

THE ECONOMICS OF CO₂ SEPARATION AND CAPTURE

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Abstract

Carbon management and sequestration offers an opportunity for reducing greenhouse gas emissions that can complement the current strategies of improving energy efficiency and increasing the use of non-fossil energy resources. When most people think of sequestering carbon, they think of planting trees. However, the focus of this paper is the capture of CO₂ from large stationary sources, primarily power plants. In this paper, we first present an overview of CO₂ separation and capture technology, followed by a detailed analysis of costs associated with today's technology for CO₂ separation and capture followed by a discussion of opportunities to lower costs in the future. Based on this cost analysis, we develop a composite model for costs from several types of power plant, followed by a sensitivity study. For coal, new technologies like gasification show the most long-term promise. By 2012, incremental costs for CO₂ sequestration could be less than 1 ¢/kWh from advanced coal plants and less than 1.5 ¢/kWh from gas plants.

I. INTRODUCTION

Fossil fuels currently supply over 85% of the world's energy needs and will remain in abundant supply well into the 21st century. They have been a major contributor to the high standard of living enjoyed by the industrialized world. We have learned how to extract energy from fossil fuels in environmentally friendly ways, controlling the emissions of NO_x, SO₂, unburned hydrocarbons, and particulates. Even with these added pollution controls, the cost of fossil energy generated power keeps falling. Despite this good news about fossil energy, its future is clouded because of the environmental and economic threat posed by possible climate change, commonly referred to as the "greenhouse effect". The major anthropogenic greenhouse gas is carbon dioxide (CO₂) and the major source of anthropogenic CO₂ is combustion of fossil fuels. However, if we can develop technology to capture and sequester the fossil fuel CO₂ in a cost-effective and environmentally sound manner, we will be able to enjoy the benefits of fossil fuel use throughout the next century.

In general, to economically sequester CO₂ produced from power plants, one must first produce a relatively pure, high pressure stream of CO₂. Reasons include:

- The economics of transporting CO₂ any distance will favor concentrated CO₂.
- Sink capacity is better utilized by injecting pure CO₂.
- Though still a subject of research, some impurities may be harmful to the operations of certain sinks or may have adverse environmental effects.

Note that there are exceptions to this rule, some of which will be explored later in this paper. The process of producing this high purity, high pressure CO₂ stream is referred to as separation and capture, which encompasses all operations that take place at the power plant site, including compression.

For ease of transport, CO₂ is generally compressed to the order of 100 atm. Most systems can be designed so that no recompression is required beyond the power plant. For example, CO₂ from the Great Plains Synfuels Plant is transported 330 km from Beulah, ND to Weyburn, Saskatchewan. It is initially compressed to 170 atm and delivered at 148 atm, with no recompression (Hattenbach *et al.*, 1999).

The idea of separating and capturing CO₂ from the flue gas of power plants did not start with concern about the greenhouse effect. Rather, it gained attention as a possible economic source of CO₂, especially for use in enhanced oil recovery (EOR) operations where CO₂ is injected into oil reservoirs to increase the mobility of the oil and, therefore, the productivity of the reservoir. Several commercial CO₂ capture plants were constructed in the late 1970s and early 1980s in the US. When the price of oil dropped in the mid-1980s, the recovered CO₂ was too expensive for EOR operations, forcing the closure of these capture facilities. However, the North American Chemical Plant in Trona, CA, which uses this process to produce CO₂ for carbonation of brine, started operation in 1978 and is still operating today. Several more CO₂ capture plants were subsequently built to produce CO₂ for commercial applications and markets. Some of these plants took advantage of the economic incentives in the Public Utility Regulatory Policies Act (PURPA) of 1978 for “qualifying facilities”. A listing of the major CO₂ capture plants are shown in Table 1.

In addition to power plants, there are a number of large CO₂-emitting industrial sources that could also be considered for application of capture and sequestration technologies. In natural gas operations, CO₂ is generated as a by-product. In general, gas fields may contain up to 20% (by volume) CO₂, most of which must be removed to produce pipeline quality gas. Therefore, sequestration of CO₂ from natural gas operations is a logical first step in applying CO₂ capture technology. In the future, similar opportunities for CO₂ sequestration may exist in the production of hydrogen-rich fuels (e.g., hydrogen or methanol) from carbon-rich feedstocks (e.g., natural gas, coal, or biomass). Specifically, such fuels could be used in low-temperature fuel cells for transport or for combined heat and power. Relatively pure CO₂ would result as a byproduct (Socolow 1997).

The first commercial CO₂ capture and sequestration facility started-up in September 1996, when Statoil of Norway began storing CO₂ from the Sleipner West gas field into a sandstone aquifer 1000 m beneath the North Sea. The CO₂ is injected from a floating rig through five pipes at a rate of 20,000 tonnes/week (corresponding to the rate of CO₂ produced from a 140 MW_e coal fired power plant). The economic incentive for this project is the Norwegian carbon tax of \$50 per tonne CO₂. Costs of the operation are approximately \$15/tonne of CO₂ avoided (Olav Kaarstad, Statoil, personal communication). An international research effort is being organized to monitor and document this effort so the experience can be built on by future endeavors.

