ECONOMIC AND TECHNICAL STUDY OF CARBON DIOXIDE REDUCTION TECHNOLOGIES

A Thesis Presented to The Academic Faculty

By

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In Partial Fulfillment Of the Requirements for the Degree Master of Science in Mechanical Engineering

Georgia Institute of Technology

December, 2006

ECONOMIC AND TECHNICAL STUDY OF CARBON DIOXIDE REDUCTION TECHNOLOGIES

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Date Approved: October 18th, 2006

ACKNOWLEDGMENTS

This study was conducted under the guidance of Dr. Sam Shelton, Associate Professor Georgia Institute of Technology and Dr. William Wepfer Vice Provost for Distance Learning and Professional Education. Dr. Shelton and Dr. Wepfer provided tremendous insight into conducting research at the academic level. My co-workers at General Electric provided invaluable assistance in identifying technologies, relevant literature and generating figures. Finally, the study would not have been possible without the support of my family, especially my parents and wife.

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SUMMARY

An economic and technical study of carbon dioxide (CO_2) reduction technologies was conducted. In order to compare technologies on a consistent economic and technical basis evaluation guidelines were proposed. Data on the emissions impact and cost impact of each technology was collected through a literature review. The CO_2 reduction cost was available for some technologies and calculated as part of the study for the remainder under consideration. The CO_2 reduction cost was compared to the current market value of CO_2 emissions credits in the European Trading Scheme. Results indicate that for existing power plants efficiency improvements such as boiler optimization are capable of providing modest CO_2 emissions reductions for less than the market value of CO_2 credits. More significant reductions are available through post-combustion flue gas decarbonization and pre-combustion fuel decarbonization at cost comprable to CO_2 credit values seen in 2006. Systems processes indicate pre-combustion fuel processing is capable of significant cost reduction through further technology development. These findings provide guidelines for how a single power plant owner or power plant portfolio owner may choose a CO_2 reduction stratedy. The impact on fuel price sensitivity and on advanced technology developers was discussed.

CHAPTER 1

INTRODUCTION

Climate change is an environmental, technical and political challenge. On the environmental front, the evidence indicating the human contribution to global warming is widely accepted in the scientific community (U.S. Greenhouse Gas Inventory Program, 2002). Meanwhile, the impact of global warming on the environment is potentially wider spread than previously conceived (Christensen, 2004). Approximately 37 percent of CO_2 emissions are from electricity and heat production; therefore, power plant equipment manufactures have the technical challenge of reducing CO_2 emissions without sacrificing efficiency and cost of electricity (Sims et al 2003). On the political front, twenty-six countries ratified the Kyoto Protocol and accepted greenhouse gas reduction targets, which together will result in a 5.2 percent reduction of greenhouse gas emissions below 1990 levels (Vitaly, 2006). The greenhouse gases targeted for reduction are listed in Table 1.

Table 1: Greenhouse gases potential and concentrations (U.S. Greenhouse Gas Inventory Program, 2002)

Greenhouse Gas	Global Warming Potential	Atmospheric Concentration (1998)	Rate of Concentration change
	Relative 100 yr horizon	Parts per trillion	Parts per trillion per year
CO_2	1	365	1.5
CH_4	21	1.745	0.007
N_2O	310	0.314	0.0008
SF_6	140 – 11700	4.2	0.24
CF_4	23900	80	1

Each greenhouse gas has a unique global warming potential relative to CO_2 (see Table, 1 column 2). Global warming potential is defined as "the cumulative radiative forcing…integrated over a period of time from the emissions of a unit mass of gas relative to [CO_2] (EPA 2002). While CO_2 has the lowest global warming potential, the atmospheric concentration, and the rate of increasing concentration, makes CO_2 the primary greenhouse gas targeted for reduction (UNFCCC 2005).

In order to facilitate CO_2 concentration reductions through credit trading, the European Union established the European Trading Scheme. Figure 1 shows the CO_2 forward trading prices from April 2005 to August 2006, prices have been converted from Euros to US dollars with an exchange rate of 1.2 U.S. Dollar per Euro. Current prices as of August 2006 are approximately \$20 per ton of CO_2.

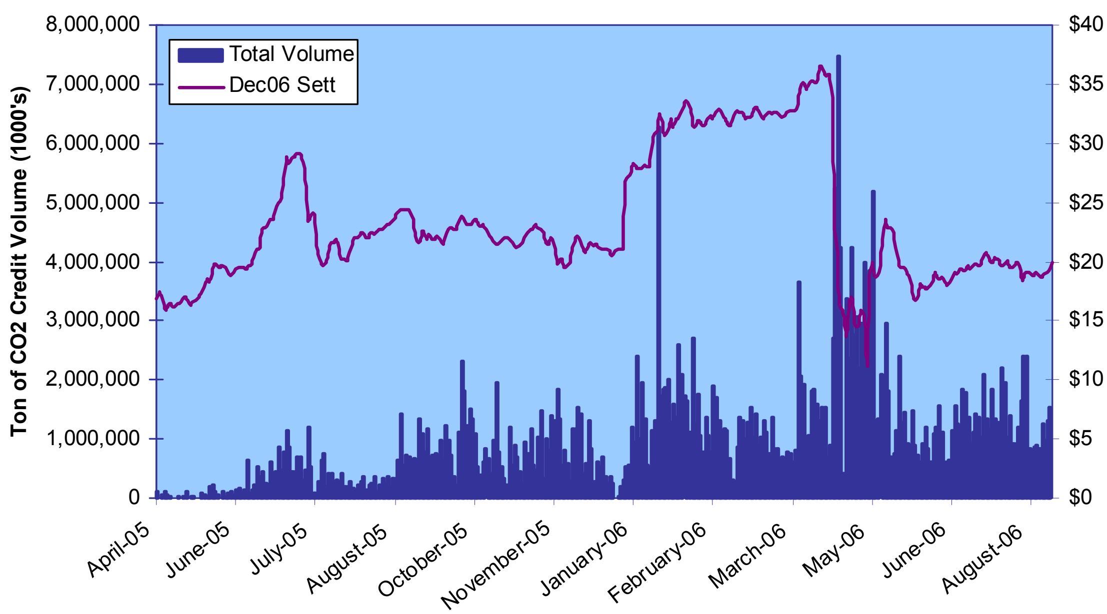

Figure 1: European Climate Exchange Forward Pricing Curve (ECX, accessed August, 2006)

At the country level, governments are formulating compliance strategies. One common aspect is the allocation of facility level targets to greenhouse gases emitting electric power producers. Consequently, electric power producers must balance the cost of greenhouse gas reductions, emissions credits, and the cost of electricity. Given that the market incentive to develop greenhouse gas reduction technologies is so new, many applicable technologies are still in the research and development phase. Some mature technologies developed for gas purification in industrial applications are suitable for CO_2 capture in power plants. One such technology is chemical absorption. Additionally, technologies typically used for higher thermal efficiency and fuel flexibility can also be applied to reduce greenhouse gas emissions. Given the plethora of potential technologies and the minimal operating experience, many power producers are faced with developing a greenhouse gas compliance strategy without sufficient data to compare options on a consistent technical and economic basis.

The purpose of this study is to review the current literature on greenhouse gas emissions reduction from power plants and to develop guidelines for comparing CO_2 mitigation technologies on a consistent technical and economic basis. The findings will aid the power producer's decision-making process regarding CO_2 mitigation strategies. Additionally, the findings will assist CO_2 reduction technology developers in understanding the competitive landscape. The technologies compared in this study include: chemical absorption; biological absorption; integrated gasification combined cycle; integrated reformer combined cycle; efficiency improvements; and fuel switching. Factored into the study will be CO_2 reduction cost, CO_2 credit trading, fuel price sensitivity and the impact on global warming. Not included in the scope of this study is CO_2 storage.

CO_2 storage is a critical step in a CO_2 capture process. Any CO_2 that is captured with the intent of preventing emissions must either be recycled or stored. The option to recycle will likely depend on the local industry need, and the options for storage will likely depend on local storage capabilities. For instance, power plants with CO_2 capture located near oil fields may be able to sell CO_2 for enhanced oil recovery. The evaluation of the various storage and recycling options are beyond the scope of this study. Nevertheless, when evaluating CO_2 reduction technologies, the quantity of CO_2 will incur additional cost or benefit depending on the disposal method. Kruetz notes that an approximate transport and storage cost for a ton of CO_2 is $5 (Kruetz, 2005).

CHAPTER 2

LITERATURE REVIEW

2.0 Introduction to CO_2 Capture

CO_2 capture from power plants entails the integration of a capture technology into a power plant system. The primary CO_2 capture technologies being considered are cryogenics, Adsorption, chemical absorption, and biological remediation.

Cryogenics is refrigeration of the gas stream to reduce the vapor pressure so phase change occurs and the liquid CO_2 can be distilled out of the mixture. Significant energy is required to cool the gas especially since the majority of power plant processes occur at high temperature. Without substantial new system integration, cryogenics does not appear either efficient or economically feasible for power plants and will not be included further in this study (Kohl 1997).

Biological remediation harnesses the natural process that plants undergo to consume CO_2 and convert it into biological material. Photosynthesis is the most common method of biological absorption, but some algae are known to utilize CO_2 in the absence of light. A portion of all CO_2 emissions is absorbed biologically by terrestrial plant life. However given the increased CO_2 atmospheric concentration of 0.4 percent per year, the absorption rate does not keep pace with emissions (U.S. Greenhouse Gas Inventory Program, 2002). To increase the rate of biological absorption, bioreactors are being developed to integrate into power plant systems (Bayless 2003).

Adsorption, occurs by passing the flue gas stream through a microporous solid adsorbent stream so that surface forces capture the CO_2 on the surface of the adsorbent without chemical reaction. Modifications of this process include pressure swing adsorption and temperature swing adsorption, which rely on high pressure and temperature respectively to activate surface forces and then low pressure or temperature to regenerate the adsorbent (ESRU 2006). Significant process and system development work is underway to implement absorption in power plants for CO_2 capture. Specific technologies will be addressed further in this study.

Like adsorption, chemical absorption entails passing the flue gas stream through an absorbent stream but in this case the CO_2 chemically reacts with the absorbent to reduce the Gibbs free energy of the mixture. The absorption reaction requires a low temperature of approximately $50^{o}C$ and the desorption reaction to regenerate the absorbent occurs at approximately 120 ^{o}C (ESRU 2006). Chemical absorption is most effective with low CO_2 concentrations and is therefore appropriate for flue gas processing where the CO_2 is diluted with air and steam.

To further consider CO_2 capture technologies, the technology must be placed in the context of the power plant. Among power plants fueled by natural gas, the current predominant system is natural gas combined cycle (NGCC). Among power plants fueled by coal the most common system is a pulverized coal power plant (PC). In both systems, the fuel is combusted without chemical preprocessing except that which is necessary to remove contaminants. However, both coal and natural gas are capable of being chemically reformed through partial oxidation reactions into syngas, a mixture of CO and

H_2. Subsequently the syngas may be combusted in a combined cycle system for electricity generation. When coal is the fuel the reforming occurs in a gasifier, this entire process is called integrated gasification combined cycle (IGCC). With natural gas the reforming can take place with catalytic partial oxidation (CPO) and the process is called integrated reforming combined cycle (IRCC). Chemical preprocessing through gasification or catalytic partial oxidation enables the carbon to be separated out of the syngas before the syngas is diluted by air in the combustion process. When capturing carbon pre-combustion, adsorption is typically employed to separate the carbon bearing species from the syngas. When coal or natural gas is combusted without chemical modification, chemical absorption is well suited to remove CO_2 from the flue gas. The performance of the separation technology is largely dependent on how it is integrated into the power plant system; therefore, for the majority of this study, capture technologies will be considered within the context of the power generation system. As seen in Figure 2, pre-combustion capture occurs at high total pressure and high CO_2 fraction. These conditions are present because the syngas exiting the reformer is at high pressure and has not yet been diluted with air. Capture under these conditions is inherently easier because there is a larger driving force so less energy input is required. Post-combustion capture occurs after the syngas has been diluted in the combustion process and expanded in the turbine. Therefore less driving force is present and separation is more difficult. Nevertheless, post-combustion capture requires less system integration than pre-combustion capture.

