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The Economic Impacts of Technical Change in Carbon Capture

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THE ECONOMIC IMPACTS OF TECHNICAL CHANGE IN CARBON CAPTURE

A Thesis Presented

by

PETER G. RASMUSSEN

Submitted to the Graduate School of the
University of Massachusetts Amherst in partial fulfillment
of the requirements for the degree of

MASTER OF SCIENCE IN INDUSTRIAL ENGINEERING AND OPERATIONS RESEARCH

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DEDICATION

To Naomi, my amazing wife.

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First and foremost, I would like to thank my advisor, Dr. Erin Baker, for all her guidance and support during this process. I would also like to thank Dr. Hari Balasubramanian and Dr. Jenna Marquard for being members on my committee and for providing me with valuable feedback. Finally, I am grateful for the company and camaraderie of the other graduate students in Dr. Baker's research group.

ABSTRACT

THE ECONOMIC IMPACTS OF TECHNICAL CHANGE IN CARBON CAPTURE

FEBRUARY 2012

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There is a general consensus in the literature that carbon capture and storage (CCS), a technology that controls CO₂ emissions from fossil fuel power plants, figures to be a critical technology to reduce CO₂ emissions to CO₂ concentration stabilization levels prescribed in the literature (Katzer, Moniz, Deutch, Ansolabehere, & Beer, 2007). We completed three projects that advance the understanding of how technical change in carbon capture affects both near-future costs of CCS and the economy in the long term. First, we conducted a literature review of near-future capture cost estimates in order to get an idea of how expensive carbon capture will be in the near-future. We identified and related key cost and performance measures for carbon capture, including energy penalty, additional cost of levelized electricity (LEC), and CO₂ avoidance cost. The literature indicates that pre-combustion capture is the least expensive carbon capture technology because its combustion process best facilitates carbon capture. Second, we explored the limits of incremental technical change in each near-future capture technology using a performance-cost model. Incremental technical change occurs within an existing technology and is constrained by that technology's inherent performance improvement limits. The results of the sensitivity analysis showed that pre-combustion capture could be the least expensive capture technology after incremental technical change has occurred. Third, we

used an integrated assessment model (IAM) to investigate how rapid incremental and breakthrough technical change in carbon capture could impact the electric energy market, total CO₂ abatement cost and CO₂ price over time. Breakthrough technical change is the transition to a totally different technological paradigm with superior cost and performance because it is not constrained by the performance limits that constrain improvements to its predecessor technology. We modeled breakthrough technical change using data from a paper in the literature that provides cost and performance estimates for chemical looping, a radical carbon capture technology still in the early stages of research and development (R&D) (Baker, Chon, & Keisler, 2009). We found that CCS dominates electricity market share over time given a chemical looping breakthrough.

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CHAPTER 1

INTRODUCTION

Climate change¹ is a serious problem that has significant economic, social, political and geographical consequences. Since climate change is caused by rising greenhouse gas concentrations, which is itself a function of greenhouse gas (GHG) emissions, we can reduce the extent of climate change by reducing our GHG emissions. The majority of GHG emissions are from CO₂ emissions, and a significant percentage of these CO₂ emissions, 60%, are emitted by fossil fuel power plants which supply 66% of the world's demand for electricity (EIA 2006, 2009). Thus, in order to make meaningful reductions in overall GHG emissions, we must control CO₂ emissions from fossil fuel power plants.

Carbon capture and storage (CCS) is the term used to refer to the process that controls CO₂ emissions from fossil fuel power plants. CCS can be considered “two consecutive processes – the capture and compression of CO₂ followed by the transport and storage of it” (Baker, Nemet, & Rasmussen, 2011). There is a general consensus in the literature that CCS figures to be a critical technology to reduce CO₂ emissions to CO₂ concentration stabilization levels prescribed in the literature (Katzner, Moniz, Deutch, Ansolabehere, & Beer, 2007).

CCS is unique among the low carbon energy technologies (e.g. solar, wind, geothermal, etc.) because CCS can only be realized in the presence of a tax on carbon dioxide emissions. CCS must always be more expensive than traditional coal-fired energy, because it involves an extra process to capture CO₂ emissions. Other low carbon energy technologies, while currently more

¹ We define climate change using the definition provided by the Article 1 of the United Nations Framework Convention on Climate Change (1992): a change of climate which is attributed directly or indirectly to human activity that alters the composition of the global atmosphere and which is in addition to natural climate variability observed over comparable time periods.

expensive relative to estimated CCS costs, could someday be less expensive than current coal-fired energy.

Since CCS is a new, not-yet commercialized technology, it can be significantly improved by research and development (R&D), which can lead to technical change. R&D holds the promise of significantly improving existing technologies and ushering in brand new breakthrough technologies. Efforts by National Energy Technology Laboratories (NETL) and other government agencies across the world to spearhead CCS R&D efforts indicates that policy makers are interested in which CCS technologies can be improved by R&D and to what extent. But how do we know which CCS technologies to invest in?

The choice of how R&D should be allocated across CCS technologies follows basic criteria. First, R&D should be allocated to technologies for which significant technical change is possible. We would not want to conduct R&D on a technology that has no potential for improvement. For instance, it would not make sense to conduct R&D to improve the efficiency of a process that is already operating at 99% efficiency. This is because the cost savings realized by improving the efficiency is minimal, which brings us to the second criteria. That is, R&D should be allocated to technologies for which significant cost savings are possible. Thus, the choice of how CCS R&D should be allocated is guided by how technical change in CCS impacts the cost of CCS.

In this thesis, we complete three projects that advance the understanding of how technical change in carbon capture affects both near-future costs of CCS and the economy in the long term. First, we establish baseline CCS costs by surveying CCS cost estimates in the literature. Second, we conduct a sensitivity analysis to investigate how technical change induces cost reductions. Third, using the information obtained from the sensitivity analysis, we model the long-term economic impacts of technical change in CCS.

The first part of this thesis summarizes estimates of the cost of CCS in the literature. We limit our analysis to carbon capture costs only and exclude carbon storage costs. Since there are no commercial CCS plants today, we need to obtain baseline CCS cost estimates in the literature. We find CCS cost estimates across a variety of literature sources and assess the degree of variation between these estimates. We compare CCS cost estimates versus one another which allows us to identify cost outliers and to assess whether there is a CCS cost consensus in the literature. We can then calculate the additional cost of CCS by comparing mean CCS costs we find in the literature to the mean costs of plants without CCS. Knowing the additional costs of CCS then lets us calibrate the extent to which technical change can reduce these costs.

In the second part of this thesis, we conduct a sensitivity analysis to investigate how technical change in near-future carbon capture technologies impacts CCS costs. Carbon capture technologies are largely immature, which implies that their costs are sensitive to technical change. We model technical change as improvements to key performance parameters such as process efficiency. We use a well-known CCS cost-performance model to identify key performance parameters to which cost is sensitive. We present and discuss the results of the sensitivity analysis in this thesis.

The third part of this thesis models the impacts of technical change in carbon capture on electricity market share, the total cost of CO₂ abatement and the CO₂ price over time using a well-known economic-environmental-technological integrated assessment model (IAM). We use the results of the sensitivity analysis in addition to carbon capture cost and performance estimates in the literature as inputs in the model. In sum, we wish to monitor what happens at the macroscopic economic level given bottom-up technical change in CCS.

This thesis is organized as follows. Chapter 2 provides an overview of CCS technologies in the literature. Chapter 3 provides the results of the literature review. Chapter 4 provides the

methodology for the sensitivity analysis. Chapter 5 provides the results of the sensitivity analysis. Chapter 6 models the economic impacts of technical change in carbon capture over time. Chapter 7 concludes the thesis.

CHAPTER 2

TECHNOLOGIES OVERVIEW

In this chapter we introduce and discuss the primary carbon capture and storage (CCS) technologies. CCS involves two consecutive, discrete processes. In the first process, carbon capture, CO₂ emissions are removed from the emissions stream from a coal-fired power plant. Carbon capture occurs onsite at the fossil fuel plant, and can be integrated with the combustion of the fossil fuel to facilitate improved process performance. The second process, carbon storage, occurs after the carbon capture process is completed: purified CO₂ is transported via a pipeline to an underground reservoir where the CO₂ can be safely and permanently stored. Figure 1 provides a simplified process schematic of the aforementioned CCS process. This thesis focuses on carbon capture and not on the downstream portion of CCS, transport and storage.

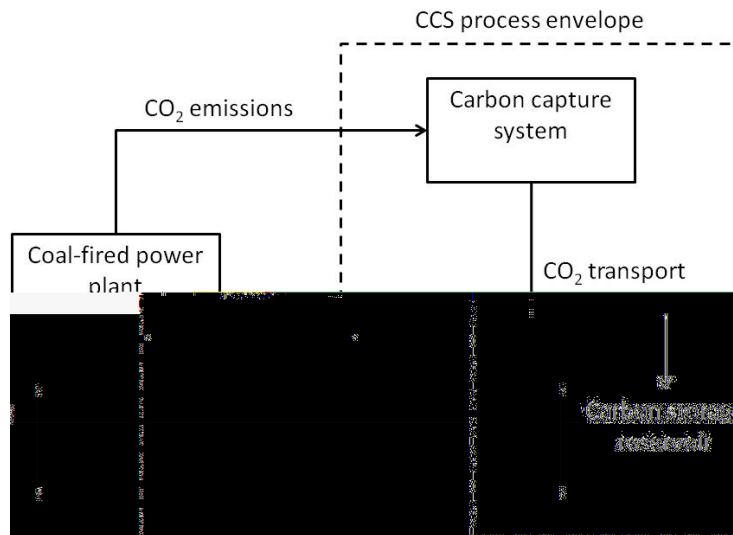


Figure 1: Simplified CCS process schematic

We group carbon capture and storage (CCS) combustion technologies as follows: post-combustion, oxy-fueling and pre-combustion. Post-combustion CCS removes carbon dioxide from combustion exhaust gas. Oxy-fueling is a modification of post-combustion CCS in which a purified oxygen feed is combusted with fuel instead of air, resulting in carbon dioxide (CO₂)-rich

exhaust gas stream that is ready for transportation and disposal upon little further purification. Pre-combustion CCS removes carbon from the fuel before the fuel is combusted. A simplified process schematic of each type of CCS (i.e. post-combustion, oxy-fueling and pre-combustion) is depicted in Figure 2. Blue arrows show where electricity is produced and red arrows show where power is lost due to CCS. In other words, the red arrows in Figure 2 represent power that would otherwise be used as electric power is instead used to power the CCS process. The lost power due to CCS, known as parasitic energy loss, reduces overall plant efficiency and directly affects the cost of CCS. One of the goals of CCS R&D is to minimize the parasitic energy loss.

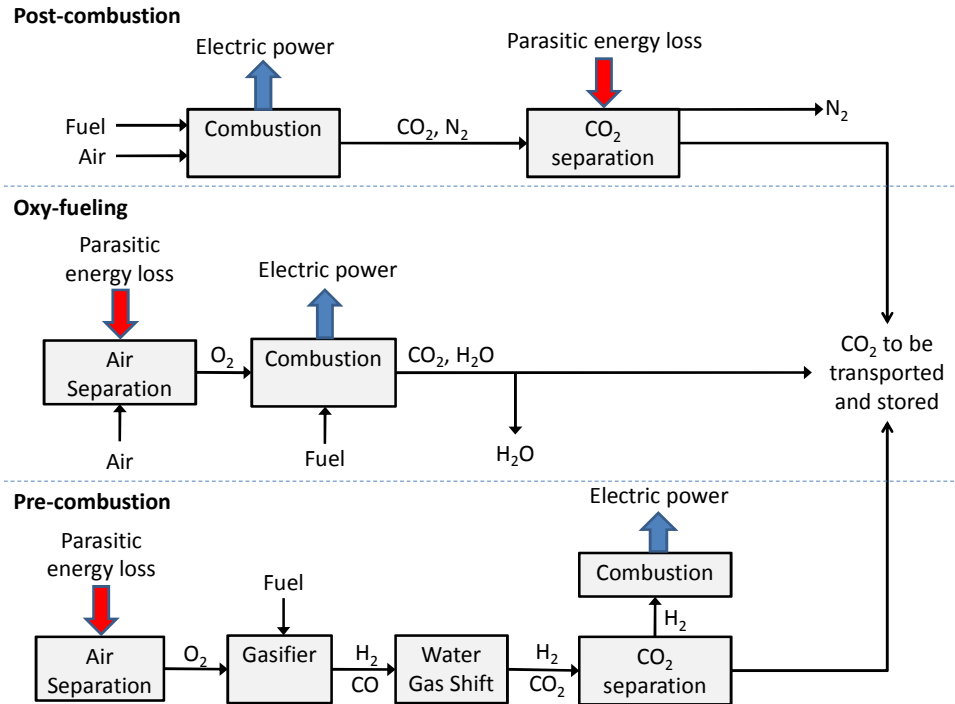


Figure 2: Post-combustion, oxy-fueling and pre-combustion capture technologies (reproduced from Rackley, 2010)

2.1 Post-combustion capture

Post-combustion capture describes the process whereby CO_2 is removed from the post-combustion stream of exhaust gas. Post-combustion figures to be an important CCS technology

since existing coal-fired plants could be retrofitted with post-combustion CO₂ capture controls. We focus most of our attention on one particular post-combustion capture technology, chemical absorption, because it is a fully commercialized process that is used in refining and natural gas processing. Accordingly, chemical absorption is the primary near-future post-combustion capture technology discussed in the literature. We also discuss other, less mature post-combustion capture technologies that are in the literature and that are in various stages of R&D.

Post-combustion capture uses typical coal-fired combustion to produce energy. The combustion technology significantly impacts the cost of carbon capture (Katzer, Moniz, Deutch, Ansolabehere, & Beer, 2007). There are three boiler types, which are classified according to the pressure and temperature in the boiler: sub-critical, supercritical, and ultra-supercritical combustion. Sub-critical combustion is widely used in the United States and abroad; however, the use of supercritical and ultra-supercritical technologies are mostly limited to Western Europe and Japan. Sub-critical combustion, in which combustion occurs below the critical temperature and pressure of air, operates at a lower efficiency but uses less expensive equipment than supercritical and ultra-supercritical combustion. Supercritical and ultra-supercritical combustion occurs above the critical temperature and pressure of air, operating at higher efficiencies albeit using more expensive equipment.

2.1.1 Chemical absorption process description

In this section, we provide a brief overview of the post-combustion chemical absorption CO₂ capture process using a simplified process flow diagram (PFD). Figure 3 is a simplified process flow diagram (PFD) of a chemical absorption capture unit. The PFD does not depict the processes that occur in the base plant, which we define as the portion of the power plant

upstream of the capture unit where combustion, electricity generation, and exhaust gas generation occur.

CO₂-laden combustion exhaust gas from the base plant is fed to the absorber, where the exhaust gas contacts a liquid sorbent. The contacted sorbent chemically binds to acid gases such as CO₂ which facilitates the mass transfer of CO₂ from the exhaust gas phase to the liquid sorbent phase. The now CO₂-laden sorbent (rich sorbent) exits the bottom of the absorber and is pumped through a cross heat exchanger, where the rich sorbent is heated to facilitate regeneration. The heated rich sorbent is fed to a sorbent regenerator (also known as a sorbent stripper), which is further heated by a reboiler in order to liberate the chemically bound CO₂ from the liquid sorbent. The reboiler receives low pressure (LP) steam from the base plant, resulting in a plant derating, or loss of plant power output. Part of the hot, CO₂-lean sorbent is pumped to the cross heat exchanger, where the lean sorbent is cooled and then cooled again to facilitate CO₂ absorption. The cooled lean sorbent flow is increased by the addition of makeup sorbent, which compensates for the sorbent lost to, among other things, unwanted side reactions (e.g. oxidation). The lean sorbent is then fed to the top of the absorber. The other portion of the hot, CO₂-lean sorbent is fed to the sorbent reclaimer to remove heat stable salt (HSS) contaminants; HSS form as a result of unwanted sorbent oxidation. The vapor CO₂ stream that exits the regenerator is cooled before being fed to a flash vessel to remove any entrained sorbent. The purified CO₂ product stream is then compressed before transportation and storage.

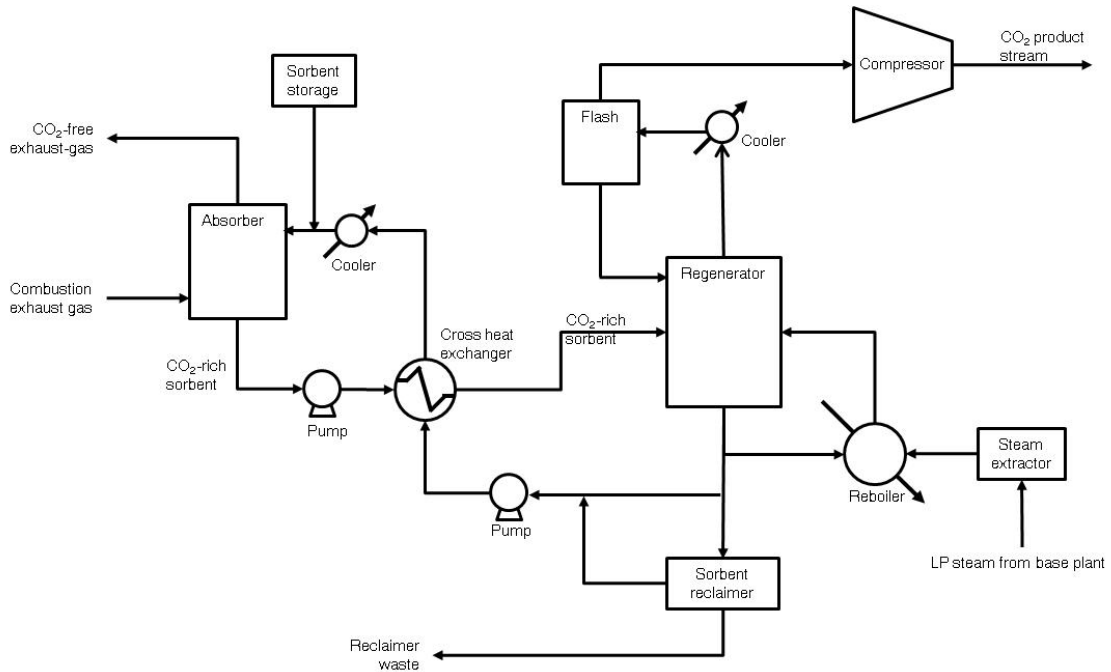


Figure 3: Post-combustion process flow diagram (modified from Rao, 2004)

2.1.2 Other post-combustion capture technologies in the literature

We discuss two other major post-combustion capture technologies in this section: adsorption-based capture and membrane capture. Adsorption-based capture involves the use of a solid surface which selectively binds to CO_2 particles, thus trapping CO_2 molecules to the solid surface while other gases pass through. Adsorption can occur via either a physical (physisorption) or chemical (chemisorption) mechanism, and sometimes via both. For both physisorption and chemisorption, the fraction of the solid surface that is covered by CO_2 molecules is a function of temperature and pressure. Once the solid surface is covered with CO_2 molecules, it is replaced by a fresh, CO_2 -free surface so that CO_2 capture can continue. Meanwhile, the “spent”, CO_2 -covered surface is regenerated through either pressure-swing adsorption (PSA) or temperature-swing adsorption (TSA), which involves reducing the pressure or increasing the temperature, respectively.

Membrane capture acts as a filter, albeit on a micro or nano scale, by separating one component (the permeate) from the other gases in the stream (the retentate). A gradient, often pressure, is used to drive the permeate across the membrane barrier. R&D is focused on three main types of post-combustion membrane technologies: high-temperature molten carbonate membrane, facilitated transport membranes and carbon molecular sieve membranes (Rackley, 2010). High-temperature molten carbonate membranes separate CO₂ from flue gas streams near the point of combustion, while the flue gases are still hot. The membrane is a “composite material that combines oxygen ion exchange through a solid metal oxide with CO₂ transport as a carbonate anion (CO₃²⁻) through the molten carbonate phase” (Rackley, 2010).

