Combined Power Generation and Carbon Sequestration Using Direct FuelCell

Final Scientific/Technical Report

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ABSTRACT

The unique chemistry of carbonate fuel cell offers an innovative approach for separation of carbon dioxide from greenhouse gases (GHG). The carbonate fuel cell system also produces electric power at high efficiency. The simultaneous generation of power and sequestration of greenhouse gases offer an attractive scenario for re-powering the existing coal-fueled power plants, in which the carbonate fuel cell would separate the carbon dioxide from the flue gas and would generate additional pollutant–free electric power. Development of this system is concurrent with emergence of Direct FuelCell® (DFC®) technology for generation of electric power from fossil fuels. DFC is based on carbonate fuel cell featuring internal reforming. This technology has been deployed in MW-scale power plants and is readily available as a manufactured product.

This final report describes the results of the conceptualization study conducted to assess the DFC-based system concept for separation of CO2 from GHG. Design and development studies were focused on integration of the DFC systems with coal-based power plants, which emit large amounts of GHG. In parallel to the system design and simulation activities, operation of laboratory scale DFC verified the technical concept and provided input to the design activity. The system was studied to determine its effectiveness in capturing more than ninety percent of CO2 from the flue gases. Cost analysis was performed to estimate the change in cost of electricity for a 200 MW pulverized coal boiler steam cycle plant retrofitted with the DFC-based CO2 separation system producing an additional 127 MW of electric power. The cost increments as percentage of levelized cost of electricity were estimated for a range of separation plant installations per year and a range of natural gas cost. The parametric envelope meeting the goal (<20% increase in COE) was identified.

Results of this feasibility study indicated that DFC-based separation systems have the potential for capturing at least 90% of the emissions from the greenhouse gases generated by power plants and other industrial exhaust streams, and yet entail in less than 20% increase in the cost of energy services for long-term deployment (beyond 2012). The anticipated cost of energy increase is in line with DOE’s goal for post-combustion systems as outlined in the “Carbon Capture and Sequestration Systems Analysis Guidelines”, published by NETL, April 2005. During the course of this study certain enabling technologies were identified and the needs for further research and development were discussed.

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1. Executive Summary

A novel concept using carbonate fuel cells for separation of carbon oxide from greenhouse gases (GHG) was explored. The application of direct (carbonate) fuel cell (DFC) for carbon dioxide sequestration is based on the unique chemistry of the carbonate fuel cells in which carbon dioxide from the greenhouse gas is separated (ready-to-capture) via the migration of the carbonate ions from the cathode to the anode of the fuel cell. In addition to the CO_2 sequestration, the system was designed to produce electric power at very high efficiencies. The simultaneous generation of power and sequestration of greenhouse gases offer an attractive scenario for re-powering the existing coal-fueled power plants, in which the carbonate fuel cell would separate the carbon dioxide from the flue gas and would generate additional pollutant–free electric power. The development of this system is concurrent with emergence of FCE's DFC® technology for generation of electric power from fossil fuels. DFC is based on carbonate fuel cell featuring internal reforming. This technology has been deployed in MW-scale power plants. The power plants based on DFC technology are simple in design and produce power with very high efficiencies and minimal environmental impact.

This project conducted the research and development essential for system design, process optimization and cost estimation to evaluate the system potential for the above application. The design activities were focused on integration of DFC-based CO_2 capture systems with coal-based power plants. The types of coal-fired power plants considered included pulverized coal (PC) boiler steam cycle, atmospheric circulating fluidized bed (CFB) boiler steam cycle, and integrated gasification combined cycle (IGCC) plants. A database of coal fired power plant exhaust stream (flue gas or GHG) was compiled based on literature search. The flue gases from PC and CFB boiler steam plants are somewhat lean in oxygen for proper operation of DFC. A simple solution was developed consisting of blending the flue gas with supplementary air before feed to the fuel cell.

A baseline DFC CO_2 separation system was configured. The system included an oxidizer to consume the unused fuel (present along with fuel cell reaction products - CO_2 and water vapor) in the DFC anode exhaust. Oxygen from a small air separation unit was used for the oxidizer reaction to prevent any dilution of CO_2 in the CO_2–rich DFC anode exhaust. The oxidation heat is recovered and utilized for preheating of the cathode feed gas (flue gas from coal plant), before condensing the water out from the CO_2–rich exhaust stream. The exhaust stream (after condenser) mainly contains CO_2 and can be further processed for sequestration. In addition to the baseline system design, alternative designs were also developed for separation rather than oxidation of hydrogen from anode tail gas. These alternatives offer an attractive option for hydrogen export as a co-product of DFC-based sequestration system.

The design activities were supported by computer process modeling and application of mass and energy balances. The system design and analysis included system simulations, and estimation of CO_2 removed from the coal plant flue gas, gas composition of the stream to sequestration and additional power generated by DFC-

based CO_2 separation system. The baseline system was designed to separate 90% of the carbon dioxide emissions from a 200MW pulverized coal power plant (PCP). The detailed design included equipment list and sizing (for cost analysis). The 200 MW PCP was retrofitted with the DFC-based CO2 separation system generating additional 126.6 MW of power. The PC plant without CO_2 separation system released 22 tons/MW-day of CO_2 into the atmosphere. With the addition of the DFC separation system, the CO_2 released to the atmosphere was 1.4 tons/MW-day (based on the 326.6 MW total power). This is about 94% reduction in the CO_2 emission to the environment per unit of energy produced. In parallel to the design activities, laboratory scale carbonate fuel cells were operated to verify the concept and to provide input to the design activity. The tests were performed using pre-mixed gas blends simulating the exhaust of typical PC and IGCC power plants. The carbonate fuel cell's potential to transfer 90% of CO_2 from the cathode feed gas to the anode side was verified by the cell tests.

Capital cost estimates and cost of electricity (COE) analysis for the baseline DFC CO_2 separation system were performed. The installed cost of CO_2 separation system is estimated to be 509 $/kW (based on total power) for a commercial production in quantities of ten units per year (exclusive of the FGD subsystem). The cost of electricity analysis included the estimation of COE for a range of DFC-based CO_2 separation plant installations (1 to 10 units per year). The key contributing factors included plant capital cost, fuel cost, and operating and maintenance (O&M) cost. The cost increment as a percentage of levelized cost of electricity was estimated for the range of separation plant installations per year and a range of natural gas cost from $6/MMBtu to $10/MMBtu. The parametric envelope meeting the goal (<20% increase in COE) was identified. The results indicated that the mature commercial DFC sequestration systems have the potential for separating ninety percent of carbon dioxide emissions from a coal power plant while increasing the COE by less than twenty percent. The anticipated cost of energy increase is in line with DOE's goal for post-combustion systems as outlined in the "Carbon Capture and Sequestration Systems Analysis Guidelines", published by NETL, April 2005.

Two alternate configurations for the DFC-based CO_2 separation system were also developed and analyzed. The alternate configurations incorporated a hydrogen separation unit. One design option was using proton exchange membrane (PEM) electrochemical hydrogen separator (EHS) technology to separate hydrogen from the DFC anode exhaust. The other option was based on the conventional technology of pressure swing adsorption (PSA) to separate H_2 from the CO_2–rich DFC anode exhaust stream. The system analyses, including mass and energy balances, were performed for the alternate DFC-based CO_2 separation systems. A substantial quantity of hydrogen (~21 lb H_2/MW-h DFC generation) would be available as a co-product. The hydrogen may be exported (sold) as a commodity or recycled to DFC anode as a supplementary fuel, therefore increasing the overall efficiency of the DFC power generation. The alternate system with EHS option shows a promising method for recovery of hydrogen from the anode exhaust gas. Further development work in this area is recommended.

2. Progress/ Performance Results

Task 1 System Design

Task 1.1 System Requirements

The 'Design Basis and Requirements' document for the CO_2 sequestration system was developed to guide the system configuration, computer simulations and analyses. The basis for the direct (carbonate) fuel cell (DFC) CO_2 sequestration system was its application to a 200 MW coal fueled power plant. The greenhouse gas (GHG) or exhaust gas from various coal-fueled power plants was considered for removal and capture of CO_2. The DFC based sequestration system, in addition to capturing CO_2 from GHG, would generate electric power supplementing the power produced by the coal-fueled power plant. The design basis document included the sequestration plant power output characteristics, and plant life and availability requirements. Specifications of the natural gas fuel required by DFC were also included. The quality of water required for generation of steam for reforming of the natural gas fuel was specified in the document. The completed document included the plant site requirements/characteristics.

In parallel, a database of coal fired power plant exhaust stream properties including emission levels was established. Literature search to gather information for the database covered many sources. However, a complete set of data was available only from a limited number of sources. Published reports on advanced coal combustion and gasification system studies were referred for the exhaust gas/flue gas composition and flow related information. Plant exhaust stream information for a pulverized coal (PC) boiler steam cycle plant; an atmospheric pressure, coal fired circulating fluidized bed (CFB) boiler steam cycle plant; and integrated (coal) gasification combined cycle (IGCC) power plant was compiled. Table 1.1-1 summarizes the information. More detailed information found on pulverized coal power plant flue gas is summarized in Table 1.1-2. The table includes the power plant size (net electrical output) and flue gas flow rate, temperature and pressure along with the gas composition. Integrated gasification combined cycle power plant flue gas information was gathered from Cool Water Coal Gasification Program final report (EPRI Report GS-6806, December 1990). The report provided data for the flue gas from the combustion turbine of the 100 MW Cool Water IGCC Demonstration power plant. The information found included extensive data on the emissions and gas compositions. Table 1.1-3 presents the information. Process simulations using the CHEMCAD software (computer models) were performed for a natural gas combined cycle (NGCC) power plant, to generate the exhaust gas information for comparison purpose. The database was used to design a CO_2 sequestration plant, suitable for a 200 MW (design basis) coal-fueled power plant. The database provided key input for CO_2 sequestration system configuration and simulation studies performed under Task1.4.