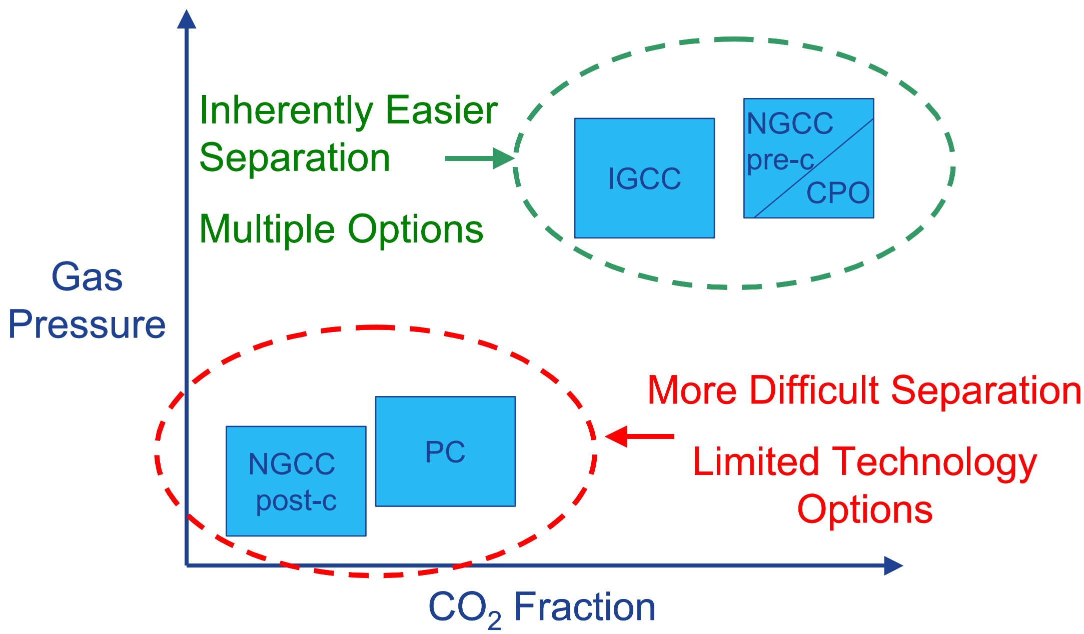

Figure 2: CO_2 capture design space (Schwerman et al, 2005)

2.1 Post-Combustion Capture

2.1.1 Chemical Absorption

Chemical absorption of CO_2 from gas streams is currently utilized in many industries using monoethanolamine as shown in Equation 1.

$$C_2H_4OHNH_2 + CO_2 + H_2O \Leftrightarrow C_2H_4OHNH_3^{+} + HCO_3^{-} \quad (1)$$

Once CO_2 is absorbed, the monoethanolamine is thermally regenerated to release CO_2 and H_2O, which must be separated through condensing the H_2O (Soong 2005). The ability to absorb and then desorb CO_2 for capture and release without degrading the reactants is the primary factor that makes monoethanolamine commonly used for CO_2 capture.

Figure 3 shows a post-combustion CO_2 capture monoethanolamine system, whereby the CO_2 rich flue gas flows through an absorption chamber with a counter flow of the lean monoethanolamine solvent. CO_2 and the solvent chemically react and are pumped out of the absorber as rich solvent. The thermal regeneration used to strip the CO_2 and regenerate the lean solvent occurs at high temperature and is endothermic requiring that approximately 4MJ of heat be added per kg of recovered CO_2 (ESRU 2006). A heat exchanger between rich and lean solvents is commonly utilized to recycle some of the heat, but the majority is extracted from the low-pressure steam turbine. The primary cost drivers of the monoethanolamine system are the heat utilized for regeneration, solvent loss, and CO_2 loading.

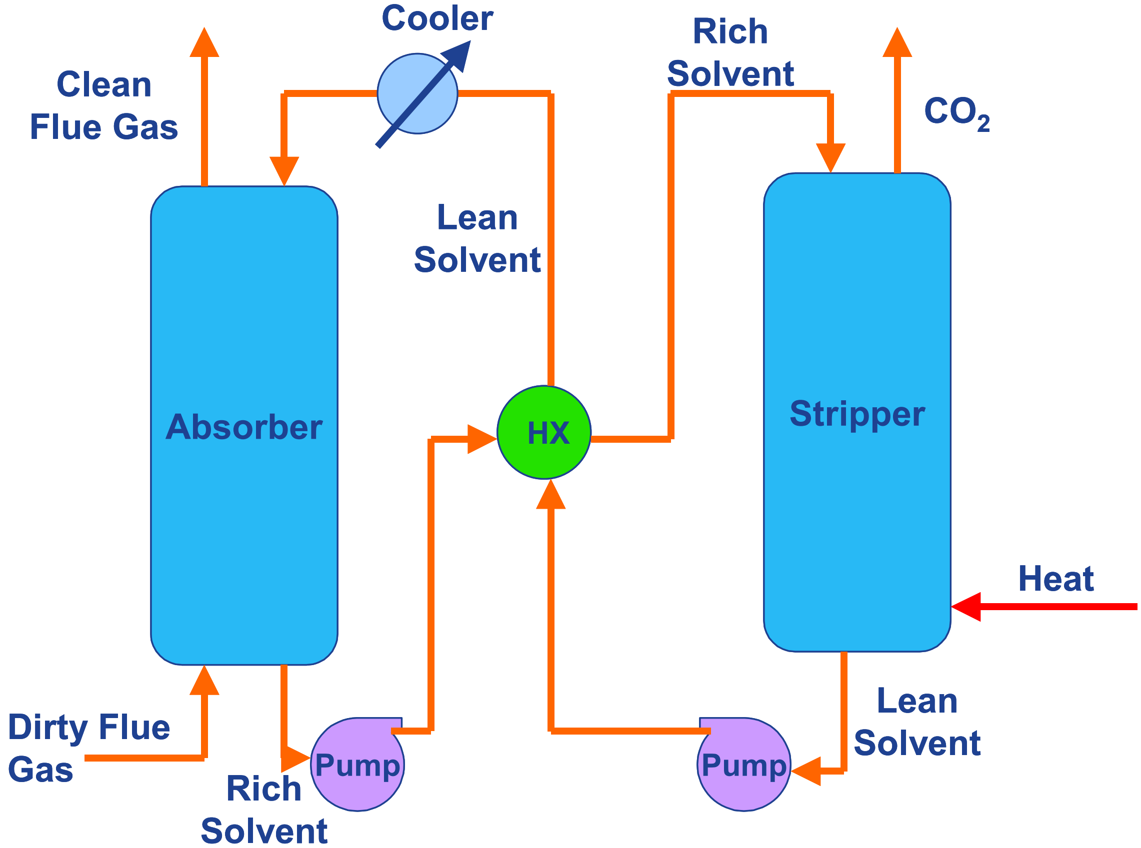

Figure 3: Schematic of post-combustion chemical absorption (Schwerman et al, 2005)

Development of power plant post-combustion chemical absorption CO_2 capture technologies has resulted in both chemical and system level advancements that reduce costs. Praxair, (Chakravarti 2001), Mitsubishi (2002) and FluorDaniel (Chapel 1999) all attempted to develop low cost products by decreasing the impact of one or more of these cost drivers.

In a review of Praxair's CO_2 capture technology, Chakravarti 2001 notes: "Chemical absorption with [monoethanolamine] has been generally used in processes such as natural gas sweetening and hydrogen production for the rejection of carbon dioxide." Similar processes using monoethanolamine are not cost effective for post-combustion CO_2 capture because of the high operating cost and corrosion rates. According to Chakravarti, Praxair determined the operating cost and corrosion rates are worth mitigating with process modifications because of the high loading rates even at low partial pressure. In order to mitigate the corrosion problems, the CO_2 rich monoethanolamine is deoxygenated by depressurization as described by Chakravarti. Praxair reduced operating costs by employing monoethanolamine blends with concentrations of up to 50 percent from 30 percent thus reducing the high cost steam consumption for regeneration.

Similarly, Mitsubishi developed advanced post-combustion CO_2 capture technology based on monoethanolamine (Mitsubishi 2002). Unlike the Praxair technology, which utilizes a unique process, Mitsubishi's technology uses a unique reagent called KS-1, a sterically hindered monoethanolamine with reduced oxidation rates. According to Mitsubishi, KS-1 has improved operating characteristics with respect to monoethanolamines, as shown in Table 2. The reduced oxidation rate decreases the degradation of the solvent and solvent loss enabling operation without a corrosion inhibitor. While the Mitsubishi data offers a relative comparison, no absolute data is provided and no background on the testing used to generate the data is discussed. Based on the data provided, Mitsubishi maintains the total CO_2 capture cost to be approximately $ per thousand standard cubic feet (MSCF) or $20 per ton for a coal fired boiler and $1.44 per MSCF or $28 per ton for a natural gas fired gas turbine. The relatively higher CO_2 capture cost per ton in gas turbine systems is due to the low CO_2 flue gas concentration of 3 to 5 percent compared to 12 to 14 percent coal fired boiler flue gas. Thus, the gas turbine KS-1 system operates with a lower CO_2 loading parameter. Despite the uncertainty of the data source, the low cost of the KS-1 system appears to make the capture process comparable with a current trading value of approximately $20 per ton and, therefore, should be considered further.

Table 2: Amine and KS-1 process Comparison (Mitsubishi, 2002)

Operating Characteristics	**Amine**	**KS-1**
Solution Circulation rate	1	0.6
Regeneration Energy	1	0.8
Degradation of the Solvent	1	0.1
Solvent Loss	1	0.1
Corrosion Inhibitor	Yes	No

A third flue gas CO_2 capture technology was developed by FluorDaniel and is described by Chapel (1999). The FluorDaniel Econamine FG process utilizes an inhibited 30 percent by mass monoethanolamine solution for CO_2 capture. According to Chapel, the inhibitor reduces corrosion and solvent degradation problems, which ultimately drives down cost. Chapel conducted an economic analysis for a coal-fired plant with a typical 13 percent by mass flue gas CO_2 concentration and natural gas fired plant with a typical 3 percent by mass flue gas CO_2 concentration. The resulting capital and operating cost for a 1000 ton per day coal-fired plant was $29.5 per ton and for a 1000 ton per day natural gas fired plant $43.5 per ton. In a conversation with co-author Carl Mariz, Mariz speculated capital cost improvements along with efficiency improvements and economies of scale could reduce the total cost to between $20 per ton and $25 per ton for a 500 MW coal-fired plant (Mariz 2005). Given the potential cost reductions cited by Mariz the Economanie FG process should be considered further because the cost could become comparable with current CO_2 credit trading values.

2.1.2 Biological Absorption

Bayless (2003), describes an alternative post-combustion capture technology known as "enhanced photosynthetic CO_2 mitigation". The photosynthetic CO_2 mitigation system described passes cooled flue gas through a bioreactor, containing thermophilic organisms that use chlorophyll to produce sugar from CO_2 as shown in Equation 2.

$$6CO_2 + 6H_20 \Leftrightarrow C_6H_{12}O_6 + 6O_2 \qquad (2)$$

As the microalgea age, the CO_2 uptake is limited. Some of the microalgea must be periodically removed to provide sufficient space and light available for new productive microalgea. Light is collected in parabolic solar dishes then transmitted through fiber optic cables to the bioreactor. According to Bayless, this current light collection and transmission system is cost prohibitive. With advances in microbial research and light delivery systems, future developments might make similar bioremediation technologies feasible, especially since photosynthesis alleviates the need for CO_2 storage. Currently, Bayless does not suggest photosynthetic CO_2 mitigation is a near term solution and consequently it will not be considered further in this study (Bayless, 2003).

2.2 Pre-Combustion Capture

Pre-combustion capture has the potential to occur under high CO_2 partial pressure and high fuel stream total pressure. In order to utilize pre-combustion capture, both coal and natural gas must be partially oxidized into syngas, a mixture of predominately CO, CO_2 and H_2. Partial oxidation or reforming can be implemented with coal in an integrated gasification combined cycle power plant and with natural gas in an integrated reforming combined cycle power plant. A discussion of both technologies follows.

2.2.1 Integrated Gasification Combined Cycle (IGCC)

In the case of coal, the coal and either oxygen or air, flow into the gasifier, where under elevated pressure and temperature, the coal undergoes partial oxidation to produce syngas. The actual composition of syngas can vary by site in the amount and type of constituents. Table 3 provides a sample of gasification sites and their respective syngas constituents from 11 different power plants or chemical plants that gasify coal (Brdar, 2000). The integrated gasification combined cycle power plant subsystems, which potentially include a CO_2 capture system, must be robust for the range of constituents and concentrations.