Facilitated transport membranes actively transport CO₂ across the membrane. Flue gas CO₂ begins on the high pressure side of the membrane. The high pressure drives CO₂ across the feed side of the membrane where it reacts with water and carbonate (CO₃²⁻) to form bicarbonate (HCO₃⁻). Equilibrium chemistry drives the bicarbonate to the permeate side of the membrane, where the bicarbonate reverts back to CO₂ before exiting the membrane on the low pressure permeate side. Figure 4 summarizes the aforementioned process.

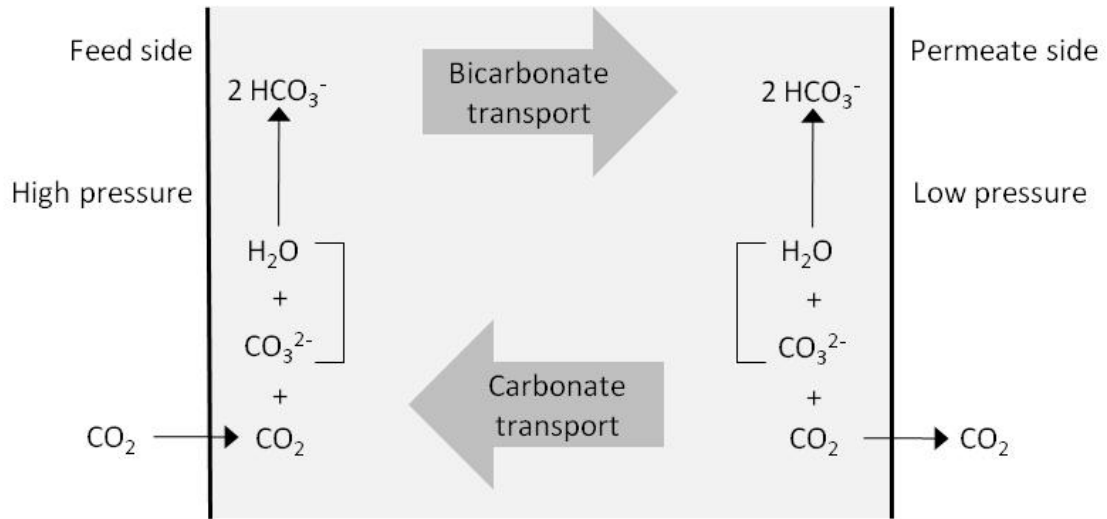


Figure 4: Facilitated transport membrane schematic (Rackley, 2010)

Carbon molecular sieve (CMS) membranes have pore sizes which can be fine-tuned to match the molecular size of the permeate, which by design primarily contains CO_2 . Laboratory experiments have demonstrated that CMS membranes have very high selectivity, which means that the concentration of CO_2 relative to other gases in the permeate is high.

2.1.3 Summary of post-combustion capture technologies

In this section we summarize post-combustion capture technologies. Table 1 is a slight modification of a table provided in Rackley (2010). Chemical absorption-based capture, which we covered in the previous section, is also included in the table. Novel capture technologies that are significantly less energy intensive than chemical absorption have the potential to be significantly less expensive assuming the capital costs of those new technologies are comparable or less than chemical absorption capital costs.

Table 1: Post-combustion capture technologies (modified from Rackley, 2010)

Technology type	Technologies under development	Example technologies under development
Absorption-based capture	Chemical solvents (e.g. MEA, chilled ammonia)	Novel solvents to improve performance; improved design of processes and equipment)
Adsorption-based capture	Zeolite and activated carbon molecular sieves	Carbonate sorbents; chemical looping
Membrane capture	Polymeric membranes	Immobilized liquid membranes; molten carbonate membranes

2.2 Oxy-fueling capture

Oxy-fueling capture involves the combustion in the presence of oxygen instead of air, resulting in an easily-separable stream of CO₂ and water. The key technologies we discuss here are those involving oxygen production. In the following sections, we provide process descriptions of two oxy-fueling processes, a more conventional one that uses an cryogenic air separation and the other using chemical looping, a more radical technology. Figure 5 summarizes the basic oxy-fueling process.

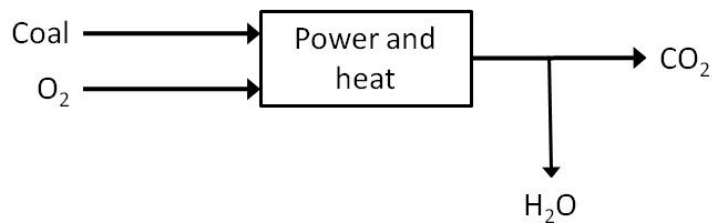


Figure 5: Oxy-fueling simplified PFD

2.2.1 Cryogenic air separation

Cryogenic air separation is a distillation process. Distillation is a separation process that is physical and which works by exploiting the different condensation and boiling points of a mixture of fluids. Air is cooled until its component gases such as N₂, O₂, and argon reach their condensation points, at which point they can be removed from the distillation column. The

whole air separation process occurs in an air separation unit (ASU). Since cryogenic distillation is a commercially mature process that has been used since the 19th century, the opportunities for R&D breakthroughs are essentially non-existent (Rackley, 2010). The key drawback of cryogenic air separation is that large amounts of energy are required to cool air's component gases to their condensation points to facilitate separation. To illustrate, O₂ condenses at -183 °C. Competing oxy-fueling technologies such as chemical looping show promise precisely because they have the potential to be significantly less costly in terms of energy consumption.

2.2.2 Chemical looping

Chemical looping combustion (CLC) integrates the air separation and combustion processes such that the energy penalty resulting from air separation and suboptimal combustion temperatures are minimized. A generic CLC process is presented in

Figure 6. CLC technology uses thermally efficient metal oxidation/reduction reaction to achieve combustion. Air is fed to a reaction chamber that oxidizes the metal catalyst. Then, the metal catalyst oxidizes the fuel to produce a relatively pure stream of water and CO₂. The now reduced metal catalyst is then recycled to be reacted with air again.

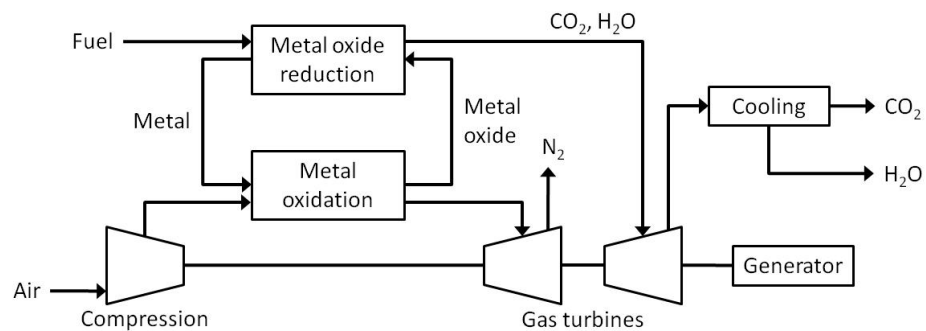


Figure 6: Chemical looping process flow diagram (modified from Rackley, 2010)

2.2.3 Summary of oxy-fueling technologies

As stated before, the primary oxy-fueling air separation technologies that were identified in the literature include cryogenic air separation and chemical looping.

Cryogenic air separation is already mature in terms of R&D and probably in terms of learning-by-doing² (LBD) and production returns-to-scale (Figueroa, 2008). Cryogenic air separation technology can serve as a baseline for comparison to air separation technologies in the R&D phase. Chemical looping shows much promise according to multiple sources in the literature (Figueroa, 2008), (Jerndal, Mattisson, & Lyngfelt, 2006), (Moghtaderi, 2010). In particular, Moghtaderi discusses a low energy chemical looping technology that could represent a “step change” in air separation technology and McGlashan (2008) reports a chemical looping process efficiency of 86.5%.

Figure 6 provides an illustration of the chemical looping process.

Other oxy-fueling air separation technologies in development include adsorption processes and ceramic membranes. Adsorption processes include zeolite and activated carbon molecular sieves (Rackley, 2010). According to Dyer (2000), ceramic membranes are currently more suited to integrated gasification combined cycle (IGCC) technologies, although research is being conducted on using ceramic membranes for oxy-fueling combustion (Dyer, 2000), (Figueroa, 2008). We discuss IGCC in further detail in the following section.

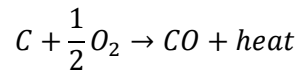
2.3 Pre-combustion capture

In this section we provide a general process description of state-of-the-art pre-combustion technologies. The simplest definition of pre-combustion technology is that carbon is removed from the process before combustion. Pre-combustion capture is most commonly used

² Learning-by-doing (LBD) is a form of technical change whereby cost reductions occur as workers accumulate more operating experience.

in conjunction with integrated gasification combined cycle (IGCC), and the scope of this analysis is limited to IGCC.

Figure 7 is a simplified pre-combustion process flow diagram. Coal is fed to a gasifier where it is partially oxidized in an exothermic reaction according to the following chemical equation:



where

C – generic coal char;

CO – carbon monoxide; and

heat – exothermic reaction heat.

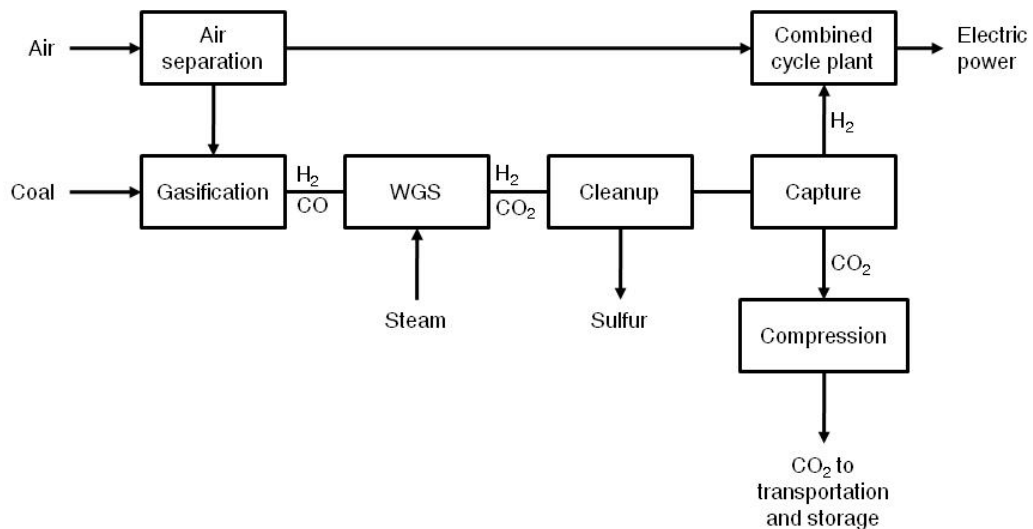
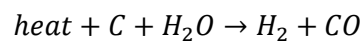
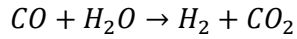


Figure 7: Pre-combustion process flow diagram (modified from Rackley, 2010)

The heat from the above reaction enables the following endothermic reaction where carbon char is reacted with water, resulting in the production of a cooled stream of syngas:



The syngas, a mixture of H₂ and CO produced from the above chemical reactions, is fed to a water-gas shift reactor (WGS), where CO is fully oxidized by water to produce CO₂ and H₂ by the following reaction:



Impurities such as sulfur oxides that are present in the gas stream are removed in a cleanup stage before the carbon capture stage, where CO₂ is removed. CO₂ is currently removed using absorption methods; although a variety of CO₂ removal technologies are in various stages of research in development. Following carbon capture, H₂ is combusted in a gas turbine that produces the majority of power output; a smaller quantity of plant output is produced in a downstream steam turbine. The dual operation of the gas and steam turbines, known as a combined cycle, are integrated to optimize overall plant efficiency.

2.3.1 Pre-combustion technologies in the literature

The results of a brief survey of the literature on pre-combustion technologies are provided in Table 2, which lists pre-combustion technologies across three levels of technological development: commercial, demonstration and development. Table 2 shows that research is targeted at multiple process areas, including the power block (gas and steam combined cycle), carbon capture processes, and desulfurization processes.

Table 2: Pre-combustion carbon capture technologies

Process	Technology	Development level		
		Commercial	Demonstration	Development
Power block	Ultra-high gas turbine firing temperatures	GE 7-FA turbines	Advanced F-frame turbines (NETL, 2010)	Improved turbine base alloys (high Ni with single crystal) (Kehlhofer, 2009); Closed-steam cooling of stationary and rotating parts (Kehlhofer, 2009); Advanced turbines
Power block	Compressors	-	-	High pressure ratios (Kehlhofer, 2009)
Power block	Main steam parameters	Current main pressure at 170 bar; Current main steam temperature “as high as 600 C”. (Kehlhofer, 2009)	-	Temperature-resistant alloys (Kehlhofer, 2009)
Carbon capture	Absorption-based separation	Physical solvents; Chemical solvents	-	“Novel solvents to improve performance; Improved design of processes and equipment” (Rackley, 2010)
Carbon capture	Adsorption-based separation	-	-	“Zeolites, activated carbon, carbonates, hydrotalcites and silicates” (Rackley, 2010)
Carbon capture	Membrane separation	-	ITM (NETL, 2010)	“Metal membrane WGS reactors” (Rackley, 2010); ITM (Rackley, 2010); H ₂ membranes (NETL, 2010)
Carbon capture	Cryogenic separation	CO ₂ liquefaction (Rackley, 2010)	-	“Hybrid cryogenic and membrane processes” (Rackley, 2010)
Desulfurization	Warm gas cleanup (WGSU)	-	Kingsport, TN demonstration (NETL, 2010)	Combined WGSU with H ₂ membranes (NETL, 2010)
Desulfurization	Absorption-based separation	Physical solvents (e.g. Selexol, Sulfinol)	-	-

CHAPTER 3

CARBON CAPTURE TECHNOLOGY AND COST LITERATURE REVIEW

This chapter constitutes the first part of the work of this thesis, in which we summarize estimates of the cost of CCS in the literature. We summarize the plant-wide cost estimates of post-combustion, oxy-fueling and pre-combustion capture technologies as if the capture plants were built today. This allows us to establish baseline carbon capture costs. Cost estimates exclude CO₂ transportation and storage costs, which have a lower degree of variability (Katzner, Moniz, Deutch, Ansolabehere, & Beer, 2007). Before discussing CO₂ capture costs, we first define the cost measures used in the literature.

We assess the degree of variation between various carbon capture cost estimates. We then compare carbon capture cost estimates versus one another, which allows us to identify cost outliers and to assess whether there is a carbon capture cost consensus in the literature. After that, we calculate the additional cost of carbon capture by comparing mean carbon capture costs we find in the literature to the mean costs of plants without carbon capture. Knowing the additional costs of carbon capture then lets us calibrate the need for technical change in carbon capture to reduce costs.

3.1 Definition of common cost measures used in the literature

In this section we define the common cost measures found in the literature. We will trace the steps taken to calculate levelized electricity cost (LEC) and CO₂ avoidance cost (C_a), two key comprehensive cost measures used in the literature. CCS costs are comprised of capital costs, operation and maintenance (O&M) costs and fuel costs. Capital costs (K , presented in units of \$) result from the purchase of land, buildings, process equipment, and engineering and construction labor. O&M costs (L , presented in units of \$/yr) are ongoing costs resulting from

the purchase of feed stocks, chemicals, utilities, waste disposal, plant maintenance, and plant operation. Fuel costs (presented in units of \$/MBtu) are ongoing costs resulting from the purchase of coal.

3.1.1 Levelized electricity cost

The total plant cost is the sum of the capital, O&M and fuel costs. However, before we can sum these costs, we convert them into a common cost measure, known as the levelized electricity cost (LEC, \$/MWh). The capital cost LEC (\$/MWh) is given by

Equation 1

$$LEC_K = \frac{K \cdot CRF}{MW_{net} \times HPY}$$

where

- K is capital cost (\$).
- CRF is the capital recovery factor. Also known as the fixed charge factor (FCF), the CRF is the “factor that annualizes the [capital cost] of the plant” and is a function of both the discount rate and “useful lifetime of the plant” (Rao, 2004) (1/yr).
- MW_{net} is the power plant’s output to the grid. MW_{net} is the gross output net any parasitic energy losses (MW).
- HPY is the hours of operation per year (h/yr).

The O&M LEC (\$/MWh) is given by

Equation 2

$$LEC_{O\&M} = \frac{L}{MW_{net} \times HPY}$$

where

- L is the total O&M cost (\$/yr).
- MW_{net} and HPY are defined per Equation 1.

HPY is itself a function of the capacity factor (CF), which is a function of market demand and scheduled and unscheduled plant downtime. HPY is given by:

Equation 3

$$HPY = CF \times 8760$$

where

- CF is the capacity factor (dimensionless).
- 8760 is the number of hours per year (h/yr).

The fuel LEC (\$/MWh) is given by

Equation 4

$$LEC_{fuel} = \frac{3.142 \times C_{fuel}}{\eta}$$

where

- 3.142 converts from MBtu to MWh.
- C_{fuel} is the cost of fuel (\$/MBtu).
- η is the plant-wide efficiency.

Plant-wide LEC is the sum of LEC_K , $LEC_{O\&M}$ and LEC_{fuel}

Equation 5

$$LEC = LEC_K + LEC_{O\&M} + LEC_{fuel}$$

LEC can measure the cost of a plant with or without capture. Thus, we define the LEC of a plant without capture, what we call the “baseline” plant, as LEC_{base} and a plant with capture as

LEC_{cap} . We can then calculate the additional cost of capture, LEC_{add} , as the difference between LEC_{cap} and LEC_{base} :

Equation 6

$$LEC_{add} = LEC_{cap} - LEC_{base}$$

where

- LEC_{add} is additional cost of electricity resulting from carbon capture;
- LEC_{cap} is the plant-wide cost of a capture plant;
- LEC_{base} is the plant-wide cost of baseline, non-capture plant.

3.1.2 Energy penalty

Energy penalty is a useful quantity that measures the increase in plant fuel energy input per unit of electrical energy output that results from the installation of carbon capture controls to a baseline, non-capture plant. Energy penalty directly measures the increase in fuel costs of carbon capture. We can calculate energy penalty (EP, dimensionless) if we have the plant efficiencies of the baseline and capture plants

Equation 7

$$EP = \frac{\eta_{base}}{\eta_{cap}} - 1$$

where

- η_{base} is the baseline plant efficiency.
- η_{cap} is the capture plant efficiency.

Now we can then define capture fuel costs ($LEC_{fuel,cap}$) in terms of the baseline fuel cost and energy penalty:

Equation 8

$$LEC_{fuel,cap} = (1 + EP) \times LEC_{fuel,base}$$

where

- EP is the energy penalty.
- $LEC_{fuel,base}$ is the baseline plant fuel levelized electricity cost.

3.1.3 CO₂ avoidance cost

CO₂ avoidance cost is useful because it “gives an idea of how high a carbon price would have to be before CCS is adopted” (Baker, Nemet, & Rasmussen, 2011).

The CO₂ avoidance cost is calculated by dividing the additional LEC resulting from capture by the change in emissions resulting from capture. Thus, we define CO₂ avoidance cost (C_a , \$/tonne CO₂) as:

Equation 9

$$C_a = \frac{LEC_{add}}{\dot{V}_{base} - \dot{V}_{cap}}$$

where

- LEC_{add} is additional cost of electricity resulting from carbon capture;
- \dot{V}_{base} is the baseline plant CO₂ emissions intensity (tonne CO₂/MWh);
- \dot{V}_{cap} is the capture plant CO₂ emissions intensity (tonne CO₂/MWh).