To date, all commercial CO₂ capture plants use processes based on chemical absorption with a monoethanolamine (MEA) solvent. MEA was developed over 60 years ago as a general, non-selective solvent to remove acid gases, such as CO₂ and H₂S, from natural gas streams. The process was modified to incorporate inhibitors to resist solvent degradation and equipment corrosion when applied to CO₂ capture from flue gas. Also, the solvent strength was kept relatively low, resulting in large equipment sizes and high regeneration energy requirements

(Leci, 1997). As shown in Figure 1, the process allows flue gas to contact an MEA solution in the absorber. The MEA selectively absorbs the CO₂ and is then sent to a stripper. In the stripper, the CO₂-rich MEA solution is heated to release almost pure CO₂. The lean MEA solution is then recycled to the absorber.

An initial reaction some people have to CO₂ capture technology is that it is “expensive”. However, “expensive” is a subjective (as opposed to objective) term. If one can produce CO₂ for \$25 per tonne from flue gas, is that expensive? Yes, if \$10 per tonne CO₂ is available from natural reservoirs. No, if one has to pay typical commercial rates of \$70-100 per tonne.

In applying these commercial processes to CO₂ sequestration, it is worthwhile exploring why there is the perception that CO₂ separation and capture is expensive. Reasons include:

- It will always be more expensive to sequester CO₂ than to just emit it to the atmosphere.
- Most studies show that the bulk of the cost in sequestering power plant CO₂ are due to separation and capture (including compression) as opposed to transport and injection.
- The commercial MEA process is old and has not been optimized for sequestration.
- The basis of design is very different for plants producing CO₂ for commercial markets as compared to plants producing CO₂ for sequestration. This relates to the difference between the cost of capture and the cost of avoidance, as discussed below.

The primary difference in capturing CO₂ for commercial markets versus capturing CO₂ for sequestration is the role of energy. In the former case, energy is a commodity, and all we care about is its price. In the latter case, using energy generates more CO₂ emissions, which is precisely what we want to avoid. Therefore, capturing CO₂ for purposes of sequestration requires more emphasis on reducing energy inputs than the traditional commercial process. Figures 2 and 3 help define the difference between CO₂ captured and CO₂ avoided and the concept of the “energy penalty”.

Other processes have been considered to capture the CO₂ from the flue gas of a power plant -- e.g., membrane separation, cryogenic fractionation, and adsorption using molecular sieves -- but they are even less energy efficient and more expensive than chemical absorption. This can be attributed, in part, to the very low CO₂ partial pressure in the flue gas. Therefore, two alternate strategies to the “flue gas” approach are under active consideration – the “oxygen” approach and the “hydrogen” or “syngas” approach.

The major component of flue gas is nitrogen, which enters originally with the air feed. If there were no nitrogen, CO₂ capture from flue gas would greatly simplify. This is the thinking behind the oxygen approach, where instead of air, the power plant is fed oxygen produced by an air separation plant. However, combustion with oxygen yields temperatures too large for today’s materials, so some flue gas must be recycled to moderate the temperature. Applying this process is easier for steam turbine plants than gas turbine plants. In the former, relatively straightforward

boiler modifications are required. For the latter, much more complex gas turbine design changes will be required.

The flue gas approaches in use today require clean-up of the NO_x and SO_2 prior to CO_2 separation. The oxygen route does not. If the sinks are tolerant to NO_x and SO_2 , we can eliminate separate control steps and sequester the NO_x and SO_2 along with the CO_2 , resulting in a zero emissions power plant.

Integrated coal gasification combined cycle (IGCC) plants are an example of the hydrogen route. Coal is gasified to form synthesis gas (syngas) of CO and H_2 . The gas then undergoes the water-gas shift, where the CO is reacted with steam to form CO_2 and H_2 . The CO_2 is then removed, with the hydrogen being sent to a gas turbine combined cycle. This approach allows for a CO_2 removal process (e.g., a physical solvent process like Selexsol) that is much less energy intensive than the MEA process because capture takes place from the high pressure syngas as opposed to the atmospheric pressure flue gas. A similar process is available for natural gas, where the syngas is formed by steam reforming of methane.

The hydrogen route opens up opportunities for “polygeneration”, where besides electricity and CO_2 , additional products are produced. For example, instead of sending hydrogen to a turbine, it can be used to fuel a “hydrogen economy”. In addition, syngas is an excellent feedstock for many chemical processes.

In this paper, we start by describing an analysis of published studies on the economics of CO_2 separation and capture and a summary of the results. Detailed results of this analysis were presented in Herzog and Vukmirovic (1999). Based on this analysis, we develop a Composite Economic Model. Using this model, we then perform some sensitivity analyses on two key parameters, the reference plant heat rate and the capture plant energy penalty, to illustrate how we can improve the economics of CO_2 capture and sequestration.