Table 1.1-1
Coal Fueled Power Plant Exhaust Stream Composition, Flow Rate and Conditions

	Pulverized Coal Boiler Steam Cycle Plant [1]	Atmospheric Circulating Fluidized Bed Boiler Steam Cycle Plant [2]	Integrated (coal) Gasification Combined Cycle Power Plant [2]	
			Existing Plant	Commercially Offered Future Plant
Gas Composition (mole %)				
CO_2	12.06	14.40	7.49	7.85
O_2	4.47	3.32	11.95	11.76
N_2	69.49	74.81	64.79	71.64
H_2O	13.13	7.45	14.84	7.83
Ar	0.83	-	0.94	0.91
SO_2	0.014	0.02	-	-
Cl_2	0.009	-	-	-
Temperature (deg F)	129	291	280	280
Pressure (psia)	14.8	14.7	14.7	14.7
Flow Rate (lbmole/h)*	69,269	63,032	100,563	115,573

* Scaled to 200 MW net plant size
[1] E. Parsons (NETL) and W. Shelton (EG&G), “Advanced Fossil Power Systems Comparison Study,” Final Report, Dec 2002, Prepared for: National Energy Technology Laboratory (NETL)
[2] “Greenhouse Gas Emissions Control by Oxygen Firing in Circulating Fluidized Bed Boilers: Phase I – A Preliminary Systems Evaluation,” Final Report (Volume I), May 2003, Prepared for: National Energy Technology Laboratory, By: Alstom Power, Inc., Windsor, CT

Table 1.1-2
PC Power Plant Flue Gas Data

Plant	Shand	Trenton	Genesee
Location	Saskatchewan	Nova Scotia	Alberta
Coal	Lignite	Bituminous	Subbituminous
ESP	Dry	Dry	Dry
FGD	LIFAC (Limestone Injection into the Furnace and Activation of Calcium oxide) on one train	None	None
NOx	Low NOx burner Overfired Air	Low NOx burner	Low NOX burner, Overfired Air
Net Capacity, MW	272	156	381
Flue Gas Flow Rate, lbmoles/hr	114,709	52,283	137,446 (corrected)
Flue Gas Flow Rate, lbs/hour	3,337,958	1,556,507	4,071,914
Flue Gas Temperature, °F	297	297	214
Flue Gas Pressure, psig	0.2	0.2	0.2
Major Gas Stream Components, Volume %			
CO_2	12.8	13.5	13.6
O_2	4.5	3.9	4.8
H_2O	12.4	6.7	8.7
N_2	69.4	74.9	72.0
Ar	0.9	1.0	0.9
Minor Gas Stream Components, ppm			
SO_x	450	1,300	234
NO_x	251	335	337
Hg, ug/m^3 dry @6%O_2	12	3.4	0.47-1.6
Hg, Elemental/Oxidized (%)	90/10	50/50	79.3/20.4
SO_3/SO_2 distribution (%)	99.5/0.5	99.5/0.5	99.5/0.5
NO/NO_2 distribution (%)	98/2	98/2	98/2

Table 1.1-3
100 MW Cool Water IGCC Demonstration Plant Flue Gas Data

Coal	Sufco (Utah)	Illinois #6	Pittsburgh #8
Net Combined Cycle Output, MW	107.1	93.3	94.9
Flue Gas Flow Rate, lbmoles/hour	76,125 (Recalculated)	74,307 (Recalculated)	60,966 (Recalculated)
Flue Gas Temperature, °F	194	229	223
Flue Gas Pressure, psig	~0.2	~0.2	~0.2
Major Gas Stream Components, Volume (mole) %			
CO_2	6.8	6.3	7.7
O_2	13.8	15.4	13.6
H_2O	7.4	7.9	8.1
N_2 (including Ar)	72.0	70.4	70.6
Minor Gas Stream Components, ppm			
SO_2	4.8	15.4	28.6
$H2SO_4$	0.88	n.r.	<0.58
NH_3	1	< 0.2	0.13
NOx	22	30	21
CO	730	1.9	<1
Particulates, mg/nM3	78	54	59
Volatile Trace Elements, ppm			
Antimony	<0.005	<0.001	<0.001
Arsenic	<0.004	0.0019	0.0013
Barium	<0.004	0.0041	0.0029
Beryllium	<1	<0.01	0.0014
Boron	<0.71	0.45	<0.057
Cadmium	<0.01	<0.001	<0.001
Calcium	0.31	0.14	0.49
Chromium, total	<0.01	0.04	0.012
Cobalt	<0.01	0.0014	0.0012
Copper	<0.01	0.0088	<0.001
Iron	0.052	0.099	0.012
Lead	<0.01	0.012	<0.0012
Magnesium	<0.16	0.033	<0.015
Manganese	<0.04	0.0032	<0.0.0049
Mercury, elem.	<0.01	<0.009	<0.001
Molybdenum	<0.01	<0.0042	<0.001
Nickel Carbonyl	<0.038	<0.001	<0.001
Nickel, total	<0.02	0.016	0.025
Potassium	<0.25	0.18	<0.015
Selenium	<0.001	0.003	<0.001
Silicon	0.88	0.26	0.044
Silver	0.018	<0.001	<0.001
Sodium	0.31	1.1	1.7
Strontium	<0.01	<0.001	<0.001
Thallium	<0.007	<0.001	<0.001
Tin	<0.054	0.034	<0.01
Titanium	<0.02	<0.0084	<0.0013
Vanadium	<0.01	<0.0032	<0.001
Zinc	0.025	0.097	0.23

Task 1.2 Greenhouse Gas Conditioning

Technologies for desulfurization of GHG, prior to its utilization as the fuel cell cathode gas were considered. Technical information on one such technology called flue gas desulfurization (FGD) was gathered and reviewed. FGD units, also called scrubbers, can be used to scrub sulfur oxides out of the GHG from coal-burning boilers used in steam cycle power plants. Most of the FGD systems in the U.S. (90%) use limestone or lime as the sorbent. Limestone is a common natural substance found in abundance. In most scrubbers, limestone/lime is mixed with water and sprayed where it comes in contact with the flue gas/GHG. The limestone and sulfur combine with each other to form a wet paste or in some new scrubbers a dry powder. Sulfur is thus captured and removed from GHG. The new types of scrubbers, tested under the Clean Coal Technology Program, are more effective, low-cost and more reliable than other scrubbers.

FGD can be utilized upstream of the fuel cell in the DFC-based CO_2 separation system, to remove sulfur compounds harmful to the fuel cell operation. A specification was prepared for the FGD subsystem required to treat exhaust from a 200 MW pulverized coal boiler steam cycle plant (PC power plant or PCP). The FGD subsystem can also provide the added benefit of deep desulfurization of the flue gas before release to environment.

Task 1.3 Anode Exhaust Post-Treatment

In the DFC-based CO2 separation system for the GHG, the CO_2-rich anode exhaust stream from fuel cell also contains water vapor and unused fuel (mainly H_2 and some CO). To make the stream CO_2 sequestration-ready, some processing or post-treatment is required. Various system options were considered. Two alternatives for post-treatment of the unused fuel were developed to make anode exhaust stream CO_2 sequestration-ready:

1) Consuming all the hydrogen and other combustibles in the oxidizer and utilizing the energy content for preheating of fuel cell cathode inlet stream (desulfurized GHG from coal-fueled power plants);
2) Recovering hydrogen so that any excess H_2, after providing the required preheat for the cathode inlet stream, can be made available for sale as a co-product or can be recycled to DFC anode as supplementary fuel.

The former approach was taken for the baseline system configuration mainly due to its simplicity and expected lower cost. For the baseline system, the combustibles in the anode exhaust were reacted in an oxidizer. The heat was then used to preheat the Cathode-In stream. After recuperative heat exchange, the anode exhaust/oxidizer exhaust stream was cooled down in a condenser to remove water. Options of using O_2 from an air separation subsystem/unit or using air in the oxidizer were explored. The use of O_2 prevents dilution of CO_2 from N_2 present in air. However, to control the oxidizer temperature to desired level (avoid catalyst overheating), some water injection is required when using O_2 in the oxidizer. The added water is then condensed out (downstream of the oxidizer) along with water already present in the anode exhaust stream to concentrate CO_2 in the oxidizer exhaust for sequestration readiness. For the system using GHG from a PC boiler steam cycle power plant, the stream to CO_2 sequestration contained 89% CO_2 and 10% H_2O (with 74% fuel utilization) compared to 58% CO_2 when air used in the oxidizer.

In the alternative system, H_2 present in the anode exhaust is separated/recovered. Only the necessary amount of the recovered H_2 is then consumed in the oxidizer to provide cathode inlet stream preheat. The remaining (excess) H_2 is available as a co-product. This excess H_2 can also be recycled to DFC anode, thereby reducing the natural gas fuel requirement. Additionally, in the alternative system configuration, oxidizer exhaust is separate from the stream containing CO_2 for sequestration. Air can therefore be used in the oxidizer, eliminating the need for air separation unit and water injection (for oxidizer temperature control).

