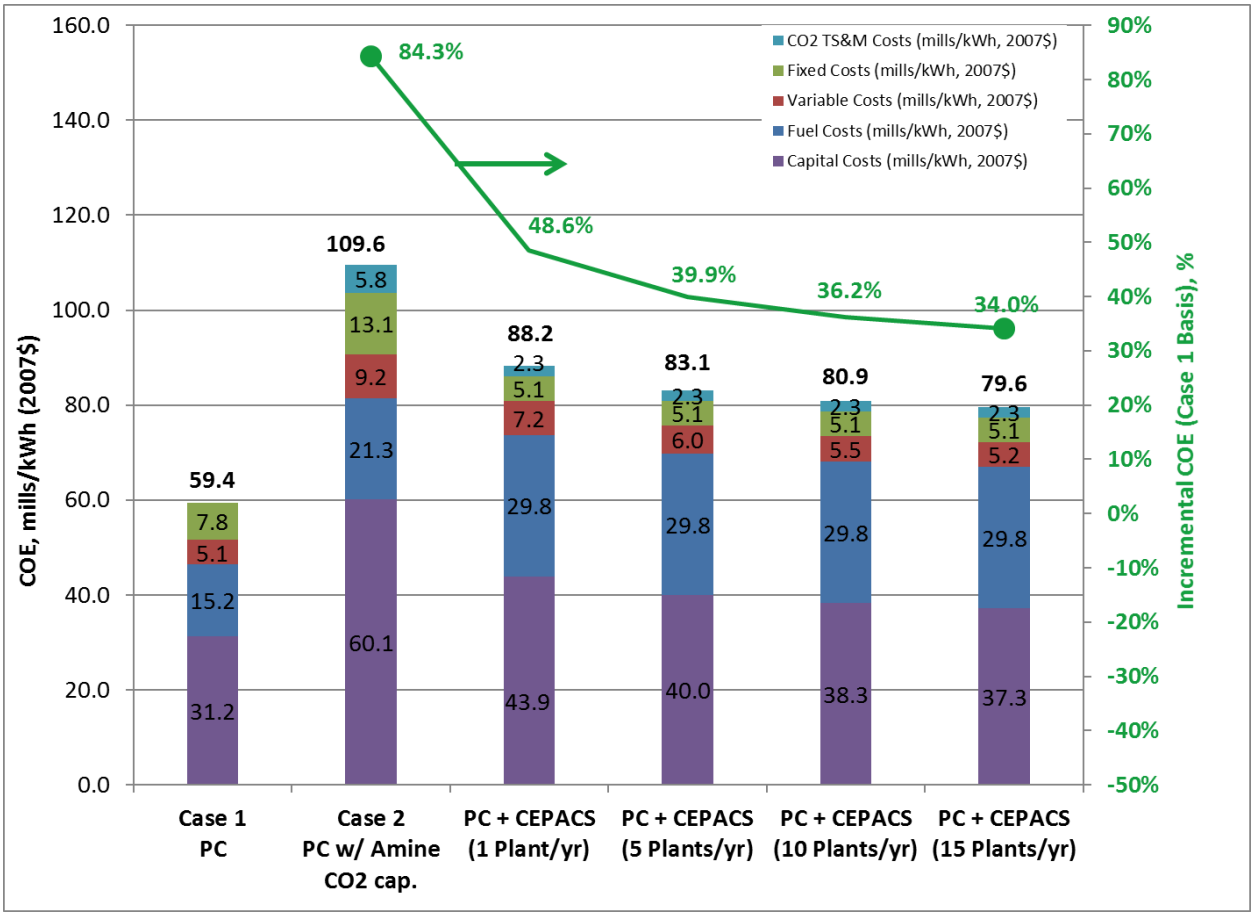

Figure 3-4. Cost of Electricity Breakdown for CEPACS-Equipped PC plant at Four Production Rates, Compared to a PC Plant without CCS and with an Amine Scrubber.

The second parameter studied was the sensitivity of the CEPACS plant economics to natural gas (NG) price. The baseline TE&FS, as well as the sensitivity study presented above, was performed using a NG price of $6.55/MMBtu. As shown in Figure 3-4 above, fuel costs (coal plus natural gas) represent a significant portion of the COE for a CEPACS-equipped PC plant. Due to recent increases in domestic natural gas production levels, the price of NG in the United States has decreased significantly. Figure 3-5 shows the historical US natural gas prices ($/Mcf) for the electric power sector (from the US Energy Information Administration). Based on this data, the sensitivity study was performed over a range of NG prices from $2 - $10/MMBtu ($2.06 – $10.28/Mcf).