II. ANALYSIS OF ECONOMIC STUDIES

We have conducted a comparison of published studies from the past several years that analyzed the economics of capturing CO_2 from fossil fuel-fired power plants. These studies fall into three categories:

- Using the hydrogen route to capture CO_2 from the shifted synthesis gas of Integrated Gasification Combined Cycle (IGCC) power plants using a physical absorption process (e.g., Selexol or Rectisol).
- Flue gas clean-up from conventional Pulverized Coal (PC) power plants using an MEA scrubbing process.
- Flue gas clean-up from Natural Gas Combined Cycle (NGCC) power plants using an MEA scrubbing process.

All studies were made using commercially available technology and include the cost of compressing the captured CO₂ to over 100 atm. for pipeline transportation. The studies analyzed in our work are listed below.

IGCC Studies:

Argonne National Laboratory (Doctor *et al.*, 1996; Doctor *et al.*, 1997)
Politecnico di Milano, Italy (Chiesa *et al.*, 1998)
SFA Pacific (Simbeck, 1998)
University Of Utrecht, Netherlands (Hendriks, 1994)
EPRI (Condorelli *et al.*, 1991; Booras and Smelser, 1991)

PC Studies:

University Of Utrecht, Netherlands (Hendriks, 1994)
EPRI (Smelser *et al.*, 1991; Booras and Smelser, 1991)
SFA Pacific (Simbeck, 1998)

NGCC Studies:

SFA Pacific (Simbeck, 1998)
Norwegian Institute of Technology (Bolland and Saether, 1992)

We analyzed two cases from each study, a power plant with no capture (reference plant) and the same plant with CO₂ capture. Where necessary, we adjusted the fuel feed rates so that they were the same for both cases of a study. This means that the net power output for the capture plant will be less than the reference plant due to the energy requirements of the capture process (see Figure 3).

From each study, we extracted the following data for both the reference and capture cases:

- Cost of electricity ($\text{\$/kWh}$) broken down into capital, fuel, and operation and maintenance (O&M)
- Capital cost ($\text{\$/kW}$)
- Net power output (MW)
- CO₂ emitted (kg/kWh)
- Heat rate (Btu/kWh) defined on a low heating value (LHV) basis (note that the thermal efficiency is simply 3412 Btu/kWh divided by the heat rate)

In addition, we extracted the following data so that we could put each of the studies on a common economic basis:

- the annual capacity factor (defined as operating hours per year divided by 8760, where 8760 is the total number of hours in a year).

- the cost of fuel in \$ per million Btu based on fuel LHV.
- the capital charge rate. The capital charge rate can be roughly correlated to the cost of capital and is used to annualize the capital investment of the plant. Specifically, the capital component of the cost of electricity (\$/kWh) equals the capital charge rate (fraction/yr) times the capital cost (\$/kW) divided by the hours per year of operation.

We adjusted each study to the following economic basis:

- Capital charge rate of 15%/yr
- Annual capacity factor of 0.75 (6570 hrs/yr)
- Fuel costs for gas of \$2.93 per million Btus based on LHV
- Fuel cost for coal of \$1.24 per million Btus based on LHV

The studies all reported their results in U.S. dollars, but used different year dollars in their calculations. It should be noted that, despite inflation, electricity production costs have been falling. We decided not to adjust for different year dollars since the precision that might be gained in converting these estimates to the same year dollars is small relative to the uncertainty inherent in and across these cost estimates.

In addition to the above studies, we included very recent data from the Coal Utilization Research Council (CURC, 1998) for all three types of plants. This data was limited to the reference plants.

The results of the initial phase of the analysis are summarized in Figure 4, which plots the cost of electricity versus CO₂ emissions for each of the analyzed studies. In terms of emissions, the plants cluster into three groups: reference coal plants at about 0.75 kg CO₂ per kWh, reference natural gas plants at about 0.35 kg CO₂ per kWh, and the capture plants at about 0.1 kg CO₂ per kWh. If we ignore the EPRI results (this is the oldest study and was based on very conservative assumptions), we can make the following observations about costs:

- NGCC reference plants are 3-4 ¢/kWh
- Coal reference plants are 4-5 ¢/kWh, with PC plants slightly less expensive than IGCC plants
- NGCC capture plants are 5-6 ¢/kWh
- IGCC capture plants are 6-7 ¢/kWh
- PC capture plants are 7-8 ¢/kWh

III. COMPOSITE MODEL

In order to construct composite economic models for the three types of power analyzed in the previous section, we did the following:

- Used reference plant data from CURC (1998) for capital and O&M costs, heat rate, and CO₂ emissions.
- Averaged data from all studies analyzed above (except the ERPI studies, which our initial analysis showed to outliers) for incremental capital and O&M costs for the capture plants, as well as energy requirements of the capture plants.
- Defined a 90% CO₂ recovery rate as our basis.

Model results are shown in Table 2 under the “Today” columns. Key results are:

- NGCC plants produce the least-cost electricity, whether one captures the CO₂ or does not capture.
- IGCC plants show the least incremental cost of electricity from CO₂ capture due to their more efficient capture process.
- PC plants present the largest economic hurdle to CO₂ sequestration.

We then used our model to project costs for the year 2012 as follows:

- Lower capital costs of the reference plant from CURC (1998).
- Lower heat rates (i.e., higher thermal efficiencies) for the reference plant from CURC (1998).
- Lower energy requirements for the capture process from Mimura *et al.* (1997) for PC and NGCC and from Herzog and Drake (1993) for IGCC.
- Lower capital costs for the capture process (assumed 10% reduction from the current levels).

