An analysis of how climate policies and the threat of stranded fossil fuel assets incentivize CCS deployment

By

Victoria Clark

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Tufts University, 2008

Submitted to the Engineering Systems Division
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Signature of Author ____
Technology and Policy Program
Engineering Systems Division
May 8, 2015

Certified by ____
Howard J. Herzog
Senior Research Engineer, MIT Energy Initiative
Thesis Supervisor

Accepted by ____
Dava J. Newman
Professor of Aeronautics and Astronautics and Engineering Systems
Director, Technology and Policy Program

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Abstract

To be on track to stabilize climate change, scientists estimate that up to two thirds of global coal, oil, and natural gas reserves will need to remain stranded in the ground. Carbon capture and storage (CCS) is the only technology that has the potential to mitigate climate change while utilizing these potentially stranded fossil fuel assets. The Intergovernmental Panel on Climate Change (IPCC), International Energy Agency (IEA), and other international expert organizations see CCS playing a large role in the mix of climate mitigation technologies, but deployment has been slow. In light of the expected role of CCS and current limited deployment, this thesis explores the political and financial incentives that can further drive funding and implementation of CCS projects and evaluates the role of CCS in rescuing potentially stranded fossil fuel assets.

This thesis includes three detailed analyses: (1) an evaluation of proposed command-and-control regulations from the US EPA for new and existing fossil fuel-fired power plants; (2) cases studies of how two successful CCS projects, Boundary Dam in Canada and Gorgon in Australia, were incentivized; and (3) an analysis of results from the AMPERE modeling study to estimate the global scale and value of stranded fossil fuel assets.

From these analyses, five key conclusions are drawn. (1) CCS has the potential to rescue substantial coal, natural gas and oil assets and has the potential to hugely reduce global mitigation costs compared to a scenario without CCS. (2) The design of policy is crucial for CCS. Carbon pricing mechanisms must have a price high enough to incentivize CCS; command-and-control policies must not create loopholes for lower cost technologies; and financial incentives must provide sufficient funds, flexibility, and time to complete projects. (3) The role of bioenergy with CCS (BECCS) in top-down climate stabilization scenarios needs to be better understood, as these models seem to be overly optimistic regarding BECCS. (4) On an individual project level, stranded assets have the most value when there is no viable substitute available (e.g., transportation fuels) or when the fuel user also owns the asset (e.g., utility-owned lignite). (5) CCS on fuel production processes (e.g. oil refining and natural gas processing) are easier to finance than fuel utilization processes (e.g. power generation and cement production), but power plants remain the biggest potential market for CCS if it is to become a major climate mitigation technology.

Thesis supervisor:
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Acronyms

AR5	IPCC Fifth Assessment Report
ARRA	American Recovery and Reinvestment Act
BECCS	Bioenergy with CCS
BSER	Best System of Emission Reduction
CAA	Clean Air Act
CATF	Clean Air Task Force
CCPI	Clean Coal Power Initiative
CCS	Carbon Capture and Storage
COE	Cost of Electricity
CPP	Clean Power Plan
DOE	Department of Energy
EGU	Electricity Generating Unit
EIA	Energy Information Administration
EJ	ExaJoule
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency
ETS	Emissions Trading Scheme
GHG	Greenhouse Gas
GW	GigaWatt
GWh	GigaWatt hour
HECA	Hydrogen Energy California
ICCS	Industrial CCS
IEA	International Energy Agency
IGCC	Integrated Gasification Combined Cycle
IPCC	Intergovernmental Panel on Climate Change
LCOE	Levelized Cost of Electricity
LNG	Liquefied Natural Gas
MEA	Monoethanolamine
MHI	Mitsubishi Heavy Industries
MWh	MegaWatt hour
NGCC	Natural Gas Combined Cycle
NGCT	Natural Gas Combustion Turbine
NSPS	New Source Performance Standards
O&M	Operations and Maintenance
PC	Pulverized Coal
RIA	Regulatory Impact Assessment
SCC	Social Cost of Carbon
SCPC	Supercritical pulverized coal
TCEP	Texas Clean Energy Project
TWh	TeraWatt hour
TRIG	KBR Transport Reactor Integrated Gasifier

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Chapter 1: Overview

1.1 Background

Science has never been clearer that humans are changing the climate through increased greenhouse gas emissions. The latest Intergovernmental Panel on Climate Change (IPCC) report on the physical science behind climate change highlights increases in global mean surface and ocean temperatures, rising sea level, irreversible melting of ice in the Arctic, Antarctic, and Greenland, and increased intensity and frequency of extreme weather events that have been linked to anthropogenic (i.e. human-caused) emissions of greenhouse gases since the industrial revolution (IPCC 2013).

According to the IPCC, these global changes are expected to impact ecosystem resilience, coastal settlements, and human health. As average mean temperatures increase faster than ecosystems can naturally adapt and as extreme weather events become more prevalent, the IPCC estimates that 20-30% of plant and animal species will be at increased risk of extinction if global average temperatures exceed 1.5 degrees Celsius. By the 2080s, the IPCC warns that millions of coastal residents will experience effects of floods, sea level rise and coastal erosion due to climate change. Finally, climate change will cause indirect human health effects though increases in malnutrition, diarrheal diseases, and cardio-respiratory diseases (IPCC 2007).

The amount of fossil fuels remaining in the world can be defined in different ways. Estimates are broken down into groups by what has already been discovered and what will be discovered based on geologic surveys and past experiences, what type of technology is necessary to recover reserves, and how financially viable it will be to access the resources, as illustrated in Figure 1 (Intergovernmental Panel on Climate

Change, 2011). The IPCC defines “reserves” as the amount of fossil fuels that can be extracted economically with current technology. “Resources,” on the other hand, are fossil fuels that can be extracted with improvements in technology or that are anticipated to be discovered in the future. The sum of reserves and resources are carbon stocks in the ground. This terminology is used throughout this thesis.