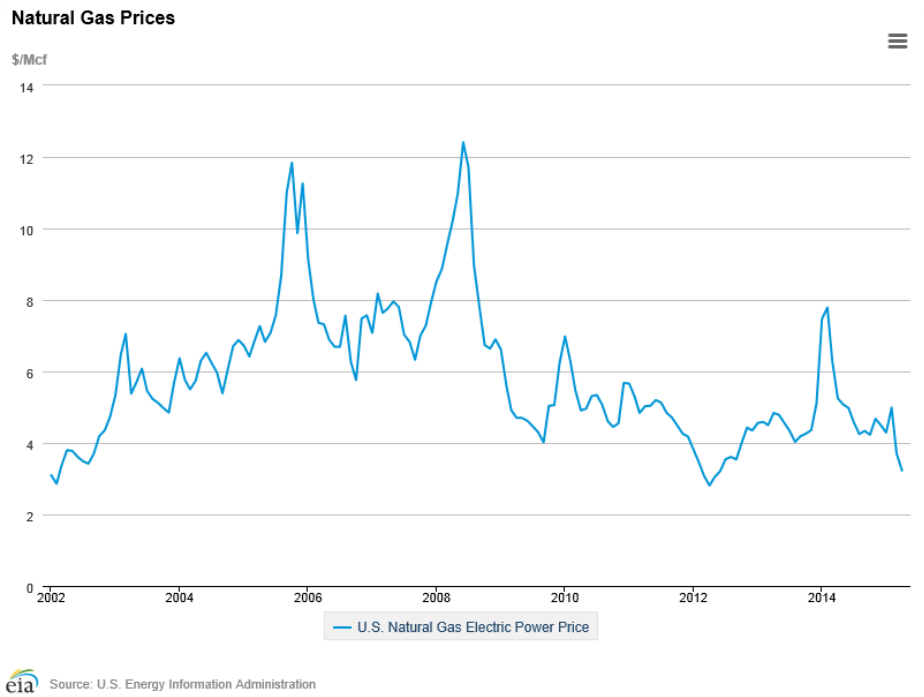

Figure 3-5. Historical Natural Gas Price for the Electric Power Sector ($/Mcf)

Figure 3-6 shows the sensitivity of the CEPACS-equipped PC plant COE to the price of natural gas. An annual production volume of 10 plants was assumed, consistent with the baseline T&EFS. The baseline case, with NG price of $6.55/MMBtu, is shown as a point on the graph. The results show that natural gas price has a significant linear effect on the plant economics. At current-day natural gas prices ~$3/MMBtu for the electric power sector, the CEPACS-equipped PC plant has an incremental COE of less than 18%, compared to a PC plant without CCS. That represents a 36% reduction in COE compared to the Baseline approach of amine scrubbing.