Note that if gas prices rise about 30%, in 2012 the cost of electricity from an IGCC capture plant will be about equal to that of an NGCC capture plant.

The choice of the base case is a major determinant in mitigation cost expressed as \$ per tonne of CO₂ avoided. In Table 2, two different base cases are used. The first calculation uses the reference plant of the same type as the capture plant. In other words, we compare an IGCC capture plant to an IGCC reference plant. The second calculation compares everything to an NGCC reference plant, which is the power plant of choice today.

Typically, to account for the transportation and injection of the CO₂ once it leaves the power plant, an additional \$5-15 per tonne CO₂ avoided should be added. However, if the CO₂ is going to be utilized for commercial purposes, a credit can be taken, improving the economics greatly.

IV. SENSITIVITY STUDIES

There is great potential for technological improvements that can significantly lower costs. Strategies include improving the thermal efficiency of the reference plants, reducing the energy requirements for CO₂ capture, or lowering capital costs of the power or capture plant. Even larger costs reductions are possible in the future with new innovative technologies. For example, it may be possible to develop new types of power plants and power cycles.

In this section, we look at the quantitative effect of reducing reference plant heat rates and capture plant energy requirements. Starting with the composite model (today case) that we described above, we assume improved performance with no impact on capital costs. Calculations were done over the range of 0-50% improvement for three cases: capture plant energy requirements, improved reference plant heat rate, and both together. Note that the definition of improved heat rate uses the theoretical value of 3412 Btu/kWh as the base value. So, for the IGCC case, the heating value for a 10% improvement over the starting value of 8124 Btu/kWh is $8124 - 0.1*(8124-3412)$, or 7653 Btu/kWh.

The results of the sensitivity studies for the IGCC case are presented in Figures 5 and 6. The PC and NGCC cases show similar trends. Figure 5 plots absolute cost of electricity versus percent improvement. Note that reducing heat rates has a bigger effect on the cost than reducing capture energy requirements. The reason for this is that heat rates reduce electricity costs for both the reference and capture plants, while capture energy requirements just effect the capture plant. If one just looks at the decline in the incremental cost of electricity (Figure 6), the two parameters are more evenly matched. Nonetheless, this shows how improving heat rates is extremely important for improving the economics of CO₂ sequestration. This supports a mitigation strategy that focuses on improved efficiency in the near-term, with sequestration becoming more important in the longer-term.

V. CONCLUDING REMARKS

We are continuing our work on the topic of the economics of CO₂ separation and capture. Other important issues we need to address beyond the scope of this paper include:

- Retrofits. This paper just looked at new plants.
- Possible improvements beyond 2012. How much more can we improve the economics?
- One box solutions for controlling NO_x and SO₂ simultaneously with CO₂. Numbers in this paper assume sequential control.

For clarity, we have treated CO₂ separation and capture discretely from transportation and injection. However, a systems approach is needed to understand the most economical way to proceed. For example, enhanced coal bed methane (ECBM) can utilize nitrogen as well as CO₂. Therefore, for ECBM, it may not be necessary to separate out the nitrogen prior to injection. On the other hand, the use of flue gas in place of pure CO₂ has some drawbacks, such as much higher energy requirements for compression.

One cannot judge the numbers presented in this paper in isolation. One has to take into account the cost of alternative mitigation options, as well as how much society is willing to pay to reduce greenhouse gases. This gets complicated because costs change as technology changes. Also, partly based on new scientific information, society's view on the seriousness of climate change will also evolve, changing the view on what costs are acceptable to mitigate greenhouse gas emissions. To couple our effort with the bigger picture issues, we are working with the Integrative Assessment community to feed these numbers into their more comprehensive economic models.

Finally, if we are to be successful in mitigating climate change, we will need as many technical options as possible to be available. The question is not whether improved efficiency, increased renewables, or carbon management is the best approach. We will need them all.

VI. ACKNOWLEDGMENT

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Table 1. Commercial CO₂ Recovery Plants

Operator	Location	Capacity (tons/day CO ₂)	Fuel Source	CO ₂ Use	Technology	Status
Carbon Dioxide Technology	Lubbock, TX	1200	gas boiler	EOR	Dow MEA	Shut
North American Chemical Co.	Trona, CA	800	coal boiler	Carbonation of brine (soda ash)	Kerr-McGee MEA	Operational since 1978
Mitchell Energy	Bridgeport, TX	493	gas heaters, engines, turbine	EOR	Inhibited MEA	Shut
Northeast Energy Associates	Bellingham, MA	320	gas turbines	PURPA (food-grade)	Fluor Daniel	Operational since 1991
Soda Ash Botswana	Sua Pan,	300	coal boiler	Carbonation of brine (soda ash)	Kerr-McGee MEA	Operational since 1991
Applied Energy Systems	Poteau, OK	200	coil boiler (fluidized bed)	PURPA (food-grade)	Kerr-McGee MEA	Operational since 1991
Sumitomo Chemicals	Chiba, Japan	165	gas boilers plus oil/coal boiler	food-grade	Fluor Daniel	Operational since 1994
Luzhou Natural Gas	China	160	NH ₃ plant reformer exhaust	Urea	Dow MEA	No Information
Indo Gulf Fertilizer Co.	India	150	NH ₃ plant reformer exhaust	Urea	Dow MEA	Operational since ~1988
N-ReN Southwest	Carlsbad, NM	104	gas boiler plus NH ₃ reformer exhaust	EOR	Retrofit to Dow MEA	Shut
Prosint	Rio de Janeiro, Brazil	90	gas boiler	food-grade	Fluor Daniel	Operational since 1997
Liquid Air Australia	Australia	2 x 60	gas boiler	food-grade	Dow MEA	Operational since ~1985