The CO₂ emissions intensity is simply the ratio of CO₂ emissions to net energy output, so a higher CO₂ emissions intensity translates into higher CO₂ emissions. We are interested in expressing the $\dot{V}_{base} - \dot{V}_{cap}$ denominator in Equation 9 in terms of energy penalty so that can see the impact that energy penalty has on CO₂ avoidance cost. Before we can show this, we

need to derive the baseline and capture CO₂ emissions intensities. The baseline CO₂ emissions intensity is a function of the baseline efficiency and the fuel CO₂ content:

Equation 10

$$\dot{V}_{base} = \frac{3.6 \left(\frac{GJ}{MWh}\right) * Fuel\ CO_2\ content\left(\frac{tonne\ CO_2}{GJ}\right)}{\eta_{base}}$$

where

- 3.6 GJ/MWh is a conversion factor;
- Fuel CO₂ content (tonne CO₂/GJ) is the amount of CO₂ that would be emitted given combustion at 100% efficiency. Fuel CO₂ content is dependent on the type of fuel selected;

The capture CO₂ emissions intensity is a function of the capture efficiency, the fuel CO₂ content and the CO₂ capture rate:

Equation 11

$$\dot{V}_{cap} = \frac{3.6 \left(\frac{GJ}{MWh}\right) * Fuel\ CO_2\ content\left(\frac{tonne\ CO_2}{GJ}\right) * (1 - CR)}{\eta_{cap}}$$

where

- CR is the CO₂ capture rate. CR is 0.9 in all cases in this thesis;

Now, assuming CR = 0.9, we can derive $\dot{V}_{base} - \dot{V}_{cap}$ in Equation 9 as a function of energy penalty:

Equation 12

$$\dot{V}_{base} - \dot{V}_{cap} = \frac{3.6 \left(\frac{GJ}{MWh}\right) * Fuel\ CO_2\ content\left(\frac{tonne\ CO_2}{GJ}\right)}{\eta_{base}} * (0.9 - 0.1EP)$$

Clearly, the energy penalty plays an important role in determining CO₂ avoidance cost: a higher energy penalty drives down $\dot{V}_{base} - \dot{V}_{cap}$ which drives the CO₂ avoidance cost up.

3.2 Survey of CCS plant-wide costs in the literature

In this section we survey, compare and interpret carbon capture cost estimates in the literature in order to get an idea of the near-future cost of carbon capture. By near-future costs, we mean the cost of carbon capture *after* the first plant of its kind was built but *before* significant, cost-reducing technical change has occurred. This distinction between first-of-a-kind plants and the near future plants is important because first-of-a-kind plant costs can be twice as expensive as typical near-future costs in the literature (Al-Juaied & Whitmore, 2009). Katzer et al. (2007) state that near future costs, such as those from the literature that are provided in this section, are applicable when the number of plants of a particular technology is greater than one but less than or equal to nine. We limit the scope of our literature review to near-future carbon capture cost estimates and thus do not consider more radical, breakthrough technologies such as chemical looping.

The capture cost estimates provided in this section were standardized to the extent possible to facilitate side-by-side comparisons of each estimate. We standardized the following key parameters of each cost estimate: cost year, capital recovery factor (CRF), coal type, coal as-delivered cost and capacity factor. We normalized capacity factor for each combustion technology. Although capacity factor is a function of plant reliability, it is also a function of market demand for electricity. The scope of this thesis excludes market forces and as such we decided to fix capacity factor instead of treating it as an R&D parameter amenable to technical change. We selected a capacity factor of 80% because most of the pre-combustion estimates in the literature we surveyed used capacity factors of 80% (7 of 11 reported capacity factors). There were two estimates that used capacity factors of 75% and two estimates that used capacity factors of 85%. In addition, key post-combustion and oxy-fueling estimates (EPRI and

Rubin) used capacity factors of just 75%, whereas the MIT and NETL post-combustion and oxy-fueling estimates used capacity factors of 85%. Each basis was standardized according to Electric Power Research Institute (EPRI) bases. Cost estimate normalization assumptions are summarized in Table 3.

Table 3: Cost normalization assumptions

Basis	Value
Cost year	2009 USD
Capital recovery factor (CRF)	0.117 yr ⁻¹
Coal type	Illinois #6
Coal cost	1.8 USD/GJ
Capacity factor	80%
Baseline LEC	57 \$/MWh
Baseline efficiency	38.3%

In Figure 8, we present our LEC with capture cost normalization results and we refer the reader to Table 4 for the key to the combustion and gasification technology acronyms used in the figure. We organize the literature estimates by combustion technology and, in the case of pre-combustion capture, gasifier technology. With the exception of generic IGCC technology estimate, the normalized costs are slightly less than the as-reported costs, due primarily to the EPRI capital recovery factor that we used.

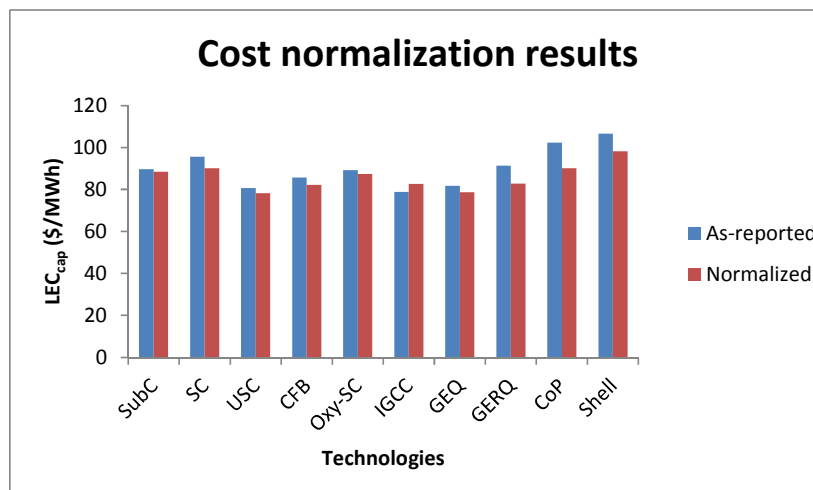


Figure 8: Literature review cost normalization results

Table 4: Key to combustion technologies provided in Figure 8

Combustion technology acronym	Combustion/gasification technology	Capture type
SubC	Subcritical combustion	Post-combustion
SC	Supercritical combustion	Post-combustion
USC	Ultra-supercritical combustion	Post-combustion
CFB	Circulating fluidized bed combustion	Post-combustion
Oxy-SC	Supercritical combustion	Oxy-fueling
IGCC	Generic IGCC gasifier	Pre-combustion
GEQ	GE Quench gasifier	Pre-combustion
GERQ	GE Radiant Quench gasifier	Pre-combustion
CoP	ConocoPhillips gasifier	Pre-combustion
Shell	Shell gasifier	Pre-combustion

After each cost estimate was normalized using the bases in Table 3, we needed to select a baseline, non-capture LEC and corresponding efficiency that we could use to calculate CO₂ avoidance costs and energy penalties, respectively, for each cost estimate. The selection of the baseline is important since additional LEC, CO₂ avoidance cost and energy penalty are functions of baseline parameters. We selected conventional pulverized coal technologies (i.e., subcritical, supercritical and ultra-supercritical combustion) to create our baseline because pulverized coal is the default coal combustion technology used in the United States. We present baseline LEC data for pulverized coal combustion (the combustion technology that post-combustion capture

uses), oxy-combustion (the combustion technology that oxy-fueling capture uses) and IGCC (the gasification technology that pre-combustion capture uses) in Figure 9. Figure 9 shows that conventional pulverized coal combustion is clearly less expensive than both oxy-combustion and IGCC, and consequently oxy-combustion and IGCC by themselves are not economically competitive with pulverized coal in the absence of a price on CO₂. As we will see later in the section, oxy-combustion and IGCC become economically competitive against pulverized coal combustion once the technologies are equipped with CO₂ capture units.

Finally, if we were to use oxy-combustion and IGCC baselines instead of the constant pulverized coal baseline, the additional LECs and CO₂ avoidance costs of oxy-fueling and pre-combustion would be artificially lower. We use the pulverized coal baseline to arrive at more accurate additional LEC and CO₂ avoidance cost for oxy-fueling and pre-combustion.

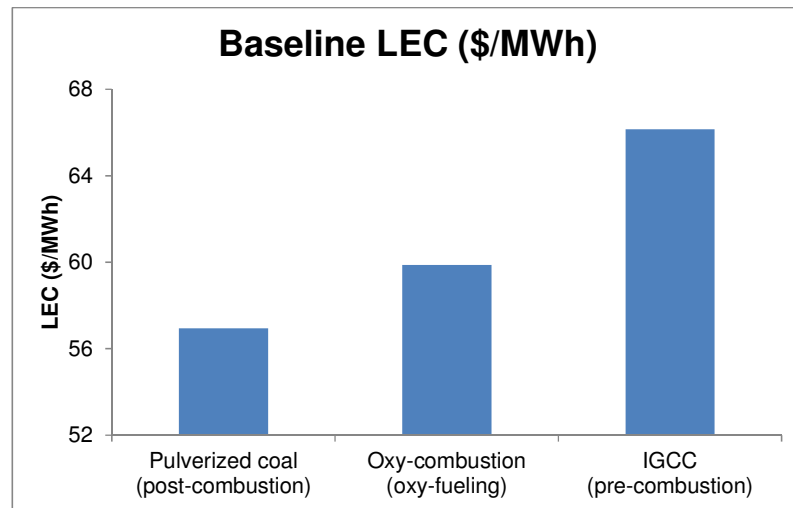


Figure 9: Comparison of literature baseline LECs for pulverized coal, oxy-combustion and IGCC technologies

Table 5, Table 6 and Table 7 summarize mean capture costs for post-combustion, oxy-fueling and pre-combustion technologies, respectively, in the literature. We provide the energy penalty (dimensionless), the LEC with capture (LEC_{cap} , \$/MWh), the additional LEC (LEC_{add} , \$/MWh) and the CO₂ avoidance cost (C_a , \$/tonne). Cost estimates are organized in ascending

order by CO₂ avoidance cost. The baseline LEC and efficiency are \$57/MWh and 38.3%, respectively.

We make the following observations about the post-combustion literature review performance and cost data in Table 5. First, CO₂ avoidance cost and the additional LEC correlate well, even across citations. Second, the LECs with capture for the subcritical combustion technology estimates tend to be more expensive than supercritical and ultra-supercritical estimates, particularly when compared to estimates of the same citation. This suggests that the efficiency benefits of using supercritical and especially ultra-supercritical combustion technologies in a post-combustion capture system outweigh the increased capital and maintenance costs of using these technologies. Within citations, the only exception is MIT's circulating fluidized bed (CFB) technology with its especially high energy penalty. However, energy penalty for a CFB post-combustion capture system is mitigated because CFB uses a significantly less expensive type of coal, lignite. Across citations, however, energy penalty does not correlate as well with the additional LEC and CO₂ avoidance cost, meaning that cost estimation methodologies and differences in non-energy costs such as O&M and capital costs play a larger role in determining the cost of capture.

Table 5: Summary of post-combustion capture costs surveyed in the literature (modified from Baker, Nemet, & Rasmussen, 2011)

Citation ¹	Technology ²	Energy ³ penalty	LEC _{cap} ⁴ \$/MWh	LEC _{add} ⁵ \$/MWh	C _a ⁶ \$/tonne
MIT	USC	0.12	78	21	29
MIT	SC	0.31	83	26	35
IPCC	SC	0.23	85	28	36
MIT	CFB	0.50	82	25	36
SFA	SC	0.23	89	32	44
MIT	SubC	0.52	88	32	44
Rubin	SC	0.28	89	32	44
NETL	SC	0.41	94	37	51
IEA	SC	0.42	93	36	53
EPRI	SC	0.38	98	41	58
NETL	SubC	0.54	109	52	73
Mean		0.36	90	33	46

¹ The key to the citations is as follows: MIT (Katzner, Moniz, Deutch, Ansolabehere, & Beer, 2007); IPCC (Metz, Davidson, de Coninck, Loos, & Meyer, 2005); SFA from SFA: Pacific study as reported in (Katzner, Moniz, Deutch, Ansolabehere, & Beer, 2007); Rubin (Rubin, Chen, & Rao, 2007); NETL (NETL, 2007); IEA (Kerr, 2008); EPRI from EPRI Report 1013355 as reported in (Katzner, Moniz, Deutch, Ansolabehere, & Beer, 2007).

² The key to the technologies is as follows: CFB – circulating fluidized bed technology; SubC – subcritical pulverized coal technology; SC – supercritical pulverized coal technology; USC – ultra-supercritical pulverized coal technology.

³ Energy penalty was calculated using a baseline efficiency is 38.3%.

⁴ LEC_{cap} – levelized electricity cost of fossil fuel plant with capture.

⁵ LEC_{add} – additional levelized electricity cost that results from equipping a fossil fuel plant with CO₂ controls. LEC_{add} was calculated using a baseline LEC of \$57/MWh.

⁶ C_a – CO₂ avoidance cost.

We make the following observations about the oxy-fueling literature review near-future performance and cost data in Table 6. First, there are fewer estimates in the literature for oxy-fueling capture than for post-combustion or pre-combustion capture. Second, as expected, there is a good correlation between LEC_{add} and CO₂ avoidance cost C_a. Third, while there is a positive correlation between energy penalty and LEC_{add} and C_a, it is not very strong. For instance, the energy penalty in the least expensive estimate by MIT is only 2 hundredths less than the Rubin estimate, yet the cost of capture is significantly higher for the Rubin estimate. Clearly, non-energy costs such O&M and capital play a larger role in determining overall cost than does the cost of fuel.

Table 6: Summary of oxy-fueling combustion capture costs surveyed in the literature (modified from Baker, Nemet, & Rasmussen, 2011)

Citation ¹	Technology ²	Energy ³ penalty	LEC _{cap} ⁴ \$/MWh	LEC _{add} ⁵ \$/MWh	C _a ⁶ \$/tonne
MIT	OXY SC	0.25	75	19	25
Rubin	OXY SC	0.27	87	30	41
SFA	OXY SC	0.27	90	34	44
IEA	OXY SC	0.53	97	40	55
	Mean	0.33	87	30	41

¹ The key to the citations is as follows: MIT (Katzner, Moniz, Deutch, Ansolabehere, & Beer, 2007); Rubin (Rubin, Yeh, Antes, Berkenpas, & Davison, 2007); SFA from SFA: Pacific study as reported in (Katzner, Moniz, Deutch, Ansolabehere, & Beer, 2007); IEA (Kerr, 2008).

² The key to the technologies is as follows: Oxy SC – supercritical pulverized coal oxy-fuel technology.

³ Energy penalty was calculated using a baseline efficiency is 38.3%.

⁴ LEC_{cap} – levelized electricity cost of fossil fuel plant with capture.

⁵ LEC_{add} – additional levelized electricity cost that results from equipping a fossil fuel plant with CO₂ controls. LEC_{add} was calculated using a baseline LEC of \$57/MWh.

⁶ C_a – CO₂ avoidance cost.

We make the following observations about the pre-combustion literature review near-future performance and cost data in Table 7. First, there is a reasonably strong correlation between LEC_{add} and C_a, with the exception of the NETL CoP estimate. Second, the correlation between energy penalty and LEC_{add} and C_a is not very strong, which indicates that non-energy costs such as O&M and capital play a stronger role in determining cost than fuel costs. A notable exception is the NETL CoP estimate, which has an exceptionally high energy penalty that is significant enough to drive up the estimate’s capture costs. Third, we present two means in Table 7, one that includes all the estimates and one that excludes IEA’s IGCC BIO estimate, which is significantly higher than the other estimates because it uses bio-fuel, which is significantly more expensive than coal. Although it is beyond the scope of this thesis, it would be interesting to see if the CO₂ avoidance cost of IGCC BIO could be recalculated to account for the use of carbon-neutral bio fuel.

Table 7: Summary of pre-combustion capture costs surveyed in the literature (modified from Baker, Nemet, & Rasmussen, 2011)

Citation ¹	Technology ²	Energy ³ penalty	LEC _{cap} ⁴ \$/MWh	LEC _{add} ⁵ \$/MWh	C _a ⁶ \$/tonne
MIT	GERQ	0.19	70	13	18
Rubin	GEQ	0.17	73	16	21
MIT	GEQ	0.20	73	16	22
IPCC	IGCC	0.19	73	16	22
SFA	GEQ	0.18	81	24	32
EPRI	GEQ	0.23	82	25	34
EPRI	CoP	0.27	87	30	39
EPRI	GERQ	0.21	88	31	42
NETL	GERQ	0.25	91	34	44
IEA	IGCC	0.22	92	35	48
EPRI	Shell	0.16	100	43	59
NETL	Shell	0.59	96	39	60
NETL	CoP	1.39	93	36	64
IEA	IGCC BIO	0.17	113	56	73
	Mean	0.32	87	30	41
	Mean excluding IGCC BIO	0.33	85	28	39

¹ The key to the citations is as follows: MIT (Katzner, Moniz, Deutch, Ansolabehere, & Beer, 2007); Rubin (Rubin, Chen, & Rao, 2007); IPCC (Metz, Davidson, de Coninck, Loos, & Meyer, 2005); SFA from SFA: Pacific study as reported in (Katzner, Moniz, Deutch, Ansolabehere, & Beer, 2007); EPRI from EPRI Report 1013355 as reported in (Katzner, Moniz, Deutch, Ansolabehere, & Beer, 2007); NETL (NETL, 2007); IEA (Kerr, 2008).

² The key to the technologies is as follows: GERQ – GE Radiant Quench gasifier; GEQ – GE Quench gasifier; IGCC – integrated gasification combined cycle; CoP – ConocoPhillips gasifier; Shell – Shell gasifier; IGCC BIO – IGCC that uses biomass fuel.

³ Energy penalty was calculated using a baseline efficiency is 38.3%.

⁴ LEC_{cap} – levelized electricity cost of fossil fuel plant with capture.

⁵ LEC_{add} – additional levelized electricity cost that results from equipping a fossil fuel plant with CO₂ controls. LEC_{add} was calculated using a baseline LEC of \$57/MWh.

⁶ C_a – CO₂ avoidance cost.

We now present the means of post-combustion, oxy-fueling and pre-combustion performance and cost estimates in Table 8. The pre-combustion means exclude IEA’s IGCC BIO estimate. First, post-combustion estimates have the highest energy penalty and also the highest LEC_{add} and C_a, suggesting that oxy-combustion and IGCC technologies integrate better when CO₂ capture is required than pulverized coal combustion does. Second, the oxy-fueling and pre-combustion means are close to one another, although pre-combustion the slightly less expensive technology of the two. Third, although pre-combustion capture is less expensive than post-combustion and oxy-fueling capture, it is not by much. This suggests that each near-future

capture technology is appreciably competitive with the others and that all should continue to be researched to improve performance and reduce estimated costs.

Table 8: Mean carbon capture costs surveyed in the literature

Technology	Energy penalty ¹	LEC _{cap} ² \$/MWh	LEC _{add} ³ \$/MWh	C _a ⁴ \$/tonne
Post-combustion	0.36	90	33	46
Oxy-fueling	0.33	87	30	41
Pre-combustion	0.33	85	28	39

¹ Energy penalty was calculated using a baseline efficiency is 38.3%.

² LEC_{cap} – levelized electricity cost of fossil fuel plant with capture.

³ LEC_{add} – additional levelized electricity cost that results from equipping a fossil fuel plant with CO₂ controls. LEC_{add} was calculated using a baseline LEC of \$57/MWh.

⁴ C_a – CO₂ avoidance cost.

CHAPTER 4

METHODOLOGY

In this chapter we provide the methodology for the sensitivity analysis that we present in Chapter 5. We focused on four criteria to guide our sensitivity analysis.

- Select an appropriate model.
- Identify which key performance parameters most impact cost.
- Identify reasonable limits of improvement for each performance parameter.
- Select an appropriate non-capture baseline plant.
- Present sensitivity analysis results in a visual, intuitive way.

We discuss each of these criteria in turn.

4.1 Selection of an appropriate model

Before conducting the sensitivity analysis, we had to select a model that would allow us to simulate the effect of technical change on cost in CCS. We desired a model that satisfactorily fulfilled the following criteria. First, we wanted a model that marries engineering design principles to engineering economics. Such a model would allow us to realistically simulate the effect that technical change has on cost by allowing us to adjust key model performance input parameters and observing the effect on cost outputs.

Second, we wanted a model that calculates cost on multiple, hierarchical levels. By this we mean that capital costs could be calculated from the equipment level to the unit level to plant level. In addition, O&M costs could be calculated from the feedstock level to the unit level to the plant level. We also desired a model that calculated LEC and CO₂ avoidance costs, cost measures which are functions of capital, O&M and fuel costs, from the equipment level on up.

Using a model that calculates costs on multiple, hierarchical levels allows us to zero in on the precise effects that a given technical change has on cost.