The alternative system configuration included a H_2 separation unit. Options of using an electrochemical hydrogen separator (EHS) or a pressure swing adsorption (PSA) unit were considered. EHS considered employed proton exchange membrane (PEM) fuel cell to electrochemically transfer H_2 (from EHS anode) to the recovery side (EHS cathode). Figure 1.3-1 shows the EHS operating principle. The EHS consists of two electrodes separated by a proton exchange membrane. At EHS anode, hydrogen present in gas stream is selectively oxidized to H^+, which is then transported to the cathode through the proton exchange membrane. At the EHS cathode (in absence of an oxidant), H^+ is reduced to gaseous hydrogen. Thus, the EHS can selectively transport H_2 from the gas fed to the anode electrode to the cathode electrode using no moving parts and with minimum energy input. In addition, the hydrogen at the cathode electrode can be compressed (if required for export) electrochemically with relatively low energy input. The theoretical potential of the reversible hydrogen reaction is zero volts. However, to obtain the desired reaction rate for hydrogen gas transport, the ohmic, activation and diffusion over-potentials in the system need to be overcome, which are relatively low. EHS technology is currently being developed by FuelCell Energy for separation of hydrogen from reformates.

To maximize H_2 recovery and prevent carbon monoxide poisoning of EHS catalyst, the process steps for the anode exhaust (from DFC) included high and low temperature carbon monoxide shift, and preferential oxidation (with controlled air injection). Carbon monoxide in the anode exhaust was reduced to ppm level. Some of the H_2 recovered by EHS was reacted in an oxidizer using air to provide preheat for Cathode-in stream. The remaining 55% of the H_2 recovered (assuming 95% H_2 recovery in EHS) can be made available as a co-product. The stream to CO_2 sequestration contained 89% CO_2 and 9% H_2O after removing most of the water out in a condenser.

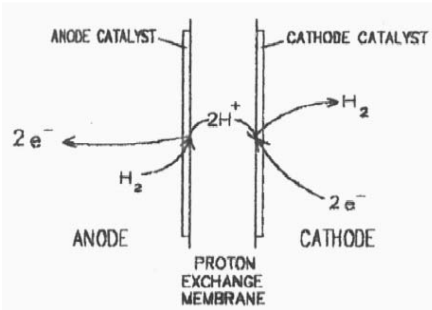

Figure 1.3-1. EHS Operating Principle and EHS Cell Components: Unlike Conventional Processes, EHS Separates Hydrogen from CO_2 bulk

The alternative configuration including PSA (conventional technology) option for H_2 separation did not require the preferential oxidation step (to lower CO to ppm level). However, it required compression of the anode exhaust stream after removal of water in a condenser. The PSA option therefore requires a seal-tight gas compressor and is somewhat energy intensive. A two stage compressor with intercooler was used to pressurize the stream to ~200 psia for feed to PSA. About 40% of the H_2 recovered (assuming 90% H2 recovery by PSA) can be made available as a co-product. The stream to CO_2 sequestration contained 96% CO_2 as more water was condensed out in this case.

The baseline system configuration, system description and analyses are presented under Task 1.4.

Task 1.4 System Analysis

Figure 1.4-1 shows the conceptual system, which was utilized in the development of the simulation models. The computer based system model was used for system performance estimation and generating heat and material balances for sizing of process equipment and fuel cell. A baseline system and alternatives were configured to separate CO_2 (for sequestration) from a coal-fired power plant exhaust stream. The systems are based on DFC, which transfers one mole of CO_2 from the cathode to the anode for each mole of hydrogen consumed in the electrochemical process of generating electric power.

Baseline System

Process flow diagram for the baseline DFC carbon separation system is shown in Figure 1.4-2. Inlet process conditions were established for the system based on exhaust from a 200 MW plant that operates on pulverized coal. The exhaust (or GHG) from the pulverized coal power plant entering the system at 129°F (through a blower) contains 12% CO_2 and 4.5% O_2. It is mixed with supplemental air to ensure that the O_2 concentration at DFC cathodes is adequately high for fuel cell operation. The stream is heated to 1075°F and flows to the cathodes of the fuel cells where 70% to 90% of the CO_2 is transferred to the anodes. The stream leaving the cathodes at about 1180°F is depleted in CO_2 depending on the design CO_2 utilization. The cathode exit stream is depleted in oxygen to about 5%. The cathode exhaust stream provides heat for preheating the incoming stream as well as humidifying the natural gas for the fuel cells.

The fuel cell system for CO_2 separation operates on natural gas fuel. The natural gas is desulfurized, humidified and pre-reformed before flowing to the fuel cell anodes at 1000°F. The anode exhaust at 1150°F, which includes the CO_2 transferred from the cathodes as well as water produced in the fuel cells, is used to preheat the incoming fuel stream. The anode exhaust is then further cooled by evaporation of water, mixed with oxygen and fed to a catalytic oxidizer where residual hydrogen and CO from the cells are oxidized. The oxidizer exit stream at about 1200°F provides a portion of the heat needed for the cathode inlet stream in the recuperator. Water from the fuel cells as well as the water formed in the oxidizer is condensed to 110°F and separated, leaving a stream with close to 89% CO_2, 10% water vapor and 1% oxygen which then flows from the system to CO_2 sequestration. Water recovered in the condenser is treated and recycled so that the system is self sufficient in its requirement for process water.

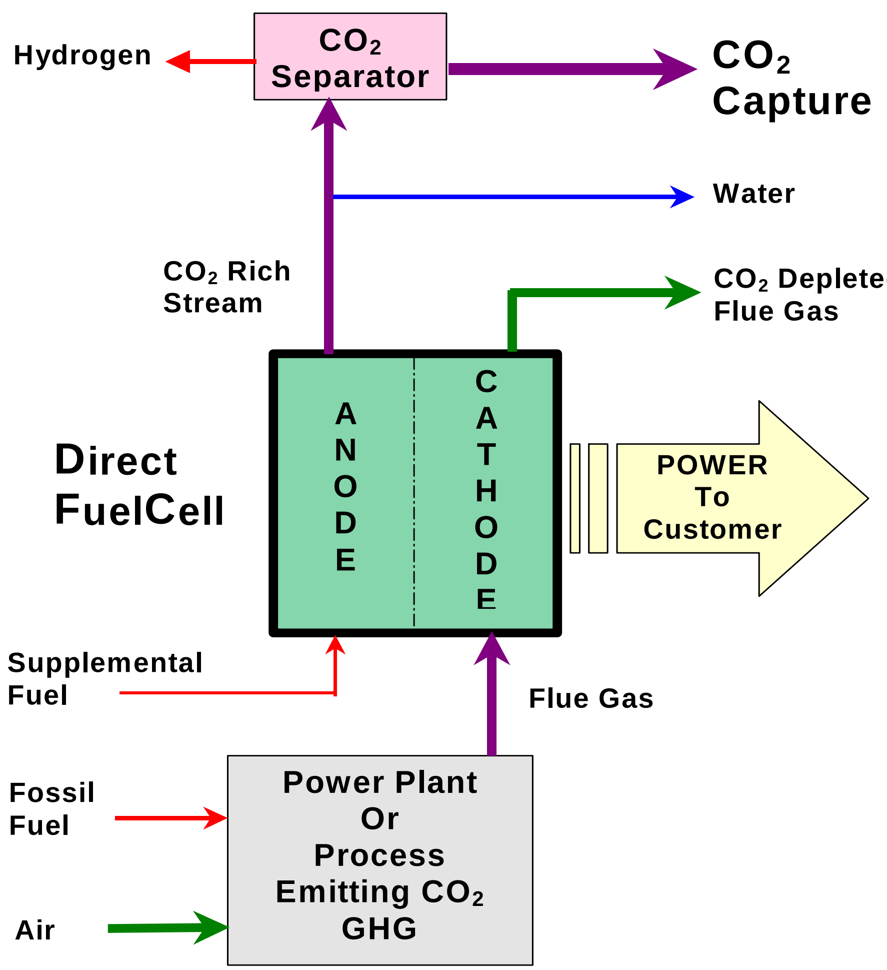

Figure 1.4-1. CO_2 Capturing System Concept Utilizing Direct FuelCell

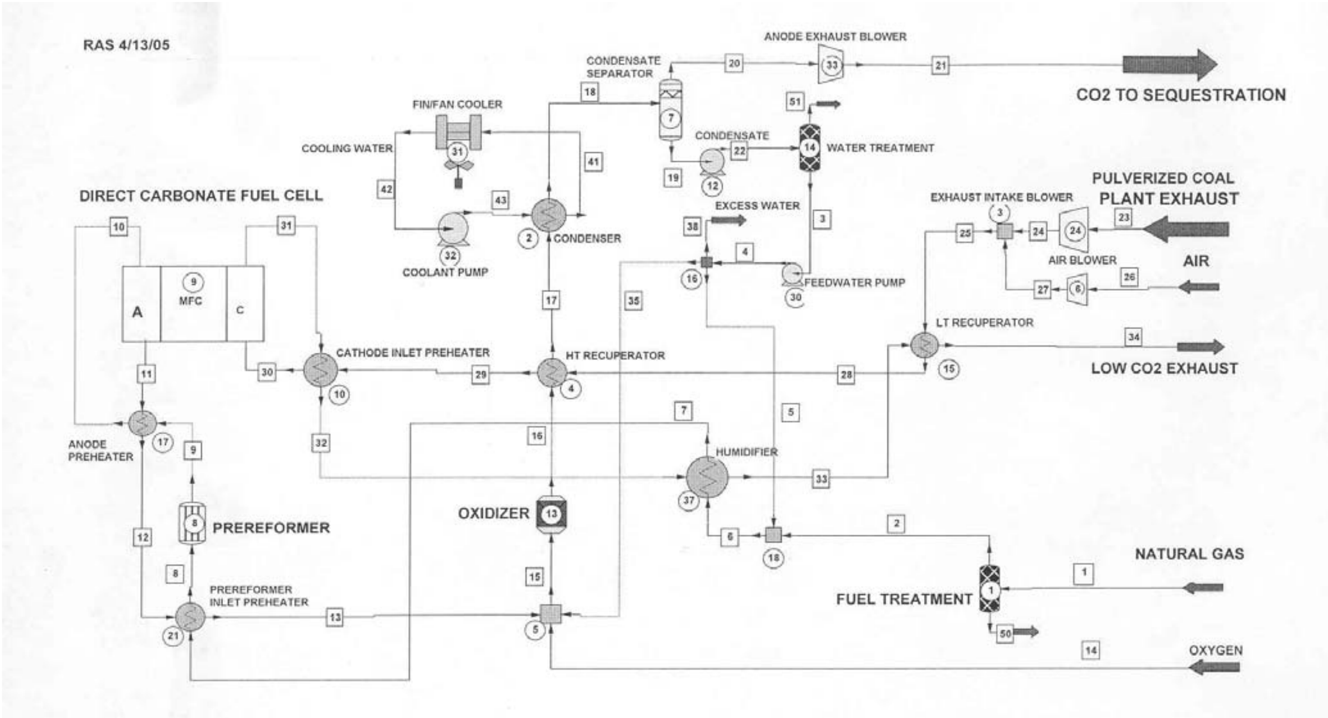

Figure 1.4-2 DFC-based CO_2 Separation System (Baseline Configuration)