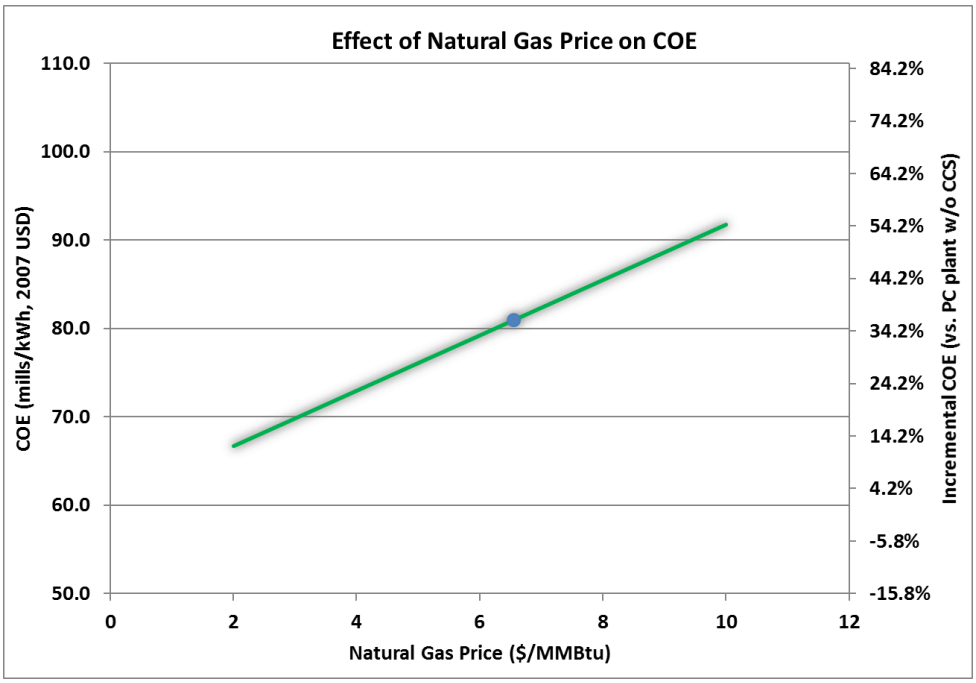

Figure 3-6. Sensitivity of Cost of Electricity for CEPACS-Equipped PC plant to NG Price

Figure 3-7 shows the sensitivity of the CEPACS-equipped PC plant cost of CO_2 captured and avoided to the price of natural gas. The costs are shown in year 2007 US Dollars to be consistent with the T&EFS basis. At a low natural gas price of $2/MMBtu, the CEPACS-equipped PC plant achieves a cost of CO_2 captured less than $12/tonne and a cost of CO_2 avoided less than $10/tonne.

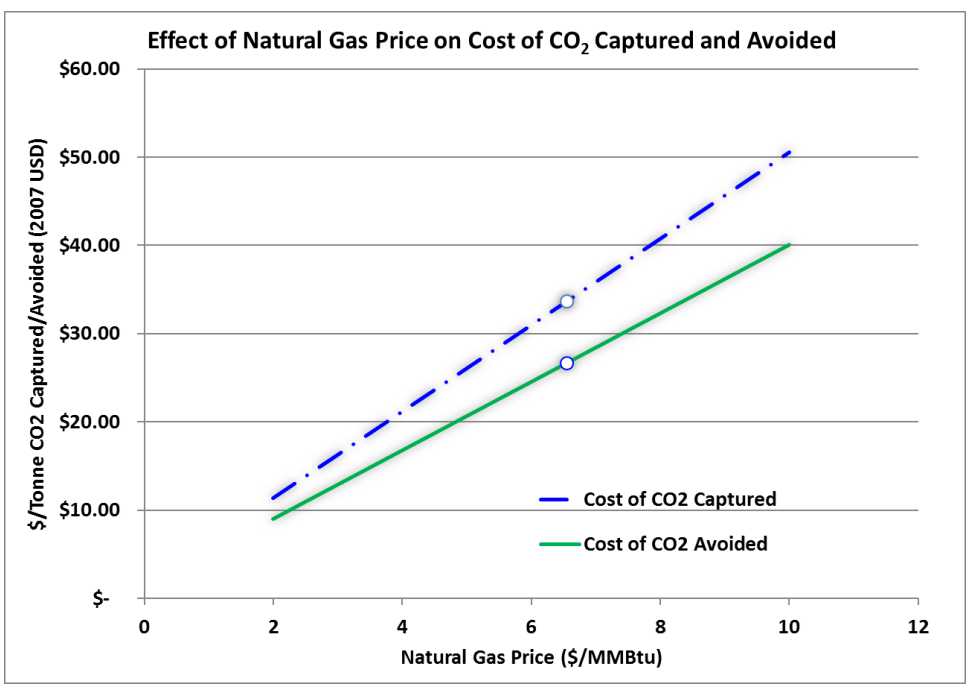

Figure 3-7. Sensitivity of Cost of CO_2 Captured and Avoided for CEPACS-Equipped PC plant to NG Price

Figure 3-8 presents a summary of the sensitivity study results, showing the effects of both ECM production rate (i.e. ECM capital and replacement costs) and natural gas price on the economics of the CEPACS-equipped PC plant designed for 90% CO_2 capture. All cases studied, even those with low ECM production volume and high natural gas prices, resulted in a cost of electricity for the CEPACS-equipped PC plant that was lower than that for a PC plant equipped with an amine scrubber. The impact of natural gas price on CEPACS system economics was found to be more significant than the effects of ECM cost. With natural gas prices projected to remain below $6/MMBtu through 2031[1], the CEPACS system presents a compelling case as an enabling technology for CCS system deployment.