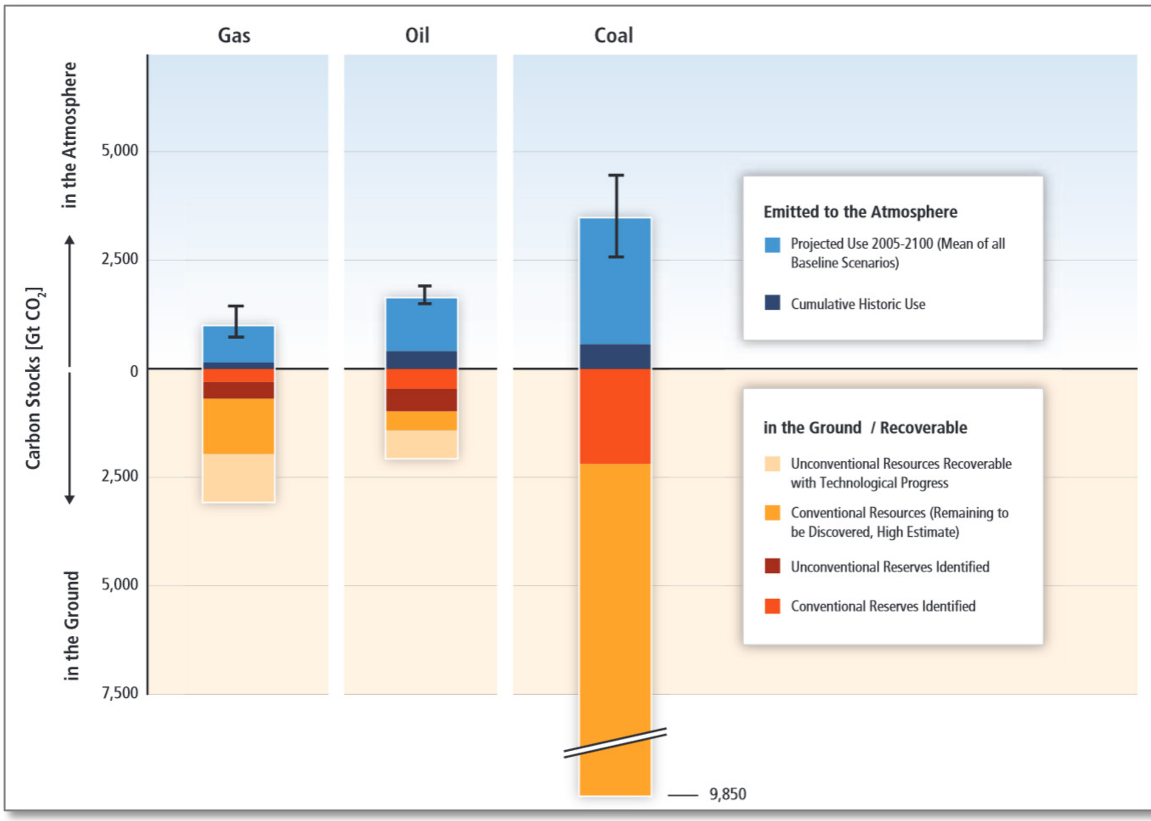

Figure 1: Carbon dioxide emissions already released and embedded in carbon stocks

Burning all fossil fuels (reserves, resources, and previously released emissions) visualized in Figure 1 is estimated to raise global temperatures by 9 degrees Celsius, or 16 degrees Fahrenheit, which far exceeds the allowable emissions for any currently proposed global climate target (Greenstone, 2015; Matthews, Gillett, Stott, & Zickfeld, 2009). Recent studies have evaluated the amount of the world’s coal, oil, and natural gas that can be burnt while meeting global climate targets, also called carbon dioxide budgets

(Caldecott, Tilbury, & Ma, 2013; Carbon Tracker Initiative, 2013). To meet an ambitious two degree Celsius climate target, the International Energy Agency (IEA) estimates that no more than 884 Gt CO_2 can be emitted globally between 2012 and 2050, equivalent to only burning approximately one third of global carbon reserves (International Energy Agency, 2013b). The Carbon Tracker Initiative estimates that only 975 Gt CO_2 can be emitted by 2100 to reach the same goal of two degrees Celsius of warming above average pre-industrial temperatures (consistent with a 450 ppm stabilization scenario) (Carbon Tracker Initiative, 2013). The two-degree goal is admittedly among the most ambitious, but even less stringent targets will require leaving large amounts of coal, oil and natural gas in the ground and unutilized.

Figure 2 compares two estimates of fossil fuel assets to carbon dioxide budgets. Fossil fuel stocks are defined as "recoverable carbon from fossil fuels in the ground," and includes fossil fuels recoverable with technological progress, as well as and those fossil fuels expected to be discovered (see Figure 1) (Intergovernmental Panel on Climate Change, 2011). Proved fossil fuel reserves are defined by BP as "those quantities that geological and engineering information indicates with reasonable certainty can be recovered in the future from known reservoirs under existing economic and operating conditions" (2013). Carbon dioxide budgets for 2°C and 3°C were taken from the Carbon Tracker Initiative, and are assumed to have an 80% probability of not exceeding the temperature threshold (2013).

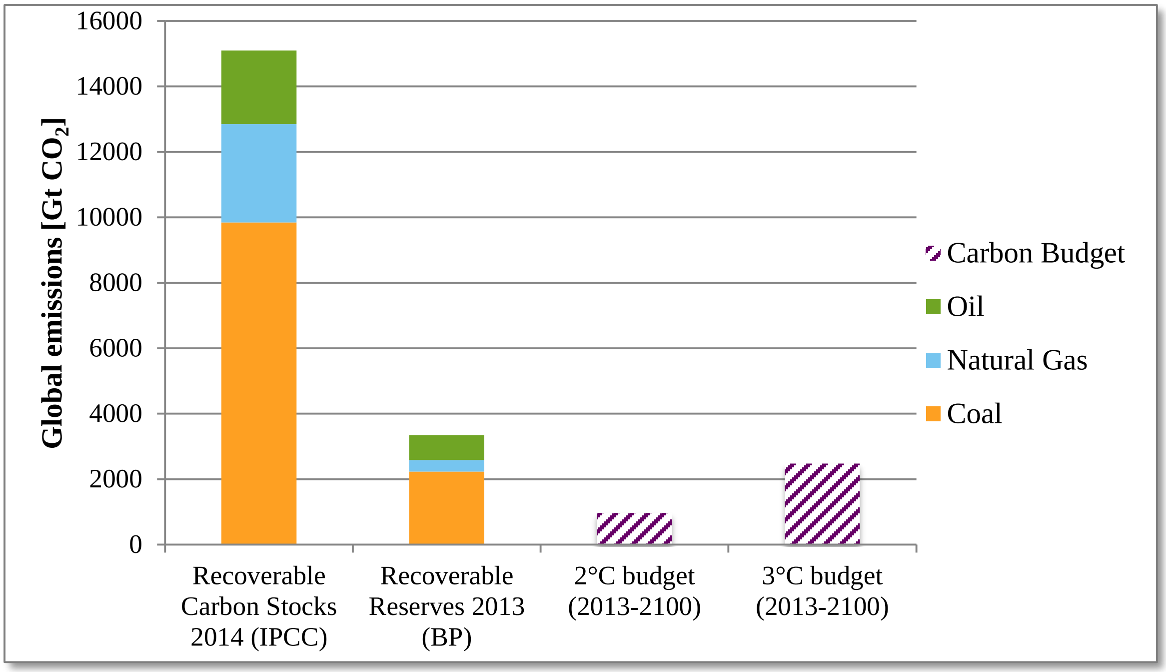

Figure 2: Global carbon stocks and reserves compared to the allowable emissions for a 2- and 3-degree Celsius emissions target

Any reserve surplus greater than a given carbon dioxide budget has been referred to as "stranded" or "unburnable" carbon, because external constraints may render these assets unable to be utilized for energy end uses. As with many buzzwords, stranded assets have been previously analyzed with different objectives in mind. IEA and others focus on the environmental risk of burning more than an environmentally healthy amount of greenhouse gas emissions, as illustrated in Figure 2 (International Energy Agency, 2013b). Groups like the Carbon Tracker Initiative have focused on the economic value of fossil fuel assets and financial risk asset holders will face (Carbon Tracker Initiative, 2013).