The CO_2 separation achieved in the system was estimated based on system simulations using typical exhaust compositions from three types of conventional coal fired power plants: a pulverized coal/boiler/steam cycle plant, an atmospheric pressure circulating fluidized bed/boiler/ steam plant and an integrated gasifier combined cycle plant. The GHG or flue gas feed flow rate used for the simulations corresponded to 200 MW plant output. The performance of the DFC CO_2 separation system for processing of the three types of power plant exhausts is shown in Table 1.4-1. The results are shown for three levels of CO_2 utilization (or transfer efficiency) at the cathodes, 70%, 80% and 90%. The table shows the CO_2 emissions to the atmosphere and the amount of CO_2 in the CO_2-rich stream available for sequestration. For example, a 200 MW PC power plant with DFC CO_2 separation system running at 80% CO_2 utilization would put only 990 tons/MW-yr CO_2 into the atmosphere and send 5,317 tons/MW-yr CO_2 to sequestration. The additional power generated by DFC-based CO_2 sequestration system was also included in estimation of these numbers. The gas compositions of the stream available for CO_2 sequestration for the three plant types studied were very similar. The table also shows the CO_2 emissions to the atmosphere that would occur in the coal fueled plants in absence of the CO_2 separation system. For example, a 200 MW PC plant would put about 8,050 tons of CO_2/MW-yr into the atmosphere. A 200 MW CFB would put 8,746 tons/MW-yr into the atmosphere, and an existing IGCC plant would put 7,258 tons/MW-yr into the atmosphere.

Table 1.4-1
DFC-based CO_2 Separation System Performance

PLANT TYPE	200 MW EXHAUST FLOW LB MOLE/HR	CO2 UTILIZATION %	FC PWR MW	TOTAL MW	CO2 TO ATM MOLE/HR	CO2 TO SEQUEST MOLE/HR	CO2 TO ATM TONS/MWYR	CO2 TO SEQUEST TONS/MWYR
PULVERIZED COAL/STEAM PLANT	69,269	BASE PLANT		200	8354		8050	
		70	109	309	2503	7849	1559	4888
		80	125	325	1670	8971	990	5317
		90	141	341	832	10092	471	5708
ATM CIRCULATING FLUIDIZED BED	63,032	BASE PLANT		200	9077		8746	
BOILER/ STEAM PLANT		70	119	319	2739	8529	1655	5153
		80	136	336	1814	9747	1040	5592
		90	153	353	909	10964	496	5987
IGCC PLANT (EXISTING)	100,563	BASE PLANT		200	7532		7258	
		70	99	299	2261	7079	1458	4567
		80	113	313	1501	8091	925	4984
		90	127	327	750	9102	442	5365

Detailed design of the baseline CO_2 separation system was then developed. Its application to pulverized coal (PC) boiler steam cycle plant was selected for further studies. It is anticipated that the developed detailed design for PC plant will also be suitable for the IGCC and CFB cases with minor or no modifications. The system simulation was revised to reflect the fuel cell performance (with 90% CO_2 utilization at the cathodes) established based on fuel cell tests conducted under Task 2.1. Tables 1.4-2 through 1.4-4 summarize the results for a 200 MW PCP retrofitted with the DFC-based CO2 separation system (baseline configuration). This plant without CO_2 separation system releases 22 tons/MW-day of CO_2 into the atmosphere. With the addition of the DFC separation system, the CO_2 released to the atmosphere from the combined PCP and DFC system is 1.4 tons/MW-day. The CO_2 flow to sequestration is 16.3 tons/MW-day. The performance and flow conditions for the DFC system supporting the 200 MW PCP are shown in Table 1.4-3. The parasitic power estimate does not include power for cooling fans (for air-cooled system), flue gas desulfurizing or an oxygen plant. The configuration of the DFC system producing 126.6 MW of net AC power is specified in Table 1.4-4. Overall, for a typical PC power plant, the DFC-based CO2 separation system reduces the CO2 released into the atmosphere from 22 to 1.4 tons/MW-day. This is about 94% reduction in the CO_2 emission to the environment per unit of energy produced.

An equipment list was prepared as shown in Table 1.4-5. The fuel cell plant is arranged in 14 sections. Each section includes 10 fuel cell modules, which are grouped in two 5-module clusters as shown in Figure 1.4-3. Each 5-module cluster produces about 5 MW which is converted to 13.8 kV in a power conditioning system. Each section also includes the balance of plant equipment for fuel and GHG delivery, and thermal management subsystems to support the operation of the fuel cell modules. The plant has a central control system that includes the process control logic for operation of the plant, as well as provisions for coordination and sequencing of the plant’s start-up and shutdown. Heaters for plant start-up are also included in each plant section.

Table 1.4-2
PCP Exhaust Summary

		LB MOLE/HR	LB/HR	TONS/DAY
PCP POWER OUTPUT, MW	200			
PCP EXHAUST FLOW		69,269	2,002,000	24,000
PCP EXHAUST CO2 SEPARATED, %	90			
STREAM FLOW TO SEQUESTRATION		11,385	470,000	5,640
STREAM TO SEQUESTRATION, DEWPOINT, F	110			
STREAM COMPOSITION TO SEQUESTRATION,%				
CO2	88.8			
H20	9.1			
N2+AR	0.96			
O2	1.2			

Table 1.4-3
DFC-based CO_2 Separation System Summary

		LB MOLE/HR	LB/HR	TONS/DAY
DFC SYSTEM GROSS AC OUTPUT, MW	134			
FUEL CELL SYSTEM NET AC POWER, MW	126.6			
NATURAL GAS FLOW TO SYSTEM		2,530	43,700	513
OXYGEN FLOW TO OXIDIZER		1,528	48,600	583
DFC SYSTEM EXHAUST FLOW		80,108	2,200,000	26,000
DFC SYSTEM EXHAUST TEMP, F	177			
EXHAUST STREAM COMPOSITION ,%				
CO2	1			
H20	11.4			
N2 + AR	82.6			
O2	5.0			
FUEL CELL PERFORMANCE, mA/cm^2 @ 0.77V/cell	104.4			
FUEL CELL HYDROGEN UTILIZATION,%	74			
DFC SYSTEM PARASITIC LOADS, KW TOTAL	7,128			
PCP EXHAUST BLOWER, kW	4,859			
(SUPPLEMENTAL) AIR BLOWER, kW	1,497			
ANODE EXHAUST BLOWER, kW	490			
CONDENSATE PUMP, kW	9			
FEED WATER PUMP, kW	2			
COOLANT PUMP, kW	271			

Table 1.4-4
DFC-based CO_2 Separation System Configuration

DFC PLANT CONFIGURATION	
Number of fuel cell stacks	560
Number of MW-class (M10) fuel cell modules	140
Number of M10 module clusters	28
Number of plant sections	14
Number of power conditioning units	28
NET POWER PER FUEL CELL SECTION, KW	9043

Table 1.4-5.
DFC-Based CO_2 Separation System Equipment List

	SCHEMATIC DESIGNATION	QUANTITY (NUMBER)
MECHANICAL EQUIPMENT		
4-STACK FUEL CELL MODULES	9	140
PRE-REFORMER	8	14
ANODE GAS OXIDIZER	13	14
NATURAL GAS FUEL TREATMENT	1	1
FLUE GAS DESULFURIZATION SYSTEM	NS *	1
OXYGEN SUPPLY SYSTEM	NS *	1
WATER TREATMENT SYSTEM	14	1
I&C AIR SYSTEM	NS *	1
HUMIDIFIER	37	14
PREREFORMER INLET PREHEATER	21	14
ANODE PREHEATER	17	14
LT (LOW TEMPERATURE) RECUPERATOR	15	14
HT (HIGH TEMPERATURE) RECUPERATOR	4	14
CATHODE INLET PREHEATER	10	14
FIN/FAN COOLER	31	14
CONDENSER	2	14
CONDENSATE SEPARATOR	7	14
CELL STACK START HEATER	NS *	28
PRE-REFORMER START HEATER	NS *	14
EXHAUST INTAKE BLOWER	24	14
AIR BLOWER	6	14
AIR FILTER	NS *	14
ANODE EXHAUST BLOWER	33	14
CONDENSATE PUMP	12	14
FEEDWATER PUMP	30	1
COOLANT PUMP	32	1
ELECTRICAL EQUIPMENT		
POWER CONDITIONING SYSTEMS	NS *	28
CENTRAL CONTROL SYSTEM	NS *	1
MOTOR CONTROL CENTER	NS *	1
* NS =NOT SHOWN ON SCHEMATIC		