Table 3: Coal Gasification Syngas Composition (Brdar, 2000)

Syngas	PSI	Tampa	El Dorado	Pernis	Sierra Pacific	ILVA	IBIL	Schwarze Pumpe	Sarlux	Fife	Exxon Singapore
H2	24.8	27	35.4	34.4	14.5	8.6	12.7	61.9	22.7	34.4	44.5
CO	39.5	35.6	45	35.1	23.6	26.2	15.3	26.2	30.6	55.4	35.4
CH4	1.5	0.1	0	0.3	1.3	8.2	3.4	6.9	0.2	5.1	0.5
CO2	9.3	12.6	17.1	30	5.6	14	11.1	2.8	5.6	1.6	17.9
N2 + AR	2.3	6.8	2.1	0.2	49.3	42.5	46	1.8	1.1	3.1	1.4
H2O	22.7	18.7	0.4	--	5.7	--	11.5	--	39.8	--	0.1
LHV, - Btu/ft	212	202	242	209	127	193	115	318	163	322	242
kJ/R4	8350	7960	9535	8235	5000	7600	4530	12,520	6420	12,690	9,530
Tfuel, F/ C	570/300	700/371	250/121	200/98	1000/538	400/204	1020/549	100/38	392/200	100/38	350/177
H2/CO Ratio	0.63	0.75	0.79	0.98	0.62	0.33	0.83	2.36	0.74	0.62	1.25
Diluent	Steam	N2/H2O	N2/Steam	Steam	Steam	--	--	Steam	Moisture	Water	N2/Steam
Equivalent LHV											
Btu/FY4	150	118	113*	198	110**	--	115	200	--	*	116
kJ/R4	5910	4650	4450	7800	4334	--	4500	7880	--	--	4600

* Always co-fired with 50% natural gas
** Minimum range

In an integrated gasification combined cycle power plant without CO_2 capture, as shown in Figure 4, the syngas is scrubbed to remove SO_2 and combusted in a gas turbine to produce about 60 percent of the electricity. The hot exhaust is delivered to a heat recovery steam generator (HRSG) to produce steam, which is sent to a steam turbine that produces the remaining 40 percent of the plant's electricity. The thermal efficiency of advanced integrated gasification combined cycle power plants and subcritical coal fired boiler power plants are 46 percent higher heating value and 34 percent higher heating value respectively (Hughes, 2000). Consequently integrated gasification combined cycle power plants convert coal to electricity 35 percent more efficiently than pulverized coal power plants so they can use 35 percent less coal to produce the same amount of electricity. In terms of CO_2 emissions, the 35 percent less fuel utilized per kWh translates into a 35 percent CO_2 reduction on a tons/kWh basis.

Other advanced coal technologies such as super-critical coal boilers and fluidized bed combustors are capable of achieving comparable efficiencies. Nordjyllands, the ultra super-critical coal fired power plant in Denmark, operates at 4200 PSI and 47 percet lower heating value (Bendixen 2003). The formation of syngas, however, provides integrated gasification combined cycle power plants with an opportunity to employ pre-combustion capture, a significant competitive advantage in a carbon constrained market. As seen in Figure 5 of an integrated gasification combined cycle power plant with pre-combustion CO_2 capture, syngas leaves the gasifier and is processed in a shift reactor, which reacts the CO with H_2O to form CO_2 as shown in Equation 3.

$$CO + H_2O \Leftrightarrow CO_2 + H_2 \tag{3}$$

The shift reaction is performed in a series of two reactors. Upon leaving the gasifier at approximately 1400°F, the syngas is cooled in a steam generator to approximately 700 °F, then mixed with steam in a high temperature shift reactor to react 80 to 95 percent of the CO. Next, the mixture is cooled to approximately 400°F and sent to the low temperature shifter, which will exhaust up to 99 percent CO free syngas.

After SO_2 scrubbing, adsorption can be employed using UOP's proprietary product Selexol, a mixture of polyethylene glycol derivatives. The solubility of CO_2 in Selexol is 15 times greater than in syngas, therefore, almost 95 percent of CO_2 can be captured from the syngas. Moreover, the low vapor pressure of Selexol enables the CO_2 to be flashed out to regenerate the Selexol solution and isolate the CO_2. Additional benefits of integrated gasification combined cycle beyond the ability to utilize pre-combustion capture include a reduction in emissions of criteria pollutants, a reduction in water contamination, and a reduction in solid waste (Ratafia-Brown, 2002). For a comprehensive review of integrated gasification combined cycle' environmental impact see Ratafia-Brown 2002.

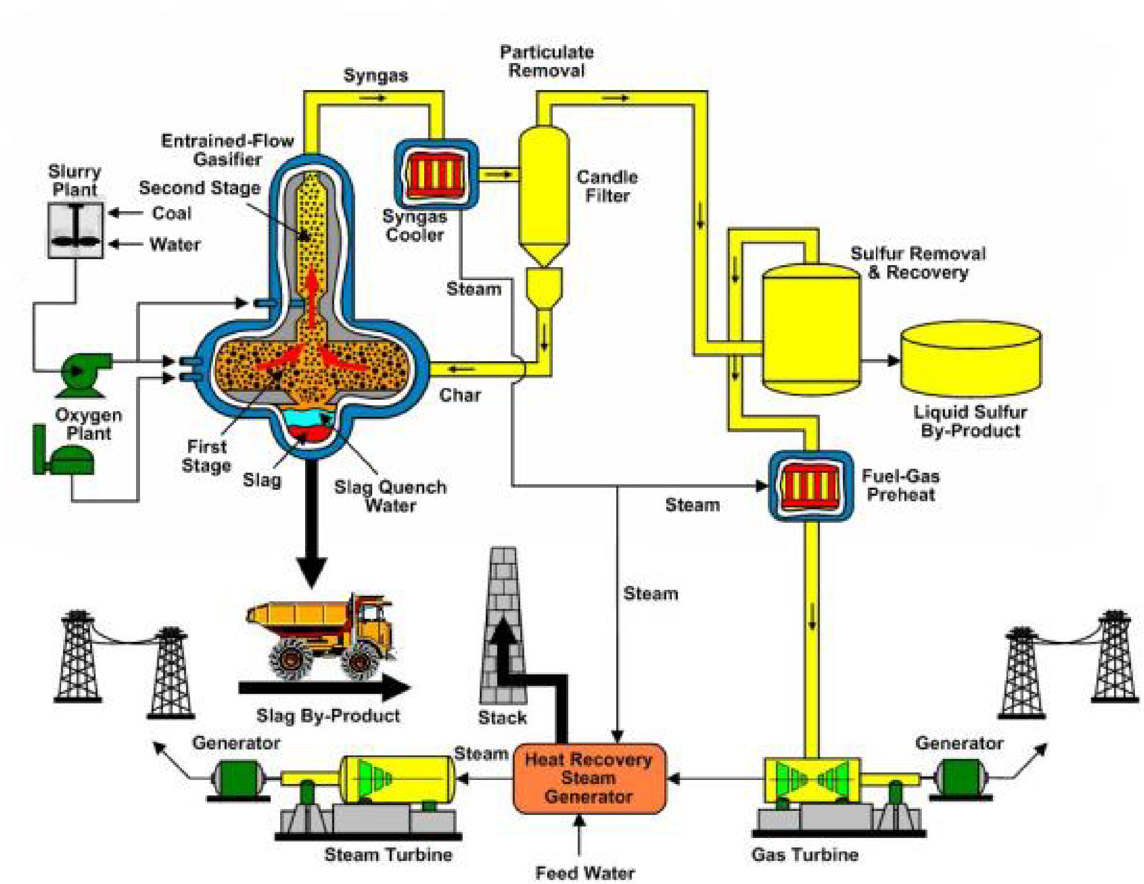

Figure 4: IGCC plant schematic (Wabash, 2005)

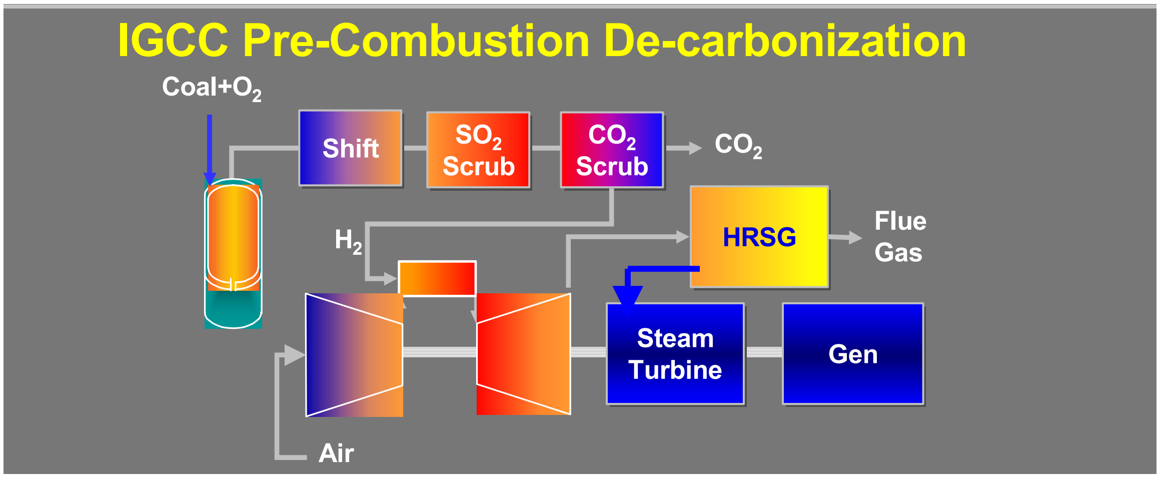

Figure 5: Schematic of IGCC with CO_2 capture (Schwerman et al, 2005)

2.2.2 Integrated Reformer Combined Cycle (IRCC)

Similar to coal, natural gas can be reformed into a syngas and processed to separate CO_2 from the exhaust stream before combustion. Two technologies capable of natural gas reforming in combined cycle applications are auto-thermal reactor (ATR) and catalytic partial oxidation (CPO). While the auto-thermal reactor is a more mature technology, with further development catalytic partial oxidation has potential to be the lower cost solution. In either case, the syngas may be cleaned to remove constituents that lead to hardware degradation or pollutant formation. Steam is then added in a shift reactor to transform the syngas equilibrium to primarily H_2 and CO_2. Nagl (2003), describes the reactions that occur during the gasification process and the various technologies employed for cleaning syngas.

Audus (2003) reviews technical and economic aspects of ATR and air blown catalytic partial oxidation (CAPO) systems. Auto thermal reforming consists of combustion of gas turbine exhaust gas and hydrogen-rich fuel gas in a reformer furnace in order to convert natural gas into syngas (Audus, 2005). Alternatively, air blown catalytic partial oxidation requires air, steam, and natural gas mixed in a conical combustion zone at the top of the refractory lined reactor. In this zone both partial oxidation and steam reforming reactions take place. In the downstream catalyst zone the steam-methane reaction is brought to near equilibrium (Audus, 2005). One of the primary benefits of air blown catalytic partial oxidation over auto thermal reforming is a shorter resonance time, which reduces the reactor size, real estate requirement, and capital cost, all of which are closely related.

Through an energy balance and economic analysis, Audus, 2005, estimates the CO_2 reduction cost of air blown catalytic partial oxidation and auto thermal reforming CO_2 capture systems to be \$27 per ton and \$37 per ton respectively. Audus' CO_2 reduction cost calculation is based on the results shown in Table 4. Results generated by Audus are based on a natural gas price of \$2 per MMBTU. Since natural gas prices are currently much higher, one must consider the effect of fuel price on the CO_2 reduction cost.

A fuel price sensitivity study on the cost of electricity for both air blown catalytic partial oxidation and natural gas combined cycle power plants is shown in Figure 6. Over a wide range of natural gas prices, the difference in cost of electricity remains relatively constant as the fuel price changes. Moreover, the CO_2 reduction cost is based on the difference in the cost of electricity between the two technologies. Since the difference remains relatively constant over a wide range of fuel prices, so does the CO_2 reduction cost. Air blown catalytic partial oxidation incurs an efficiency penalty that increases fuel consumption per MWe. The increase in fuel price is small enough that the change is negligible in the low fidelity CO_2 reduction calculation.