1.2 Motivation

There is only one technology that has the ability to utilize potentially stranded fossil fuel assets while mitigating climate change: carbon dioxide capture and storage

(CCS). CCS involves capture (i.e., separation and compression), transportation, and long-term geologic storage of carbon dioxide from large point sources. Despite the potential for CCS to rescue stranded assets, deployment has been slow. While several commercial-scale CCS projects have been implemented in the past two decades, only one was at a power plant. A major barrier to CCS in the power industry is the high capital costs and parasitic load (termed "energy penalty") of CCS compared with conventional fossil fuel-fired generation.

Without policies that effectively limit carbon dioxide emissions to the atmosphere, the added costs of CCS are hard to justify. These policies would put an effective price on carbon dioxide emissions, either directly (e.g., a tax or cap-and-trade system) or indirectly (e.g., emissions standards). Agreements that would require significant CO_2 emissions reductions in the near-term are not being reached on either a national or global level. Where a price is established, as in the European Emissions Trading System, it is much lower than the cost needed to justify CCS. Australia did establish a carbon tax in 2012, but it was repealed in July of 2014 (Taylor & Hoyle, 2014). In the United States, the Environmental Protection Agency has proposed CO_2 emissions standards from new and existing power plants, but these will not incentivize CCS deployment (U.S. Environmental Protection Agency, 2013a, 2014a).

1.3 Objective and approach

The objective of this thesis is to explore how climate policies can help incentivize CCS and whether the specter of stranded fossil assets can help drive CCS deployment.

In order to meet this objective:

Chapter 2 provides a background on CCS technology, projects, and policy, to inform later chapters.

Chapter 3 focuses on the EPA's assessment of CCS as a technology included in the New Source Performance Standards (NSPS) on new coal and natural gas power plants and the Clean Power Plan (CPP) for existing power plants. The NSPS identified CCS as a Best System of Emission Reduction (BSER) for coal-fired plants but not for natural gas-fired plants. The CPP includes CCS less directly. These proposed power plant rules raised two key questions: (1) why was CCS on a coal-fired power plant considered a BSER for the NSPS, but not CCS on a natural gas-fired power plant? And (2) will the NSPS or CPP incentivize CCS?

Chapter 4 provides a bottom-up economic analysis of successful CCS projects. For each of the two selected projects, Boundary Dam and Gorgon, two questions are addressed: (1) what role did stranded assets play? and (2) what can be generalized from the analysis?

In *Chapter 5*, a global view of stranded assets is taken by comparing global energy-economic models that participated in the AMPERE collaborative modeling project. All of these models were run to meet specific climate targets with scenarios that both included and excluded CCS. Models and scenarios are compared to answer three questions: (1) what is the quantity of stranded coal, oil, and natural gas assets under stringent climate targets? (2) what is the value of these assets? and (3) what potential is there for CCS to rescue stranded assets?

In *Chapter 6* and *Chapter 7* the policy implications and conclusions, respectively, are discussed.

Chapter 2: Current state of affairs for CCS

This section serves as a brief overview of the state of CCS technology, projects, and the policies that incentivize climate action and CCS deployment.

Carbon dioxide capture from industrial processes for commercial operations is over 90 years old. However, the idea of using this technology to capture and store the CO_2 started in the 1980s when awareness of climate change started to become prominent (Intergovernmental Panel on Climate Change, 2005).

The first large-scale demonstration of CCS was Statoil's Sleipner Project, which captured CO_2 from natural gas processing operations. It began operation in 1996 off the coast of Norway. Since then there has been a move from relatively low cost CCS installations on fuel processing and industrial operations to more expensive ones on power plants. While many small demonstration and pilot projects have operated on power plants, it wasn't until 18 years after Sleipner that the first commercial CCS power plant began operation at SaskPower's Boundary Dam plant in Saskatchewan, Canada.

2.1 CCS technology

CO_2 capture

CO_2 capture processes on power plants or industrial processes are characterized as post-combustion, pre-combustion, or oxy-combustion.

Post-combustion is the most proven of capture technologies on power plants and was recently implemented on the first utility scale power plant at Boundary Dam (Ball, 2014; Massachusetts Institute of Technology, 2015; SaskPower, 2012). The post-combustion process captures CO_2 from the flue gases of fossil fuel combustion. Chemical absorption techniques utilizing amines, most notably monoethanolamine (MEA), are the most common and commercialized (Massachusetts Institute of Technology, 2007).

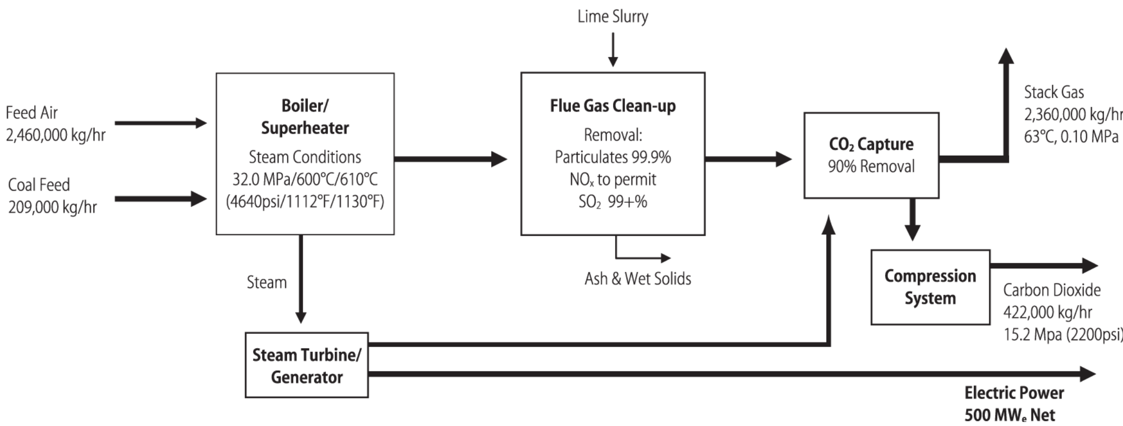

Figure 3: An ultra-supercritical pulverized coal unit with post-combustion CO_2 capture, reproduced from MIT's Future of Coal study

Pre-combustion capture at power plants is associated with integrated gasification combined cycle (IGCC) systems, which utilize a gasifier to produce a synthesis gas (syngas). The CO_2 is captured from the syngas before it is combusted in a gas turbine. The relatively high CO_2 concentration and pressure in the syngas allows for less expensive capture than post-combustion. However, because IGCC power plants are more expensive than conventional coal plants, it is unclear whether the total costs are higher or lower than the post-combustion process (Massachusetts Institute of Technology, 2007).