Notes:

1. ABB Lummus Crest licensed the Kerr-McGee MEA technology in 1990.
2. Fluor Daniel licensed the Dow MEA technology (ECONAMINE FG) in 1989.
3. A number of small plants (~6 tons/day CO₂) producing food-grade CO₂ exist in the Philippines and other places using Fluor Daniel/ Dow MEA technology.

Table 2. Composite Model of the Cost of CO₂ Capture and Separation

Cycle:		IGCC	IGCC	PC	PC	NGCC	NGCC
Technology:		Today	2012	Today	2012	Today	2012
Data Description	Units	Value	Value	Value	Value	Value	Value
Reference Plant							
coe: CAPITAL	mill/kWh	30	26	26	25	12	12
coe: FUEL	mill/kWh	10	9	10	10	18	17
coe: O&M	mill/kWh	6	6	6	6	2	2
Capital Cost	\$/kW	1300	1145	1150	1095	525	525
Net Power Output	MW	500	500	500	500	500	500
CO ₂ emitted	kg/kWh	0.74	0.65	0.77	0.73	0.37	0.33
Thermal Efficiency (LHV)		42.0%	47.8%	40.3%	42.4%	54.1%	60.1%
Heat Rate (LHV)	Btu/kWh	8124	7137	8462	8042	6308	5677
Cost of Electricity	¢/kWh	4.6	4.1	4.3	4.1	3.3	3.1
CO₂ Capture Plant							
coe: CAPITAL	mill/kWh	39	33	45	40	26	22
coe: FUEL	mill/kWh	12	10	13	12	21	18
coe: O&M	mill/kWh	8	8	11	11	6	5
Capital Cost	\$/kW	1730	1433	1967	1748	1120	956
Net Power Output	MW	421	443	400	417	432	463
CO ₂ emitted	kg/kWh	0.09	0.07	0.10	0.09	0.04	0.04
Thermal Efficiency (LHV)		35.4%	42.4%	32.2%	35.4%	46.8%	55.6%
Heat Rate (LHV)	Btu/kWh	9639	8056	10581	9650	7293	6133
Cost of Electricity	¢/kWh	6.0	5.0	6.9	6.3	5.2	4.5
Comparison							
Incremental coe	¢/kWh	1.4	0.9	2.7	2.2	2.0	1.4
Energy Penalty		16%	11%	20%	17%	14%	7%
Mitigation Cost vs. ref	\$/tonne CO ₂	\$21	\$16	\$40	\$34	\$61	\$47
Mitigation Cost vs. gas	\$/tonne CO ₂	\$96	\$76	\$135	\$132	\$61	\$47
Basis							
Capital Charge Rate		15.0%	15.0%	15.0%	15.0%	15.0%	15.0%
Yearly Operating Hours	hrs/yr	6570	6570	6570	6570	6570	6570
Fuel (Coal) Cost, LHV	\$/MMBtu	1.24	1.24	1.24	1.24	2.93	2.93