Table 4: ATR and CPO GTCC economic analysis results (Audus, 2005)

	NGCC (base-case)	**ATR + GTCC (recycled turbine exhaust)**	**Partial oxidation +GTCC (air-blown)**
Efficiency (LHV)	59%	48%	50%
CO_2 emissions (gCO_2/kWh)	350	60	60
gas turbine fuel (mole%)	85% CH_4	95% H_2	53% H_2, 43% N_2
Specific cost (US$/kW)	630	1040	940
Cost of electricity (cents/kWh)	2.5	3.6	3.4
Cost of avoidance in $/ton CO_2	**-----**	**37**	**27**

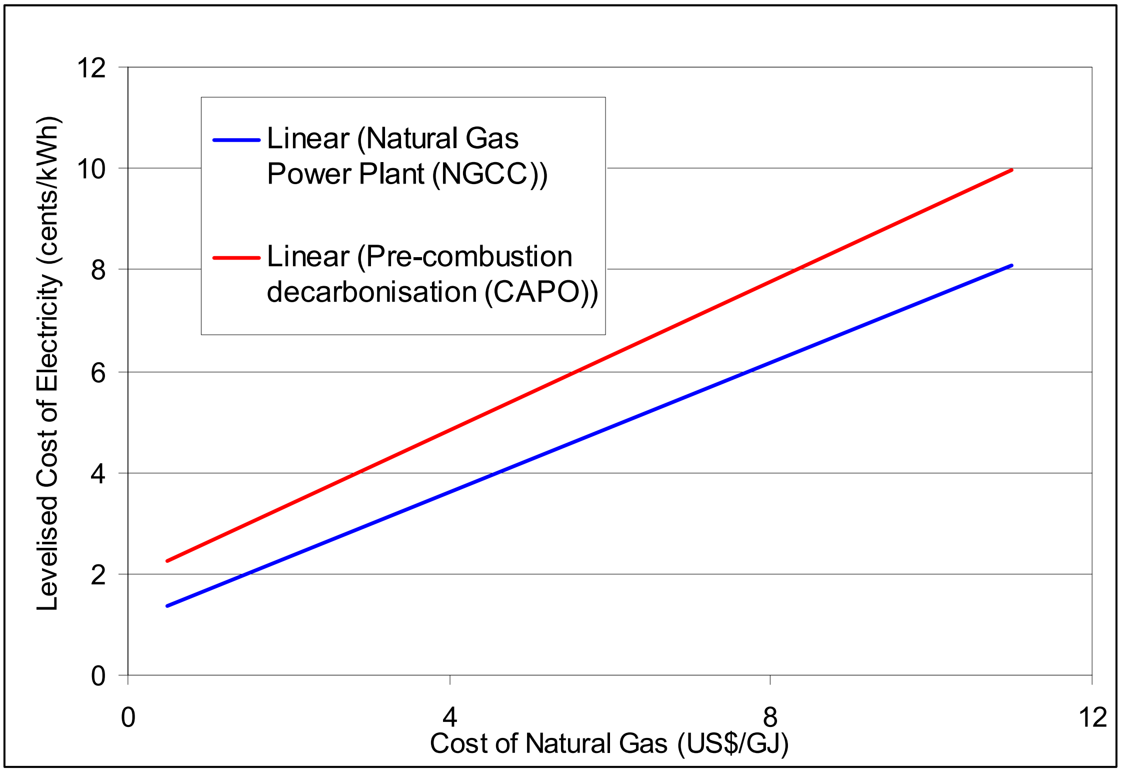

Figure 6: Sensitivity to cost of natural gas (Audus, 2005)

Audus, 2005, notes future developments, such as CO_2 capture membranes to replace the current amine systems will likely drive down cost. Significant technological barriers remain, however, including the development of a gas turbine that can operate on syngas with 50 percent H_2 and meet NO_x regulations. Furthermore, the development of an air blown catalytic partial oxidation gas turbine combined cycle(CPO-GTCC) or auto thermal reforming gas turbine combined cycle (ATR-GTCC), as shown in Figure 7, has yet to be commercially proven and bears the risk associated with implementing a new large-scale power generation system. In such a system, the air blown catalytic partial oxidation system or the auto thermal reformer would be installed upstream of the gas turbine to enable pre-combustion CO_2 capture. Similar to the integrated gasification combined cycle plant, a shift reactor and separator are necessary to capture CO_2. System performance issues, such as reliability, availability, and transient operation, have not been addressed in the current body of literature and will be required for implementation due to the added complexity inherent to the pre-combustion capture subsystem. Figure 8 illustrates a detailed plant schematic with integrated auto thermal reactor, gas turbine, heat recovery steam generator, and CO_2 capture system.

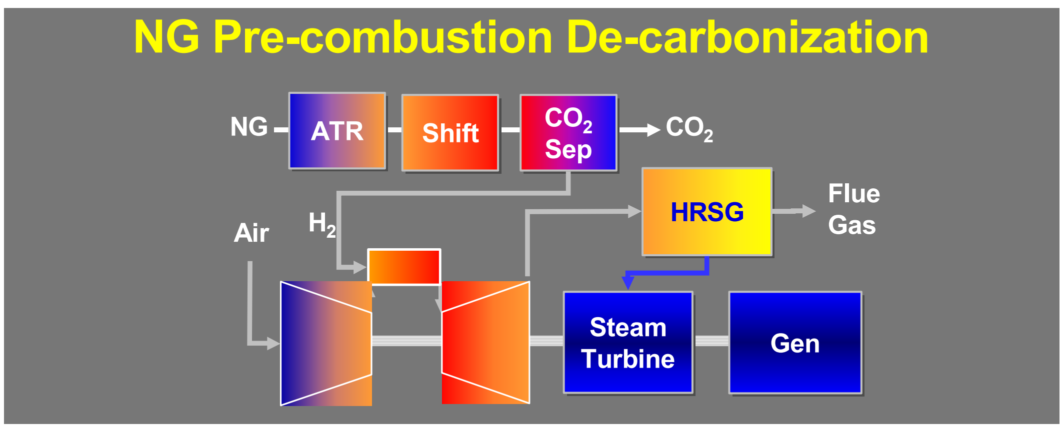

Figure 7: Schematic of ATR-GTCC with CO_2 capture (Schwerman et al, 2005)

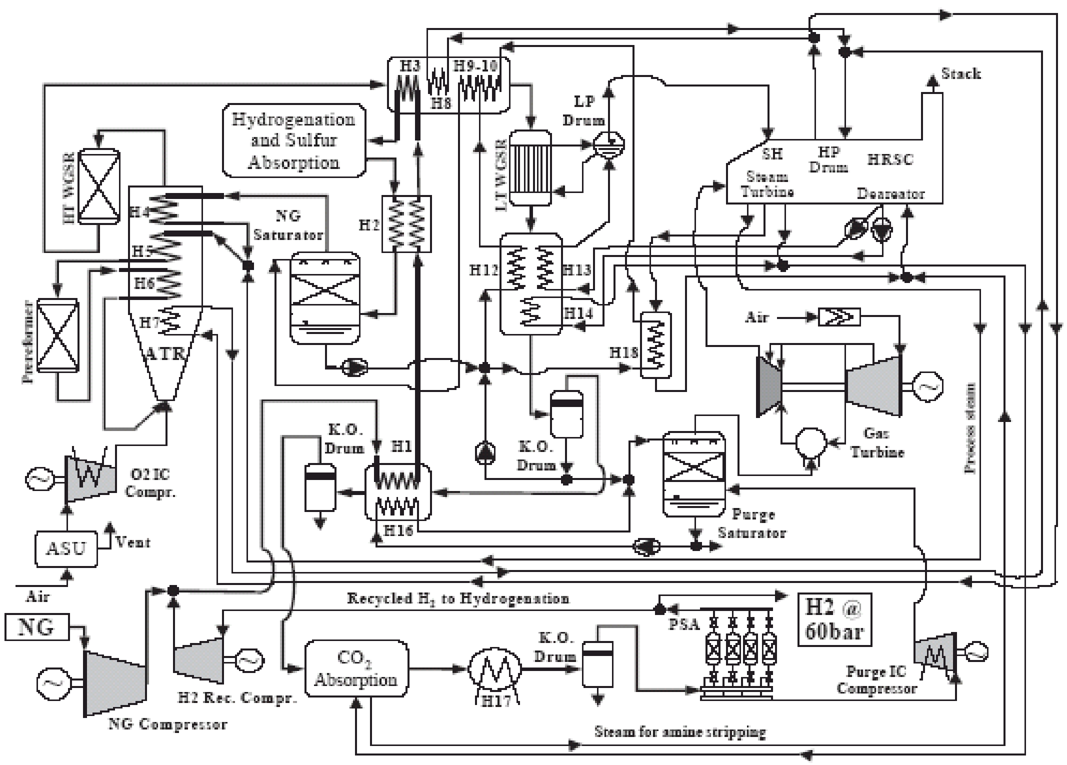

Figure 8: Schematic of ATR-GTCC plant with ATR (Nagl, 2003)

2.3 Efficiency Improvements

As shown with the integrated gasification combined cycle, efficiency improvements can drive significant reductions in CO_2 emissions from power plants. For some existing coal fired boiler power plants, a switch to an integrated gasification combined cycle is not possible, however, there are commercially available efficiency improvements that can be implemented to reduce CO_2 emissions, as well as fuel costs and costs of electricity.

Perrin Quarles Associates (PQA), (2001), found the efficiency of existing subcritical and supercritical coal fired plants could be improved by 3 to 5 percent through a combination of the actions listed in Table 5. A 5 percent point efficiency improvement for a 30 percent efficient power plant will result in the power plant being 31.5 percent efficient. A typical power plant owner will be unable to implement all of the actions listed and is likely to find that the results vary, especially when implementing multiple improvements. One common efficiency improvement package is boiler optimization, which typically entails combustion optimization software, digital boiler controls, and CO sensors. According to PQA the potential efficiency improvement from a boiler optimization ranges from 0.5 to 5 percent. The wide range of potential benefit is due to variations in operating equipment, conditions, and maintenance practices. Several of the items listed in Table 5 may be considered part of plant maintenance. A plant that performs rigorous maintenance protocols could be expected to have fewer one-time potential efficiency improvements, while an under-maintained plant would find the converse true.

Table 5: Potential Coal Fired Plant Efficiency Improvements (PQA, 2001)

Action*	Efficiency Improvement (%)
Restore Plant to Design Conditions	
Minimize boiler tramp air	0.42
Reinstate any feedheaters out of service	0.46 - 1.97
Refurbish feedheaters	0.84
Reduce steam leaks	1.1
Reduce turbine gland leakage	0.84
Changes to Operational Settings	
Low excess air operation	1.22
Improved combustion control	0.84
Retrofit Improvements	
Extra airheater surface in the boiler	2.1
Install new high efficiency turbine blades	0.98
Install variable speed drives**	1.97
Install on-line condenser cleaning system	0.84
Install new cooling tower film pack**	1.97
Install intermittent energisation to ESPs	0.32

2.4 Fuel Switching

In addition to efficiency improvements, fuel switching provides an opportunity to reduce CO_2 emissions without major plant overhauls. Switching from coal to natural gas reduces a range of emissions, including CO_2 emissions, from 208,000 to 117,000 pounds per Billion British thermal units of energy input (BBTU), as shown in Table 6.

Table 6: Fossil Fuel Emission Levels (Natural Gas.org, 2006)

- Pounds per Billion Btu of Energy Input			
Pollutant	**Natural Gas**	**Oil**	**Coal**
Carbon Dioxide	117,000	164,000	208,000
Carbon Monoxide	40	33	208
Nitrogen Oxides	92	448	457
Sulfur Dioxide	1	1,122	2,591
Particulates	7	84	2,744
Mercury	0	0.007	0.016

Two commercially available technologies for switching a portion of the fuel input in a coal fired boiler from coal to natural gas are natural gas reburn and natural gas co-firing (Electric Power Research Institute, 2002). In a natural gas reburn system; natural gas is injected through a secondary set of reburn injectors and combusted in the reburn zone with overfire air (Electric Power Research Institute, 2002). The reburn injectors are typically installed above the main fuel burners as shown in Figure 9. The primary advantage of reburn is NOx control. An additional benefit is the reduction in CO_2 emissions per MWe. The CO_2 reduction occurs because natural gas, the reburn fuel, has a lower carbon to hydrogen ratio (C/H) than coal. A portion of the heat input from coal is replaced with heat input from natural gas, thus lowering the fuel's carbon intensity and, consequently the CO_2 emissions (EPRI, 2002).

When NO_x control is not required, natural gas co-firing can be used to achieve the same CO_2 reduction as natural gas reburn with less capital cost. Natural gas co-firing occurs through co-injection of natural gas and coal in the main combustion zone, thus reducing the part count and size of the boiler. The traditional advantage of natural gas co-firing is increased power plant flexibility. Plants can reduce the plant startup time to respond faster to the electric market demand (EPRI, 2002). The advantage of reduced CO_2 emissions from natural gas reburn or co-firing is not addressed by EPRI or other available literature.