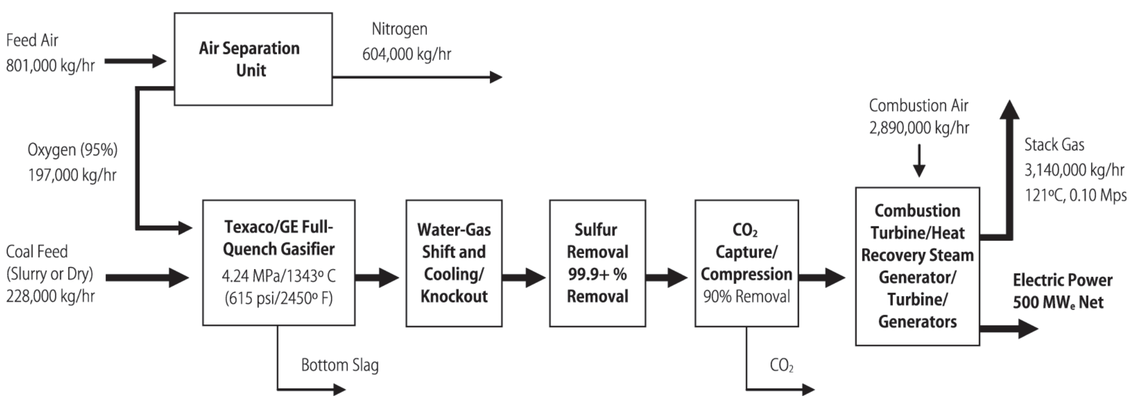

Figure 4: An IGCC unit with pre-combustion CO_2 capture, reproduced from MIT's Future of Coal study

Oxygen-blown, or *oxy-combustion,* involves burning feedstock fuel in almost pure oxygen rather than regular air, producing a flue gas consisting mainly of CO_2 and water vapor. While this greatly simplifies the flue gas clean up, it does require an air separation unit (ASU) to generate the oxygen. Oxy-combustion capture allows for higher boiler efficiencies than traditional post-combustion capture but has an additional energy penalty from the ASU, as shown in Figure 5 (Massachusetts Institute of Technology, 2007). Initial cost estimates for oxy-combustion capture show comparable overnight capital costs and levelized costs of electricity to post-combustion capture systems (International Energy Agency, 2013b).

Figure 5: A supercritical pulverized coal power plant with oxy-combustion CO_2 capture, reproduced from MIT's Future of Coal study

The technology needed for *carbon capture from industrial processes* depends on the specific industry. Industrial applications that are appropriate for CCS include natural gas sweetening, iron and steel production, cement production, and ammonia production. Natural gas sweetening reduces CO_2 in natural gas to about 2% by volume before pipeline transportation and can utilize chemical or physical solvents or membranes, with MEA being the most common. The iron and steel industry has the ability to capture CO_2 from blast furnace gas using oxy-combustion and pre-combustion capture from direct reduction of iron. Cement plants produce high concentrations of CO_2 in flue gas, making post-combustion and oxy-combustion capture promising technologies. Ammonia production removes CO_2 from a syngas prior to ammonia synthesis, which is very similar to pre-combustion capture in a power plant (Intergovernmental Panel on Climate Change, 2005).

Storage

Decades of research and geologic study have found promising possibilities for successful injection of CO_2 for permanent storage in spent oil and gas wells, saline formations, and coal seams. Studies evaluating the global CO_2 storage capacity vary widely, with potential of at least 675 Gt CO_2 storage from oil and gas wells, 1000 Gt CO_2 storage from saline formations, and 3 Gt CO_2 from coal seams being conservatively estimated, with other sources reporting potentials that are a couple orders of magnitude higher (Intergovernmental Panel on Climate Change, 2005). Enhanced oil recovery (EOR) is the most promising form of storage in the near term, happening in active oil fields, due to the opportunity for additional revenue from the sale of CO_2. As of 2015, 10 projects are currently injecting anthropogenic CO_2 for EOR storage, some operating since the 1970s and 80s, and located in the US, Canada, and Brazil (Global CCS Institute, 2014a).

In the longer term, projects will need to move to more geologic storage. Large potential exists for CO_2 storage, but concerns remain related to the amount of viable EOR potential, financial viability of non-EOR storage to overall project costs, safety of long-term storage, and public acceptance. Though storage of CO_2 presents potential barriers to deployment, this thesis focuses on financial incentives and barriers for carbon capture.

2.2 Projects operating with CCS

This section divides large-scale CCS projects (>$100 million) into two categories: those projects that have received little to no government financial support, and those projects that are receiving some substantial amount of government money.

There are six projects that are either completed or under construction that were built with limited government support. Of these, five were on industrial processes and one is at a power plant, highlighted further in Table 1.

Table 1: Key characteristics of independently financed CCS projects[1]

Name	CO_2 Source	Started operation	Project Driver
Weyburn	Synfuels plant	2000	EOR revenue
Schwarze Pumpe	PC power plant	2008	Private investment from Vattenfall for RD&D
Sleipner	Natural gas processing	1996	Norwegian CO_2 tax
In Salah		2004	Private investment from BP for RD&D
Snøvit		2008	Norwegian CO_2 tax
Gorgon		2015 (expected)	High NG price in Asia, voluntary inclusion

Of government-supported projects, seven are at power plants (one operating, two under construction, four in planning) and five are at industrial facilities (three operating, two under construction) and are shown in Table 2.

[1] More information on all projects listed here can be found on the MIT project database (Massachusetts Institute of Technology, 2015)

Table 2: Key characteristics of major government-supported CCS projects[2]

Name	CO_2 Source	Started operation	Type of government support	Other support
Air Products, US	Methane reformers	2013	- $284 million in DOE ICCS program funding	EOR revenue
Quest, Canada		2015 (expected)	- C$120 Canada Clean Energy Fund - C$745 Alberta provincial subsidy	Possible EOR revenue
ADM, US	Ethanol processing	2015	- $67 million DOE subsidy for injection tests - $141 million in DOE ICCS program funding	
Mongstad, Norway	Refinery	2012	- $462 million in Norwegian government CCS support	
Alberta Trunk Line, Canada	Refinery and fertilizer	2015 (expected)	- C$30 million Canada Clean Energy Fund - C$33 million Canada ecoENERGY Technology Initiative - C$495 million Alberta provincial subsidy	EOR revenue
Boundary Dam, Canada	PC power plant	2014	- C$240 million in Canadian federal subsidy	EOR, sulfuric acid, and fly ash revenue
Petra Nova, US		2016 (expected)	- $154 million in DOE CCPI funding	EOR revenue
White Rose, UK		2019 (expected)	- Up to £1 billion from CCS Commercialisation Programme - €300 Million from NER300	
Kemper, US	IGCC power plant	2016 (expected)	- $270 million federal cost-share grant from CCPI funding - $133 million in investment tax credits	EOR revenue
Texas Clean Energy Project, US		2019 (expected)	- $450 million in DOE CCPI funding	EOR revenue
Hydrogen Energy CA, US		2019 (expected)	- $30 million in CA PUC funding - $408 Million in DOE CCPI funding - $104 million in investment tax credits	EOR revenue
Peterhead, UK	NGCC power plant	2019 (expected)	- Up to £1 billion from CCS Commercialisation Programme	

[2] More information on all projects listed here can be found on the GCCSI and MIT project databases (Global CCS Institute, 2014a; Massachusetts Institute of Technology, 2015)

Over the past few years, there has been a reduction in the number of CCS projects under development. The Global CCS Institute (GCCSI) actively tracks projects at all stages of development and investment, from project identification to the full-scale operation. GCCSI annual reports show a net loss of 10 projects between 2013 and 2014, and an additional loss of 10 projects the year before, amounting to a loss of 27% in the last two years across all stages of development (Global CCS Institute, 2013, 2014c).