Third, we wanted a model that models all three CCS combustion technologies: post-combustion, oxy-fueling and pre-combustion. While there is significant overlap between each combustion technology, each has its own unique inputs. For example, pre-combustion technology uses a gasifier to gasify coal into hydrogen, a process configuration that does not exist for either post-combustion or oxy-fueling technologies.

Fourth, we wanted a model whose results and input assumptions are clearly and explicitly presented in the literature. Using such a model would allow us to calibrate our baseline inputs so that they are in line with the values used in the literature. In addition, a well-documented model gives us a better understanding of how the model works and what assumptions it uses. Then, we could compare our sensitivity analysis results to results presented in the literature.

4.1.1 Carnegie Mellon Integrated Environmental Control Model – Carbon Capture

Based on our criteria elucidated above, we selected the Carnegie Mellon Integrated Environmental Control Model – Carbon Capture, version 6.2.4 (IECM). We used IECM to carry out the performance parameter/cost sensitivity analysis across post-combustion, oxy-fueling and pre-combustion technologies.

IECM provides plant-level performance (e.g. carbon removal efficiency, energy penalty) and cost data for fossil fuel plants over a wide range of plant configurations and inputs. IECM conveniently breaks costs down into capital, O&M, LEC and CO₂ avoidance cost. The model supports three combustion types: boiler combustion (with and without oxy-fueling), turbine combustion (NGCC), and IGCC. Boiler combustion can be configured to model both post-

combustion and oxy-fueling technologies while IGCC is the combustion technology used for pre-combustion capture. Specification of plant type establishes which configurations and parameters can be selected. Given pollution control inputs, IECM also provides output Criteria Pollutant (SO₂, NO_x, PM) and Toxic Air Pollutant (mercury) emissions in addition to CO₂ emissions. In addition, IECM can incorporate uncertainty analysis and benefits incurred through R&D. Finally, IECM is the model used in seminal CCS papers by A.B. Rao and E.S. Rubin (Rubin, Chen, & Rao, 2007) and is a model is well-documented in terms of how it works (Rubin E. B., 2007), (Rubin E. R., 2007), (Rao, 2004).

4.1.2 Limitations of IECM

While IECM is excellent for modeling incremental technical change to the near-future technologies that the software provides, it is unable to model other, more advanced technologies. Specifically, IECM lacks the following configurations associated with significant new technologies under development:

- Warm gas cleanup (WGCU).
- H₂ separation membrane.
- Chemical looping combustion.
- Adsorption-based capture.
- Membrane-based capture, specifically ion transport membrane (ITM).

All of these technologies replace whole process units of the default configuration of IECM, and their implementation significantly affects multiple inputs. Thus, these technologies were not modeled in IECM. Instead, the percent LEC improvement data reported in NETL (2010) and baseline IECM cost data were used to calculate LEC data for the WGCU and H₂ membrane separation technologies.

While IECM allows for varied oxy-fueling combustion configurations, the model is understandably limited to a cryogenic ASU, since cryogenic air separation is the only commercially available air separation technology. Cryogenic air separation can be considered a mature technology, and thus is not significantly amenable to cost reductions via R&D investments. This is unfortunate, given the whole of carbon capture costs are mostly comprised by the ASU, which is expensive both in terms of capital and O&M costs.

We modeled the effects of replacing the default air separation unit (ASU) with an ITM. The replacement of the ASU by the ITM was simulated by adjusting critical parameters affected by the implementation of the new configuration: the unit ASU power requirement and direct capital cost. Input data for both parameters was obtained from NETL (2010). Since changes to direct capital costs cannot be made in IECM (only indirect capital cost parameters can be adjusted), these changes were done manually in Excel. Table 9 provides the method by which the capital costs were calculated.

Table 9: Total capital required (TCR) calculation method (Rao, 2004)

	Capital cost element	Value (M\$)
A	Process area equipment costs	A_1, \dots, A_n
B	Total process facilities capital (PFC)	$\sum A_i$
C	Engineering and home office	10% PFC
D	General facilities	15% PFC
E	Project contingency	15% PFC
F	Process contingency	5% PFC
G	Total plant cost (TPC)	B+C+D+E+F
H	AFUDC (interest during construction)	calculated
I	Royalty fees	0.5% PFC
J	Pre-production	1 months total O&M
K	Inventory (s/u) cost	0.5% TPC
L	Total capital required (TCR)	G+H+I+J+K+L

4.2 Identification of key performance parameters that most impact cost

Having selected our model, we then proceeded to identify key performance parameters to which cost is most sensitive. There are two criteria that we used to identify key performance parameters. First, a key performance parameter is one for which a small change in its value has a significant impact on cost. Second, the change in a key performance parameter must be physically possible (e.g. sorbent cost cannot be negative) and the limit of its improvement is constrained by a theoretical limit or by some value established in the literature or in the model documentation.

We provide an in-depth description of how we selected our post-combustion parameters. Oxy-fueling and pre-combustion parameters were selected using the same approach, although we do not go into the same level of detail for oxy-fueling and pre-combustion for the sake of brevity.

4.2.1 Identification of key post-combustion capital costs

We work backwards to find key performance parameters by first identifying the most expensive capital costs for a baseline post-combustion plant. After identifying the most expensive capital costs, we then find the parameters used to calculate each capital cost. We show that IECM calculates capital costs using scaling factors.

Equipment scales according to factors such as temperature or flow rate. For pieces of equipment that have one scaling factor, we scale using the following (Peters, Timmerhaus, & West, 2004):

Equation 13

$$C_i = C_{i,ref} \cdot \left(\frac{X}{X_{i,ref}} \right)^n$$

where

- C_i is the cost of equipment i of arbitrary size.
- $C_{i,ref}$ is the reference cost of equipment i .
- X_i is the equipment scaling factor for equipment i (e.g. pressure, mass flow rate);
- $X_{i,ref}$ is the reference equipment scaling factor for equipment i (e.g. pressure, mass flow rate).
- n determines whether equipment returns are constant, increasing or decreasing. The integrated process and economic model we use, IECM, assumes $n = 0.6$ for all equipment (Rao, 2004).

For pieces of equipment that have two scaling factors instead of one, we scale using the following (Peters, Timmerhaus, & West, 2004):

Equation 14

$$C_i = C_{i,ref} \cdot \left(\frac{X_i}{X_{i,ref}} \cdot \frac{Y_i}{Y_{i,ref}} \right)^n$$

where

- C_i is the cost of equipment i of arbitrary size;
- $C_{i,ref}$ is the reference cost of equipment i ;
- X_i is the first equipment scaling factor for equipment i (e.g. pressure, mass flow rate);
- $X_{i,ref}$ is the first reference equipment scaling factor for equipment i (e.g. pressure, mass flow rate);
- Y_i is the second equipment scaling factor for equipment i (e.g. pressure, mass flow rate);

- $Y_{i,ref}$ is the second reference equipment scaling factor for equipment i (e.g. pressure, mass flow rate);
- n determines whether equipment returns are constant, increasing or decreasing. The integrated process and economic model we use, IECM, assumes $n = 0.6$ for all equipment (Rao, 2004).

Table 10 lists post-combustion equipment capital costs as functions of scaling parameters. The equipment list is organized in descending order by nominal cost, which was calculated using IECM. Nominal settings are defined explicitly in the Table 10 notes. IECM is limited to chemical absorption (also known as amine capture) for post-combustion capture, which is a completely commercialized, mature technology. Thus, Table 10 is necessarily limited to amine capture equipment capital costs.

The absorber (55 M\$), drying and compression unit (39 M\$), sorbent regenerator unit (31 M\$), the direct contact cooler (DCC, 19 M\$) and reboiler (18 M\$) are the most costly pieces of equipment, constituting approximately 85% of the total process facilities cost (PFC) of the carbon capture unit. Given their share of the PFC, reducing the costs of this equipment would have a greater impact on reducing the overall cost of CO₂ capture than proportional cost reductions in the other capture equipment listed in Table 10.

Table 10: Post combustion amine capture unit equipment capital costs as functions of scaling factors

Equipment			Scaling factor 1		Scaling factor 2	
name	Symbol	Nom (M\$)	Symbol	Description	Symbol	Description
Absorber	C_{absorb}	55	$V_{\text{fg,in}}$	$V_{\text{fg,in}}$ = flue gas blower exit volumetric flow rate. It is a function of base plant and DCC performance and configuration inputs.	$T_{\text{fg,in}}$	$T_{\text{fg,in}}$ = flue gas blower exit temperature. It is a function of base plant and DCC performance and configuration inputs.
Drying and compression unit	C_{compr}	39	m_{CO_2}	m_{CO_2} = captured CO ₂ mass flow rate. It is a function of base plant inputs and desired capture efficiency	NA	NA
Sorbent regenerator	C_{regen}	31	V_{sorb}	V_{sorb} = sorbent volumetric flow rate. It is a function of multiple inputs, which are listed below in the Table 10 notes.	NA	NA
DCC	C_{dcc}	19	V_{fg}	V_{fg} = base plant flue gas exit volumetric flow rate. It is a function of base plant inputs.	T_{fg}	T_{fg} = base plant flue gas exit temperature. It is a function of base plant inputs.
Reboiler	C_{reb}	18	V_{sorb}	V_{sorb} = sorbent volumetric flow rate. It is a function of multiple inputs, which are listed below in the Table 10 notes.	m_{steam}	m_{steam} = low pressure steam required to regenerate sorbent. It is a function of Q and Q_{steam} .
Other equipment	NA	31	Refer to the notes listed below Table 10 for a breakdown of the cost of each piece of equipment.			
Process facilities capital	PFC	193	NA	NA	NA	NA

Notes:

Sorbent – MEA-based chemical used to absorb CO₂ from flue gas streams.

Sorbent processing area consists of sorbent cooler, MEA storage tank, and a mixer.

Rich sorbent – sorbent loaded with dissolved CO₂. Lean sorbent – sorbent exiting regenerator.

The following comprise the base plant input parameters to the CO₂ capture system: gross plant size (MW_g); net plant size (prior to environmental controls) (MW_{nocti}); flue gas composition and flow rate (as entering into the amine system); the total molar flow rate of the flue gas (G); the molar fraction of CO₂ in the flue gas (y_{CO_2}); temperature of flue gas (T_{fg}); plant capacity factor (PCF); annual hours of operation (HPY = (PCF/100)*365.25*24 h/yr).

V_{sorb} is a function of: base plant input parameters to the CO₂ capture system; lean sorbent loading; desired CO₂ capture efficiency; acid gas removal efficiency (excluding CO₂); nominal sorbent loss; NH₃ generation rate; heat stable salt generation; caustic consumption in reclaimer; density of sorbent; CO₂ product purity.

The equipment collectively referred to as “other equipment” consists of: circulation pumps (9 M\$), sorbent processing (6 M\$), sorbent reclaimer (6 M\$), rich/lean cross heat exchanger (4 M\$), flue gas blower (4 M\$) and steam extractor (2 M\$).

4.2.2 Identification of key post-combustion O&M costs

As we did for capital costs, we also work backwards to find key O&M performance parameters by first identifying the most expensive O&M costs for a baseline post-combustion plant. We are less interested in fixed O&M (FOM) costs than variable O&M (VOM) costs because technical change does not directly reduce FOM costs. After identifying the most expensive VOM costs, we find the parameters used to calculate each VOM cost.

Equipment scales according to key material inputs such as flow rate. With the exceptions of inhibitor and reagent VOM costs, VOM costs listed in Table 10 generally follow Equation 15 (Rao, 2004):

Equation 15

$$VOM_i = UC_i \cdot Q_i$$

where

- VOM_i is the cost of VOM i ;
- UC_i is the unit cost of quantity i (e.g. sorbent unit cost, inhibitor unit cost).
- Q_i is the quantity associated with VOM_i (e.g. regeneration energy, sorbent usage).

Table 11 is analogous to Table 10, except that VOM capture costs are provided instead of capital costs. Table 11 highlights the most significant VOM capture costs and key VOM scaling factors. The identification of key equipment scaling factors provides some insight as to which factors drive VOM costs the most. VOM capture costs are listed in descending order of nominal cost. CO₂ capture electrical energy (39 M\$/yr) and sorbent usage (28 M\$/yr) are significantly more costly than any of the other VOM costs.

Table 11: Post-combustion amine capture unit VOM costs as functions of scaling factors

Description	VOM type		Quantity Q_i		Unit cost UC_i	
	Symbol	Nom (M\$/yr)	Symbol	Description	Symbol	Description
CO ₂ capture energy	VOM _{en}	39	$E_{CO_2, tot}$	$E_{CO_2, tot}$ = CO ₂ capture electrical energy requirement. It is a function of E_{regen} , E_{compr} and E_{pump} .	COE _{noct}	COE _{noct} = unit cost of base plant electricity. It is a base plant inputs
Sorbent	VOM _{sorb}	28	m_{makeup}	m_{makeup} = sorbent makeup mass flow rate. It is a function of $m_{sorb, nom}$, $m_{sorb, organics}$, $m_{sorb, poly}$ and $m_{caustic}$.	UC _{sorb}	UC _{sorb} = unit cost of sorbent. It is a function of market prices
Waste disposal	VOM _{was}	6	m_{waste}	m_{waste} = waste mass flow rate. It is a function of $m_{sorb, nom}$, $m_{sorb, organics}$ and m_{act-C} .	UC _{waste}	UC _{waste} = unit cost of waste disposal. It is a function of market prices.
Corrosion inhibitor	VOM _{inhib}	6	VOM _{sorb}	VOM _{sorb} = sorbent VOM cost.	NA	NA
Activated carbon	VOM _{act-C}	1	m_{CO_2}	m_{CO_2} = captured CO ₂ mass flow rate. It is a function of base plant inputs and desired capture efficiency.	UC _{caust}	UC _{act-C} = unit cost of activated carbon. It is a function of market prices.
Caustic	VOM _{caust}	1	m_{CO_2}	m_{CO_2} = captured CO ₂ mass flow rate. It is a function of base plant inputs and desired capture efficiency.	UC _{caust}	UC _{caustic} = unit cost of caustic. It is a function of market prices.
Process water	VOM _{water}	0.1	m_{water}	m_{water} = capture unit process water requirement.	UC _{water}	UC _{water} = unit cost of process water. It is a function of market prices.

Notes:

Sorbent – MEA-based chemical used to absorb CO₂ from flue gas streams.

The following comprise the base plant input parameters to the CO₂ capture system: gross plant size (MW_g); net plant size (prior to environmental controls) (MW_{noct}); flue gas composition and flow rate (as entering into the amine system); the total molar flow rate of the flue gas (G); the molar fraction of CO₂ in the flue gas (y_{CO_2}); temperature of flue gas (T_{fg}); plant capacity factor (PCF); annual hours of operation (HPY = (PCF/100)*365.25*24 h/yr).

Corrosion inhibitor VOM cost is a function of sorbent VOM cost and reagent VOM cost is the sum of activated carbon and caustic VOM costs.

After identifying the most expensive capital and O&M costs, we were able to map those costs to relevant parameters. We then screened these parameters by performing a preliminary sensitivity analysis, eliminating parameters whose adjustment did not significantly reduce key capital and O&M costs. The parameters which did significantly reduce costs are provided in Table 12. Our method for determining parameter improvement limits for the parameters listed in Table 12 is discussed in the following section.

Table 12: Parameters that map to key capital and O&M costs

Symbol	Description	Δ output cost given \uparrow input
[sorb]	Sorbent concentration	$\downarrow C_{\text{absorb}}$ $\downarrow C_{\text{regen}}$ $\downarrow C_{\text{reb}}$ $\downarrow \text{VOM}_{\text{en}}$ $\downarrow \text{VOM}_{\text{sorb}}$
q_{regen}	Regeneration energy	$\uparrow \text{VOM}_{\text{energy}}$
F_{HE}	Heat-to-electricity equivalence factor	$\uparrow \text{VOM}_{\text{energy}}$
ϕ_{lean}	Lean sorbent loading	$\uparrow C_{\text{absorber}}$ $\uparrow \text{VOM}_{\text{energy}}$
$m_{\text{sorb, nom}}$	Nominal sorbent loss	$\uparrow C_{\text{sorb reclaimer}}$ $\uparrow \text{VOM}_{\text{sorb}}$ $\uparrow \text{VOM}_{\text{waste}}$ $\uparrow \text{VOM}_{\text{inhibitor}}$ $\uparrow \text{VOM}_{\text{reagents}}$
UC_{sorb}	Sorbent unit cost	$\uparrow \text{VOM}_{\text{sorb}}$ $\uparrow \text{VOM}_{\text{reagents}}$ $\uparrow \text{VOM}_{\text{water}}$

4.3 Establishment of performance improvement limits

In this section we present our performance improvement limits for each key parameter across post-combustion, oxy-fueling and pre-combustion technologies. However, for the sake of brevity, we provide an-depth discussion of key post-combustion parameters only in Section 4.3.2. Then, in Section 4.3.3, we present the performance improvement limits for all three combustion technologies.

Since we are interested in cost reductions, we focus on the performance limits that drive cost reductions instead of those that drive cost increases. Ideally, we define the performance limits by what is theoretically achievable; however, such theoretical limits are not always available. It should be noted that costs can either increase or decrease given an increase in a given performance parameter. For example, output costs decrease upon an increase of sorbent concentration, but output costs increase upon an increase in regeneration energy.

4.3.1 Discussion on post-combustion parameters and their performance improvement limits

The remainder of this section provides background information on three important performance inputs (regeneration energy, heat-to-electricity equivalence factor, and sorbent unit cost) as well as a few technologies which were not modeled in IECM.

The regeneration energy (q_{regen}) is the amount of energy required to liberate (strip) chemically-bound CO_2 from the rich sorbent. Regeneration energy is a significant input parameter since the parasitic energy loss associated with stripping rich sorbent is high, as will be shown in the results of the sensitivity analysis. The regeneration energy minimum (1163 kJ/kg CO_2) is the minimum value allowed in IECM; for reference theoretical regeneration energy for MEA is 1900 kJ/kg CO_2 . Thus, the 1163 kJ/kg CO_2 value represents the theoretical regeneration energy of a novel sorbent.

The heat-to-electricity equivalence factor is an input parameter that directly affects the significant regeneration energy parameter. The heat-to-electricity equivalence factor describes the efficiency of the conversion of base plant LP steam to sorbent regeneration energy. Output costs decrease along with decreases in the heat-to-electricity equivalence factor, and improvements to better integrate the capture unit with the base plant decrease the heat-to-electricity equivalence factor. The lower limit is based on the minimum cited in the IECM

technical manual for new post-combustion chemical absorption capture plants; retrofit plants with poorly integrated bolt-on capture units may have much higher heat-to-electricity equivalence factors.

Given that sorbent cost is among the highest VOM costs, it is not surprising that the sorbent unit cost is another important input parameter. While sorbent unit cost is not a technological parameter but is instead a function of market prices, discovery of a new, significantly less expensive sorbent that performs as well as the nominal sorbent, MEA, would significantly reduce sorbent VOM and thus overall CO₂ capture costs.

R&D improvements for the absorber, solvent formulation and electro dialysis were noted in the literature but are not currently included in this analysis since affected performance parameters, including absorption reaction rate, rich sorbent loading, and electro dialysis capital and operating cost data, are not included as inputs in IECM. However, chemical engineering software programs such as Aspen Plus can accept such inputs, which the program can use to generate outputs (e.g. lean sorbent loading rate) which we can input to IECM. This roundabout method of incorporating certain inputs into IECM may allow us to use IECM to evaluate more technologies than it is equipped to evaluate as a stand-alone software program.

4.3.2 Sensitivity parameter limits for post-combustion, oxy-fueling and pre-combustion

In this section we present our key performance improvement limits for each combustion technology. We present a table of the parameters on which we do sensitivity analysis, including their ranges. We also reference each performance parameter limit. Tables 13, 14 and 15 summarize post-combustion, oxy-fueling and pre-combustion key performance parameters, respectively. Each table lists input performance parameters; provides suggestions of how R&D might improve these parameters; includes the ranges used to do the sensitivity for each

parameter; and provides the direction in which output cost will change given an increase in an input performance parameter. The rightmost two columns of each aforementioned table explain where we got the values for the high and low ranges and give references. Nominal performance inputs are based on default values in IECM and on the settings explicitly defined in Appendix A. Nominal settings remain uniform and are assumed to reflect the state of current carbon capture technologies. Not all affected cost outputs are provided; only the ones of sufficient magnitude as determined using engineering judgment are provided in Tables 13, 14 and 15.