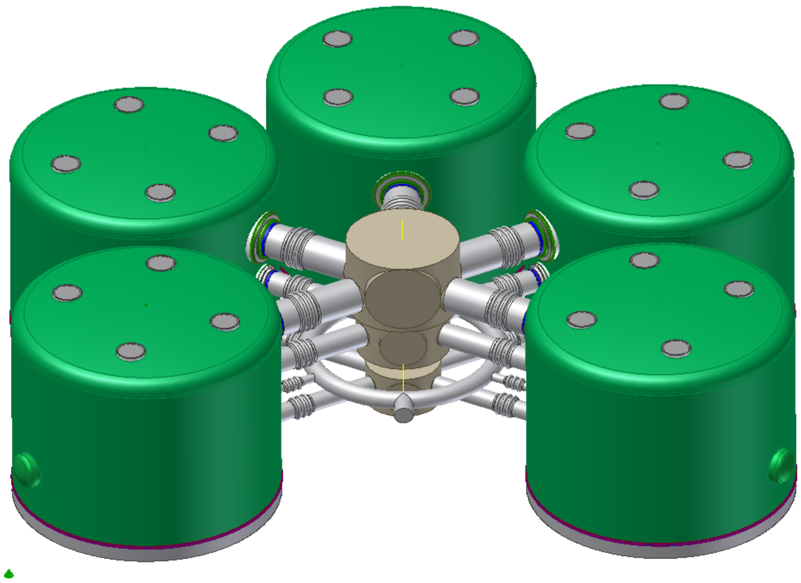

Figure 1.4-3. Five-Module Fuel Cell Cluster

The plant includes a central oxygen supply that provides oxygen to the anode gas oxidizer in each of the 14 plant sections. The requirement for the oxygen plant was estimated to be 583 tons/day. A specification for the oxygen plant was prepared and a meeting was arranged with PRAXAIR, a leading supplier of air separation plants. Information acquired in the meeting discussions included the recommendation that a cryogenic process air separation plant providing 97% oxygen purity was optimum. The technical and cost Information on the oxygen plant provided by PRAXAIR included parasitic power requirement estimated at about 6300 KW, plant footprint estimated at 150' x 150', capital cost estimated at 11-12 million dollars and yearly maintenance cost estimated at 2-2.5% of capital cost. This information was utilized in the system cost analysis covered later in the report.

Cost Estimate and COE Analysis for Baseline System

The baseline direct fuel cell system for carbon sequestration separates 90% of the CO_2 from flue gas of a 200 MW PCP and delivers an additional 126.6 MW of power. A capital cost estimate was prepared for the initial installation of the CO_2 separation system. Where similar, the cost of equipment was derived from FCE's recently updated cost database for multi-MW fuel cell power plants. Cost scaling factors were used for each equipment item, based on equipment size and number of items required for the plant. In addition to the process equipment cost, the estimate also included the cost of material and equipment that are part of the site installation such as civil works, piping, cabling and insulation, and the installation labor cost. Specification for a flue gas desulfurization subsystem (FGD) was prepared and forwarded to Babcock Power. However, FGD subsystem cost was not available in time to be included in the cost analysis. Estimated cost of the DFC-based CO_2 separation system is \$2467/kW, exclusive of the FGD subsystem. This capital cost is the incremental capital investment based on the 126.6MW additional power produced by the DFC system. On the basis of the total (DFC + PCP) 326.6 power, the cost is 886$/kW for the first unit. The cost analysis was extended to study the effect of DFC system annual manufacturing rate (production rate) on the capital cost requirements. The analytical approach used was based on the “learning curve” method, which is a prevalent method in manufacturing industry. The learning curve methodology predicts the effect of production rate on manufactured product cost. The analysis resulted in sets of cost reduction factors (CRF), which were used to scale down the initial capital cost estimates as a function of production rate per year.

Based on the cost reduction factors developed, the capital cost was estimated for various system installation quantities per year (manufactured quantities per year). The capital cost in $/kW of the 126.6 MW DFC-based CO_2 separation plant is shown in Figure 1.4-4 for 1 to 10 installations per year. Based on the estimated cost and the learning curve in manufacturing, the plant cost is expected to be lowered from 2467$/kW for the initial plant down to 1428 $/kW for a mature commercial product with a production rate of ten plants per year. These costs are based on the additional power of 126.6 MW generated by the fuel cell. Figure 1.4-4 also shows the specific cost ($/kW) based on the total power plant output (PCP + DFC) of 326.6 MW.

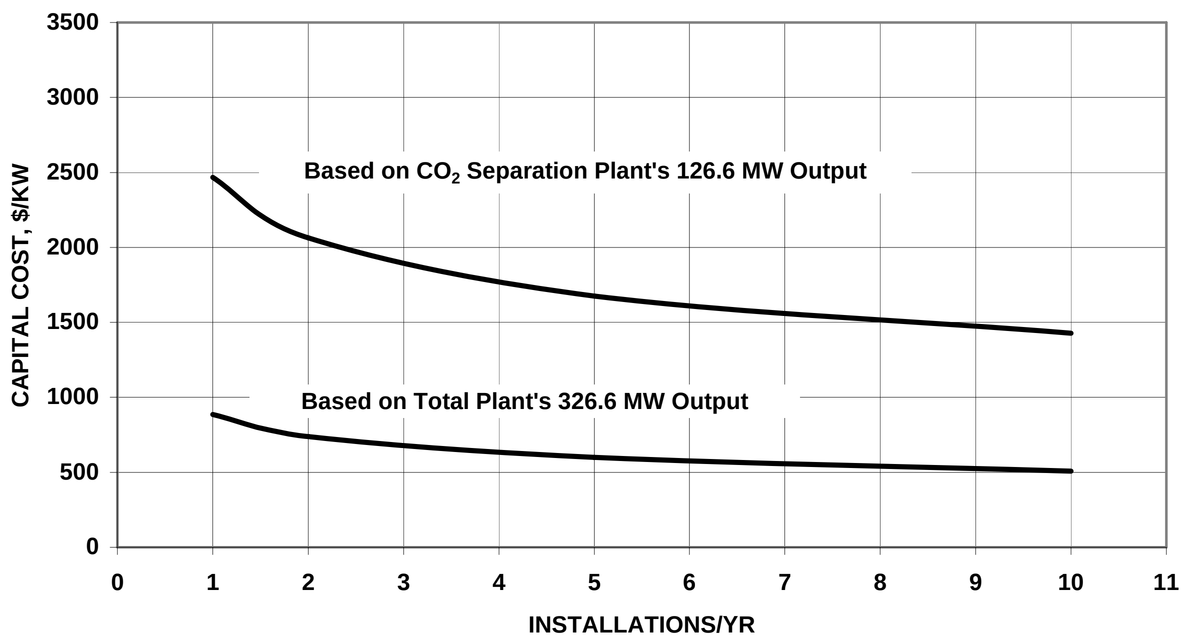

Figure 1.4-4 Capital Cost Estimate For Fuel Cell Based CO2 Separation Plant

For comparison, the capital cost of a base 200 MW PCP was estimated at about 1700 \$/kW including flue gas desulfurization. This estimate[1] is based on Figure 1.4-5 where PCP plant capital cost is shown for a range of plant sizes.

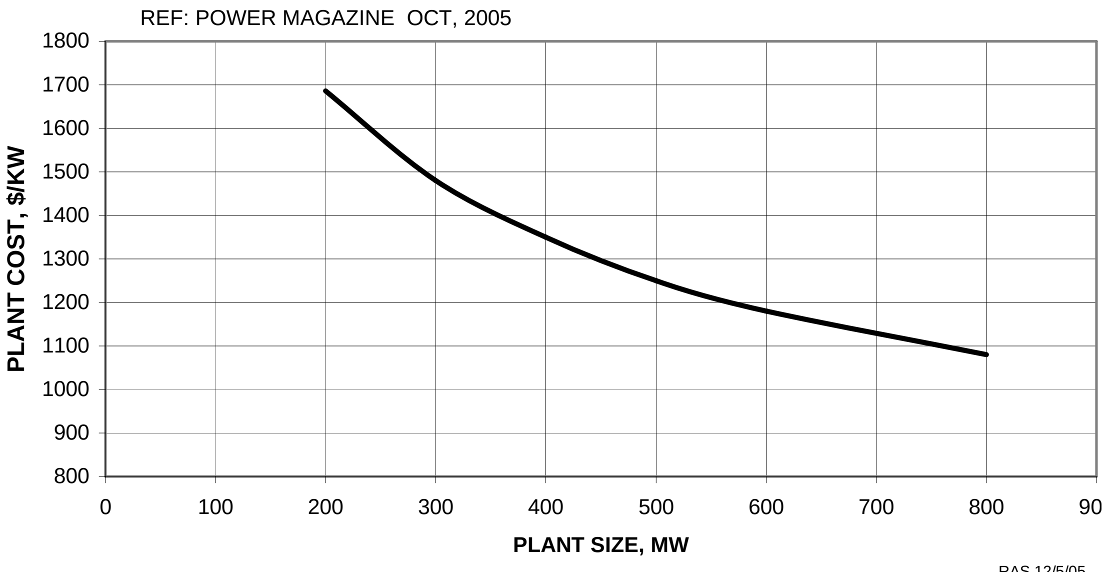

Figure 1.4-5 Pulverized Coal Plant (PCP) Cost vs. Plant Size

Subsequent to the derivation of capital and installation costs, a cost-of-electricity (COE) analysis was performed. The analysis was performed for a range of DFC-based CO_2 separation plant installations from 1 to 10 units/year. Since the DFC-based CO_2 separation plant operates on natural gas, the COE estimates were also based on a range of natural gas cost from \$6/MMBtu to \$10/MMBtu. The basis of 7.42 cents/kWhr COE (reported as average COE on the Energy Information Administration website) was used for the 200 MW PCP power generation. The total levelized cost of electricity for a 200 MW PCP retrofitted with DFC-based CO_2 separation plant (producing 126.6 MW additional power, thereby outputting total 326.6 MW) is shown in Figure 1.4-6. The cost increase, to the existing PCP, associated with this CO_2 separation and supplementary power generation is shown in Figure1.4-7. The cost increase, in the levelized cost of electricity, as a percentage is presented in Figure 1.4-8 for a range of separation plant installations per year and a range of natural gas cost. The plot also shows the goal (<20% increase in COE) reference line, thereby identifying the parametric envelope meeting the goal. As shown in Figure 1.4-8, the objectives of limiting the increase in cost of power generation (COE) to below 20% is achievable at production rates of 5 or more units per year, in line with DOE targets[2]. Therefore, it is anticipated that commercial DFC systems are able to reach a competitive pricing structure for carbon sequestration.