2.3 Assessment of current policies for CCS

Considering the increasing push for climate mitigation technologies and the extent to which CCS has been demonstrated, one would expect to see more utility-scale CCS projects. Like many other low-carbon technologies, CCS shares in political barriers and high capital costs. Unlike other low-carbon technologies, CCS needs a policy driver because it will always be cheaper to emit CO_2 from power plants and industrial operations and CCS has no benefits other than CO_2 reduction. Both comprehensive climate policy and CCS-specific mechanisms can drive CCS deployment, but implementation of both kinds of policies has varied in regional implementation.

2.3.1 US: EPA Clean Air Act rules

Comprehensive climate policy:

Legislative approaches to comprehensive climate change policy have been widely shot down in the United States, so it took a Supreme Court case in 2007 to get the US to start regulating GHGs at a national level (U.S., 2007). The relevant outcomes for CCS are the two recently proposed rules on new and existing power plants. The new power plant rule, NSPS, sets technology-specific standards for coal and natural gas power plants. For coal-fired plants only, it recommends partial CCS capture as a best system of emission reduction (BSER) to meet an emissions limit of 1100 lb CO_2/MWh (U.S. Environmental Protection Agency, 2013a). The existing power plant rule, CPP, lets individual states determine the best way to achieve long term rate-based goals, but says that CCS is not considered a BSER for existing systems (U.S. Environmental Protection Agency, 2014b).

CCS-specific mechanisms:

In addition to climate policy, CCS-specific mechanisms have incentivized deployment, such as $3.4 billion in federal stimulus money from the American Recovery and Reinvestment Act (ARRA) (Wald, 2009). Stimulus money was a significant driver for Petra Nova, TCEP, and HECA projects included in Table 2 through the Clean Coal Power Initiative (CCPI). The Industrial Carbon Capture and Sequestration program (ICCS) was funded by ARRA and supported the Air Products and ADM projects.

Two additional mechanisms for CCS were proposed in President Obama's 2016 budget. First, refundable investment tax credits of up to $2 billion will be available to new and retrofitted power plants with CCS. The second mechanism focuses on carbon sequestration – a tax credit of $10/tonne stored CO_2 through EOR and $50/tonne for all other geologic storage (US Office of Management and Budget, 2015).

2.3.2 Canada: EPA technology requirements

Comprehensive climate policy:

The Canadian government revised their Environmental Protection Act in 2012 to include an emissions limit for coal power plants similar to the US EPA rule for new power plants. The rule sets a limit of 420 tonne CO_2/GWh (approximately 940 lb/MWh), for all new coal power plants and units greater than 40 years old (Canadian Ministry of Environment, 2012).

CCS-specific mechanisms:

Much like the US, federal and provincial subsidies are incentivizing deployment of CCS, such as for the Quest, Alberta Truck Line, and Boundary Dam projects.

2.3.3 UK

Comprehensive climate policy:

The UK has an informal carbon tax, called the climate change levy, which is a tax on non-domestic energy used in industry, commerce, agriculture, and public services. The larger incentive to CCS is the contract for differences, which provides protection against variable electricity prices for renewable, nuclear, and CCS-equipped electricity generation, thereby lowering investment risk (Canadian Department of Energy & Climate Change, 2013, 2014).

CCS-specific mechanisms:

A major driver of CCS deployment is a technology-specific mechanism, the CCS Commercialisation competition, which accepts project bids and awards up to £1 billion total in capital funding. The White Rose and Peterhead projects are moving forward in the UK after the second round of funding (U.K. Department of Energy & Climate Change, 2013). White Rose has also received additional backing from EU financial mechanisms.

2.3.4 EU

Comprehensive climate policy:

In Europe, the comprehensive climate policy is the Emissions Trading Scheme (ETS), but a recessed economy and excessive allowances have dropped the carbon price to be about €7/tonne in early 2015, far lower than what would be necessary to incentivize CCS (Neslen, 2015).

CCS-specific mechanisms:

The New Entrants Reserve of the EU Emissions Trading System (NER300) included allowances for commercial-scale CCS projects in addition to renewable demonstration projects. This 2009 program sought to be a financial mechanism for "full chain" (i.e. capture, transport, and storage) projects of at least 250 MW of power generation or 500 kt/y storage for industrial applications. However, no projects were funded in the first round due to a combination of insufficient funding, a lack of flexibility in terms, shifting political circumstances, and a low ETS carbon price (Lupion & Herzog, 2013).

2.3.5 Australia

Comprehensive climate policy:

Australia enacted a carbon tax in 2012, but political pressures led to its repeal in the summer of 2014 (Taylor & Hoyle, 2014). There has been no indication that the carbon tax in Australia encouraged CCS deployment during that time.

CCS-specific mechanisms:

No CCS-specific mechanisms are currently in place in Australia.

Chapter 3: Assessment of EPA's new power plant performance standards

3.1 Background

3.1.1 EPA and GHGs in United States courts

There has long been a consensus in the scientific community on the reality of human-caused climate change linked to emissions of greenhouse gases (GHGs) including carbon dioxide (CO_2), methane, and nitrous oxide (IPCC 2013). After decades of political debates, only recently has the United States government started to create regulation in response. The turning point was *Massachusetts vs. EPA* in 2007, where the US Supreme Court ruled in favor of a group of concerned states petitioning against the EPA to regulate GHGs, specifically related to transportation emissions. At the core of the legal debate was the issue of whether greenhouse gases can be considered "air pollutants" under the definitions of the Clean Air Act (CAA).

The Supreme Court held that GHGs are air pollutants and therefore the EPA must scientifically determine whether these gases "cause, or contribute to, air pollution which may reasonably be anticipated to endanger public health or welfare," and if so, "the Clean Air Act requires the agency to regulate emissions of the deleterious pollutant from new motor vehicles," (U.S., 2007).

In 2009, the EPA announced what has become known as the endangerment finding that six greenhouse gases: carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride "taken in combination endanger both the public health and the public welfare of current and future," (U.S. Environmental Protection Agency, 2009). This finding set in motion the necessity for

GHG emissions standards for light-duty vehicles in 2010 and heavy-duty vehicles in 2011, collectively referred to as the tailpipe rule (U.S. Environmental Protection Agency, 2010a, 2011).