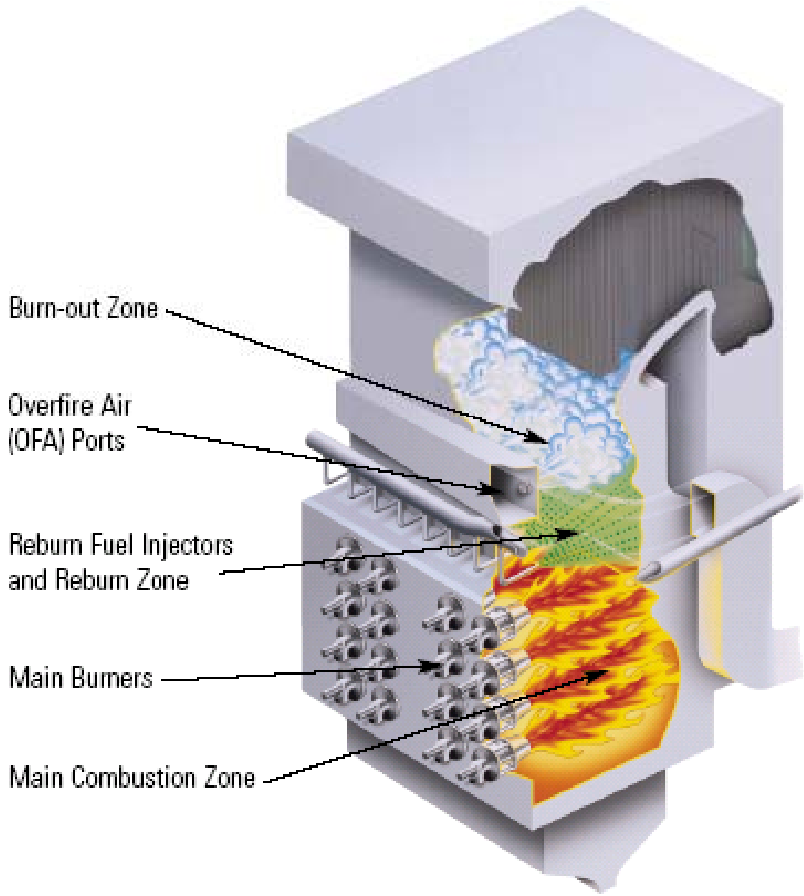

Figure 9: Wall-fired Boiler with Reburn, (Schwerman et al, 2005)

2.5 Multi-Technology Comparisons

Rubin et al (2004), compares the key operating characteristics of the following three power plant technologies with and without CO_2 capture: integrated gasification combined cycle; pulverized coal power plants; and natural gas combined cycle power plants. Based on a literature review, Rubin states pulverized coal power plants have a lower cost of electricity compared to integrated gasification combined cycle, as shown in Table 7. With CO_2 capture, the integrated gasification combined cycle cost of electricity is lower than the pulverized coal power plant cost of electricity. Furthermore, natural gas combined cycle is found to have the lowest reported cost of electricity without CO_2 capture, and also the lowest when compared to other power plants with CO_2 capture. The natural gas combined cycle finding is heavily dependent on the unreported fuel prices. Data collected by Rubin is from a variety of sources with inconsistent assumptions, including fuel cost, plant size, plant efficiency, fiscal year and others, making the comparisons inaccurate.

Table 7: Cost of Electricity (Rubin et al, 2004)

	Without CO_2 capture	With CO_2 capture
	$/MWh *	$/MWh *
Integrated gasification combined cycle power plant	41-58	54-81
Pulverized coal power plant	37-52	64-87
Natural gas combined cycle power plant	22-35	32-58

Rubin et al utilizes the Integrated Environmental Control Model (IECM) to consistently evaluate the natural gas combined cycle, integrated gasification combined cycle and pulverized coal power plants (Rubin et al, 2004). All three technology baselines are defined as 500 MW baseload facilities, with 75 percent capacity factor and fuel prices of $1.3 and $4.2 per MMBTU HIGHER HEATING VALUE for coal and natural gas respectively. When evaluating the CO_2 capture cost, a post-combustion capture chemical absorption monoethanolamine system is applied to the natural gas combined cycle and pulverized coal power plants while a pre-combustion shift and adsorption system is applied to the integrated gasification combined cycle power plant. Rubin et al's results shown in Table 8 are consistent with trends found in Rubin et al's literature review. Pulverized coal power plants have a lower cost of electricity than integrated gasification combined cycle, but with CO_2 capture, the trend is reversed. Moreover, with a natural gas fuel price of $4.2 per MMBTU HIGHER HEATING VALUE, natural gas combined cycle remains the most economical. Gas prices are currently considerably higher, which can change this ranking.

Table 8: Integrated Environmental Control Model Cost of Electricity Results (Rubin et al, 2004)

	Without CO_2 capture	With CO_2 capture
	$/MWh	$/MWh
Integrated gasification combined cycle power plant	48.3	69.6
Pulverized coal power plant	46.1	82.1
Natural gas combined cycle power plant	43.1	62.1

In a separate study, Narula et al (2001), reviews a wider scope of technologies with less detail than Rubin et al. Narula et al's study considers: 1) supercritical pulverized coal with and without CO_2 capture; 2) integrated gasification combined cycle with and without CO_2 capture; 3) natural gas combined cycle (NGCC) with and without pre-combustion CO_2 capture; 4) conversion of coal fired boilers to natural gas fired boilers, 5) repowered steam turbines with natural gas fired gas turbines; 6) nuclear power plants; and 7) wind power (Narula et al, 2001). The purpose of evaluating power plants without CO_2 capture is that a CO_2 reduction is possible by displacing an existing subcritical pulverized coal power plant which typically emits 850 kg of CO_2 per MWh with a more efficient coal power plant or a power plant that utilizes less carbon intensive fuel such as natural gas, nuclear or wind.   When evaluating the CO_2 reduction cost of the power plants without CO_2 capture, the reference plant is a subcritical pulverized coal power plant emitting 850 kg of CO_2 per MWh with an electricity cost of 2.4 cents per kWh in 2001 dollars. (Narula et al, 2001). When evaluating the integrated gasification combined cycle, natural gas combined cycle, and pulverized coal power plants with CO_2 capture, the reference plant is the same plant without CO_2 capture. Baselines for the power plants evaluated by Narula et al fall in the range of 500 to 800 MW baseload facilities, with 75 to 85 percent capacity factor and \$1.3, \$4, and \$0.5 per MMBTU HIGHER HEATING VALUE coal, natural gas, and nuclear fuel prices respectively (Narula et al, 2001). The results shown in Table 9 again indicate that the natural gas combined cycle to not only have the lowest reported cost of electricity without CO_2 capture, but also the lowest when compared to other power plants with CO_2 capture. The amount of CO_2 reduced per MWh is provided for each technology compared to the subcritical pulverized coal plant, which emits 850 kg CO_2 per MWh and compared to the capture case, where applicable. Nuclear and wind power plants have zero emissions and consequently the highest CO_2 reduction.

Table 9: Cost of Electricity and CO_2 Reduction Results (Narula et al, 2001)

	Cost of electricity with CO_2 capture	Cost of electricity without CO_2 capture	CO_2 Reduction of capture case versus no capture case	CO_2 reduction of no capture case versus baseline subcritical pulverized coal plant
	$/MWh	$/MWh	kg/MWh	kg/MWh
Integrated gasification combined cycle power plant	87	74	603	180
Supercritical Pulverized coal power plant	90	58	720	50
Natural gas combined cycle power plant	66	57	333	480
Fuel Switching	N/A	53	N/A	320
Repowering	N/A	58	N/A	400
Nuclear	N/A	74	N/A	850
Wind	N/A	87	N/A	850

CHAPTER 3

ANALYSIS

The analysis to evaluate CO_2 reduction technologies consists of 3 steps; a literature review, an incremental CO_2 reduction cost analysis, and an economic feasibility analysis. The literature review, discussed in Chapter 2, reviews commercially available and near term technologies capable of reducing CO_2 emissions from power plants. The economic analysis consists of the following steps: 1. define baseline power plant cost of electricity (CoE) and CO_2 emissions for a reference coal plant; 2. calculate the cost of electricity and CO_2 emissions for the power plant with the installed CO_2 reduction technology; and 3. utilize the results to calculate the CO_2 reduction cost of each technology. The CO_2 reduction cost analysis enables a wide range of technical solutions to be compared on a consistent basis, despite the significant variations in CO_2 reduction and cost of electricity. The economic feasibility analysis compares the reduction cost of each technology to the credit trading cost. Finally, the study considers the impact of varying fuel cost and provides insight for potential power plant investors and technology developers.

3.1 Introduction

In this section, the analysis methods are presented. The current market driver for CO_2 reduction is government induced market incentives such as the European Trading Scheme. The CO_2 credits in the European Trading Scheme are traded on a $ per ton basis. To conduct an economic comparison that is relevant to the market, the CO_2 reduction cost should be calculated. According to Narula, 2002, the incremental cost of CO_2 reduction from power plants, also known as avoided cost (A_c), is calculated as follows:

$$A_c = \frac{COE_L - COE_H}{E_H - E_L} \tag{4}$$

COE_L = Cost of electricity in $ per kWh with low-emissions plant

COE_H = Cost of electricity in $ per kWh with high-emissions plant

E_H = CO_2 emissions in tons per MWh from high-emissions plant (reference plant)

E_L = CO_2 emissions in tons per MWh from low-emissions plant (Narula, 2002).

3.2 Cost of Electricity Calculation

The cost of electricity (COE) is calculated assuming a return on investment and then determining the revenue required to meet the return on investment. The revenue calculation includes engineering procurement and construction (EPC) cost, fuel expense, operation and maintenance costs, and fixed charged rate. Capital cost is estimated as engineering procurement and construction cost, plus 20 percent for interest during the construction phase then converted to annual dollars by the fixed charge rate. Operation and maintenance cost consists of personnel cost, such as salaries and benefits, and inspection and repair cost of the equipment. Fuel cost is impacted by the plant efficiency, hours of operation and fuel price. Fixed charges represent the revenue required each year to offset all fixed costs of ownership, including principal re-payment, interest on debt, taxes, insurance, administrative costs, equity and return on equity over a 20 year term. Fixed charges can be expressed as a rate of total plant costs (take-out cost) and vary as a function of ownership type. A 15 percent fixed charged rate is assumed for this study. The cost of electricity calculation is conducted with an assumed 3 percent annual inflation and 20 year term. No cost or credit is applied for end of life decommissioning.

3.3 CO_2 calculation

The CO_2 emissions are also calculated with assumptions for the plant's net output, capacity factor, and efficiency. First, the MMBTU of fuel consumption is calculated based on these assumptions. Next, the CO_2 emissions are calculated based on the fuel mix, carbon content of the fuel(s), and the assumption that all of the carbon in the fuel is converted to CO_2 (US DOE 1998). The carbon content of the fuel is given in terms of lb_m per MMBTU (Narula 2001). Assuming all the carbon is converted into CO_2 implies that CO, un-burnt hydrocarbons and carbon-bearing slag are negligible (US DOE, 1998). Finally, the lbs of CO_2 can be converted into tons per year.

3.4 CO_2 and COE Integration

In order to integrate the CO_2 and cost-of-electricity (COE) models, the plant output, capacity factor, heat rate, and fuel mix are set to be equal in both models. The dollar per ton calculation pulls the CO_2 emissions and cost of electricity from the respective models for a reference plant and the plant under analysis then calculates the CO_2 reduction cost using Equation 4.

The exception is one version of the model that monetizes the CO_2 by taking the lowest emitting technology as a baseline and applying a trading credit to the incremental emissions. When the intent is to calculate a CO_2 reduction cost on a dollar per ton basis, monetizing the emissions in the cost-of-electricity is double accounting and will not be used in this study. If a power producer is purely interested in calculating cost of electricity in a carbon constrained market, then it might monetize the CO_2 emissions as either a credit or debit and add the value to the operations cost along with fuel and other cost. If a power producer has more CO_2 emissions than it is allocated, it could calculate the cost of credits required to offset its excess emissions based on the market value. If a power producer emits less emissions than it is allocated and can sell credits than it can forecast the potential revenue. By including the value of CO_2 credits the cost-of-electricity is tailored to reflect the reality of a carbon constrained economy. A high CO_2 emitting plant will tend to become less financially attractive and a low emissions plant will tend to become more attractive. Ultimately investment and operating decisions will be tailored to the carbon-constrained economy.

3.5 Efficiency Improvement Analysis

As discussed in the literature review, there exists a wide range of potential efficiency improvements available for coal fired power plants. CO_2 reduction cost for a wide range of efficiency improvements and capital costs are calculated to evaluate efficiency improvements as a CO_2 reduction technology. The range of efficiency improvements evaluated is based on Perkins' findings (2001). Perkins did not report corresponding capital cost estimates. Therefore, a range of cost was considered for this study. Efficiency improvements were evaluated ranging from 0.5 to 5 percent with 0.5 percent increments. The baseline efficiency was assumed to be 30 percent and the improved efficiency was calculated by multiplying the baseline efficiency by the incremental improvement. Consequently a 0.5 percent efficiency improvement resulted in an efficiency of 30.15 percent and a 5 percent efficiency improvement resulted in an efficiency of 31.5 percent. Each incremental efficiency improvement was evaluated against cost of $0.5 per kW to $20.5 per kW with $2 per kW increments. In order to represent a wide range of possible scenarios that are applicable to not only coal fired power plants, but also potentially applicable to gas turbines, each combination of efficiency improvement and cost is analyzed for the CO_2 reduction cost.