Table 13: Post-combustion key performance parameter summary

Symbol	Description	R&D improvement	Low	Nom	High	Low ref	High ref
[sorb]	Sorbent concentration	Develop less corrosive sorbent; or develop improved anti-corrosion inhibitors	15%	30%	40%	[A]	[B]
q_{regen}	Regeneration energy	Develop sorbent with lower regeneration energy requirement	1163	4468	4915	[C]	[D]
F_{HE}	Heat-to-electricity equivalence factor	Improve capture plant/base plant heat integration	9%	22%	25%	[E]	[F]
ϕ_{lean}	Lean sorbent loading	Develop improved sorbent	0.2	0.2	0.3	[G]	[H]
$m_{\text{sorb, nom}}$	Nominal sorbent loss	Develop improved acid gas side reaction inhibitors	0.75	1.5	2.25	[I]	[J]
UC_{sorb}	Sorbent unit cost	Develop less expensive sorbent	500	2206	5000	[K]	[M]
q_{flash}	Flash energy	Split flow configuration	Data is proprietary			[N]	[N]
USC	Ultra-supercritical combustion	Equip capture plant with USC	Nominal: SC Improvement: USC			[O]	

Reference key

[A] Commercial Kerr-McGee/ABB Lummus Crest Process [MEA] (Rao, 2004), (IPCC, 2005).

[B] MEA concentration that yielded the minimum regeneration energy (Abu-Zahra, 2006); Fluor reports its Econamine FG Plus process uses an MEA concentration exceeding 30 wt% (Reddy S. J., 2008).

[C] Minimum allowable in IECM (for reference, minimum MEA theoretical regeneration energy 1900 kJ/kg CO₂ (Rao, 2004)).

[D] Based on engineering judgment. Value is 10% higher than the nominal value.

[E] Low is minimum cited in IECM technical manual, which corresponds to the low-end range reported in the literature (Rao, 2004).

[F] High is upper range reported in the IECM manual (Rao, 2004).

[G] Minimum cited in literature as per IECM literature review (Rao, 2004).

[H] Maximum cited in literature as per IECM literature review (Rao, 2004).

[I] Minimum IPCC MEA makeup quantity/MEA solvent consumption (IPCC, 2005).

[J] 1/2 of maximum nominal MEA loss (Rao, 2004).

[K] Minimum allowable in IECM (Rubin E. S., 2010).

[L] Maximum allowable in IECM (Rubin E. S., 2010).

[M] \$5000/tonne is roughly double nominal value and was estimated using engineering judgment.

[N] Split flow configuration is being developed by Fluor.

[O] Ultra-supercritical combustion (USC) configuration. USC is more expensive for a baseline, non-capture plant but cost savings are realized when the post-combustion plant is equipped with USC.

Table 14: Oxy-fueling key performance parameter summary

Symbol	Description	Units	Low	Nominal	High	Low ref	High ref
AUP	ASU unit power	kWh/tonne O ₂	220	232	278	[A]	[B]
C _{ASU}	ASU direct capital cost	M\$	178	267	293	[C]	[D]
FGR	Flue gas recycle ratio	fraction	0.6	0.7	0.8	[E]	[B]
λ _{O2}	Excess O ₂	mol % theoretical	0	5	20	[E]	[F]
η _{Comp}	CO ₂ compressor efficiency	%	75	80	85	[E]	[B]
T _{FGR}	FGR recycle temperature	deg C	35	37.8	40	[G]	[H]
α _{leak}	Air leakage	mol % theoretical	0	2	10	[I]	[F]
USC	Ultra-supercritical combustion	-	Nominal: SC Improvement: USC			[J]	

Reference key

[A] Unit ASU power requirement that yields a net plant efficiency 0.33% HHV higher than nominal value. Value selected as a crude simulation of the efficiency improvement resulting from the replacement of an ASU with an ITM as reported in NETL (2010). Nominal efficiency HHV = 30.71%. Efficiency improvement = 31.04%. This closely approximates the improvement in plant efficiency reported in NETL (2010).

[B] Maximum allowable IECM input (Rubin E. S., 2010).

[C] ASU Direct capital costs estimated as 1/3 the capital costs of the ASU. Primary cost savings due to replacement of ASU by ITM due to capital cost per (NETL, 2010). The direct capital cost is embedded in the model and cannot be modified by the user. Thus, the low is estimated by multiplying the nominal output capital cost by 2/3 and by re-calculating the other costs accordingly.

[D] Value selected is 10% greater than IECM nominal value. The direct capital cost is embedded in the model and cannot be modified by the user. Thus, the low is estimated by multiplying the nominal output capital cost by 2/3 and by re-calculating the other costs accordingly.

[E] Minimum allowable IECM input (Rubin E. S., 2010).

[F] Nominal value used for IECM baseline air-fed boiler (Rubin E. S., 2010).

[G] Minimum value reported in Table 3 of IECM oxy-fueling technical manual (Rubin E. R., 2007).

[H] Maximum value reported in Table 3 of IECM oxy-fueling technical manual (Rubin E. R., 2007).

[I] Theoretical minimum.

[J] Ultra-supercritical combustion (USC) configuration. USC is more expensive for a baseline, non-capture plant but cost savings are realized when the oxy-fueling plant is equipped with USC.

Table 15: Pre-combustion key performance parameter summary

Symbol	Description	Units	Low	Nominal	High	Low Ref	High Ref
WGCU-H ₂	WGCU w/ H ₂ membrane configuration	NA	NA	NA	NA	NA	NA
T _{TIT}	Turbine inlet temperature	C	1232	1327	1426	[A]	[B]
C _{ASU}	ASU direct capital cost	M\$	77	230	253	[C]	[D]
AUP	Unit ASU power requirement	kWh/tonne O ₂	200	232	255	[E]	[F]
WGCU-Sel	WGCU configuration	NA	NA	NA	NA	NA	NA

[A] Reference plant value as used in NETL (2010). Value reported as 2250 F and converted to degrees C.

[B] Maximum allowable temperature in IECM.

[C] ITM capital costs estimated as 1/3 the capital costs of the ASU. Primary cost savings due to replacement by ITM due to capital cost per NETL (2010). The direct capital cost is embedded in the model and cannot be modified by the user. Thus, the low is estimated by multiplying the nominal output capital cost by 2/3 and by re-calculating the other costs accordingly.

[D] Value selected is 10% greater than IECM nominal value. Value selected using engineering judgment. The direct capital cost is embedded in the model and cannot be modified by the user. Thus, the low is estimated by multiplying the nominal output capital cost by 2/3 and by re-calculating the other costs accordingly.

[E] Unit ASU power requirement that yields a net plant efficiency 0.33% HHV higher than nominal value. Value selected as a crude simulation of the efficiency improvement resulting from the replacement of an ASU with an ITM as reported in NETL (2010). Nominal efficiency HHV = 30.19%. Improved efficiency = 30.52%. This closely approximates the improvement in plant efficiency reported in NETL (2010).

[F] Value selected using engineering judgment.

The warm gas cleanup-Selexol (WGCU-Sel) and warm gas cleanup-H₂ membrane improvements in Table 15 represent configuration changes that cannot be simulated using the IECM model. Thus, the cost changes resulting from the WGCU-Sel and WGCU-H₂ R&D improvements were calculated by taking plant wide capture percent LEC improvement data reported in NETL (2010) and subtracting that from the nominal plant-wide LEC with capture calculated using IECM. The WGCU-Sel LEC and WGCU-H₂ LEC percent improvements per NETL (2010) are 1.3% and 12%, respectively. Thus, the plant wide costs corresponding to the WGCU-Sel and WGCU-H₂ improvements are 1.3% and 12% lower, respectively, than the nominal plant-wide LEC with capture.

4.4 Selection of an appropriate non-capture baseline plant

To perform our sensitivity analysis, we selected a baseline, non-capture plant that we used to calculate the additional LEC estimates. In keeping with the methodology we employed in Section 3.2, we selected supercritical combustion pulverized coal as our baseline, and we generated the cost and performance estimates using IECM. Consistent with our expectations, the IECM non-capture pulverized coal cost (\$63/MWh) was less expensive than the IGCC non-capture cost (\$66/MWh). In IECM there is not a non-capture option available for oxy-fueling capture. Thus, in the sensitivity analysis results, we measure additional LEC against the IECM non-capture pulverized coal baseline for each capture technology.

4.5 Presentation of sensitivity analysis results

We present the results of the sensitivity analysis in a visual, intuitive way to better communicate our results. We use an approach commonly used to illustrate sensitivity analysis results, the tornado diagram. Tornado diagrams present the effect that changes to parameters have on variables. The variable is given along the horizontal axis, which is centered around a nominal value which corresponds to nominal values of the parameters. Tornado diagrams list parameters vertically, in descending order of their effect on the variable of interest. This ordering of the parameters gives the diagram a funnel or “tornado” look. Our variable is additional LEC, and our parameters are the performance parameters used in the IECM model. We color-code our tornado diagrams so that the reader can determine whether a cost reduction occurs as a result of a parameter increase or parameter decrease. A parameter that has a direct relationship with cost (i.e. a decrease in parameter causes a decrease in cost) is colored blue to the left of the vertical nominal cost. Likewise, a parameter that has an inverse relationship with cost (i.e. an increase in parameter causes a decrease in cost) is colored red to the left of the

vertical nominal cost. Figure 10 illustrates an example of the tornado diagrams we present in our sensitivity analysis.

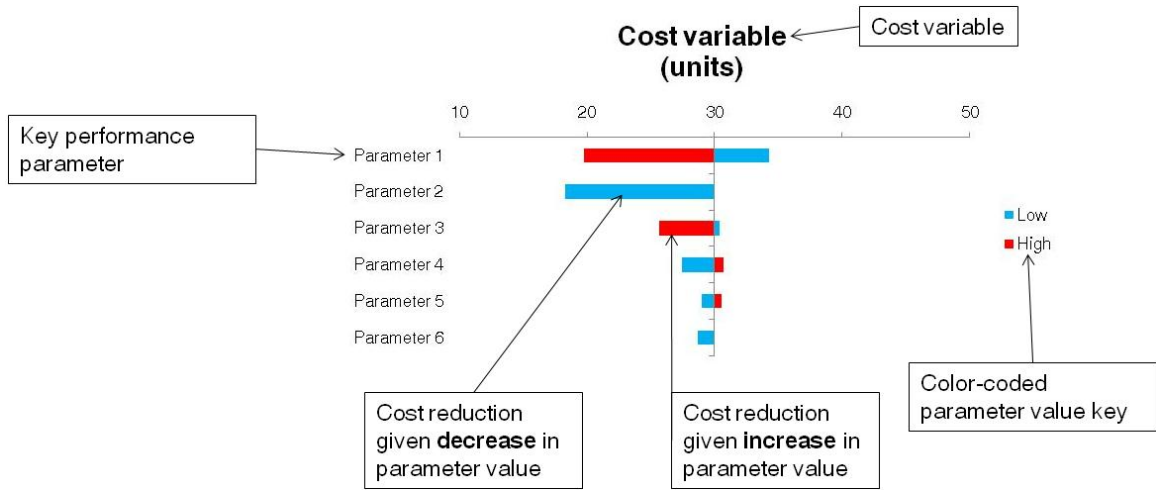


Figure 10: Tornado diagram example

CHAPTER 5

SENSITIVITY ANALYSIS RESULTS

In this chapter we present the results of the sensitivity analysis that shows how each technology's cost changes given a change to a performance parameter. We then identify performance parameters which induce the largest cost changes as key performance parameters affecting cost. Finally, we compare optimized post-combustion, oxy-fueling and pre-combustion cost and efficiency estimates to one another. We conduct our sensitivity analysis to explore how near-future, incremental technical change in CCS – the type of technical change that IECM is well suited to model – impacts the cost of CCS. All of these results were obtained using IECM.

5.1 Post-combustion chemical absorption

In this section, we present the results of the post-combustion chemical absorption sensitivity analysis. Figure 11 provides a tornado diagram of the additional LEC (\$/MWh) resulting from installing a chemical absorption capture unit modeled using IECM. The tornado diagram in Figure 11 depicts how cost changes at the low and high ends of the performance parameter inputs discussed earlier and shown again for ease of reference in Table 16. The impact on cost when a parameter decreases is shown in blue and when a parameter increases in red. Thus, a cost decrease is shown in red in the case of an increase in sorbent concentration ([sorb]) and in blue in the case of a decrease in regeneration energy (q_{regen}). The impact on cost when a configuration change has been made is shown in gray.

For reference, the baseline plant-wide LEC is 63 \$/MWh and the LEC with capture of the nominal plant configuration is 124 \$/MWh. Thus, the nominal additional LEC is 61 \$/MWh (which is by coincidence nearly equal to the baseline LEC). The high additional LEC for post-combustion capture is largely due to the technology's high energy penalty.

The energy-related performance parameters, sorbent regeneration energy (q_{regen}) and heat-to-electricity equivalence factor (F_{HE}), have the largest impact on LEC because of post-combustion capture's high energy penalty. Equipping the capture plant with an ultra-supercritical combustion (USC) boiler also significantly reduces cost in that the benefit from a reduction in energy penalty outweighs the higher capital cost. Specifically, USC technology increases the efficiency of the plant and thus helps offset post-combustion's energy penalty. Sorbent-related parameters such as lean sorbent loading and sorbent price (UC_{sorb}) impact cost to a lesser, albeit still significant, extent. Nominal sorbent loss ($m_{\text{sorb, nom}}$), and sorbent oxidation loss ($n_{\text{sorb, organics}}$) effect LEC reductions to a lesser extent. Sorbent concentration and sorbent loss due to oxidation have little impact on cost reduction.

Table 16: Inputs used to generate Figure 11 tornado diagram

Symbol	Description	Units	Low	Nominal	High
q_{regen}	Sorbent regeneration energy	kJ/kg CO ₂	1163	4489	4938
F_{HE}	Heat-to-electricity equivalence factor	%	9%	22%	25%
[sorb]	Sorbent concentration	wt %	15%	30%	40%
UC_{sorb}	Sorbent price	2009 USD/tonne	500	2346	5000
$m_{\text{sorb, nom}}$	Nominal sorbent loss	kg sorb/tonne captured CO ₂	0.75	1.5	2.25
ϕ_{lean}	Lean sorbent loading	mol CO ₂ /mol sorb	0.2	0.2	0.3
$n_{\text{sorb, organics}}$	Sorbent oxidation loss	mol sorb/mol acid	0	1	2

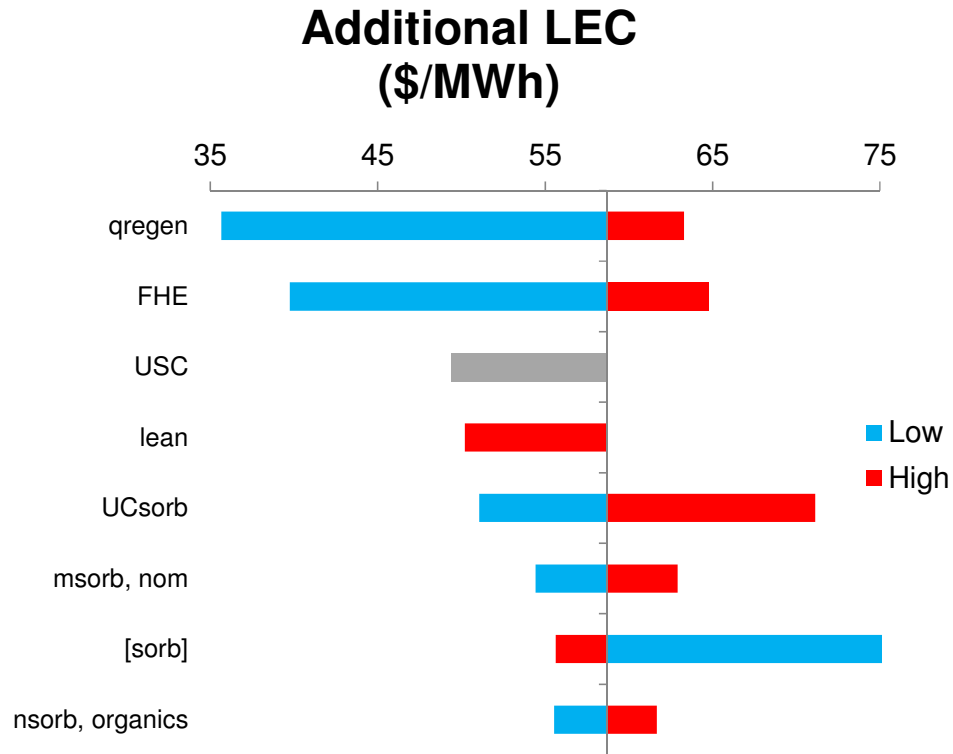


Figure 11: LEC tornado diagram for post-combustion capture plant

In summary, the most important inputs that are sensitive to technical change are those that relate to post-combustion’s energy penalty and, to a lesser extent, to the sorbent used in the absorber. In descending order of impact on the LEC, the key energy-related inputs are: absorber regeneration energy (q_{regen}), heat-to-electricity equivalence factor (F_{HE}) and ultra-supercritical combustion (USC) configuration. In descending order of impact on the LEC, the key sorbent-related inputs are lean sorbent loading rate (ϕ_{lean}), sorbent unit cost (UC_{sorb}) and nominal sorbent loss ($m_{\text{sorb, nom}}$).

5.2 Oxy-fueling sensitivity analysis

In this section we present the results of the oxy-fueling sensitivity analysis. Figure 12 provides a tornado diagram of the additional LEC (\$/MWh) of oxy-fueling capture. The tornado diagram in Figure 12 depicts how cost changes at the low and high ends of the performance

parameter inputs. The performance parameter inputs are shown in Table 17 just above Figure 12 for ease of reference. The impact on cost when a parameter decreases is shown in blue and when a parameter increases in red. Thus, a cost decrease is shown in red in the case of an increase in CO₂ compressor efficiency (η_{comp}) and in blue in the case of a decrease in ASU unit power (AUP). The impact on cost when a configuration change has been made is shown in gray.

For reference, the baseline plant-wide LEC is 63 \$/MWh (the same as the baseline plant-wide LEC used in the post-combustion chemical absorption sensitivity analysis) and the LEC with capture of the nominal plant configuration is 109 \$/MWh. Thus, the oxy-fueling nominal additional LEC is 46 \$/MWh, which is significantly less expensive than the post-combustion nominal additional LEC.

The air separation unit (ASU) is an integral and expensive part of the oxy-fueling capture process. The ASU is expensive due to its high capital cost and high energy penalty. Accordingly, cost is most sensitive to changes in parameters that reduce the capital cost and energy penalty of the ASU. Specifically, cost is most sensitive to changes in the ASU direct capital cost (C_{ASU}) and to the installation of an ultra-supercritical combustion (USC) boiler. Relative to these inputs, the other performance inputs do not generate significant cost reductions.