In 2010, the EPA also released the tailoring rule, which set GHG thresholds for regulation of new and existing industrial facilities (U.S. Environmental Protection Agency, 2010b). In the same year, the EPA confirmed it would treat any new pollutants the same way it has treated currently identified GHGs (U.S. Environmental Protection Agency, 2010c). In 2014, the US Supreme Court held that only industrial plants that emit conventional pollutants may be required by the EPA to adopt GHG regulation and industrial sources that only emit GHGs would not trigger the same permit requirements (Coleman, 2014; U.S., 2014).

The regulation of transport and industrial sectors targeted the "low-hanging fruit," especially from the automotive industry where improving fuel economy of cars and trucks would increase sales in a time of high gasoline prices (McCarthy, 2013). Reducing emissions from power plants will have greater tradeoffs to industries and consumers. Perhaps for this reason, the EPA did not voluntarily introduce performance standards for GHGs from electric generating units (EGUs); it took two lawsuits against the EPA in 2010 to push the EPA to agree to propose a new source performance standard (NSPS) for power plants by mid-2011 (and finalize by mid-2012) and similarly propose a NSPS for petroleum refineries by late-2011 (and finalize by late-2012). The NSPS for new fossil-fuel-fired EGUs was proposed in April of 2012 (later than anticipated), and due to a high volume of comments on the public record was not finalized as scheduled. A NSPS for oil refineries has yet to be proposed (Meltz, 2014).

3.1.2 Presidential memorandum

In June of 2013, Barack Obama signed a presidential memorandum that directed the EPA to consider the 2.5 million comments received and to revise and re-propose the NSPS by September of 2013. The memorandum directed the EPA to additionally propose carbon pollution standards for modified, reconstructed, and existing power plants under CAA 111(b) and 111(d) by June 1, 2014 and to finalize both rules by June 1, 2015 (Meltz, 2014; White House, 2013). Both rules were proposed by the deadline, and time will tell if the rules will be finalized by the summer of 2015.

3.1.3 NSPS and CPP

On September 20, 2013, the US Environmental Protection Agency (EPA) updated its proposed rule for "Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units," replacing the original released on April 13, 2012 (Office of the Federal Register, 2014; U.S. Environmental Protection Agency, 2013a). These performance standards set limits on the amount of CO_2 that can be emitted per megawatt-hour (MWh) of gross electricity generated from new coal-fired and natural gas-fired (also referred to as gas-fired) power plants built in the US. The rules governing CO_2 emissions from existing power plants, known as the Clean Power Plan (CPP) were released June 2, 2014 and both rules (for existing and new builds) are scheduled to be finalized by June 1, 2015 (U.S. Environmental Protection Agency, 2014a; White House, 2013).

3.2 New source performance standards

3.2.1 Introduction

The CO_2 limits for the New Source Performance Standards (NSPS) were based on determinations of the "best system of emission reduction (BSER) … adequately demonstrated," (U.S. Environmental Protection Agency, 2013a). Considerations for a BSER include feasibility, cost, size of emission reductions and future technology development (U.S. Environmental Protection Agency, 2013a). The proposed rule includes analysis by the EPA that finds partial carbon capture and storage is the BSER for coal-fired power plants, while the BSER for natural gas-fired power plants is high efficiency without CCS.

The proposed rule would require CCS for new coal-fired power plants in order to achieve a standard of 1100 lb CO_2/MWh, requiring about 40% capture of CO_2 from a conventional supercritical pulverized coal plant.(U.S. Environmental Protection Agency, 2013a) The standard for new natural gas power plants of 1000 lb CO_2/MWh can be reached with commercial high efficiency natural gas systems without CCS (U.S. Environmental Protection Agency, 2013a).

Specifically, coal power plants have the option of meeting an 1100 lb CO_2/MWh standard on a 12-operating-month rolling average or a lower standard of between 1000 and 1050 lb CO_2/MWh on an 84-operating-month rolling average (U.S. Environmental Protection Agency, 2013a). Note that the emissions standard of 1100 lb CO_2/MWh is low enough to exclude the possibility of co-firing with natural gas to meet the standard (U.S. Environmental Protection Agency, 2013a). Large natural gas power plants (>250 MW_{th}) must meet a standard of 1000 lb CO_2/MWh and smaller natural gas power plants (73-250

MW_{th}) must meet a standard of 1100 lb CO_2/MWh both on a 12-operating-month rolling average (U.S. Environmental Protection Agency, 2013a).

This section assesses the EPA's analysis that resulted in determining CCS as the BSER on coal-fired power plants but not on gas-fired plants. The goal of this assessment is to understand whether there is justification in mandating CCS for new coal plants, but not for new natural gas plants. Note that the absolute criteria for CCS as a BSER are not being judged, only the relative differences as related to coal vs. gas. Therefore, since storage issues are essentially the same for both, this section focuses on an assessment how carbon capture was treated within this rule. Five critical areas have been identified that led to the EPA's determination: demonstration, technology, costs, power plant cycling, and future technological development. The following sections examine each of these issues.

3.2.2 Demonstration

3.2.2.1 Coal-fired power plants

The EPA found that CCS is feasible for coal "because each step in the process has been demonstrated to be feasible through an extensive literature record, fossil fuel-fired industrial plants currently in commercial operation and pilot-scale fossil fuel-fired EGUs currently in operation, and the progress towards completion of construction of fossil fuel-fired EGUs implementing CCS at commercial scale," (U.S. Environmental Protection Agency, 2013a).

In the Executive Summary, the EPA rule highlights four installations that they believe demonstrate the feasibility of CCS on coal power systems (U.S. Environmental Protection Agency, 2013a). Note that in the main body of the report, they do mention additional plants, including Shady Point and Warrior Run (see Table 3). The four plants highlighted are:

1. The Kemper County Energy Facility in Mississippi is an integrated coal gasification combined cycle (IGCC) system under construction.
2. The Texas Clean Energy Project (TCEP) is an IGCC system under development by the Summit Power Group in Odessa, Texas.
3. The Hydrogen Energy California (HECA) project is an IGCC system under development in Kern County, California.
4. The Boundary Dam Project in Saskatchewan, Canada is a retrofit of a current pulverized coal (PC) unit and started operation in October, 2014

Three of the four power plants highlighted by the EPA are IGCC power plants and the fourth is a PC unit. Due to their high capital costs, there are only a handful of IGCC units operating today. MIT's *Future of Coal* study states that though more efficient and easier to adapt for CO_2 capture than conventional PC units, "the projected capital cost … and operational availability of today's IGCC technology make it difficult to compete with conventional PC units at this time," (Massachusetts Institute of Technology, 2007). As more information is gained from development of IGCC projects, capital cost estimates are only increasing. The U.S. Energy Information Administration (EIA) published 2013 estimates of overnight capital costs of IGCC units at $3700-$4400/kW, a 19% increase from 2010 estimates and significantly higher than PC units with costs of $2900-$3200/kW (U.S. Energy Information Administration, 2013e).