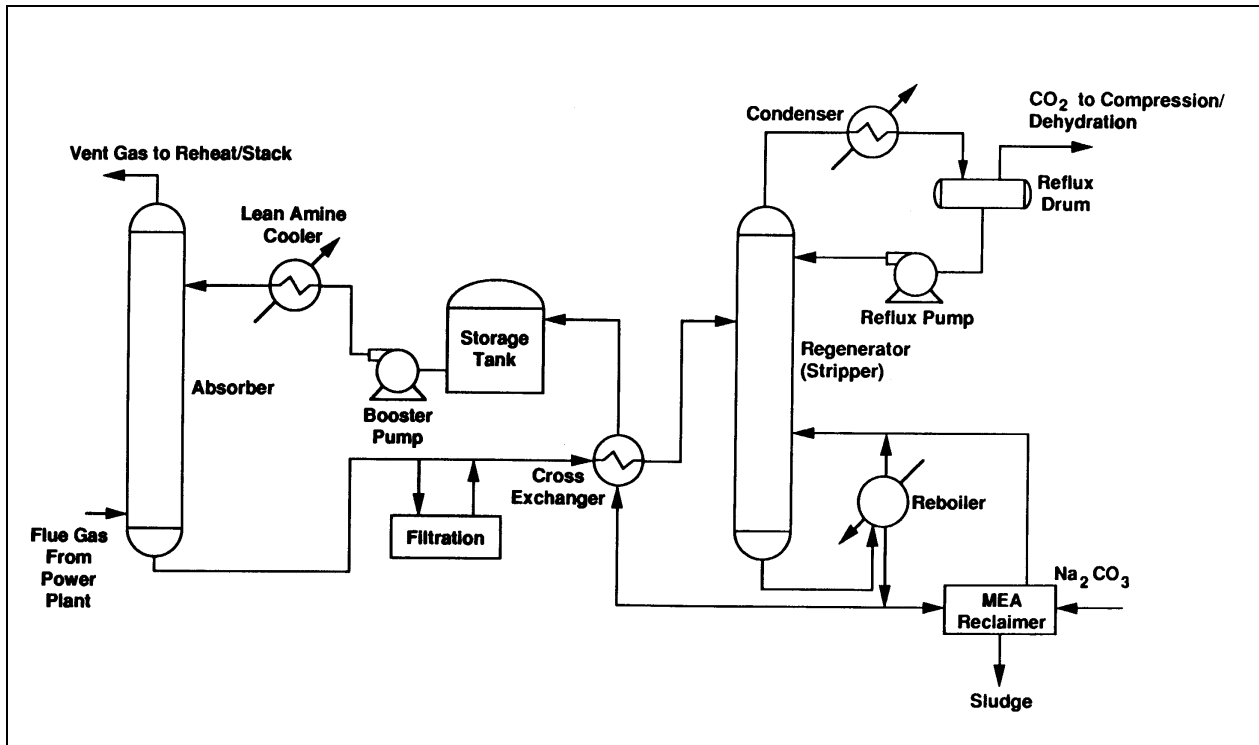


Figure 1. Schematic diagram of the amine separation process.

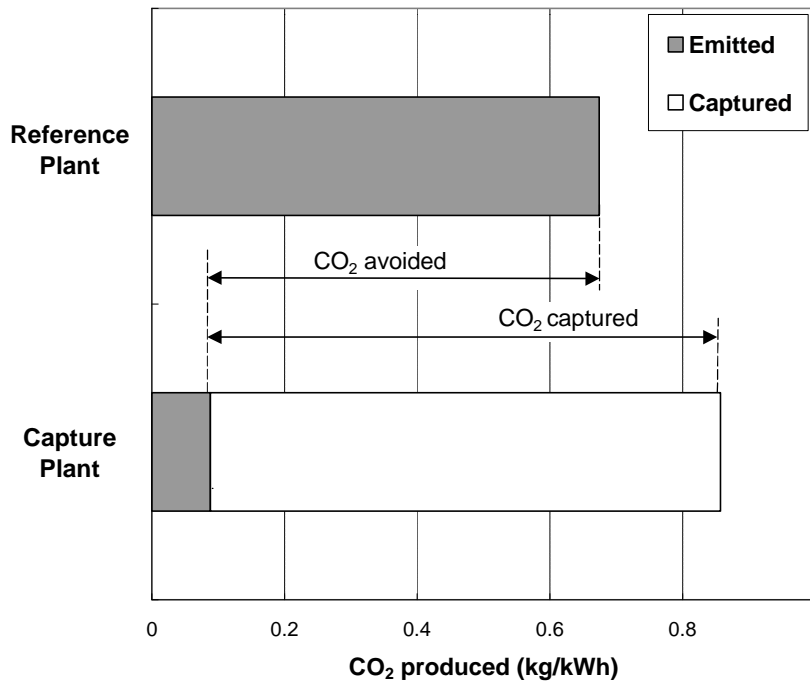


Figure 2. Defining the difference between CO₂ captured and CO₂ avoided. The numbers are from the example in Figure 3.