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[1] Bill Hoskins and George Booras, “Assessing the Cost of New Coal-Fired Power Plants”, Power Magazine, October 2005, Pages 24-28
[2] Carbon Capture and Sequestration Systems Analysis Guidelines”, NETL, April 2005

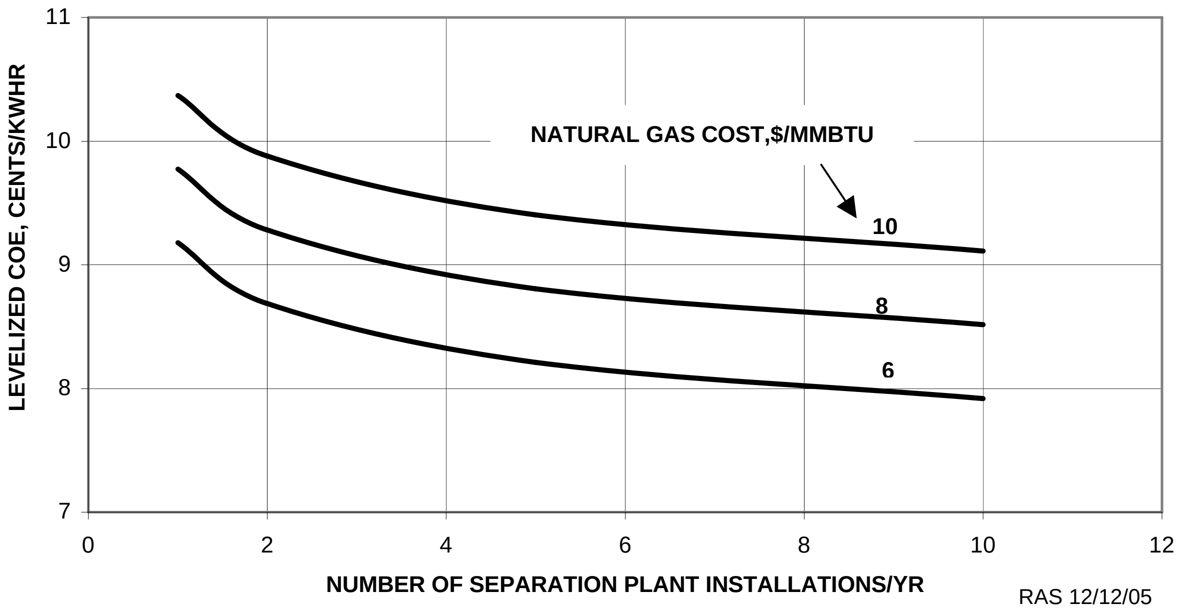

Figure 1.4-6 Cost of Electricity Estimate for 200 MW PC Plant Retrofitted with Fuel Cell Based CO_2 Separation Plant

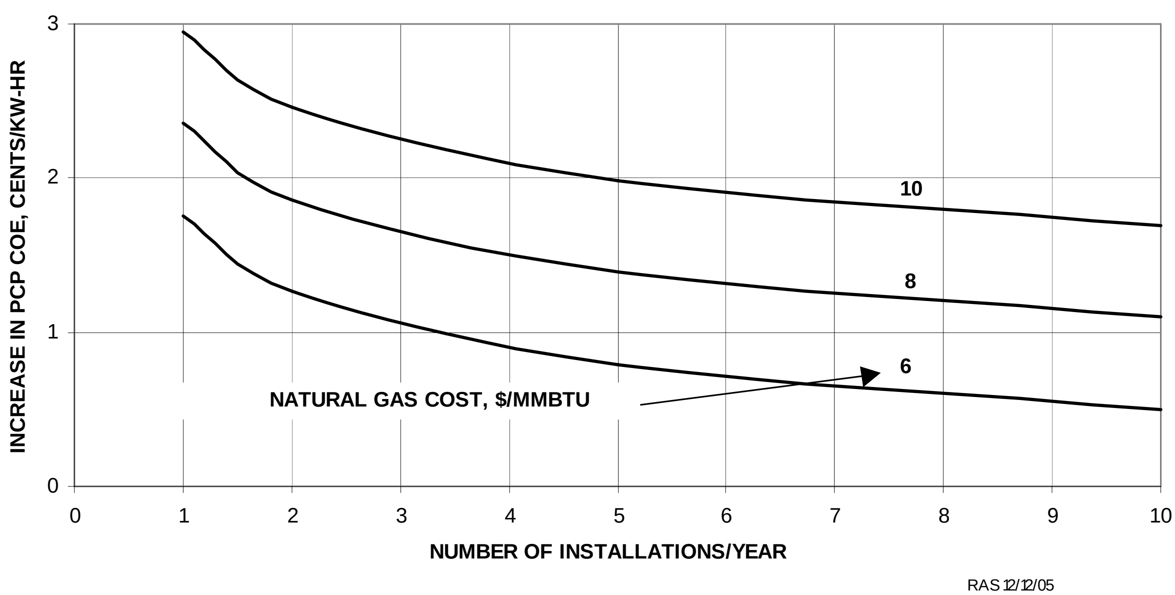

Figure 1.4-7 Increase in Cost of Electricity for 200MW PC Plant Retrofitted with Fuel Cell Based CO_2 Separation Plant

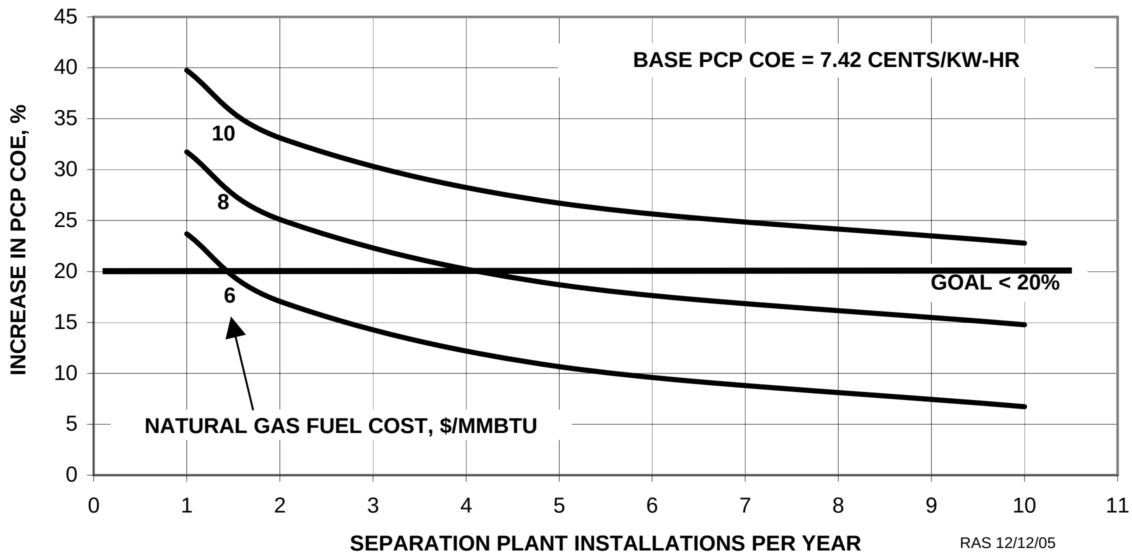

Figure 1.4-8 Percent Increase in Cost of Electricity for 200MW PC Plant Retrofitted with Fuel Cell Based CO_2 Separation Plant

Alternate Systems

In addition to the baseline configuration, two alternate configurations for the DFC-based CO_2 separation system were also developed. The alternate configurations incorporated a H_2 separation unit. One design option was using proton exchange membrane (PEM) fuel cell-based electrochemical hydrogen separator (EHS) technology to separate hydrogen from the DFC anode exhaust. The other option was based on the conventional technology of pressure swing adsorption (PSA) to separate H_2 from the CO_2–rich DFC anode exhaust stream.

The system analyses, including mass and energy balances, were performed for the alternate DFC-based CO_2 separation systems. A portion (~45% for the EHS option) of the recovered or separated (almost pure) H_2 was mixed with air (preheated) and fed to a catalytic oxidizer to provide the needed preheat for the cathode feed gas (flue gas from coal plant). The remaining H_2 (~21 lb/MW-h DFC generation) was available as a co-product. When the extra H_2 (available as a co-product) was recycled to DFC anode as a supplementary fuel, DFC natural gas fuel consumption decreased by ~14% (effective fuel utilization increased from 74 to 85.5%).