Table 17: Inputs used to generate Figure 12 tornado diagram

Symbol	Description	Units	Low	Nominal	High
AUP	ASU unit power	kWh/tonne O ₂	220	232	278
C _{ASU}	ASU direct capital cost	M\$	178	267	293
FGR	Flue gas recycle ratio	fraction	0.6	0.7	0.8
λ _{O2}	Excess O ₂	mol % theoretical	0	5	20
η _{Comp}	CO ₂ compressor efficiency	%	75	80	85
T _{FGR}	FGR recycle temperature	deg C	35	37.8	40
α _{leak}	Air leakage	mol % theoretical	0	2	10
USC	Ultra-supercritical combustion	-	Nominal: SC Improvement: USC		

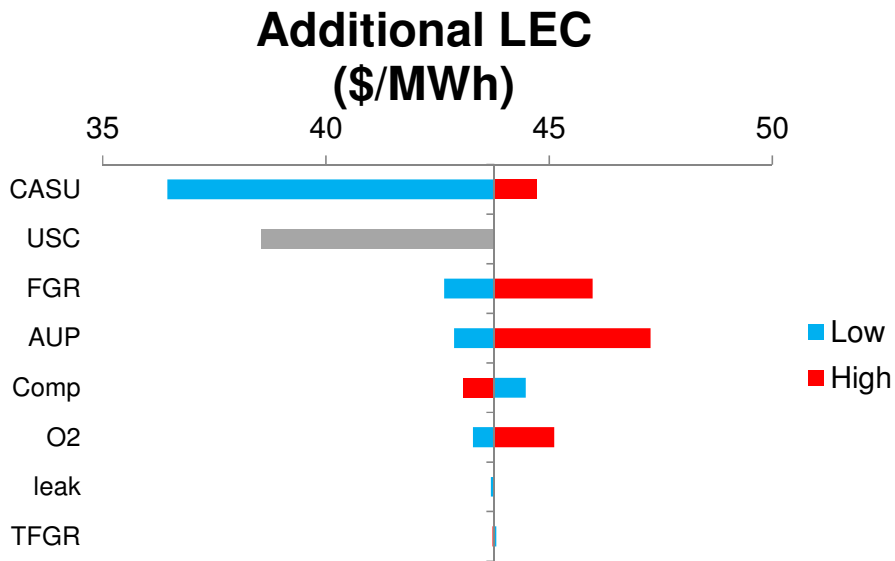


Figure 12: LEC tornado diagram for oxy-fueling capture plant

In summary, the most important inputs that are sensitive to technical change and which effect the largest reductions in cost are those that are related to the air separation unit: ASU direct capital cost (C_{ASU}) and the ultra-supercritical (USC) combustion configuration.

5.3 Pre-combustion sensitivity analysis

In this section we present the results of the pre-combustion sensitivity analysis. Figure 13 provides a tornado diagram of the additional LEC (\$/MWh) of pre-combustion capture. The

tornado diagram in Figure 13 depicts how cost changes at the low and high ends of the performance parameter inputs. The performance parameter inputs are shown in Table 18 before Figure 13 for ease of reference. We used the same color-coding scheme in Figure 13 as we did for the tornado diagrams in Figure 11 and Figure 12.

For reference, the baseline plant-wide LEC (that is, the cost minus a carbon capture unit) is 63 \$/MWh and the capture plant-wide LEC corresponding to the nominal plant configuration is 104 \$/MWh. Thus, the nominal additional LEC is 41 \$/MWh. Clearly, before technical change, pre-combustion capture is less expensive than oxy-fueling capture (\$46/MWh) and is significantly less expensive than post-combustion (61 \$/MWh).

LEC is most sensitive to the warm gas cleanup-H₂ membrane configuration (WGCU-H₂); however, the other configuration, warm gas cleanup-Selexol (WGCU-Sel), did not induce a significant change in LEC. LEC is also sensitive to turbine inlet temperature (T_{TIT}) and ASU direct capital cost (C_{ASU}). ASU unit power (AUP) did not significantly affect LEC in the pre-combustion sensitivity analysis. The ASU is not as integral to the pre-combustion process as it is in the oxy-fueling process since pre-combustion capture requires a smaller volumetric flow rate of oxygen than oxy-fueling capture does.

Table 18: Inputs used to generate Figure 13 tornado diagram

Symbol	Description	Units	Low	Nominal	High
WGCU-H ₂	WGCU with H ₂ membrane configuration	NA	NA	NA	NA
T _{TIT}	Turbine inlet temperature	C	1232	1327	1426
C _{ASU}	ASU direct capital cost	M\$	77	230	253
AUP	Unit ASU power requirement	kWh/tonne O ₂	200	232	255
WGCU-Sel	WGCU configuration	NA	NA	NA	NA

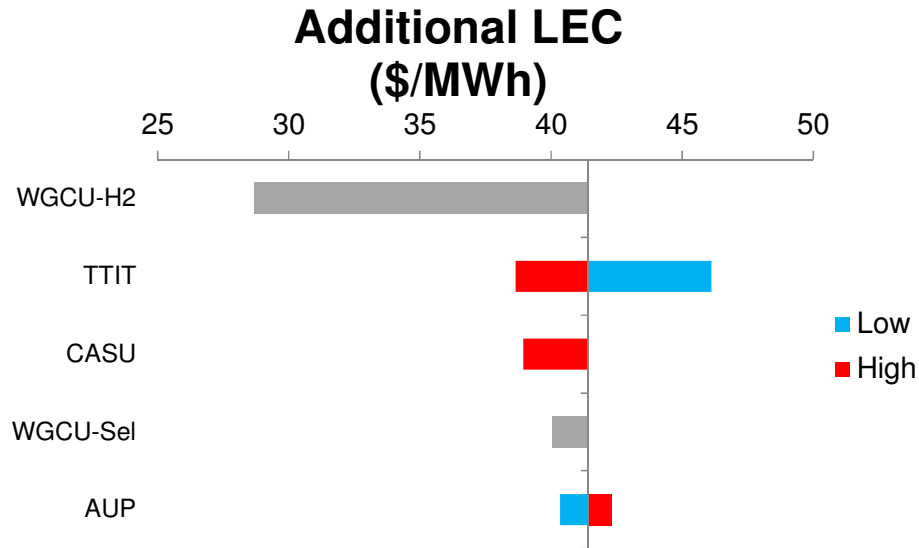


Figure 13: LEC tornado diagram for pre-combustion capture plant

In summary, the most important inputs that are sensitive to technical change and which most affect cost are the warm gas cleanup-H₂ membrane configuration (WGPU-H₂), turbine inlet temperature (T_{TIT}) and ASU direct capital cost (C_{ASU}). The warm gas cleanup-Selexol configuration (WGPU-Sel) and unit ASU power requirement (AUP) are less sensitive to technical change because the ASU plays a smaller role in pre-combustion capture than it does in oxy-fueling capture.

5.4 Comparison and subsequent discussion of each optimized capture technology

In this section we present and compare optimized LECs with capture of each capture technology. By optimized, we mean we adjusted all of the key performance parameters shown in the tornado diagrams to either their maximum or minimum levels according to whichever limit (maximum or minimum) minimizes cost. Then, we re-ran IECM using these optimum performance inputs to account for interactions between variables that result when more than one input is changed. The resulting minimized LECs with capture are the “optimized” LECs with capture.

Figures 14 and 15 present the additional LECs and LECs with capture, respectively, of each optimized capture technology. We exclude the sorbent price improvement for post-combustion capture when calculating the technology's optimized cost because sorbent price is a parameter that is a function of market conditions and, furthermore, we lack sufficient data pertaining to the price of novel, less expensive sorbent that could replace the currently used amine sorbent.

Pre-combustion capture naturally integrates with its IGCC combustion technology, and accordingly the optimized pre-combustion LEC with capture is less (\$87/MWh), albeit not by much, than both optimized post-combustion LEC with capture (\$93/MWh) and oxy-fueling LEC with capture (\$96/MWh). We use this pre-combustion estimate for our modeling work in Chapter 6.

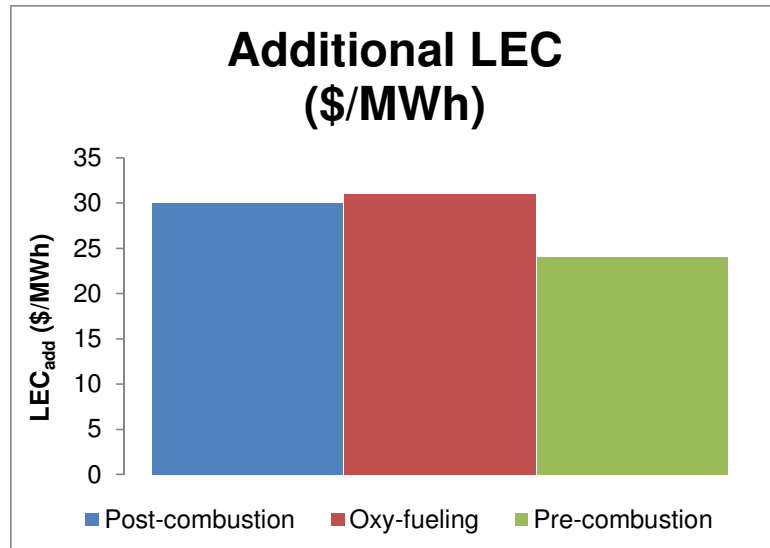


Figure 14: Comparison of additional LECs of each optimized capture technology

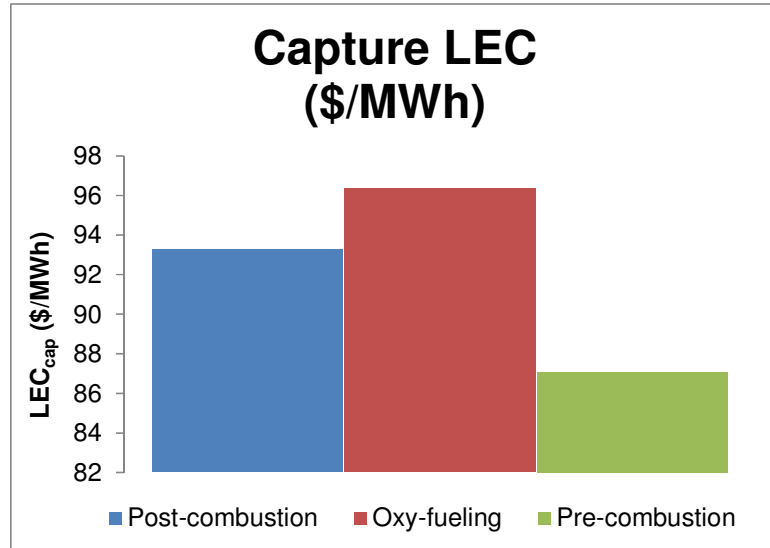


Figure 15: Comparison of LECs with capture of each optimized capture technology

CHAPTER 6

MODELING THE ECONOMIC IMPACTS OF TECHNICAL CHANGE IN CCS

In the third part of this thesis, we model the intertemporal economic impacts of technical change in CCS using a well-known economic-environmental-technological integrated assessment model (IAM), MERGE (Manne & Richels, 2008). We parameterize technical change in CCS by modifying two CCS parameters in MERGE: CCS LEC and CCS efficiency. We modify both of these CCS parameters in MERGE by using carbon capture cost and performance data presented in chapter 5 of this thesis and using data from the literature.

The rest of this chapter is structured as follows. First, we introduce and describe key features of MERGE. Second, we discuss the parameters that we modify and variables we monitor. Third, we compare near-future MERGE CCS estimates to those in the literature and as found using IECM. Fourth, we provide a brief methodology for how we model technical change in MERGE. Fifth, we present and interpret the model results.

6.1 Key features of MERGE

MERGE is an integrated assessment model (IAM) that was created by the Electric Power Research Institute (EPRI) in order to model the interrelation of climate change, economics and technology over time. MERGE does not forecast the future but it is a tool we use to compare possible future scenarios to inform policy makers and related decision-makers to find a least-cost path to meeting future possible CO₂ emissions constraints. MERGE is a global, intertemporal, top-down general equilibrium economic model that subdivides the world into nine regions (Richels & Blanford, 2008). It assumes perfect foresight across the time horizon, meaning that the model optimizes the net present value of the benefit stream across each time step. MERGE models electricity-producing technologies, including coal both with and without

CCS (Richels & Blanford, 2008). Finally, MERGE allows the user to select both emissions policies and technology policies, both of which are discussed in the paper by Richels and Blanford (2008).

MERGE allows the user to select from three pre-set emissions constraints and two pre-set technology scenarios. We use MERGE's default emissions constraint, wherein greenhouse gas emissions from developed countries (e.g. United States, Japan) are held constant at 2010 levels through 2020 and are then reduced by 3% per year. This emissions constraint does not constrain greenhouse gas emissions of developing countries (e.g. China, India) until 2050, when emissions are reduced by 3% per year. We present annual CO₂ emissions for the world in Figure 16.

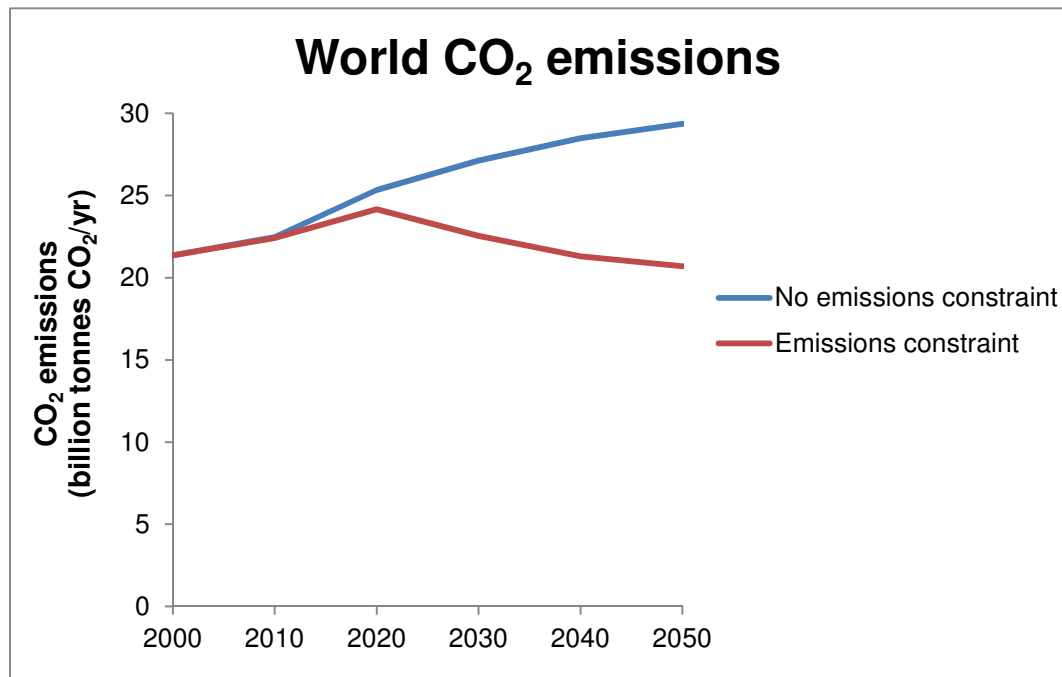


Figure 16: World CO₂ emissions with and without an emissions constraint

MERGE also allows the user to select a technology scenario. Two pre-configured technology scenarios are provided: technology-as-usual (TAU) and accelerated technology path (ATP). Table 19 is a reproduction from Richels and Blanford's 2008 paper – it summarizes the

features of both technology scenarios. MERGE parameterizes each technology using cost and performance data; CCS is parameterized by LEC and efficiency. We selected only one technology scenario, ATP, because CCS is unavailable in the TAU scenario. MERGE uses conventional supercritical pulverized coal combustion for its non-capture baseline and IGCC technology for capture. In addition, MERGE caps total coal market share at 60%.

Table 19: Technology scenarios in MERGE (reproduced from Richels and Blanford (2008))

Technology	Accelerated technology path (ATP)	Technology as usual (TAU)
CCS	Available	Not available
New nuclear power	Production can expand	Existing production levels
Renewables	Costs decline faster	Costs decline
End-use efficiency	Accelerated improvements	Improvements
Plug-in Hybrid Electric Vehicles	Available	Not available

MERGE uses efficiency and LEC data to parameterize CCS technology, and we present the efficiencies and LECs over time for MERGE’s baseline and capture technologies in Figure 17 (transport and storage costs are excluded). Although MERGE initializes its model at the 2010 time step, we only show time steps from 2020 through 2050 since CCS is not available as a technology in MERGE until 2020. As one would expect, both the efficiency and LEC gaps between baseline and capture narrow over time.

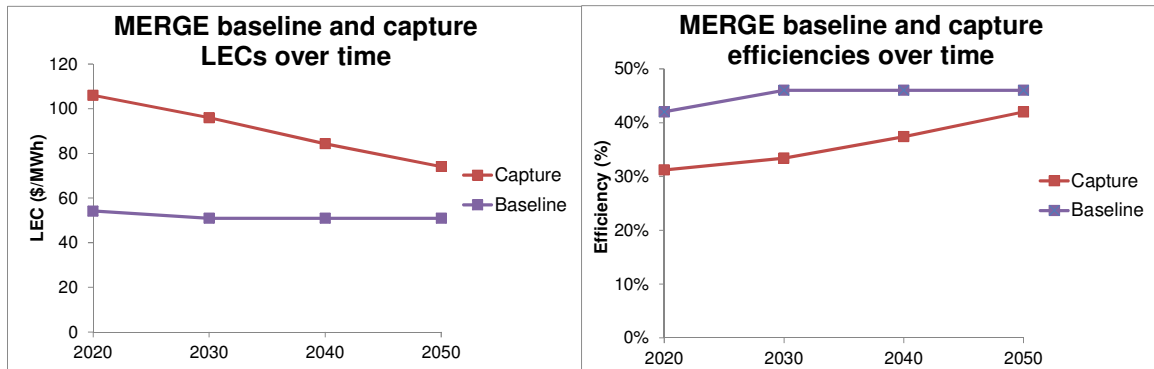


Figure 17: MERGE efficiencies and LECs for baseline and capture technologies

MERGE uses growth limits and market share constraints to prevent any one technology from dominating the entire electricity market. For example, CCS is unavailable until 2020 and is then limited to no more than 8% of market share. This limit approximately doubles each time step thereafter. New nuclear is also unavailable until 2020 and in that time step is limited to approximately 4% of market share. The electricity production decline rate is limited to 3.5% per year for new technologies (approximately 41% per ten-year time step) but there is no decline rate limit for old technologies. For new nuclear, there is also a non-market cost that represents “public concerns about security and environmental risks” (Richels & Blanford, 2008). There are no elasticities of substitutions between individual electric energy technologies in MERGE. However, MERGE uses an elasticity of substitution between electric and non-electric technologies *taken as a whole*.

Finally, it is important to point out the limitations of MERGE and by extension the limitations of our analysis that we conducted using this integrated assessment model. First, In MERGE, technical change is modeled using exogenous parameter data. In reality, technical change, in particular incremental technical change, is driven in part by “the quantity of production”, and furthermore “these production-related changes include learning-by-doing (LBD) and scale effects. Knowledge acquired from production and economies of scale drives the

resulting cost reductions. Ultimately they are spurred by increases in demand.” (Baker, Nemet, & Rasmussen, 2011). We simulate incremental change using the results from the sensitivity analysis but, consistent with the model’s setup, we do not factor the quantity of production of CCS (which would be measured in MWh net output) into our calculation of the future cost and performance of CCS. Second, MERGE is limited in the technologies it offers, especially disruptive breakthrough technologies that we have not foreseen. Third, MERGE parameterizes end-user (i.e., the consumers of electric and non-electric energy) energy efficiency improvements using an autonomous energy efficiency improvement (AEEI) parameter. Thus, as the AEEI parameter is increased, the “energy required per unit economic output” increases and less energy is required to generate the same economic output (Richels & Blanford, 2008). It follows that less CO₂ emissions would be generated given a higher AEEI. The AEEI parameter, which is indexed through time, is extrapolated using historical data. This method may or may not be a reliable method to calculate future end-user energy efficiency.

6.2 Discussion of parameters and variables

In this section, we begin by defining the parameters we modify in MERGE: CCS LEC and carbon capture efficiency. We then trace a path from the parameters forward to our variables of interest: electricity market share, CO₂ price and total abatement cost. Finally, we discuss in general how key variables are affected by changes to our parameters.

Although in previous chapters we only focused on technical change in carbon capture, in this chapter we must consider the total cost of CCS, which is just the sum of levelized costs of carbon capture and storage:

Equation 16

$$LEC_{CCS,i} = LEC_{cap,i} + LEC_{store,i}$$

where

- $LEC_{CCS,i}$ is the levelized cost of carbon capture and storage in time step i ;
- $LEC_{cap,i}$ is the levelized cost of carbon capture in time step i ;
- $LEC_{store,i}$ is levelized cost of storage in time step i .

We modify LEC_{CCS} by making changes to LEC_{cap} in Equation 16; for LEC_{store} we use MERGE's default parameter values. The other parameter we modify is capture efficiency. MERGE uses the capture efficiency parameter to calculate CO₂ emissions for a given technology and to calculate demand for coal in each time step.