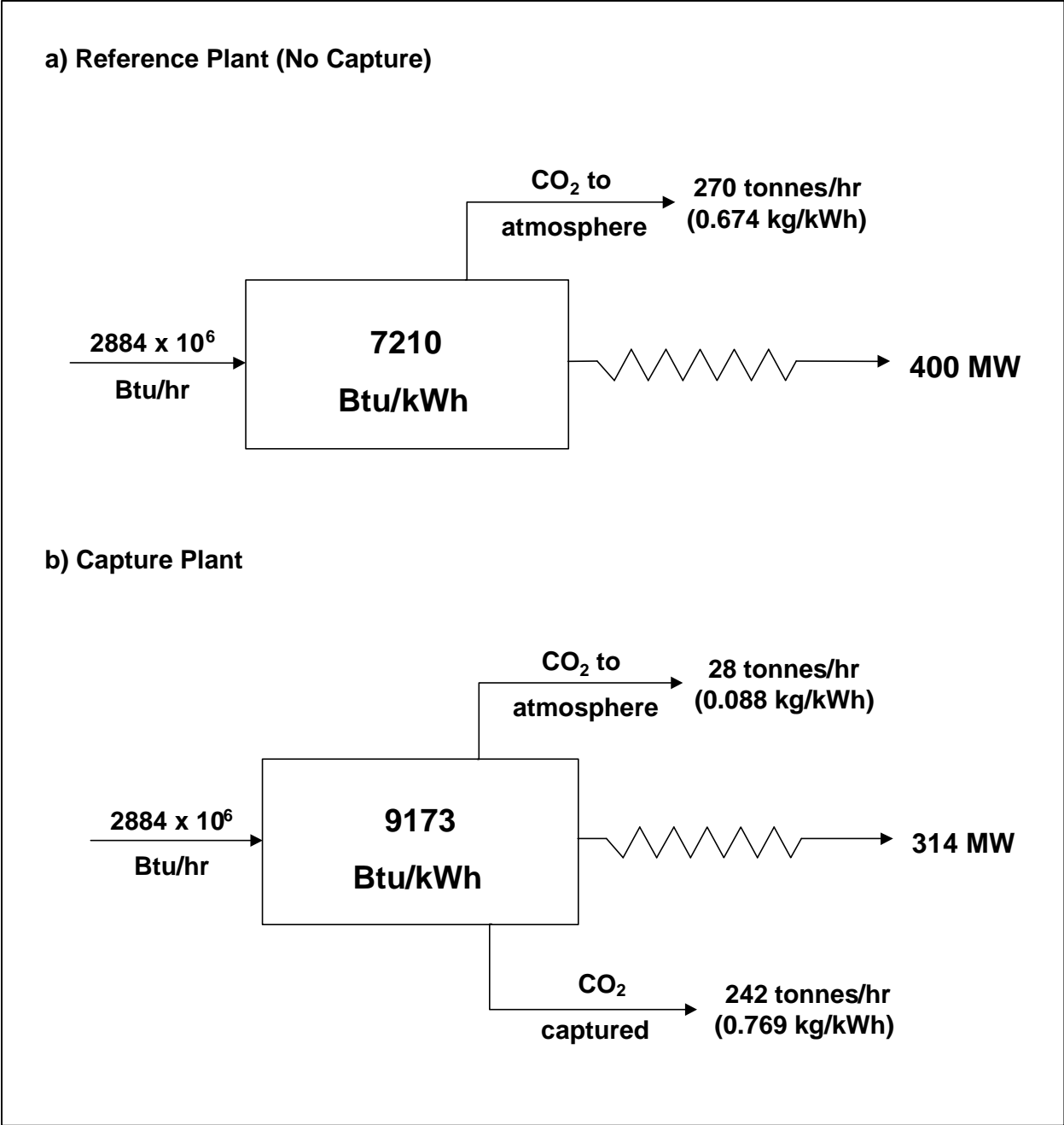


Figure 3. In this example, we have a reference power plant that emits CO₂ to the atmosphere and a power plant that captures CO₂. In both cases, the fuel input to the power plant is the same. For the capture plant, the energy output is reduced, resulting in an energy penalty of 21.5%. Based on SFA Pacific IGCC Study (Simbeck, 1998).

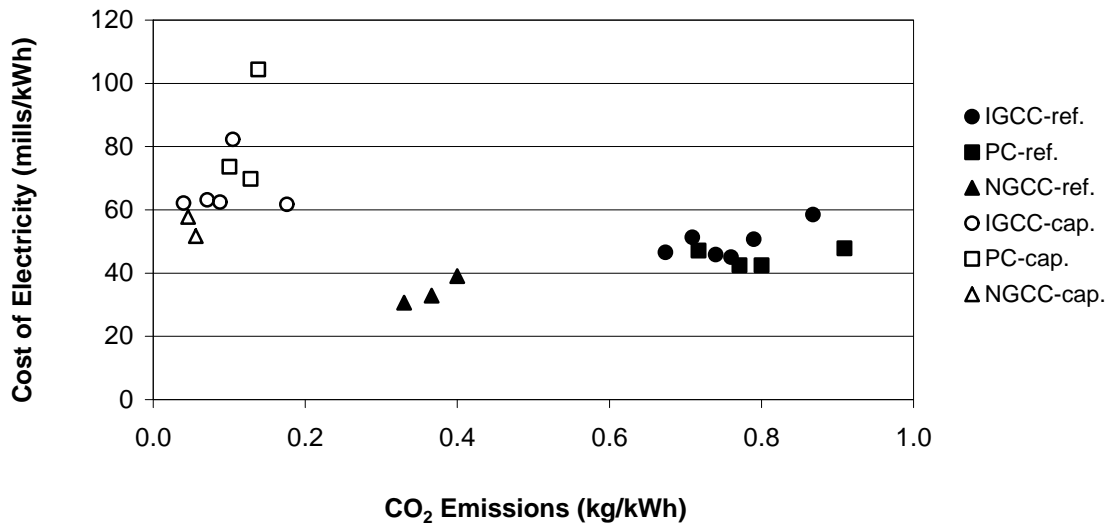


Figure 4. Cost of Electricity versus CO₂ Emissions for the 13 reference plants and the 10 capture plants analyzed.