Task 2 Fuel Cell Testing

Task 2.1 Performance Testing

Lab-scale single cells (carbonate fuel cell) were assembled to conduct the test experiments. The performance testing was carried out using bottled gas. Gas cylinders were ordered to provide pre-mixed gases simulating (on dry basis) the GHG (flue gas) from PC boiler steam cycle and IGCC power plants. The gas mix simulating PC boiler GHG included air supplementation necessary to enhance O_2 concentration sufficiently to ensure ~5% O_2 at the cathode exit. The bottled gas was used as the cathode feed after humidification to simulate GHG on wet basis. A standard fuel gas was used as anode feed. The extent of CO_2 separation from GHG (percent CO_2 seperated) is equivalent to the fuel cell carbon dioxide utilization as a result of CO_2 transfer to the anode. Constant CO_2 utilization cell polarization data were collected at 90, 80 and 70% utilizations. Fuel utilization was maintained at 74% throughout the tests to ensure consistency of the results. Cell inlet and exit gas compositions were measured using a gas chromatograph to estimate the reactant utilizations and to confirm cathode-to-anode CO_2 transfer. The test results and related data analysis are presented under Task 2.2 next.

Task 2.2 Test Data Analysis

Cell polarization characteristic curves were prepared based on the data collected during the single cell tests reported under Task 2.1 above. Figure 2.2-1 shows the data and constant CO_2 utilization curves for 90, 80 and 70% CO_2 utilizations based on the polynomial fit over the whole range of the current density, obtained using the simulated PC boiler GHG. To provide useful feedback for the system simulation work, linear least square fit was also applied in the narrower current density range of interest. Figure 2.2-2 presents the constant CO_2 utilization plot for 90% utilization. Linear trend line equation and correlation coefficient (R-squared) indicating the degree of the statistical fit between the experimental data and trend line are included. A very good correlation for the linear fit was observed.

Similarly, Figure 2.2-3 shows the data and constant CO_2 utilization curves for 90, 80 and 70% CO_2 utilizations based on the polynomial fit over the whole range of the current density, obtained using the simulated IGCC GHG. Figure 2.2-4 presents the corresponding linear least square fit plot (for 90% CO_2 utilization) in the current density range of interest. The performance observed in single cell tests using IGCC GHG was found to be comparable with that observed using simulated PC boiler GHG.

The test results showed that 90% CO_2 transfer in carbonate fuel cell application for CO_2 separation is possible. The fuel cell performance data acquired were utilized to refine the system simulations in Task 1.4. The detailed design of the baseline CO_2 separation system and related cost of electricity analysis were therefore based on the actual test results.