Kemper, HECA and TCEP are all unique installations. The Southern Company Kemper County IGCC power plant plans to start operating in 2016 using Mississippi lignite coal and will inject the CO_2 for enhanced oil recovery. It uses a first-of-a-kind gasification technology, TRIG. Southern Company objected to its use as an example for the rest of the country in a public statement after the EPA proposal, saying, “Because the unique characteristics that make the project the right choice for Mississippi cannot be consistently replicated on a national level, the Kemper County Energy Facility should not serve as a primary basis for new emissions standards impacting all new coal-fired power plants,” (Hallerman, 2013). Furthermore, both the HECA and TCEP projects are not pure power plants, but also produce chemicals. As with Kemper, they would be hard to replicate on a national level.

In summary, IGCC is currently too expensive to be a viable alternative to PC power plants. The instances where IGCC plants are being pursued are very unique circumstances and should not be generalized. Therefore, relevant demonstrations of CCS on coal-fired power plants for the purposes of these new source performance standards should be confined to PC technology. Table 3 shows the relevant assessment of demonstrated pulverized coal units with CCS (Massachusetts Institute of Technology, 2015). Only installations on the scale of approximately 50,000 t CO_2 captured per year and larger are included because they can be considered either demonstration or commercial units. Smaller units are used primarily for research purposes. All installations continue to operate today with the exception of the Mountaineer installation, managed by AEP, that is no longer operating due to lack of clear climate policy in the US incentivizing further investment.

Table 3: Relevant projects demonstrating CCS at coal-fired power plants

Plant name	Location	Capture start date	Capture end date	Annual CO_2 captured (tonnes)	Power plant technology
Shady Point	OK, USA	1991	-	76,000	PC
Warrior Run	MD, USA	2000	-	48,000	PC
Mountaineer	WV, USA	2009	2010	50,000	PC
Plant Barry	AL, USA	2011	-	150,000	PC
Boundary Dam	Canada	2014	-	1,000,000	PC

3.2.2.2 Natural gas-fired power plants

The EPA states that "CCS has not been implemented for NGCC units and we believe there is insufficient information to make a determination regarding the technical feasibility of implementing CCS at these types of units," and that they are "not aware of any demonstrations of NGCC units implementing CCS technology that would justify setting a national standard," (U.S. Environmental Protection Agency, 2013a).

When talking about carbon capture on natural gas power plants, two technologies are considered here: natural gas boilers and natural gas combustion turbines. Though CCS has been demonstrated on many natural gas boilers on a scale of hundreds of tons of CO_2 per day, exhaust gases of combustion turbines provide a more appropriate focus because combustion turbines will be the primary technology used in future base load natural gas-fired power plants. Turbines can be categorized as simple cycle (NGCT) or combined cycle (NGCC) systems. The exhaust gases from NGCT and NGCC have essentially the same composition, so the same CO_2 capture plant can handle either exhaust. Therefore both single-cycle and combined-cycle systems are considered as relevant technologies for demonstration of CCS on natural gas power plants. Table 4 summarizes the relevant assessment of carbon capture on natural gas combustion turbine power plants (Massachusetts Institute of Technology, 2015). The Bellingham operation was halted after an increase in natural gas prices and a need for the power plant to operate as a peak load power plant instead of a base load power plant, but successfully demonstrated the technology during its tenure (Fluor, 2013).

Table 4: Relevant projects demonstrating CCS at natural gas-fired power plants

Plant name	Location	Capture start date	Capture end date	Annual CO_2 captured (tonnes)	Power plant technology
Bellingham	MA, USA	1991	2005	111,000	NGCC
Mongstad	Norway	2012	-	100,000	NGCT
Peterhead	UK	2019 (expected)	-	1,000,000	NGCC

3.2.2.3 Summary

Figure 6 summarizes the assessment of where CCS has been demonstrated on power plants using pulverized boilers or natural gas turbines and producing approximately 50,000 t CO_2 per year or more. On the 100,000 ton per year scale, CCS has been demonstrated equally well on both coal-fired and natural gas-fired power plants. On the million ton per year scale, there is one coal unit that began operation in 2014 and a gas unit projected to go on-line in 2019. It is therefore hard to understand the distinction being made in the proposed rule as to the technological readiness of coal-fired vs. natural gas-fired CO_2 capture.

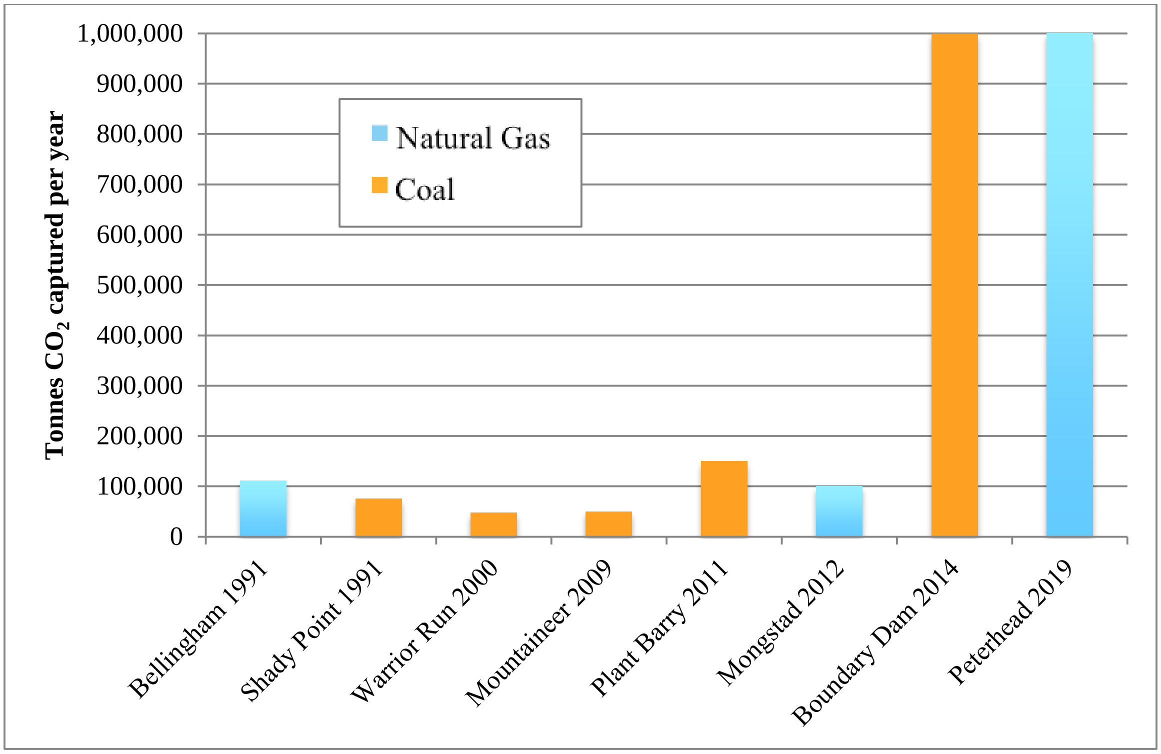

Figure 6: Relevant CCS power plant project by year it became operational and amount of CO_2 captured

3.2.3 Technology

On applying CCS technology to exhaust gases from NGCC units compared to PC units, the proposed rule states that "the EPA does not have sufficient information on the prospects of transferring the coal-based experience with CCS to NGCC units. …The concentration of CO_2 in the flue gas stream of a coal combustion unit is normally about four times higher than the concentration of CO_2 in a natural gas-fired unit," (U.S. Environmental Protection Agency, 2013a). Two issues need to be raised related to this statement:

1. While CO_2 concentrations in the flue gas are important in determining feasibility and costs, other characteristics of the flue gas are also important in making these determinations (Intergovernmental Panel on Climate Change, 2005).