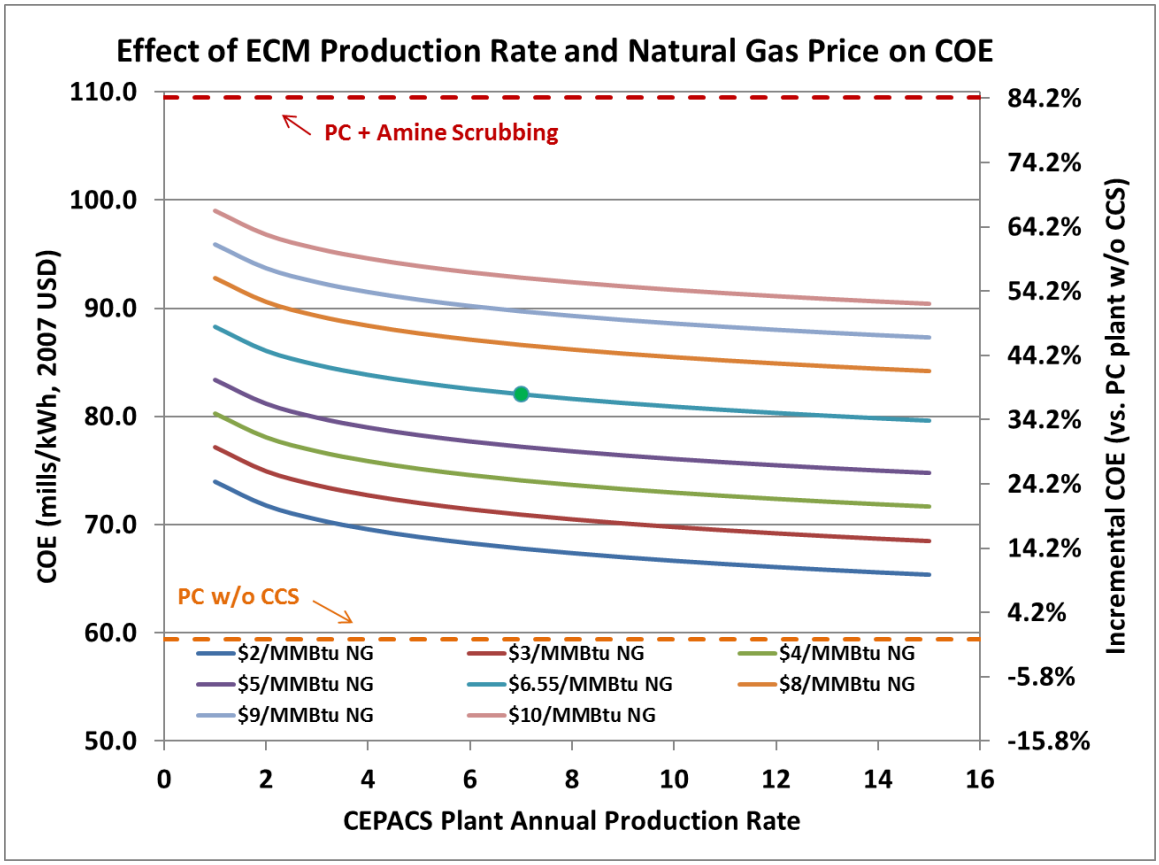

Figure 3-8. Summary of Sensitivity Study Results: Effects of ECM production rate and NG Price on CEPACS-Equipped PC Plant Cost of Electricity

[1] EIA Annual Energy Outlook 2015. http://www.eia.gov/beta/aeo/#/?id=13-AEO2015

CONCLUSIONS

This final Technical and Economic Feasibility Study conducted in BP3 has confirmed the merits of the ECM technology for Carbon Capture application compared to the amine scrubbing technology as applied to a Reference 550 MW Pulverized Coal (PC) Subcritical Steam cycle power plant. The system studies have indicated that the ECM technology, as implemented in a CEPACS (Combined Electric Power-generation And Carbon-dioxide Separation) plant, provides substantial additional power (in excess of the original PC plant) to the grid, which contributes significantly to the reduction of the cost of electricity.

The following is a summary of the key updates and impact on the results:

- The updated CEPACS Plant layout was developed. The plant is divided into 8 Sections with 224 stacks per section. The total number of ECM Stacks required is 1,792.
- The CEPACS plant operating point corresponds to a CO_2 system flux of 128 scc/s/m^2.
- The configuration of electrical equipment was selected. The transformers and inverters are located in between the Enclosures on adjoining sides to consolidate the overall footprint of the plant.
- The 1-line electrical diagrams were updated to reflect the latest CEPACS layout.
- The CEPACS plant generates 350.8 MWe while capturing >90% of CO_2 from the PC plant flue gas.
- The cost estimates were generated using a 2007 cost basis. The comparison is based on the carbon capture technology applied to the subcritical PC plant. The higher fidelity vendor quotations were used.
- The COE for the Reference Plant equipped with CEPACS (Case 3) is 36.2% more than Case 1. This is more than 48% lower than the amine based technology.
- Case 3 has the lowest Total Overnight Cost (TOC of $2,297 /kW) and the highest overall efficiency (38.8% HHV) among the two systems.
- The Reference Plant equipped with CEPACS has the lowest water consumption per unit of electricity produced. It actually reduces the water consumption of the Reference PC plant due to water-producing capabilities of the ECM operating inherently as a fuel cell.
- The Reference Plant equipped with CEPACS has the lowest emissions of NO_x, SO_x, and mercury per unit of electricity produced. ECM has the well-established capabilities for destroying a significant amount (>70%) of NO_x.
- The Reference Plant equipped with CEPACS has a cost of $33.63/tonne of CO_2 captured, which is 27.1% lower than the amine-based carbon capture alternative (Case 2).

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[1] Farooque, M., "Integrated high efficiency fossil fuel power plant/fuel cell system with CO2 emissions abatement", United States Patent 7,396,603, issued July 08, 2008.

[2] Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity, Revision 2, DOE/NETL-2010/1397, November 2010.

[3] Quality Guidelines for Energy System Studies: Cost Estimation Methodology for NETL Assessment of Power Plant Performance, April 2011, DOE/NETL-2011/1455

[4] Scope and Reporting Requirements for NETL System Studies, May 2010, DOE/NETL

[5] Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity', Revision 2a, DOE/NETL-2010/1397, September 2013

[6] Updated Costs (June 2011 Basis) for Selected Bituminous Coal Cases, August 2012, DOE/NETL-341/082312

LIST OF ACRONYMS

AC	Alternating Current
ACFM	Actual Cubic Feet per Minute
BEC	Bare Erected Cost
BFD	Block Flow Diagram
BFW	Boiler Feed Water
BOP	Balance of Plant
BP	Budget Period
CCF	Capital Charge Factor
CCUS	Carbon Capture, Use, and Sequestration
CEPACS	Combined Electric Power And Carbon-dioxide Separation
CF	Capacity Factor
C/I	Cathode-In
C/O	Cathode-Out
COE	Cost of Electricity
CP	Coefficient of Performance
DC	Direct Current
DCS	Distributed Control System
DFC	Direct Fuel Cell (FCE Molten Carbonate Fuel Cell)
DOE	United States Department of Energy
ECM	Electro-Chemical Membrane
EH&S	Environmental Health and Safety
EPCC	Engineering, Procurement and Construction Cost

FCE	FuelCell Energy, Inc.
FD	Forced Draft
FGD	Flue Gas Desulfurization
F/I	Fuel-In
F/O	Fuel-Out
GHG	Greenhouse Gases
HHV	Higher Heating Value
H&MB	Heat and Mass Balance
HRSG	Heat Recovery Steam Generator
HSS	Heat Stable Salts
HVAC	Heating Ventilation Air Conditioning
IOU	Investor Owned Utility
IRROE	Internal Rate of Return On Equity
kV	kilo-Volt
kW, kWe, kWt	Kilo-Watt, Kilo-Watt electricity, Kilo-Watt thermal equivalent
LCOE	Levelized Cost of Electricity
LHV	Lower Heating Value
LMTD	Logarithmic Mean Temperature Difference
LNB	Low NOx Burner
LTSC	Low Temperature Shift Converter
MW	Mega-Watt
NETL	National Energy Technology Laboratory
NG	Natural Gas
NGCC	Natural Gas Combined Cycle
OC_{FIX}	Fixed Operating Cost
OC_{VAR}	Variable Operating Cost
OFA	Overfire Air
O&M	Operating and Maintenance
PC	Pulverized Coal
PFD	Process Flow Diagram
PM	Particulate Matter
PMP	Project Management Plan
PNNL	Pacific Northwest National Laboratory
PT&EFS	Preliminary Technical & Economic Feasibility Study
ppm	parts per million

psia	Pound per square inch absolute pressure
SCFM	Standard Cubic Feet per Minute
SCR	Selective Catalytic Reduction
SOPO	Statement of Project Objectives
TASC	Total As-spent Cost
TOC	Total Overnight Cost
TPC	Total Plant Cost
TS&M	Transport, Storage & Monitoring
URS	URS Corporation
US	United States of America
USD	US Dollars