3.6 Natural Gas Reburn and Co-Firing Analysis

In order to evaluate the potential of partially switching from coal to natural gas for CO_2 reduction, the CO_2 and cost-of-electricity models are modified to evaluate the base line coal plant with 20 percent natural gas firing based on heat input. The initial analysis assumes no incremental capital cost. In order to identify the heat rate improvement necessary to make fuel switching economical with a $20 per ton credit value, the total annual cost-of-electricity of the 20 percent natural gas case was set equal with the 0 percent natural gas case by varying the efficiency improvement. Finally, the capital cost required to achieve the efficiency improvement and fuel switching is accounted for by conducting a variable capital cost analysis with capital cost varying from $0 per kW to $100 per kW.

3.7 Reference Plant

In order to evaluate the CO_2 reduction cost of natural gas reburn and coal power plant efficiency improvements, a baseline reference plant is necessary for comparison. Coal fired power plants often have unique components and configurations, which result in variations from one plant to another. The boiler is one of the major design variations because of the number and type of burners that can be utilized. Other variations occur in the reheaters, feedwater heater, operating pressure, steam turbine design, and steam path. The significant variations result in the necessity to conduct a power plant specific study to determine the system level effect of potential retrofits. Nevertheless, for the purpose of this study, a reference plant is required in order to evaluate each option. The reference plant assumed for this study is described in Table 10 and is intented to be representative of a common sub-critical coal fired power plant. Coal cost used in the reference plant are assumed to be $1.5 per MMBTU.

Table 10: Reference Subcritical Coal Fired Power Plant Summary

Net Output	MW	500
Capacity Factor	Percent	60.0%
Heat Rate (Baseline)	BTU/MWe-hr	9,600,000
Coal Carbon Content	lb/MMBTU HHV	57
CO_2 emissions	tons/MWH	0.90

CHAPTER 4

RESULTS

4.1 Efficiency Improvement

This section presents the results of the efficiency improvement analysis. Each combination of efficiency improvement and capital cost to achieve this improvement results in a CO_2 reduction cost. The results are graphed on constant cost lines as shown in Figure 10. The resulting CO_2 reduction costs are both positive and negative. A negative cost indicates the cost of electricity in the upgraded plant is less than the cost of electricity in the baseline plant, which is due to the fuel savings outweighing the improvement's capital cost. The most negative cost results occur with high efficiency improvements and low capital cost, while the low capital cost high efficiency improvement and low efficiency improvement low capital cost scenarios also result in negative CO_2 reduction cost. The negative cost occurs because the efficiency improvement results in a fuel savings that offsets the capital cost and results in a decreased cost of electricity. The low efficiency improvement high capital cost cases still result in a fuel savings but it its insufficient to offset the capital cost, therefore the cost of electricity increases resulting in a large positive CO_2 reduction cost.

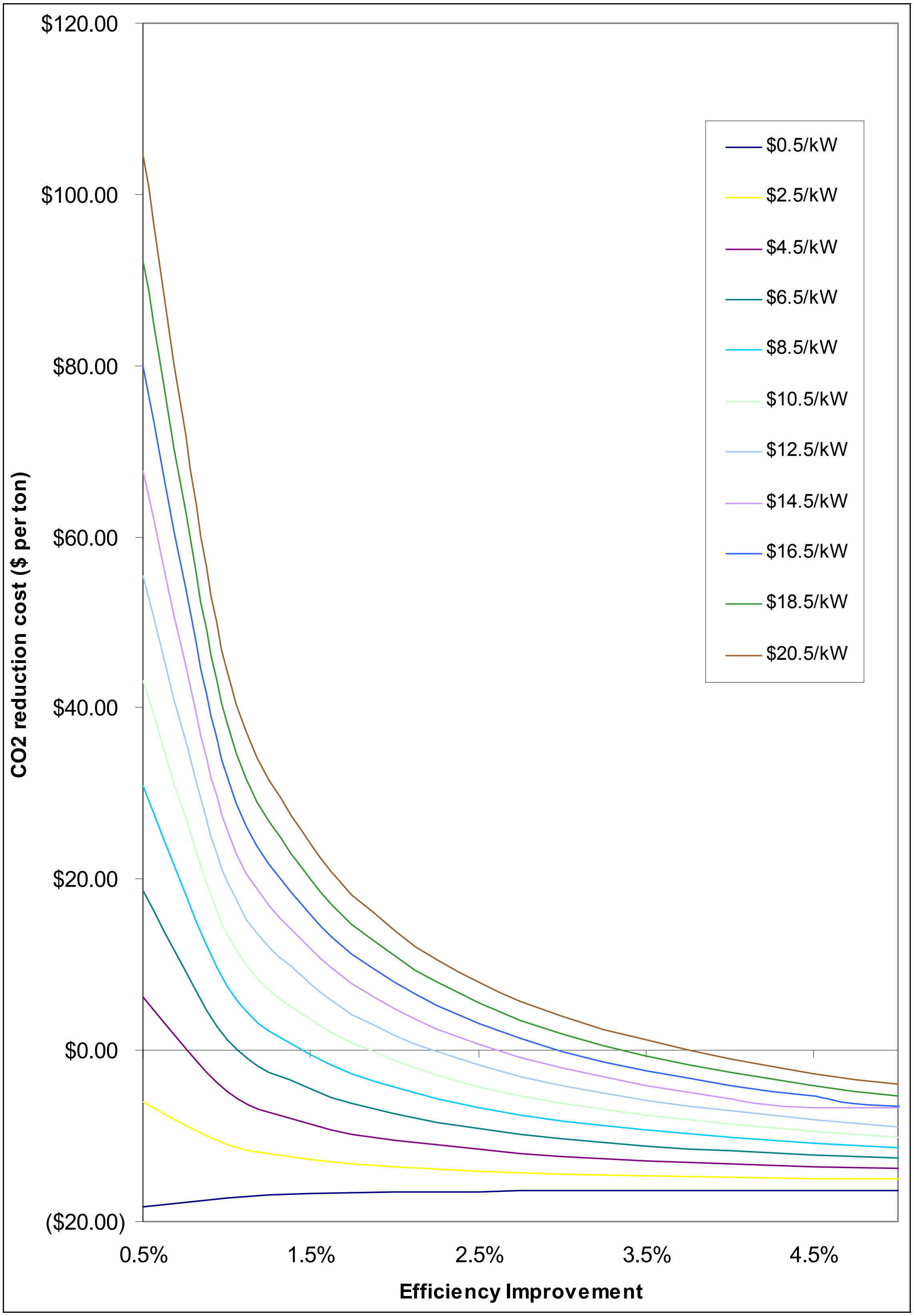

Figure 10: CO_2 reduction cost versus efficiency improvement for given capital cost

4.2 Natural Gas Reburn

This section presents the results of the natural gas reburn analysis. As seen in Figure 11, the initial analysis assumes no additional capital, operations, or maintenance cost is incurred with natural gas reburn or co-firing. Consequently, the only incremental cost incurred for fuel switching is the incremental fuel cost that results from the assumed natural gas fuel price of \$6 per MMBTU being four times greater than the assumed coal price of \$1.5 per MMBTU. The fuel costs assumed are currently below actual fuel cost therefore the results may vary. An incremental cost is assigned to the 100 percent coal cases because of the cost of purchasing, or opportunity cost of not selling, CO_2 credits for market value under a trading system such as the European Union Trading Scheme. The market value multiplied by the difference in tons of annual CO_2 emissions results in the CO_2 annual cost for the base plant. For the first case, with a market value of \$20 per ton of CO_2, the annual cost is shown to be \$18MM less than the annual cost with 20 percent fuel switching. The next two cases indicate the annual costs are not equal until a \$90 per ton CO_2 cost is applied, which is not considered likely under foreseeable market conditions.

Potential reburn technologies may result in an efficiency improvement, Figure 12 illustrates how much efficiency improvement is required for a given 20 percent fuel switching capital cost to be economical under today's market conditions with a CO_2 trading cost of \$20 per ton. When \$0 capital cost is required, a 16 percent efficiency improvement will make fuel switching economical. Subsequently, for every \$1 per kW of capital cost a 0.1 percent efficiency improvement is required.

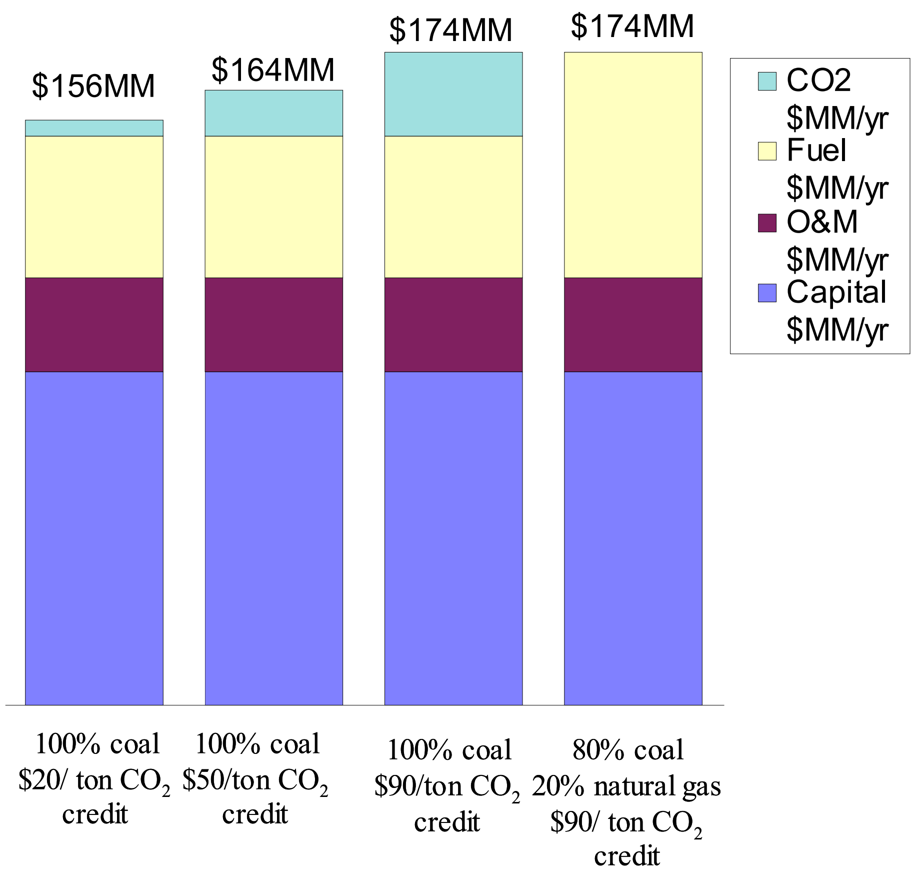

Figure 11: Comparison of coal boiler with and without natural gas reburn and CO_2 credits; coal price of $1.5 per MMBTU, and Natural gas price of $6 per MMBTU.

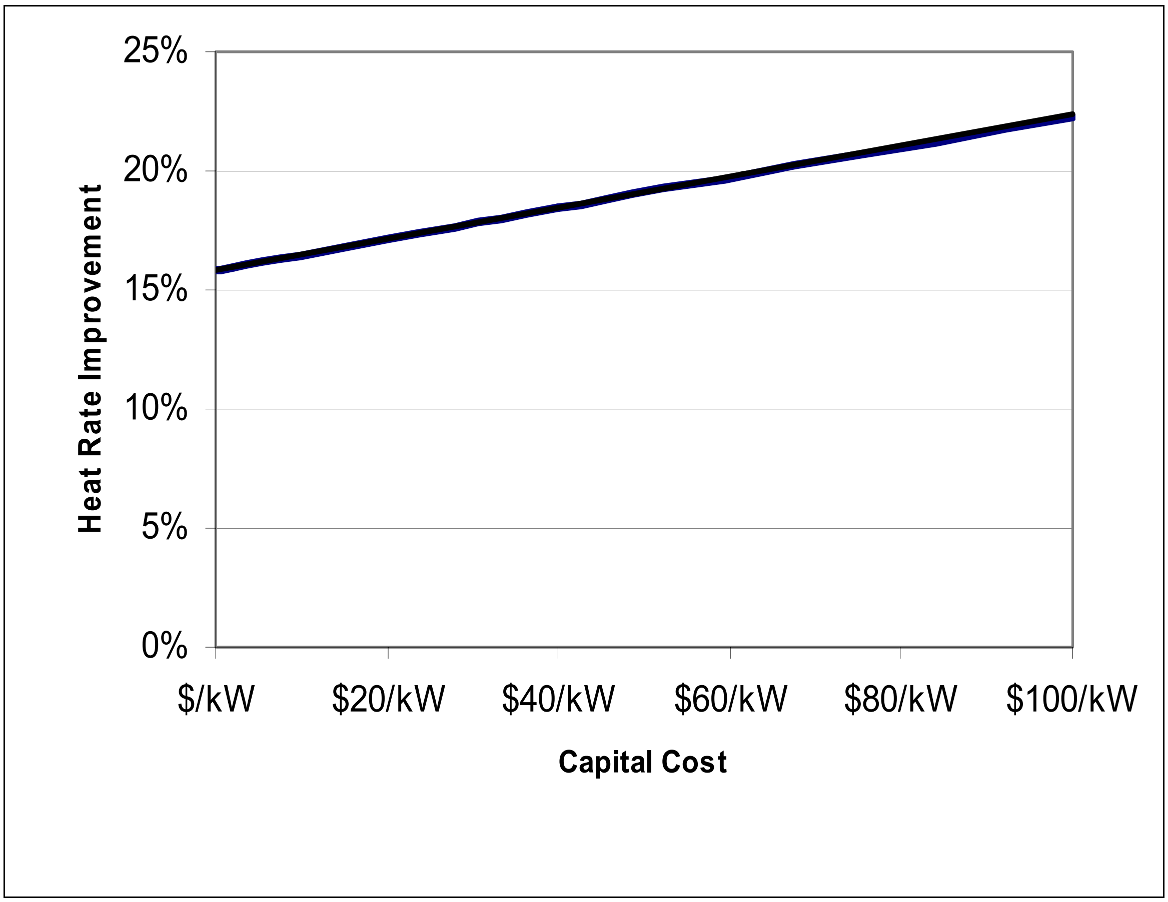

Figure 12: Variable capital cost analysis for fuel switching with efficiency improvements

4.3 Technology Comparison

CO_2 mitigation costs collected from the literature review and from the analysis are presented in Table 11. The first column indicates the power plant type to be a natural gas combined cycle (NGCC), pulverized coal steam power plant (PC), integrated coal gasification combined cycle (IGCC), renewable, or nuclear. The second column indicates the CO_2 reduction technology. The third shows the CO_2 mitigation cost in $ per ton, multiple costs indicate multiple sources as cited in the second column.