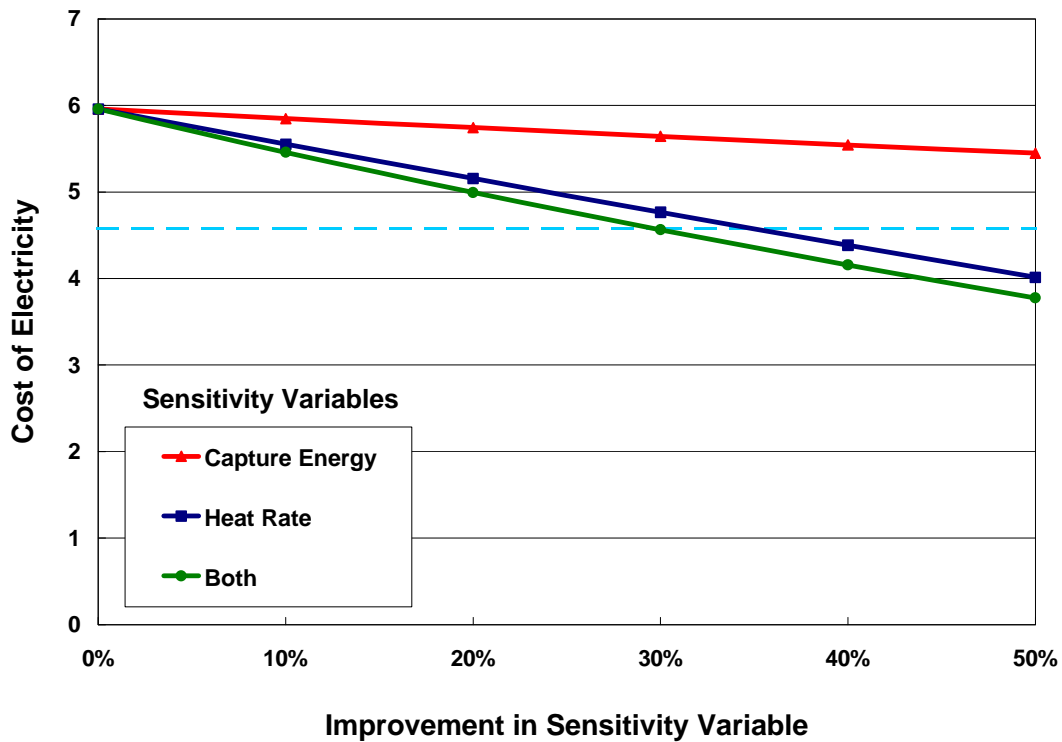


Figure 5. Results of the sensitivity study for the IGCC capture power plants, plotting the cost of electricity versus the capture plant energy requirements and the reference plant heat rates. Based on the composite model, today's case.

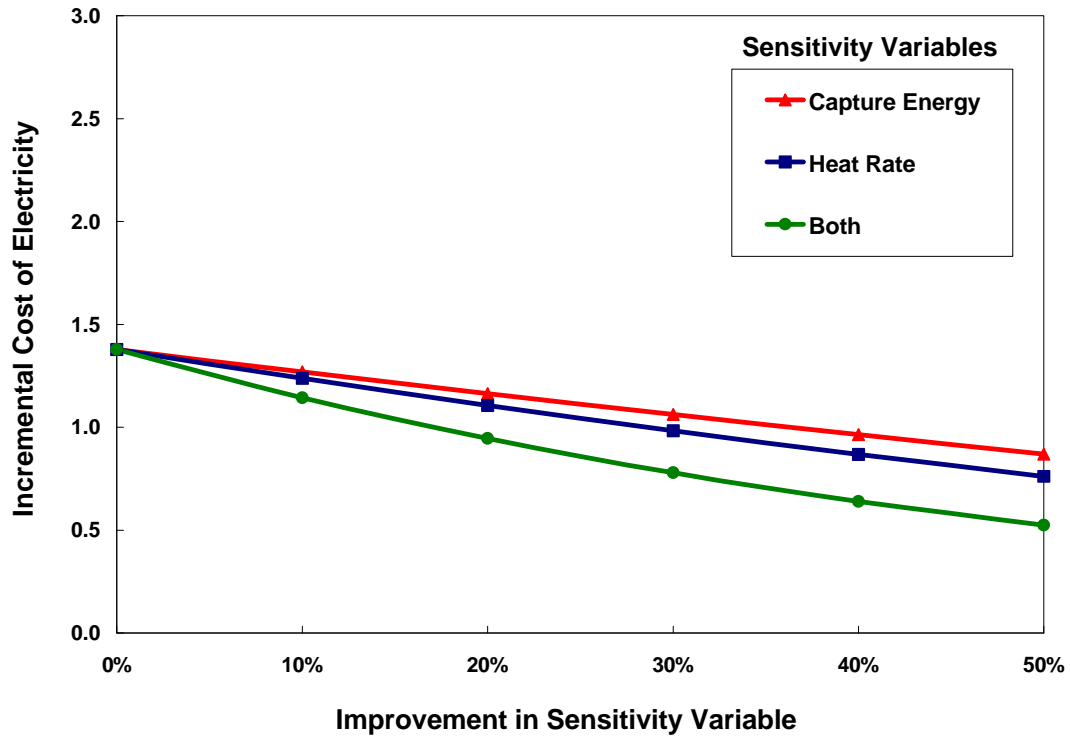


Figure 6. Results of the sensitivity study for the IGCC capture power plants, plotting the incremental cost of electricity versus the capture plant energy requirements and the reference plant heat rates. Based on the composite model, today's case.