We wish to now trace a path from the LEC_{cap} parameter to our variables of interest. In MERGE, each technology is parameterized by its levelized cost (e.g. LEC_{CCS}), which tends to decrease with time. MERGE uses levelized cost technology data to calculate the total electric energy cost of each time step:

Equation 17

$$EC_i = \sum_j LEC_{i,j} * PE_{i,j}$$

where

- EC_i (\$), a variable, is the total electric energy cost in time step i ;
- $LEC_{i,j}$ (\$/MWh), a parameter, is the levelized electricity cost of technology j in time step i ;
- $PE_{i,j}$ (MWh), a variable, is the quantity of electricity produced by technology j in time step i .

Energy cost EC is an argument in MERGE's gross domestic product³ (GDP) allocation equation. The GDP allocation function also has as its arguments consumption and investment. Each of these variables in the allocation equation has a competing claim on aggregate output. The GDP allocation equation is given by:

Equation 18

$$Y_i = C_i + I_i + EC_i$$

where

- Y_i (\$), a variable, is the total GDP in time step i ;
- C_i (\$), a variable, is the total consumption in time step i ;
- I_i (\$), a variable, is the total investment in time step i ;
- EC_i (\$) is the energy cost as defined in Equation 17.

It is important to note that total Y_i is calculated by MERGE's nested constant elasticity of substitution (CES) production function. Once Y_i is determined by the production function, the model selects an optimum combination of consumption, investment and energy cost that maximizes MERGE's intertemporal welfare function. For the sake of simplicity, we only implicitly define MERGE's production function:

Equation 19

$$Y_i = f(K_i, L_i, E_i, N_i)$$

where

- Y_i (\$), a variable, is the total production (equal to total GDP) in time step i ;
- K_i (\$), L_i (\$), E_i (\$) and N_i (\$), all variables, are the total available capital, labor, energy and non-energy in time step i .

³ The gross domestic product (GDP) is the value of all the goods, services and net trade of a state, region, continent, etc., per unit time.

Capital, labor, energy and non-energy variables are recursively calculated using the previous time step's capital, labor, energy and non-energy variables along with the previous time step's investment. So we can see that investment is an important driver for future production.

Now we move on to the variables we monitor in MERGE: electricity market share, total abatement cost and CO₂ price. From Equation 17 and Equation 18, we can see that MERGE will seek to invest in the mix of energy technologies that minimizes energy cost EC, since doing so allows a greater share of GDP to be allocated to consumption and investment. Thus, it follows that reducing the LEC of CCS will tend to increase CCS market share and increase GDP over time.

For each technology case, we evaluate the total abatement cost, which we define as the reduction in discounted GDP due to the imposition of an emissions constraint. We take the sum of the change in discounted GDP for each time step from 2000 to 2100:

Equation 20

$$TAC = \sum_i \delta_i (Y_{no\ constraint} - Y_{constraint})_i$$

where

- *TAC*, a variable, is the total abatement cost in time step *i*;
- δ_i , a parameter, is the discount factor in time step *i*;
- *Y_{no constraint}*, a variable, is the total production (equal to GDP) in time step *i* in a world where there is no CO₂ emissions constraint. We use the MERGE's ATP scenario when calculating *Y_{no constraint}* (refer to Table 19);
- *Y_{constraint}*, a variable, is the total production (equal to GDP) in time step *i* in a world where there is a CO₂ emissions constraint.

In MERGE, the imposition of an emissions constraint will always reduce GDP, since the model has to substitute away from cheaper, fossil fuel-based energy technologies to more

expensive, lower carbon technologies such as CCS to meet the emissions constraint. Thus, we expect that a reduction in the cost of low carbon energy technologies such as CCS would reduce the losses in GDP caused by the imposition of the emissions constraint. In addition, we expect that reducing the cost of low carbon energy technologies will reduce the CO₂ price.

6.3 Comparison of literature review, MERGE and sensitivity analysis capture costs

In order to inform our methodology for modifying CCS LEC and efficiency parameters, we compared near-future LEC with capture estimates from MERGE to near-future IECM and literature review LEC with capture estimates. By near-future, we mean LEC estimates before technical change has occurred. We also compared future, post-technical change LEC with capture estimates from MERGE to optimized IECM LEC estimates and future, post-technical change LEC with capture estimates from a paper in the literature (Baker, Chon, & Keisler, 2009). We selected the Baker et al. (2009) estimates because they correspond to radical technical change achieved by the successful implementation of chemical looping technology.

Figure 18 presents a side-by-side comparison of non-capture LEC (LEC_{base}), LEC with capture (LEC_{cap}) and additional LEC (LEC_{add}) estimates for MERGE, IECM results and mean capture costs from our literature review in the near-future, before technical change. We do not include storage costs in Figure 18. We select MERGE LEC estimates from 2020 because CCS is unavailable in both the 2000 and 2010 time steps. All costs are in 2009 USD and each estimate normalized according to the cost normalization assumptions provided in Table 3.

In Figure 18 when we show baseline non-capture LECs (LEC_{base}), we use pulverized coal combustion for each estimate. For the MERGE baseline LEC, we use MERGE's 2020 pulverized coal combustion estimate. For the IECM baseline LEC, we use the non-capture baseline of

\$63/MWh that we used for the sensitivity analysis. For the literature review baseline LEC, we use the mean pulverized coal combustion estimate that we presented in Chapter 3.

In Figure 18 when we show LECs with capture (LEC_{cap}), we use IGCC pre-combustion capture for each estimate. For the MERGE estimate, we use MERGE's 2020 IGCC pre-combustion capture estimate. For the IECM estimate, we use nominal IECM IGCC pre-combustion estimate that we presented in Section 5.3. For the literature review estimate, we use the mean IGCC pre-combustion estimate from Table 7 (the mean excluding the IGCC biomass estimate). The additional LECs (LEC_{add}) presented in Figure 18 are the difference between each estimate's LEC with capture and baseline LEC.

We present Figure 18 in order to provide some perspective on how near-future MERGE, IECM and literature review baseline and LECs with capture compare to one another. Our key observation about the LECs in Figure 18 is that there is not a huge discrepancy between them. If there were such a discrepancy, that could call into question the validity of our modeling work, since we use IECM estimates for that work.

However, we still find that MERGE's non-capture baseline is higher than both of the IECM and literature review estimates. This is because the MERGE capital and O&M costs are high (\$53.6/MWh). However, the MERGE estimate is not high relative to other papers published by EPRI (the creators of MERGE). In fact, the MERGE non-capture baseline estimate is only about \$4/MWh higher than the cost estimate used in Richels and Blanford's 2008 paper and other EPRI cost estimates provided in the literature (Richels & Blanford, 2008), (Katzer, Moniz, Deutch, Ansolabehere, & Beer, 2007).

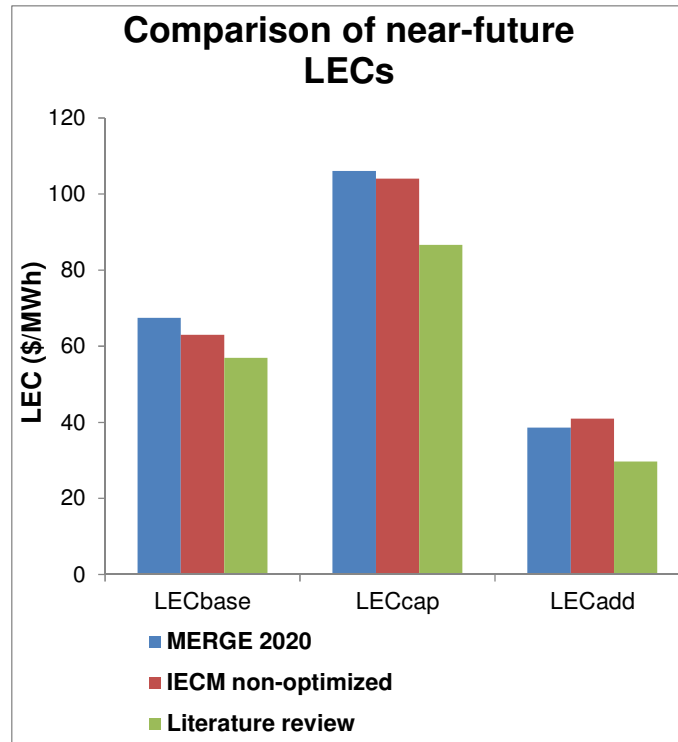


Figure 18: Side-by-side comparison of LECs before technical change

Analogous to Figure 18, Figure 19 presents a side-by-side comparison of non-capture LEC (LEC_{base}), LEC with capture (LEC_{cap}) and additional LEC (LEC_{add}) estimates for MERGE in 2050, optimized IECM results and future projections for chemical looping from Baker et al. (2009). These represent a range of estimates that incorporate technical change. Again, we do not include storage costs. We select MERGE LEC estimates from 2050 for two reasons: first, LEC with capture remains constant after 2050; and second, the Baker et al. chemical looping estimate is for the year 2050.

In Figure 19 when we show baseline non-capture LECs (LEC_{base}), we use pulverized coal combustion for each estimate. For the MERGE baseline LEC, we use MERGE's 2050 pulverized coal combustion estimate. For the IECM baseline LEC, we again use the non-capture baseline that we used for the sensitivity analysis. For the Baker et al. (2009) baseline LEC, we use that

paper's pulverized coal combustion estimate which we normalized according to the assumptions provided in Table 3.

In Figure 19 when we show LECs with capture (LEC_{cap}), we use IGCC pre-combustion capture for the MERGE and IECM estimates *only*. For the MERGE estimate, we use MERGE's 2050 IGCC pre-combustion capture estimate. For the IECM estimate, we use the optimized IECM IGCC pre-combustion estimate that we presented in Section 5.4. For the Baker et al. (2009) estimate, we use that paper's chemical looping capture estimate which we normalized according to the assumption provided in Table 3. The additional LECs (LEC_{add}) presented in Figure 19 are the difference between each estimate's LEC with capture and baseline LEC.

The key observation we make about Figure 19 is that the large cost difference between the chemical looping estimate and all other estimates shows that there is a large potential for cost reductions in CCS that has not been explored in MERGE. In addition, although the additional LEC of the optimized IECM estimate is higher than the additional LEC of the MERGE 2050 estimate, the IECM estimate is significantly less expensive than the MERGE 2020 and 2030 estimates. We compare the optimized IECM estimate to the 2020, 2030, 2040 and 2050 MERGE estimates in more detail in Table 20 in the following section.

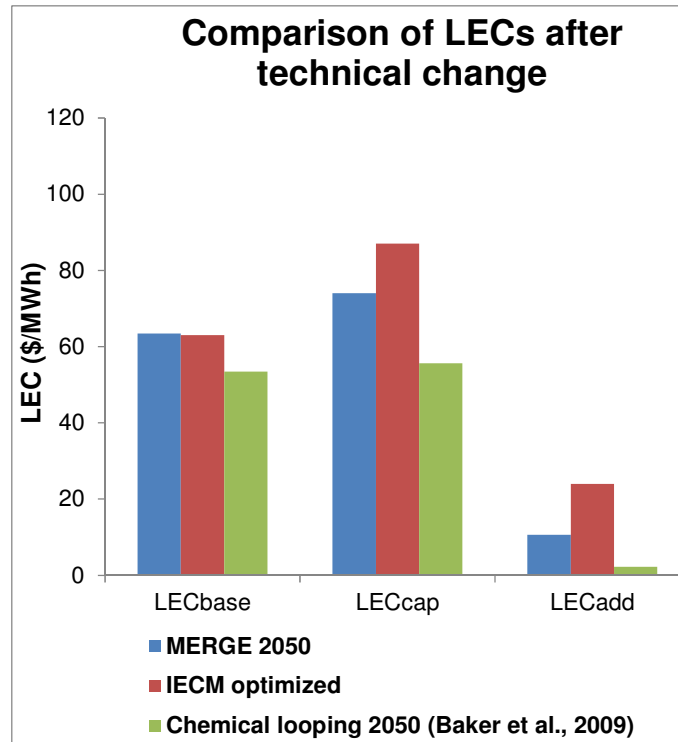


Figure 19: Side-by-side comparison of LECs after technical change

6.4 Methodology for parameterizing technical change in CCS

In this section we provide our methodology for parameterizing technical change in CCS. We begin by providing a rationale for creating our two new technology cases. We then discuss how we created our technology cases that we input into MERGE: an intermediate case and a breakthrough case. Finally, we present inter-temporal LEC and efficiency parameters for each case that we used to conduct the modeling.

6.4.1 Rationale for creating intermediate and breakthrough cases in MERGE

We are interested in modeling the economic impacts of both incremental and more radical, breakthrough technical change in CCS. We created the intermediate case to see how our variables of interest (that is, electricity market share, total abatement cost and CO₂ price) are affected given rapid incremental (albeit not breakthrough) technical change in CCS. We model

incremental technical change in CCS using our optimized pre-combustion IECM results, since IECM is limited to modeling technical change in near-future CCS technologies. We selected the optimized pre-combustion IECM estimate over the optimized IECM post-combustion and oxy-fueling estimates for this analysis because the additional LEC of pre-combustion capture was the least expensive.

We created the breakthrough case in part because MERGE limits its scope of CCS technologies to IGCC pre-combustion. Thus, we expand our analysis using parameters of another, more radical capture technology in the literature, chemical looping, to see how our variables of interest are affected given a step-change (i.e., breakthrough) improvement in CCS technology. We model breakthrough technical change in CCS using chemical looping estimates from Baker et al. (2009).

The contrast between the MERGE estimates and our IECM results and the Baker et al. (2009) estimates clearly illustrates the following: first, MERGE lacks a technology scenario that includes rapid incremental technical change and; second, MERGE lacks a technology scenario that accounts for breakthroughs in CCS. To show this, in Table 20 we tabulate MERGE CCS cost (LEC) and performance (efficiency) estimates over time along with our IECM optimized pre-combustion and Baker et al.'s (2009) chemical looping estimates. We provide each estimate's baseline LEC, LEC with capture, additional LEC and the percent increase in LEC due to capture. We also provide each estimate's baseline efficiency, capture efficiency and percent decrease in efficiency due to capture.

Table 20 shows that our IECM pre-combustion LEC with capture is significantly less than both the MERGE 2020 and MERGE 2030 LECs with capture; thus, we can model rapid incremental technical change by using our IECM results in lieu of the MERGE 2020 and 2030 estimates. In addition, Table 20 shows that the Baker et al. (2009) estimate has a significantly

lower LEC and higher efficiency than the MERGE 2050 estimates; thus, we can model breakthrough technological change using the Baker et al. (2009) results in lieu of the MERGE 2050 estimate.

Table 20: Comparison of estimates' percent LEC increase due to capture and percent efficiency decrease due to capture

Estimate	LEC _{base} (\$/MWh)	LEC _{cap} (\$/MWh)	LEC _{add} (\$/MWh)	% LEC ↑ due to capture	Baseline efficiency	Capture efficiency	% efficiency ↓ due to capture
MERGE 2020	67	106	39	57%	42%	31%	26%
MERGE 2030	63	96	33	51%	46%	33%	27%
MERGE 2040	63	84	21	33%	46%	37%	19%
MERGE 2050	63	74	11	17%	46%	42%	9%
IECM results	63	87	24	38%	39%	31%	21%
Chemical looping (Baker, Chon, & Keisler, 2009)	53	56	2	4%	48%	47%	2%

6.4.2 Creation of the intermediate case

In this section, we discuss how we created the intermediate CCS case, which simulates rapid incremental technical change in CCS. We build the intermediate case using only the IECM optimized pre-combustion results, and thus simulate rapid incremental technical change in CCS that goes above and beyond MERGE's advanced technology path (ATP).

We used MERGE's baseline LEC and efficiency estimates for each time step and we calculated new LECs with capture using the IECM results. We calculated new LECs with capture by using the percent increase of LEC estimates for each time step from Table 20. We used MERGE's efficiency estimates for all time steps because these efficiencies are higher than the IECM efficiency.

To calculate the LEC with capture for the 2020 time step, we took the midpoint of the MERGE 2020 and IECM percent increases due to capture in order to simulate that a fraction of the pre-combustion technologies modeled using IECM had been implemented. We then use the

entire IECM percent increase in the 2030 time step to represent the total implementation of the technologies we modeled in IECM. After 2040, the technical change in the default MERGE scenario outstrips that which we could model using IECM, so we use MERGE LEC estimates thereafter.

6.4.3 Creation of the breakthrough case

The breakthrough case simulates both rapid incremental and breakthrough technical change in CCS. The key feature of the breakthrough case is that we use cost (i.e. LEC) and performance (i.e. efficiency) estimates from Baker et al.'s 2009 paper in 2050. Baker et al. (2009) obtained chemical looping breakthrough estimates by conducting expert elicitations to arrive at the probability of a chemical looping breakthrough in 2050 (Baker, Chon, & Keisler, 2009). We do not take into consideration the probability of achieving a breakthrough in this thesis. We normalized the chemical looping data provided in Baker et al. (2009) according to the assumptions provided in Table 3. Finally, our breakthrough case builds on the intermediate case because we also include our IECM optimized post-combustion results.

To create our breakthrough case we used both the IECM results and the chemical looping estimates from Baker et al. (2009). The breakthrough case is identical to the intermediate case for the 2020 and 2030 time steps; that is, we model rapid technical change as we did in the intermediate case. However, to calculate the LEC with capture and efficiency for the 2040 time step, we took the midpoint of the IECM and Baker et al. (2009) percent increase and decrease of LEC and efficiency, respectively, due to capture in order to simulate the partial deployment of chemical looping capture. We then use the entire Baker et al. (2009) percent increase and decrease of LEC and efficiency, respectively, in the 2050 time step to represent the total implementation of chemical looping capture.

6.4.4 Presentation of intermediate and breakthrough case parameters over time

In Figure 20, we present the LEC parameters that we generated for the intermediate and breakthrough (we exclude storage costs). For reference, we also include the MERGE LEC with capture and MERGE baseline, non-capture LEC. Until 2040, the intermediate case is less expensive than the MERGE case. However, the breakthrough LEC is consistently less than the MERGE LECs over time. In 2040, the breakthrough case LEC breaks off from the IECM LEC in order to simulate the deployment and commercialization of chemical looping capture. After 2050, the LECs in each technology case remain constant, which is consistent with MERGE’s methodology for costing energy technologies over time.

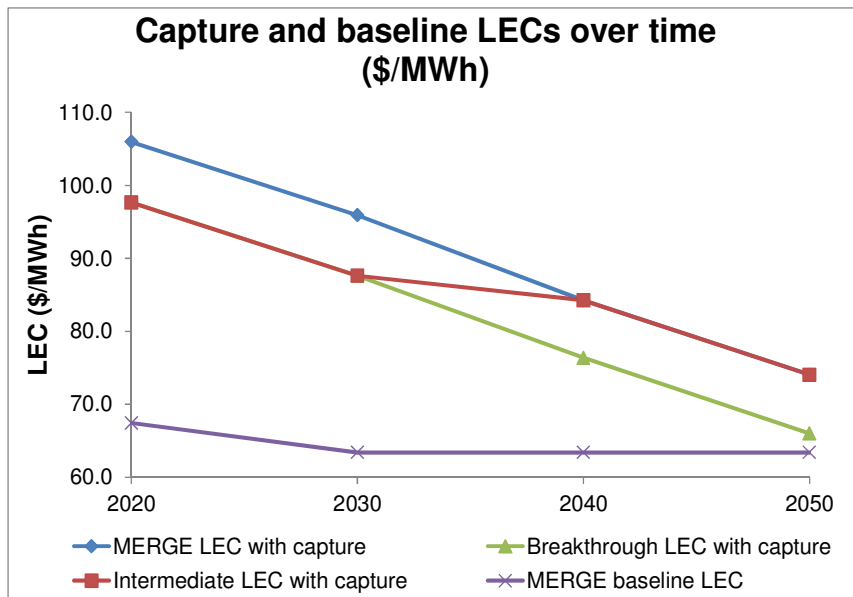


Figure 20: MERGE, intermediate and breakthrough LECs with capture over time (excluding storage costs)

In Figure 21, we present efficiency data over time for both the intermediate and breakthrough cases. We include the default MERGE case for reference. We notice that efficiencies for the intermediate case and MERGE are identical for each time step – this is because the IECM efficiency of 31% was only just as good as MERGE’s 2020 efficiency. As such, we just used MERGE’s efficiency for the intermediate case for all time steps. In the breakthrough

case, however, there is a jump in efficiency beginning in the 2040 time step and continuing through 2050 due to the deployment and commercialization of chemical looping capture.