For natural gas combined cycle power plants with pre-combustion CO_2 capture using adsorption, the CO_2 reduction cost ranges between $20 and $30 per ton (Table 11, row 1). Similarly, for natural gas combined cycle power plants with post-combustion CO_2 capture using chemical absorption, the CO_2 reduction cost ranges between $20 and $30 per ton (Table 11, row 2). For coal-fired plants, an integrated gasification combined cycle, with pre-combustion capture using adsorption, the CO_2 reduction cost is approximately $22 per ton (Table 11, row 3). For pulverized coal powered plants, with post-combustion CO_2 capture using chemical absorption, the CO_2 reduction cost ranges between $20 and $33 per ton (Table 11, row 4). For either coal fired power plants or natural gas fired power plants, efficiency improvements have a CO_2 reduction cost ranging from $–20 to $90 per ton (Table 11, row 5). With some efficiency improvements, the fuel savings offsets the capital cost, which decreases the cost of electricity and causes a negative CO_2 reduction cost. Fuel switching from coal to 20 percent natural gas and 80 percent coal has a CO_2 reduction cost of $90 per ton (Table 11, row 6). Alternatively, renewable energy options exist as shown in Table 11, rows 7 and

8, with CO_2 reduction cost ranging from \$-82 to \$1400 per ton when compared to the baseline pulverized coal fired plant defined in Table 10 (Sims, 2003). The variation is due to the cost of electricity for wind ranging from 3.0 to 8.0 cents per kWh and for solar ranging from 8.7 to 40 cents per kWh (Sims, 2003). The cost of electricity for the renewables has significant variation due to the variation in wind or solar intensity between electricity generation sites. Finally, as shown in Table 11 row 9 nuclear power has a CO_2 reduction cost of ranging from –\$38 to \$135 per ton when compared to the baseline coal fired plant (Sims, 2003). Depending on the age of the plant and plant technology type, the cost of electricity for nuclear ranges from 3.9 to 8.0 cents per kWh (Sims, 2003). The CO_2 reduction costs from the literature are cited next to the technology. When more than one reference was available a comma is placed between the cost and when a range of cost is provided in a single source a dash is used to represent the range. As shown there is significant variation for several of the technologies, however, the variation does reflect market conditions especially when relying on natural resources such as wind or solar. The variation may preclude the possibility for a generalized ranking to be established and highlights the necessity for site specific evaluations to be conducted.

Table 11: Summary of CO_2 reduction cost

Power Plant Type	Technology	CO_2 mitigation cost ($/ton)
NGCC	Pre-combustion CO_2 capture (Narula, 2001) (Audus, 2005)	26 to 37
NGCC	Post-combustion CO_2 capture (Mitsubishi, 2005), (Chapel, 1999)	28, 44
IGCC	Pre-combustion CO_2 capture (EIA, 2000)	22
PC	Post-combustion CO_2 capture (Narula, 2001),(Mitsubishi, 2005), (Chapel, 1999)	25 to 33, 20, 30
PC	Efficiency Improvements	(-)20 to 90
PC	Fuel Switching (no efficiency improvement)	90
Renewable	Wind Turbines (EIA, 2000), (Sims, 2003)	38, (-)82 to 135
Renewable	Solar PV (EIA, 2000), (Sims, 2003)	53, 175 to 1400
Nuclear	Nuclear (Narula, 2001), (Sims, 2003)	59, (-)38 to 135

4.4 Technology Credit Cost Comparison

The evaluation of CO_2 mitigation technologies depends on the technology cost compared to the CO_2 credit trading price. Assuming credits are available, a power plant owner who is either short or long on CO_2 credits has the option to sell or buy CO_2 credits at market price. Regardless of the power plant owner's position relative to his target level, the owner may benefit from reductions as long as the reduction cost is less than the trading price. Figure 13 illustrates the range of CO_2 reduction cost of each technology as well as a range of potential CO_2 trading prices. The assumed CO_2 trading price between \$20 and \$30 per ton is shown on the graph as a horizontal bar and is representative of the actual 2005 prices.

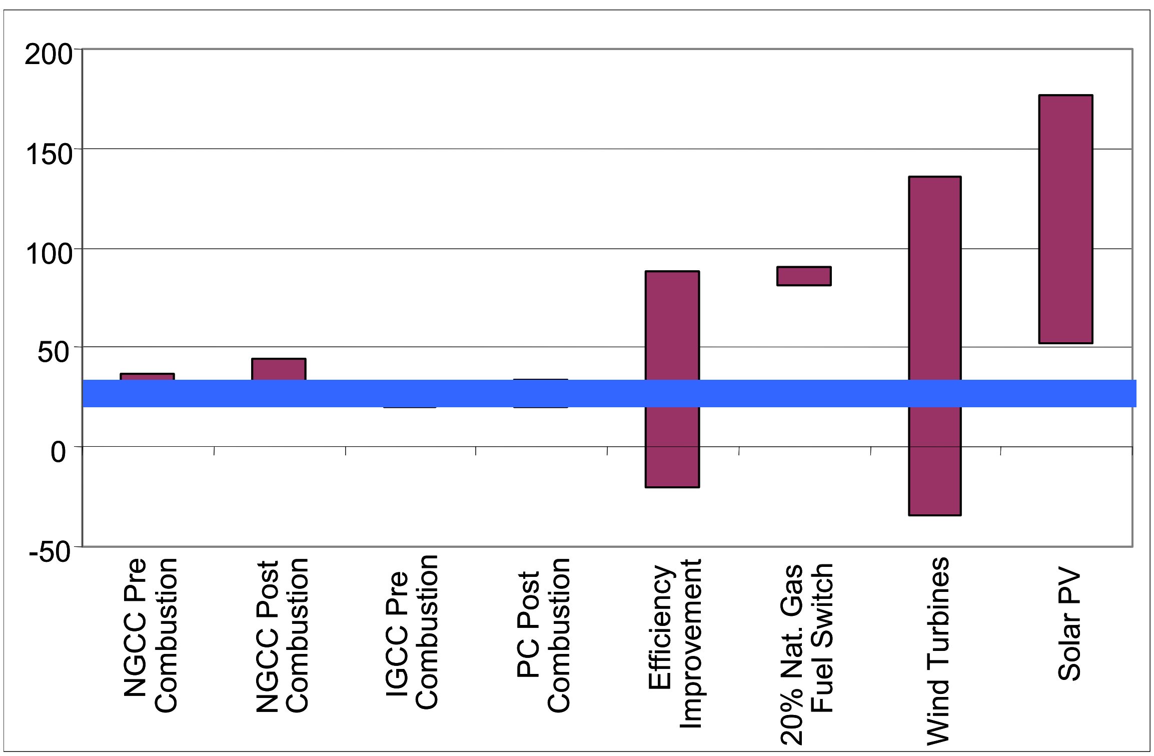

Figure 13: CO_2 Reduction Cost Versus CO_2 Credit Cost

CHAPTER 5

GENERAL DISCUSSION

5.1 Impact on Power Plant Investor

The results shown have significant implications for a technology developer as well as a power plant investor. For existing natural gas and coal power plant owners, efficiency improvements with low implementation costs are capable of offering the most economical method for CO_2 reduction. Consequently, increased attention should be given to turbine upgrades, and opportunities to reduce auxiliary loads. Turbine and balance of plant equipment manufacturers have the opportunity to introduce new high efficiency technologies at a price premium and justify the price based on high fuel prices and CO_2 reductions in markets such as Europe where CO_2 credits exist. As shown in the analysis, only high cost low efficiency improvements are not economical in a carbon-constrained economy.

For a natural gas combined cycle power plant owner, the cost of pre-combustion capture and post-combustion capture are close to the current trading cost. Therefore the decision to invest in CO_2 capture will be driven by other factors such as forecasted CO_2 policy. If the investor chooses to implement CO_2 capture, post combustion capture with monoethanolamines offers a competitive CO_2 reduction cost with less new equipment and real estate because only the flue gas treatment is modified. However, for a new natural gas power plant, pre-combustion capture with integrated reforming combined cycle provides the opportunity for significant future cost reductions. When reforming natural gas and shifting the syngas to CO_2 and hydrogen, CO_2 can be captured under high concentration and pressure. Near term capture processes such as adsorption are expensive compared to future membrane technologies that leverage further the high pressure and high CO_2 concentration typical of syngas after it has been shifted to CO_2 and hydrogen (Audus, 2005). Successful CO_2 membrane technology developers will potentially have a large market for integrated reforming combined cycles, especially if the membranes can be efficiently packaged with a reformer and shift reactor.

Similarly, for an existing coal fired power plant, post-combustion capture with monoethanolamines is a cost effective solution compared to pre-combustion capture and credit trading. However, for a new coal fired power plant, integrated gasification combined cycle with pre-combustion CO_2 capture offers the possibility for future cost reductions with new membrane technologies similar to those capable of being implemented in a integrated reforming combined cycle power plant. Equipment manufacturers such as General Electric are developing combined gasification and power-island packages with process space allocated to CO_2 capture.

For a utility or merchant plant owner with a portfolio of multiple power plants that plans on increasing capacity, integrated gasification combined cycle or integrated reforming combined cycle should be considered. The decision of which technology to implement will likely depend on the assumption of future local coal and natural gas prices. A portfolio owner may also chose to invest in the technology that utilizes the fuel that is underutilized in his other plants to diversify his investment and mitigate potential fuel price increases. Moreover, they may choose to invest in renewable energy sources despite their higher prices. Renewable energy provides an even greater hedge against increased fuel prices and might make the investor a candidate for local tax credits and improve their public image. For renewable technology developers the business climate is favorable.

5.2 Advanced Technology

Future power plant technologies are capable of drastically reducing the CO_2 reduction cost. Future technologies include but are not limited to advanced cycles and solid oxide fuel cells. A solid oxide fuel cell (SOFC), is an electrochemical device the converts the energy of the fuel directly into electrical energy. The complete combustion reaction, shown in Equation 5 below, occurs in a fuel cell, but the half reactions, oxidation and reduction, are forced to occur in physical separation at the anode and cathode, as shown in Equation 6 and 7, with a non-electrical conducting electrolyte in the middle. A similar electrochemical combustion reaction using carbon monoxide as the fuel can be utilized in a solid oxide fuel cell as well.

$$2H_2 + O_2 \Leftrightarrow 2H_2O \tag{5}$$

$$2H_2 = 4H^+ + 4e^- \tag{6}$$

$$O_2 + 4H^+ + 4e^- \Leftrightarrow 2H_2O \tag{7}$$

Separation of the half reactions creates a voltage and the resulting electrical current can be flowed through a resistive load to create electrical power. Bypassing electrical to thermal energy conversion and thermal to mechanical energy conversion allows the fuel cell to convert chemical energy into electrical energy with a simple cycle efficiency of 50 percent LHV (Tanaka et al, 2000). Solid oxide fuel cells operate at 800 to 1000^{o}C making them good candidates to operate in combined cycle with a gas turbine or steam turbine as the bottoming cycle. Tanaka et al show that under a number of design and operating scenarios, efficiencies up to 70 percent, can potentially be achieved for a solid oxide fuel cell combined cycle system shown in Figure 14. (Tanaka et al, 2000). In such as system methane fuel can be reformed in an external reformer to supply hydrogen and carbon monoxide to the fuel cell for electricity production. Unutilized fuel is combusted in the presence of compressed air and expanded in the gas turbine to drive the generator. If additional electric demand is required, fuel can bypass the fuel cell module and be sent straight to the combustor.