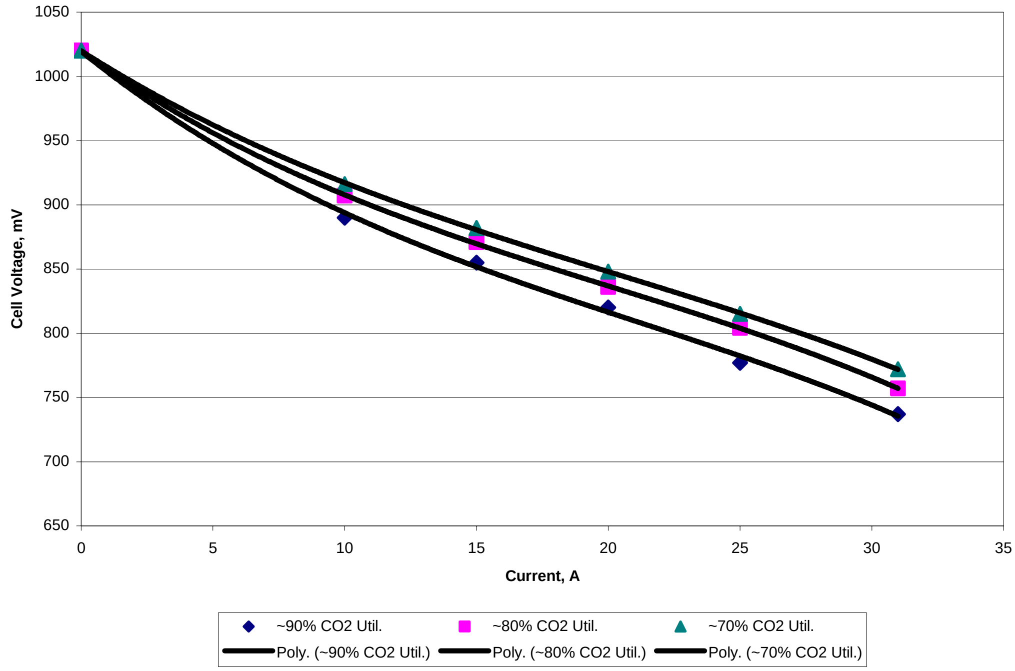

Figure 2.2-1 Single Cell Polarization Curves on Simulated PC Boiler GHG

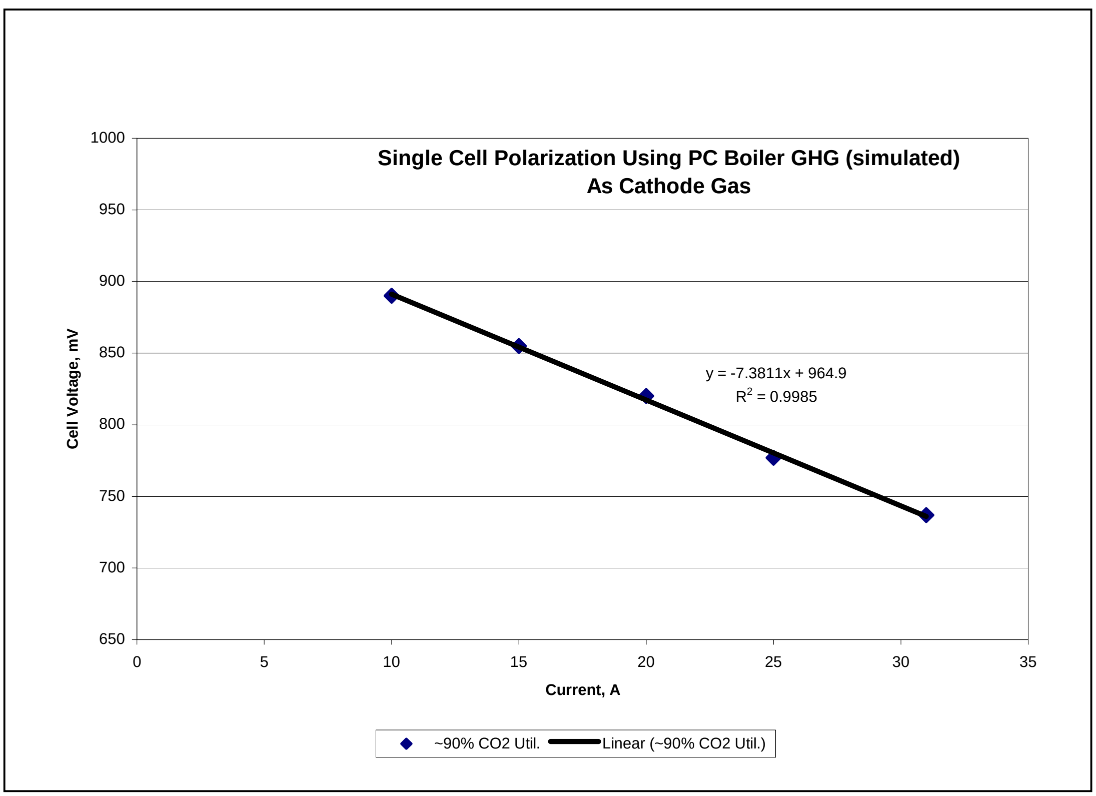

Figure 2.2-2 Constant CO_2 Utilization Plot at 90% Utilization with Linear Fit

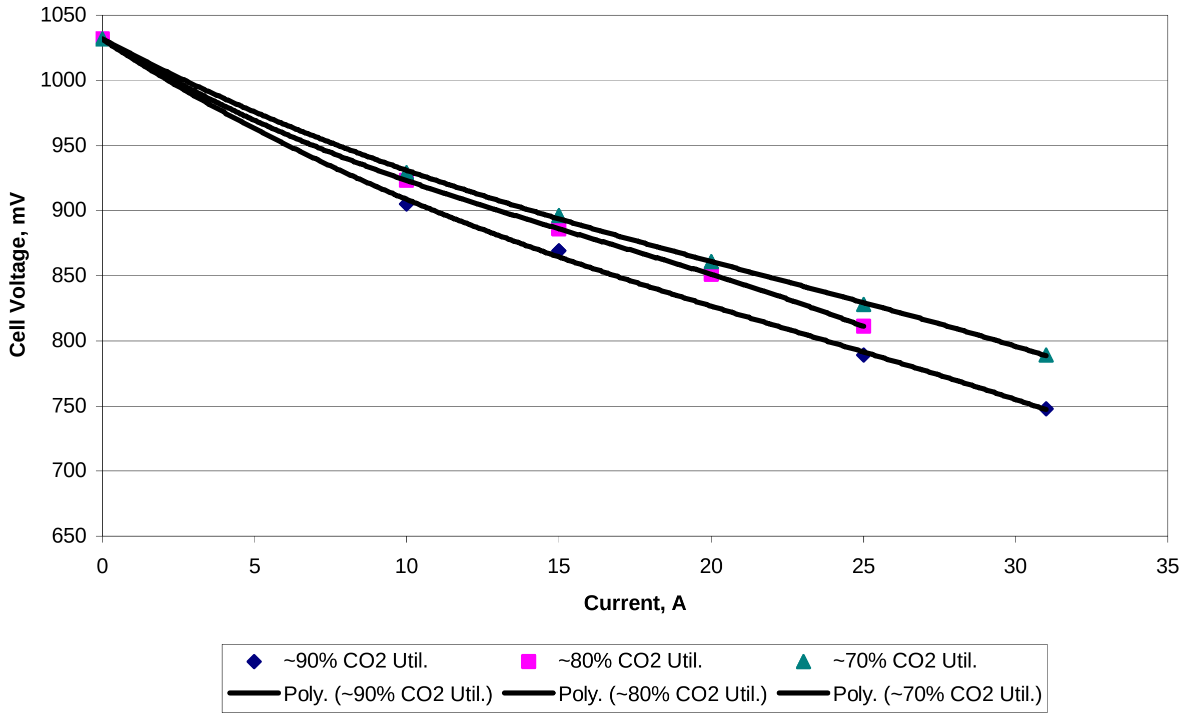

Figure 2.2-3. Single Cell Polarization Curves on Simulated IGCC GHG

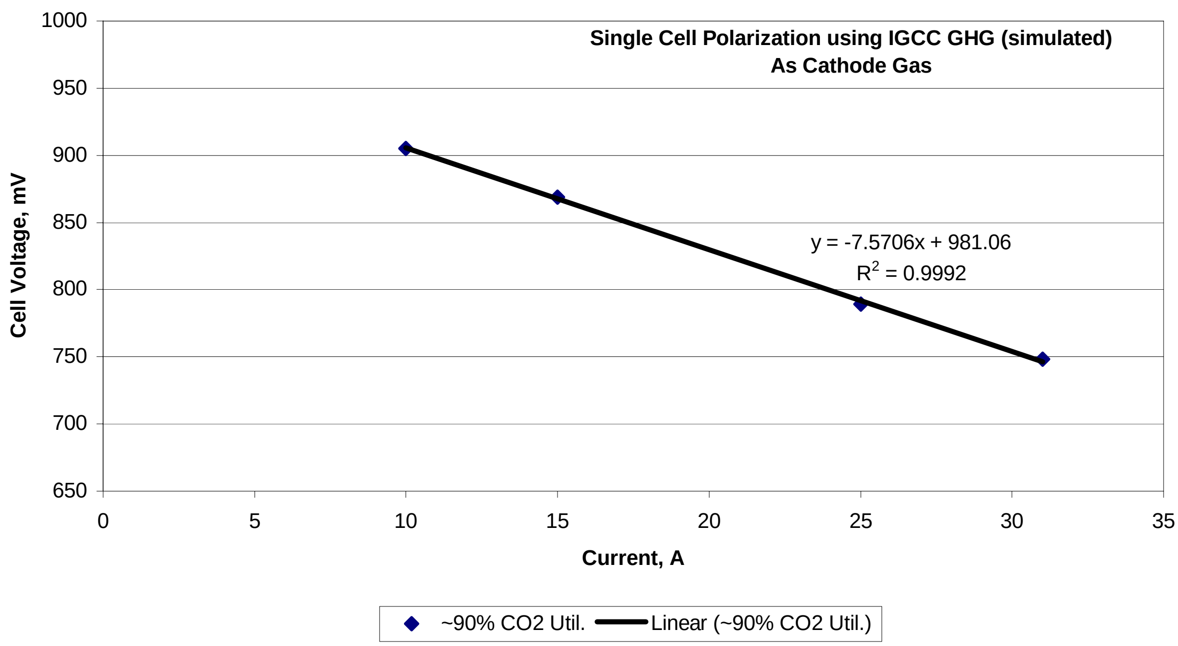

Figure 2.2-4. Constant CO_2 Utilization Plot at 90% Utilization with Linear Fit

3. Conclusion

The main objective of the project, conceptualization of carbonate fuel cells for separation of carbon oxide from the greenhouse gases (GHG), was completed successfully. The concept was applied for the removal of CO_2 from flue gas (exhaust) of the coal-fueled power plants. Three types of coal-fired power plants were considered: pulverized coal (PC) boiler steam cycle, atmospheric circulating fluidized bed (CFB) boiler steam cycle, and integrated gasification combined cycle (IGCC) plants. The project conducted the research and development essential for system design, process optimization and cost estimation of the fuel cell-based CO_2 separation system. The CO_2 separation system's potential was evaluated for its application to a 200 MW PC power plant.

A database of coal-fired power plant exhaust stream (flue gas or GHG) characteristics including emission levels was compiled based on literature search. A design bases document defining the system requirements for the DFC-based CO_2 separation system was prepared. The information was used to guide the system configuration and simulation activity. Conditioning of the coal plant flue gas to make it suitable for feed to DFC was considered. A flue gas desulfurization (FGD) unit in combination with a downstream polishing bed can be used to capture the sulfur (SO_2). Further, flue gases from the PC and the CFB boiler steam cycle plants are somewhat lean in oxygen (one of the reactant for DFC). Air supplementation prior to their feed to DFC for proper operation of the fuel cell was incorporated. It is recommended that the flue gas clean-up subsystem especially the combined deep desulfurization and mercury removal systems, be the subject of further development in the future.

The anode exhaust post-treatment options for the DFC-based CO_2 sequestration system were explored. The baseline system configuration included an oxidizer. The alternative configurations incorporated a hydrogen separation unit. Both, a PEM fuel cell-based electrochemical hydrogen separator and a pressure swing adsorption-based unit were considered.

System simulations for the baseline DFC CO_2 separation system using GHG from the 200 MW coal-fired plants were performed. System analyses included estimation of CO_2 available in the stream for CO_2 sequestration and CO_2 emitted to atmosphere, and the impact of CO_2 transfer effectiveness (CO_2 utilization at DFC cathode) in 70-90% range on these results. The baseline system was designed to separate 90% of the carbon dioxide emissions from a 200MW pulverized coal power plant (PCP). The detailed design included equipment list and sizing (for cost analysis). The DFC-based CO2 separation system retrofitted to the 200 MW PCP generated additional 126.6 MW of power. The PC plant without CO_2 separation system released 22 tons/MW-day of CO_2 into the atmosphere. With the addition of the DFC separation system, the CO_2 released to the atmosphere was 1.4 tons/MW-day (based on 326.6 MW total power). The CO_2 flow to sequestration was 16.3 tons/MW-day. Overall, for the PC power plant, the DFC-based CO2 separation system reduced the CO2 released into the atmosphere from 22 to 1.4 tons/MW-day. This is about 94% reduction in the CO_2 emission to the environment per unit of energy produced. In parallel to the design activities, laboratory scale carbonate fuel cells were operated, using bottled gas simulating GHG from PC boiler steam cycle plant and GHG from IGCC plant, to verify the benefits of the concept and to provide input to the design activity. The carbonate fuel cell's potential to transfer 90% of CO_2 from the cathode feed gas to the anode side was verified by the cell tests.

Capital cost estimates and cost of electricity (COE) analysis for the baseline DFC CO_2 separation system were performed. The capital cost for the initial installation of the CO_2 separation system was estimated to be 2467$/kW (DFC power) and 886 $/kW (total power), exclusive of the FGD subsystem. The study included the effects of the number of installations (1 to 10 installations per year) on the DFC system capital cost. The installed cost of the CO_2 separation system is anticipated to decrease down to 1428 $/kW (DFC power) and $509/kW (total power) for a commercial production in excess of ten units per year.

The cost of electricity analysis included the estimation of COE for a range of DFC-based CO_2 separation plant installations and a range of natural gas prices from $6/MMBtu to $10/MMBtu. The total levelized cost of electricity for a 200 MW PCP retrofitted with DFC-based CO_2 separation plant (producing 126.6 MW additional power) was estimated. The basis of 7.42 cents/kWhr COE was assumed for the 200 MW PCP power generation. The increase in the cost of electricity, as a percentage of the basis, was estimated for the PC power plant. The parametric envelope meeting the goal (<20% increase in COE) was identified.

The results show that even at low production quantities (5 or more), the DFC systems have the potential to meet the stringent requirements of less than 20% increase in the cost of electricity while reducing the carbon dioxide emissions by 90%. The anticipated cost of energy increase is in line with DOE's goal for post-combustion systems as outlined in the "Carbon Capture and Sequestration Systems Analysis Guidelines", published by NETL, April 2005. Overall results indicate that the utilization of Direct FuelCell may provide an attractive alternative for carbon dioxide separation from exhaust of coal fired plants and simultaneous generation of electric power at very high efficiencies.

The system analyses including mass and energy balances for the alternate DFC-based CO2 separation system configurations using PEM-based EHS option (to separate H_2 from the CO_2–rich DFC anode exhaust stream) and the conventional PSA option were completed. The system with EHS option shows a promising method for recovery of hydrogen from the anode exhaust gas. Greater than half of the hydrogen in the anode exhaust may be recovered and sold as a by-product of the CO_2 separation system. The EHS alternative has the potential for reduction of the overall cost, and offers an attractive opportunity for simultaneous co-production of electricity and hydrogen, while preventing the release of GHG to the environment. Future work towards the development of EHS and the detailed design of the alternate system is one of the research and development activities, which is strongly recommended.

List of Acronyms and Abbreviations

AC	alternating current
BOP	balance of plant
CFB	circulating fluidized bed
COE	cost of electricity
CRF	cost reduction factor
DFC	direct (carbonate) fuel cell
EHS	electrochemical hydrogen separator
EPRI	Electric Power Research Institute
ESP	electrostatic precipitator
FCE	FuelCell Energy, Inc.
FGD	flue gas desulfurization
GHG	greenhouse gas
HHV	higher heating value
HT	high temperature
IGCC	integrated (coal) gasification combined cycle
I&C	instument and control
kW	kilowatt
LHV	lower heating value
LT	low temperature
M10	FCE's megawatt-class fuel cell module
MW	megawatt
NG	natural gas
O&M	operating and maintenance
PC	pulverized coal
PCP	pulverized coal (boiler steam cycle power) plant
PEM	proton exchange membrane
PrOX	preferential oxidation
PSA	pressure swing adsorption