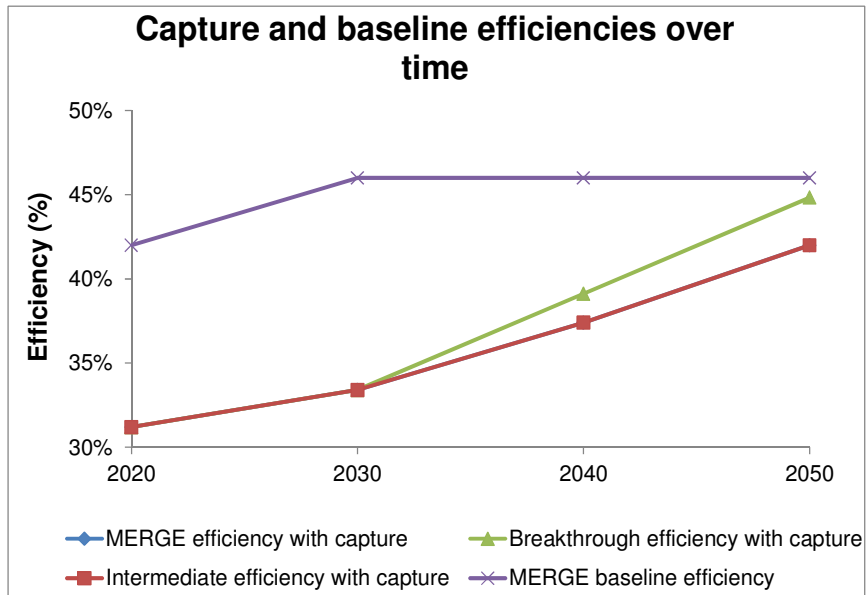


Figure 21: MERGE, intermediate and breakthrough efficiencies over time

6.5 Modeling results and discussion

In this section we present the results of our work with MERGE, which we used to investigate how technical change-inducing cost reductions in CCS could impact electricity market share, the CO₂ price and the total cost of reducing CO₂ (also known as the total abatement cost), over time. We present our results through the 2100 time step to provide a better picture of the effects of significant technical change in CCS.

6.5.1 Electricity market share

To begin, we present the results of the effect that technical change in CCS could have on electricity markets. Specifically, we are interested in seeing how the electricity market reacts to significant advances in CCS technology based on our scenarios. Figure 22 compares the electricity market share over time for the MERGE case (that is, the ATP case that is summarized

in Table 19) and the breakthrough CCS case. The market share of each technology is color coded. The key for the technology abbreviations used in Figure 22 for each technology is provided in Table 21.

Not surprisingly, the breakthrough CCS case has a significant impact on the electricity market share, resulting in CCS technology (highlighted in gray) dominating the electricity market by 2100. In addition, the electricity supply as a whole is slightly greater in the breakthrough case than in the MERGE case because of the lower cost of CCS⁴. CCS market share increases at the expense of new nuclear (highlighted in red). The reason for this becomes apparent if we investigate the price of new nuclear versus CCS over time for the different cases.

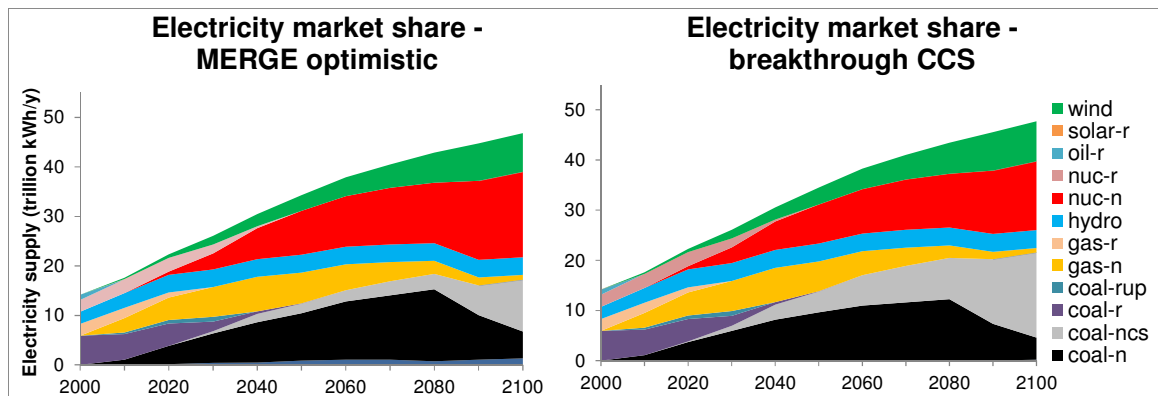


Figure 22: Comparison of electricity market share for MERGE optimistic and breakthrough CCS cases

⁴ The total electricity supply would be less if the AEEI parameter were lower, which is the case in MERGE's Technology As Usual (TAU) scenario. The reason is that a lower AEEI would result in more CO₂ emissions per unit of energy being generated and the emissions constraint would be met at a lower total supply of electric energy. If AEEI were modeled endogenously, then end-user technological efficiencies would be explicitly modeled. However, our results, and specifically CCS market share, should not be affected if such were the case.

Table 21: Technology abbreviation key to electricity market share figure

Technology	Abbreviation
Wind	wind
Solar	solar-r
Oil	oil-r
Vintage nuclear	nuc-r
New nuclear	nuc-n
Hydro power	hydro
Vintage gas	gas-r
New gas	gas-n
Up-rated coal	coal-rup
Vintage coal	coal-r
CCS	coal-ncs
New coal	coal-n
Biomass	biomass

Figure 23 compares MERGE, intermediate and breakthrough CCS LECs versus nuclear LECs over time. (storage costs are included here). Only in the breakthrough case does the CCS LEC dip below the nuclear LEC, which does not occur until the 2050 time step. In the absence of growth and market share constraints, we would expect CCS to dominate market share from the 2050 time step on because the model would minimize its total energy cost by substituting away from other, more expensive low carbon technologies, in particular new nuclear. However, the reason why CCS does not assume nuclear power's entire market share in the breakthrough case is because there *are* growth rate constraints for new nuclear and CCS. New nuclear, which is less expensive than CCS until the 2050 time step, cannot assume more than 4% market share in 2020, 8% market share in 2030, 16% market share in 2040 and 32% market share in 2050. Thus, new nuclear is not able to "crowd out" CCS from 2020 through 2040 because of the growth rate constraints placed on the technology. A similar rationale can be applied to explain why CCS does not crowd out new nuclear in 2050 and thereafter. The decline rate limit for new technologies including new nuclear is limited to 3.5% per year, and total coal-fired energy is limited to 60% market share. In the 2100 time step, total coal fired electric energy reaches that 60% market

share limit: CCS and uncontrolled coal-fired energy have 59.2% and 0.8% market shares, respectively⁵. Finally, from Equation 18 we can see that the reduction in total energy cost allows more GDP to be allocated to consumption and investment, which indirectly increases the total supply of electric energy (this is not noticeable in Figure 23 because the increase is slight).

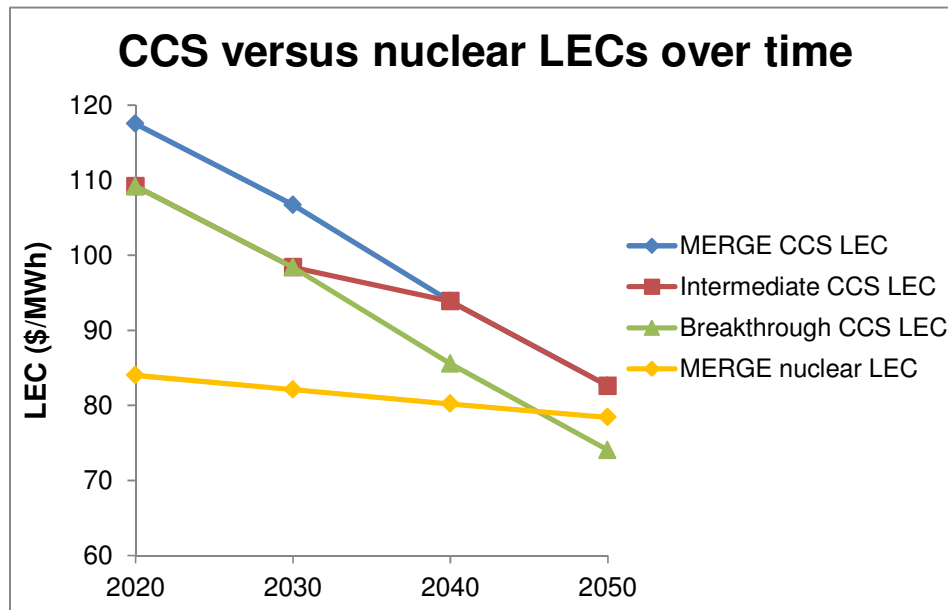


Figure 23: CCS and nuclear LECs for MERGE optimistic, advanced CCS and breakthrough CCS cases (storage costs included)

6.5.2 Total abatement cost savings

In this section, we investigate how the total abatement cost, as defined in Equation 20, could be affected by significant technical change in CCS. We present our results for total abatement cost for each technology case in Figure 24. We see that a savings of approximately 100 billion discounted USD are realized in the breakthrough CCS case compared to the MERGE

⁵This result might be reversed if MERGE included an endogenously driven learning-by-doing (LBD) cost reduction equation since new nuclear gets a head start over CCS. This is because learning-by-doing cost reductions would favor new electric energy technologies that claim a larger share of the market in earlier time steps (e.g., new nuclear), since those technologies would undergo a greater degree of LBD-driven cost reductions sooner.

optimistic case. Thus, there is clearly an economic benefit given a chemical looping breakthrough in CCS.

If the expected value of investing in advanced CCS R&D such as chemical looping is less than the 100 billion discounted USD, then it would be worth the investment in advanced CCS R&D. The literature suggests that it pays to invest in CCS R&D: in Baker et al. (2009), for instance, experts estimated that chemical looping would have a 42.4% chance of technical success given a ten year R&D funding trajectory totalling \$82.4 million (on a 2009 cost year basis). Using these numbers, the expected benefit to GDP of investing in chemical looping in our case is approximately \$42 billion, meaning it is worthwhile to invest in risky breakthrough technologies such as chemical looping in MERGE.

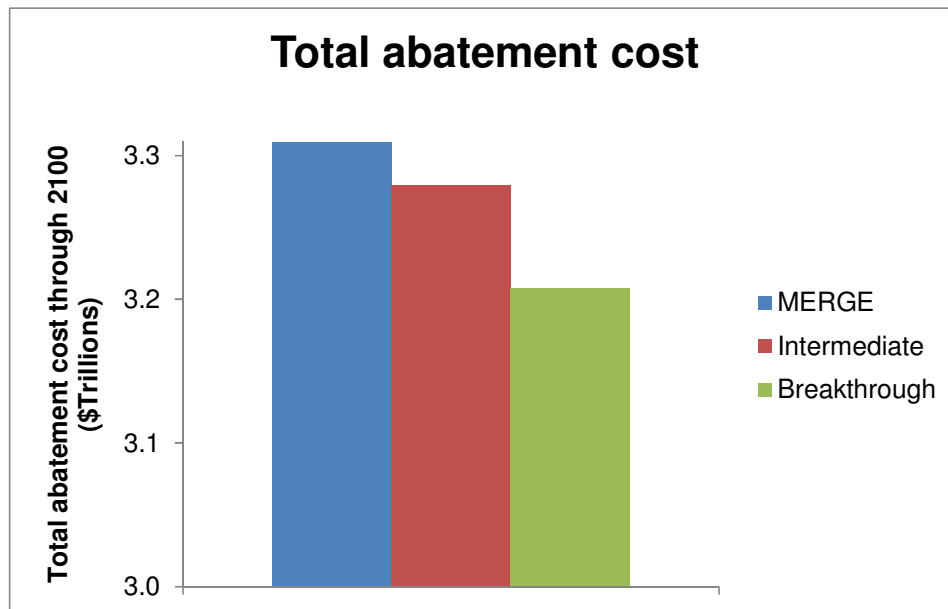


Figure 24: Total abatement cost due to emissions constraint for each technology case

6.5.3 CO₂ price

Finally, we investigate the effect that significant technical change in CCS could have on the price of CO₂. In MERGE this is modeled as the hypothetical price on energy and non-energy

CO₂ emissions required to induce each region (e.g., United States, China, etc.) to just meet its emissions constraint. Thus, a less expensive mix of low carbon electric energy technologies requires a lower price on CO₂ emissions to meet the emissions constraint. We present the CO₂ price results in Figure 25.

In the intermediate and breakthrough cases, the CO₂ price is only slightly less than the MERGE case. In the intermediate and breakthrough cases, MERGE substitutes away from nuclear and toward CCS. However, as we see in Figure 23, the difference in LEC between CCS and nuclear is small, meaning that the total cost of electric energy as calculated in Equation 17 in the intermediate and breakthrough cases is only slightly less than in the MERGE case. Thus, only a slightly lower price on CO₂ emissions is required to meet the emissions constraint in the intermediate and breakthrough cases.

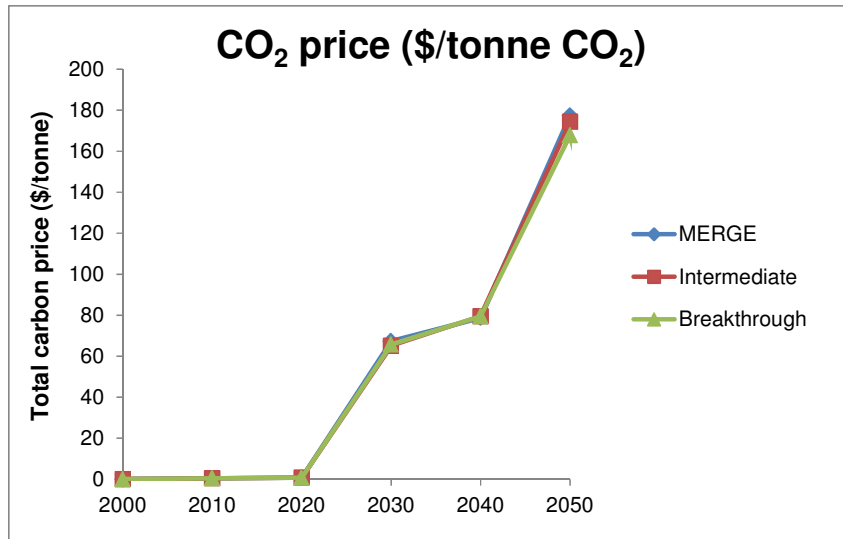


Figure 25: CO₂ price over time for each technology case

CHAPTER 7

CONCLUSIONS

In this thesis, we completed three projects that advance the understanding of how technical change in carbon capture might reduce the cost of capture technologies, and the implications of this on the costs of controlling climate change. We conduct this work because it is crucial to reduce CO₂ emissions in order to mitigate future climate change damages. This work is a small piece of the collective effort to best determine our future course of action to combat climate change in a way that is economical.

First, we conducted a literature review to establish near-future costs of carbon capture. That is, how much extra would CCS cost? LEC with capture may cost approximately 49% more than baseline pulverized coal combustion. Second, we conducted a sensitivity analysis to see how technical change in existing carbon capture technologies reduces the cost of CCS. Third, we used our results from the sensitivity analysis along with estimates from the literature as inputs in an integrated assessment model to evaluate the long-term impacts of both rapid incremental and breakthrough technical change in carbon capture.

We explored the limits of incremental technical change in carbon capture in our sensitivity analysis by optimizing each capture technology in IECM. By incremental technical change, we mean technical change that occurs within an existing technology and which is constrained by that technology's inherent performance improvement limits. The reduction of sorbent regeneration energy in post-combustion absorption capture is an example of incremental technical change because resulting cost reductions are constrained by the performance limits of the selected sorbent. However, breakthrough technical change is wholly different in that it involves the transition to a totally different technological paradigm (e.g., chemical looping) with superior cost and performance because it is not constrained by the

performance limits that constrain improvements to its predecessor technology. In fact, those performance limits do not even exist. The IECM cost-performance model is excellent for modelling incremental technical change but is unsuitable for modelling breakthrough technical change because IECM is limited in the number of technologies it offers.

The results of our literature review and sensitivity analysis show that pre-combustion capture is the least expensive of the capture technologies, both before and after incremental technical change. This is because its combustion technology, IGCC, best integrates with CO₂ capture process. The other capture technologies, especially post-combustion, suffer from high energy penalties which significantly increase the additional cost of capture. Our results reaffirm the US government's decision to allocate a plurality of its carbon capture R&D funding towards pre-combustion capture. However, there currently are no IGCC plants in the United States because IGCC is more expensive than conventional pulverized coal combustion as the results of our literature review show. Thus, technical change in the form of learning-by-doing and returns-to-scale, which can only occur after a technology has been deployed and commercialized, has not yet begun.

In our work with the integrated assessment model, we explored the economic impacts of two types of technical change: incremental technical change to near-future carbon capture technologies and breakthrough technical change realized by the deployment and commercialization of entirely new, radical capture technologies – namely chemical looping capture. Chemical looping, with its near-zero energy penalty and additional cost of capture, would be a technology that would seamlessly accommodate carbon capture. The integrated assessment model we worked with, MERGE, lacked a technology scenario that accounted for breakthroughs in CCS; thus, we created a new technology scenario that used chemical looping capture parameters from the literature (Baker, Chon, & Keisler, 2009). The results of our model

runs show that CCS dominates the market share given a chemical looping breakthrough. In addition, we found that an expected net benefit of 42 billion USD could be realized if we invest in chemical looping R&D. Note, however, that it is possible that breakthrough technical change in CCS could have less economic impact if learning were endogenous, since endogenous learning favors energy technologies that enter the market sooner (e.g., new nuclear) versus those that do not (e.g., CCS).

CCS figures to be an important technology, perhaps the most important, of the energy technology portfolio that we will use to reduce our CO₂ emissions. However, CCS is a uniquely vulnerable low-carbon energy technology in that its deployment and commercialization, that is, its success, is totally conditional upon there being a price on CO₂. Given that top-down political action needs to occur to effect such a CO₂ price, it seems that we should investigate the likelihood that the federal government create an energy policy that assigns a CO₂ price. An investor in low carbon energy technologies may find it useful to know the probability that lawmakers will pass a bill that assigns a price to CO₂ by the year 2030.

In sum, combating climate change will cost society; however, our results help to illuminate a lowest-cost path for decisionmakers who are looking for the least expensive mix of energy technologies to reduce our CO₂ emissions.

APPENDIX

BASELINE AND CAPTURE PLANT CONFIGURATION ASSUMPTIONS USED IN IECM

Post-combustion

Baseline plant is a 500 MW-net pulverized coal power plant without capture. Supercritical (SC) boiler, Illinois #6 coal, low NO_x burners, hot-side SCR post-combustion NO_x controls, cold-side ESP PM controls, wet FGD SO₂ controls, costs calculated in 2005 USD and then reported in 2009 USD. All other program defaults remained unchanged.

Nominal capture plant is a 500 MW-net pulverized coal power plant with capture unit. Amine system CO₂ controls, monoethanolamine (MEA) sorbent. All other inputs were otherwise identical to those of the baseline plant.

Oxy-fueling

Baseline plant is the 500 MW-net pulverized coal power plant without capture described above.

Nominal capture plant is a 500 MW-net oxy-combustion coal power plant with capture. SC boiler, Illinois #6 coal, cryogenic ASU, no NO_x controls, cold-side electro-static precipitator (ESP) PM controls, no SO₂ controls, costs calculated in 2005 USD and then reported in 2009 USD. All other program defaults remained unchanged.

Pre-combustion

Baseline plant is the 500 MW-net pulverized coal power plant without capture described above.

Nominal capture plant is a 500 MW-net IGCC coal power plant with capture. GE 7-FB turbine, 2350 degree F gasifier temperature, 1% (by weight) total carbon in slag, Illinois #6 coal, Selexol H₂S controls, Selexol sour shift CO₂ capture, no NO_x controls, costs calculated in 2005 USD and then reported in 2009 USD. All other program defaults remained unchanged.

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