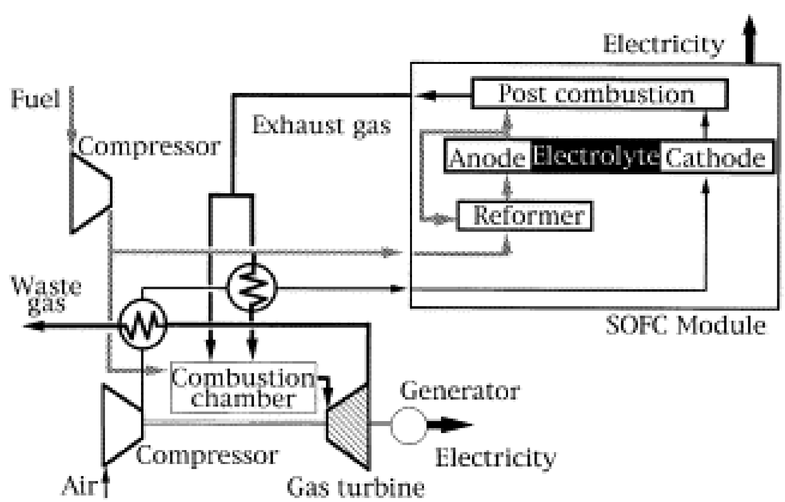

Figure 14: Solid oxide fuel cell combined cycle system diagram (Tanaka et al, 2000)

A solid oxide fuel cell developer who is looking to commercialize an integrated gasification fuel cell system in a carbon constrained economy can utilize the proposed framework to set program targets. For instance, the developer can determine the capital cost target required to have a CO_2 reduction cost less than the credit market value.

Assuming the baseline plant is the same 500 MW pulverized coal power plant utilized in the analysis, and with the capacity factor, operation and maintenance cost and fuel price assumed equivalent, the change in cost of electricity and CO_2 emissions can be calculated and used to get the CO_2 reduction cost as shown in Figure 15. The cost differential on the x-axis indicates the price premium compared to the baseline. The results for a 70 percent LHV efficiency system indicate the technology can be competitive in the market with a $1000 per kW premium as long as the CO_2 credit value is greater than $18 per ton. If the price premium is less than $300 per kW the technology is competitive based on cost of electricity alone and any CO_2 credit makes it even more economical. This comparison is valid for comparing a new integrated gasification fuel cell combined cycle power plant operating on $6 per MMBTU natural gas against a new pulverized coal power plant operating on $1.5 per MMBTU coal. If the pulverized coal power plant is already fully amortized the analysis will be less favorable.

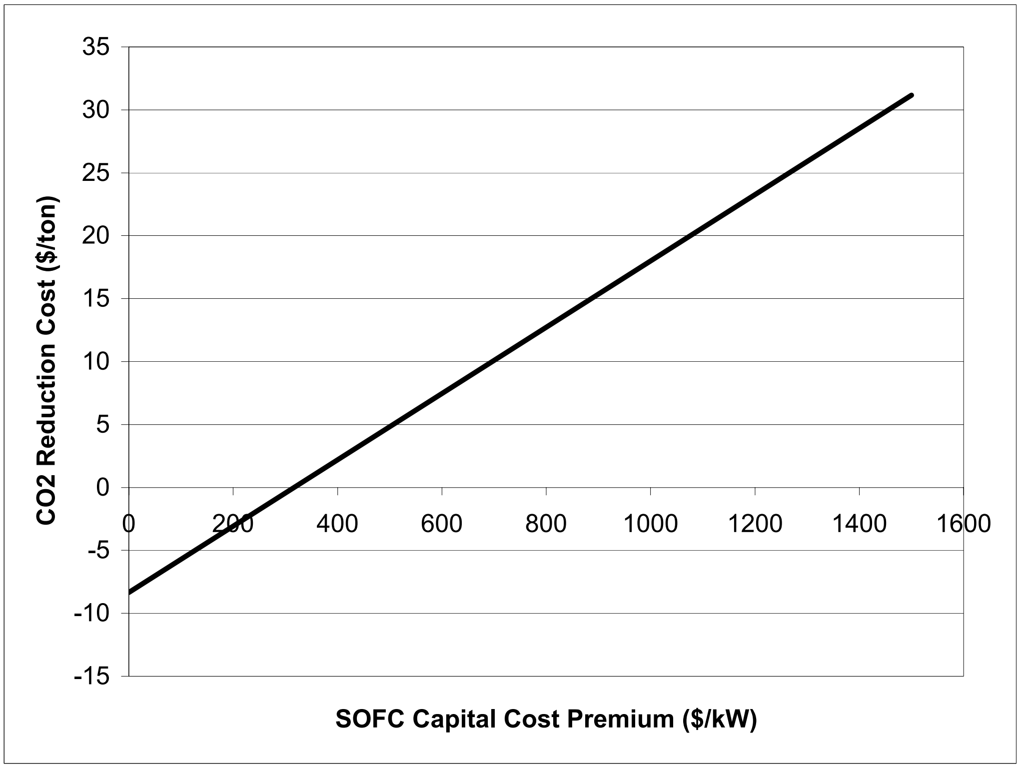

Figure 15: Sensitivity analysis of CO_2 reduction cost to capital cost premium over pulverized coal powered steam turbine with coal price of $1.5 per MMBTU and Natural gas price of $6 per MMBTU

Moreover, the separated half reactions in a fuel cell produce individual product streams. With methane fuel the anode off-gas consists of CO and H_2O that can be processed in a water gas shift membrane reactor to produce CO_2, H_2O and H_2. The H_2 is separated and recycled in the reactor and the H_2O can be condensed out leaving the CO_2 for further compression and storage. The combination of high efficiency and simple CO_2 capture may result in a low CO_2 mitigation cost if the cost of electricity is comparable to existing power plants.

5.3 Fuel Price Sensitivity

Fuel prices assumed in this study are based on Department of Energy projections (EIA, 2005). The projected natural gas fuel price for the electric power sector is between \$4 and \$6 per MMBTU from 2005 until 2025. Therefore, \$6 per MMBTU was the assumed natural gas fuel price utilized in this study. Similarly, the coal price for the electric power sector is projected to remain between \$1 and \$1.5 per MMBTU from 2005 to 2025. Therefore, \$1.5 per MMBTU was the assumed coal price utilized in this study. Nevertheless, fuel prices have been increasingly volatile and 2005 prices exceed those predicted in 2025. Wide variations in fuel prices are, therefore, critical to consider.

In the case of efficiency improvements, the analysis with current fuel prices indicates some efficiency improvements are economically viable based on the fuel savings alone. In the event of increased fuel prices, the economic savings of efficiency improvements will increase and drive down the CO_2 reduction cost. The CO_2 reduction cost is negative for some efficiency improvements, therefore, generators are likely to consider efficiency improvements regardless of increasing fuel prices. With increasing fuel cost, power plant investors have greater incentive for efficiency improvements, which brings about CO_2 reductions. As fuel costs rise, the fuel savings increase and will offset higher capital cost. A power plant facility study in conjunction with fuel price projections is recommended to determine the specific economical efficiency improvements achievable at a respective plant.

On the other hand, 20 percent fuel switching from coal to natural gas incurs a $90 per ton CO_2 reduction cost with $6 per MMBTU natural gas cost and $1.5 per MMBTU coal cost. An equal increase in coal prices and natural gas prices will have little impact on the CO_2 reduction cost. If natural gas prices increase with respect to coal prices, the CO_2 reduction cost would increase as well and become less economical. Opportunity fuels such as landfill gas and biogas can enable power producers to attain the CO_2 reduction benefits of natural gas fuel switching without incurring the increased fuel price. Moreover, landfill methane recovery for power production prevents methane, a greenhouse gas, from being emitted into the atmosphere. Such opportunity gases should be considered further on a site-specific basis, especially if natural gas prices continue to rise relative to other fuels.

5.4 CO_2 Credit Trading

Trading credits to reduce emissions of harmful chemicals into the environment was first implemented in 1990. According to Komer, 2004, the 1990 Clear Air Act Amendments instituted policy that required electricity generators to purchase a SO_2 credit for each ton of SO_2 emitted above the emissions cap. Generators have the opportunity to either reduce SO_2 emissions or purchase allowances from a capped supply. The SO_2 trading program demonstrates the ability of market forces to respond with innovative solutions. The financial incentives spurred the development of low cost solutions for reducing SO_2 emissions.

While credit trading has the capacity to achieve reductions in environmental impact with lower economic cost than mandated power plant level reductions, potentially the environmental impact may be measured on an inappropriate geographic scale. In some cases, pollutants can cause environmental damage on a community level, even though pollutant emissions are reduced to an acceptable national or global level. CO_2 and other greenhouse gases are traded to mitigate global warming, a phenomenon that is caused by global emissions' impact on atmospheric concentrations. Trading credits is, therefore, an appropriate way to achieve CO_2 reductions with minimal economic cost and no additional localized environmental impact.

5.5 Impact on Investors' Decision Making Process

The results of this analysis may be used to help power plant owners compare various CO_2 reduction technologies among each other and with the CO_2 trading price. The decision on which option to implement will not only depend on the CO_2 reduction cost, but also on which options are technically feasible given the power pants' equipment, available capital, and other site specific needs. For example, a site that utilizes CO_2 for enhanced oil recovery may prefer an option that allows for large volumes of CO_2 to be captured. Alternatively, a site with a renewable energy portfolio may consider installing wind turbines to offset CO_2 emissions. Essentially, the CO_2 credit cost addresses just one of the power plants' critical-to-quality characteristics (CTQ's). Other critical-to-quality characteristics that may be used to evaluate CO_2 reduction technologies include: volume of CO_2 captured; availability; reliability; cost of electricity; efficiency; power output; and many more. One technology may be chosen over another technology with a lower CO_2 reduction cost if the first is more capable of meeting the power plant owners other requirements. A power plant owner with multiple potential solutions to consider against multiple critical-to-quality characteristics may consider using a trade-off matrix, a decision making tool to evaluate technologies.

As seen in the results section, efficiency improvements have the lowest potential CO_2 reduction costs. Pre-combustion and post-combustion technologies for coal and natural gas are shown to have cost ranging from \$20 to \$30 per ton. The small range in estimated cost indicates presently no clear advantage between these two technologies exist. The decision is, therefore, likely to be affected by site configuration and other critical-to-quality characteristics.

5.6 Impact on Global Warming

The effort to reduce mankind's contribution to global warming occurs on multiple levels. Countries, states, corporations and individuals have committed to reducing greenhouse gas emissions. The intent of this study is to provide a tool to be utilized by power plant investors in evaluating CO_2 reduction technologies. Moreover, the study is intended to contribute to the effort of reducing humankind's impact on global climate change. Climate change will not be curbed by one study or even one country, but by a committed global effort that encompasses not only CO_2 emissions reductions, but also by demand side efficiency improvements and enhanced natural sinks.

CHAPTER 6

CLOSING

In an effort to reduce mankind's impact on climate change, multiple technologies will be tested, implemented and deemed successful or not. No one technology independently will likely remedy global warming. The purpose of this study is to compare technologies on a common technical and economic basis. The metric utilized for comparison is the CO_2 reduction cost measured in dollars per ton. The CO_2 reduction cost metric captures the economic impact through the change in cost of electricity and the environmental impact through the change in CO_2 emissions. Some efficiency improvements enable a power producer to reduce CO_2 emissions for a low CO_2 reduction cost, but reductions are at most 15 percent. More substantial reductions, on the order of 90 percent, may be achieved with a variety of commercially available and near-term CO_2 capture solutions. Technologies such as integrated gasification combined cycle with pre-combustion adsorption, are capable of \$20 to \$30 per ton CO_2 reduction cost. With CO_2 credits trading at \$20 to \$30 per ton in 2005, a significant opportunity for advancements in CO_2 mitigation technologies exist that will enable power plant owners to reduce CO_2 emissions and will a profit from the sale of credits. In the near term, while technology options are limited and not differentiated by CO_2 reduction cost, the selection of CO_2 reduction technologies will likely be driven by site level critical-to quality-characteristics other than the CO_2 reduction cost. Alternatively, power plant owners may opt to utilize efficiency improvements and fuel switching to cover a portion of their targeted reduction, and to purchase credits for the rest.

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