2. Historically, CO_2 capture technology has been applied first to exhausts from gas-fired units and then transferred to coal-fired units, not the other way around as implied by the EPA (Rochelle, 2009).

There are multiple characteristics that need to be considered when applying CO_2 capture to a flue gas. As raised by the EPA rule, the concentration of CO_2 in the flue gas is important. In general, the lower the concentration of CO_2, the more costly it will be to remove from the flue gas. However, other important considerations are:

1. Oxygen (O_2) in the flue gas can lead to corrosion and solvent degradation, which is usually controlled by adding inhibitors to the solvent.
2. Sulfur Oxides (SO_X) in the exhaust gas will react with the solvent to form heat-stable salts. To reclaim the solvent, additional equipment and energy use is required.
3. Particulates will lead to foaming of the solvent, making the process inoperative. To prevent this, adequate cleanup prior to the CCS unit is required, as well as adequate filtration of the solvent in the CCS unit.

In comparing flue gas from NGCC and PC units, NGCC has lower CO_2 concentrations and higher O_2 concentrations, but essentially no SO_X or particulates. Historically, as is shown below, CCS technology has first been used for gas-fired exhausts and then adapted to coal-fired exhausts. This implies that coal-fired exhausts pose more feasibility problems for CCS than do those from gas-fired plants.

Fluor highlighted three reasons that their technology was "notable" in the Bellingham, MA NGCC installation: 1) that the CO_2 concentration in the flue gas was low (2.8-3.1%), 2) that the oxygen concentration was high (13% by volume), and 3) that constant pressure of the flue gas must be maintained (Reddy, Scherffius, & Freguia, 2003). The operation of the plant for about 15 years showed that these challenges could be adequately addressed.

Aker Solutions (previously known as Aker Clean Carbon), the developer of the CCS technology used at Mongstad, stated that the company "considers its technology qualified for full-scale application" on gas turbine exhausts (Anheden, 2013).

As with Fluor and Aker, MHI developed their solvent originally for gas-fired exhausts and now are working to transfer that technology to coal-fired exhausts (Sander & Mariz, 1992; Strazisar, Anderson, & White, 2001). MHI released a statement before the start of the pilot project at the Plant Barry coal-fired power plant in 2009, saying that though "the technology to recover and compress CO_2 from natural gas-fired flue gas has already been applied commercially, the planned development and demonstration testing of the plant in the application of CO_2 recovery from flue gas of a coal-fired generation plant, which contains more impurities, will be on a scale unprecedented anywhere in the world," (Mitsubishi Heavy Industries, 2009).

In summary, the demonstration and performance of CCS systems confirm that there are no technological barriers that make scaling up carbon capture technology on natural gas combustion turbine systems any less feasible than on coal systems. Both systems must deal with a set of technological challenges that have been addressed by technology manufacturers through years of pilot and demonstration projects.

3.2.4 Costs

The EPA uses a cost criterion based on cost of electricity (COE), concluding that new technologies should fit within the range of other current electric generating technologies. "Based on data from the EIA and the DOE National Energy and Technology Laboratory (NETL), the EPA believes that the levelized cost of technologies other than coal with CCS and NGCC range from $80/MWh to $130/MWh," (U.S. Environmental Protection Agency, 2013a). The EPA finds full capture (about 90%) of CO_2 on supercritical pulverized coal systems to have a cost of $147/MWh, which is "outside the range of costs that companies are considering for comparable generation and therefore should not be considered BSER for CO_2 emissions for coal-fired power plants," (U.S. Environmental Protection Agency, 2013a). Partial capture of CO_2 (about 40% for supercritical PC), according to the EPA, has costs "ranging from $92/MWh to $110/MWh, depending upon assumptions about technology choices and the amount, if any, of revenue from sale of CO_2 for EOR [Enhanced Oil Recovery]," (U.S. Environmental Protection Agency, 2013a). The EPA argument is that because partial CCS on coal is within the range and full CCS is outside the range, it follows that partial CCS can be considered as the BSER because its "implementation costs are reasonable," (U.S. Environmental Protection Agency, 2013a).

This argument leaves two key questions unanswered. The first is that natural gas with full capture of CO_2 would be within this range, so why is CCS not considered the BSER for natural gas systems (U.S. Department of Energy, 2013)? The EPA indirectly responds to this issue by arguing that most future power plants will be NGCC and therefore any additional technology requirement on such a large part of the grid would increase electricity prices to the consumer. The EPA states that "identifying partial or full CCS as the BSER for new stationary combustion turbines would have significant adverse effects on national electricity prices, electricity supply, and the structure of the power sector. Because virtually all new fossil fuel-fired power is projected to use NGCC technology, requiring CCS would have more of an impact on the price of electricity than the few projected coal plants with CCS and the number of projects would make it difficult to implement in the short term," (U.S. Environmental Protection Agency, 2013a). The EPA argues that no plans currently exist to construct large coal power plants in the US, and therefore no impact will be seen on electricity rates. This seems to be a different criterion than above, mainly that little or no impact on electricity costs should be associated with requiring new emissions control technologies. In the early 2000s when gas prices were high, it was anticipated that a significant number of new coal-fired power plants would be built. This may be the case again in the future. If that happens, then this regulation would have significant adverse effects on national electricity prices.

Second, why does the EPA not utilize cost-benefit analysis and consider the social cost of carbon? To do a cost-benefit analysis, the conventional approach would be to look at cost per metric ton of CO_2 avoided, a calculation that takes into account both the cost of a technology and the environmental benefit from emissions reductions. The Department of Energy (DOE) reports avoided costs (in 2007$) of $69/t CO_2 for supercritical PC power plants with full CCS and $84/t CO_2 for NGCC power plants with full CCS (U.S. Department of Energy, 2013). (Note that in terms of $/t CO_2 avoided, costs for partial capture will be higher than full capture (Hildebrand, 2009).) The avoided costs are inclusive of capture, transport, and storage. The no capture reference plant from which the emissions are avoided is taken to be the same technology as the capture plant (i.e., supercritical PC for coal, NGCC for gas).

Following the line of argument that \$/t CO_2 avoided is the correct metric, then the above numbers should be compared to the U.S. government's social cost of carbon. The social cost of carbon (SCC) is a financial estimate of damages (environmental, human, economic, etc.) caused by each metric ton of CO_2 emitted to the atmosphere (Interagency Working Group on Social Cost of Carbon, 2010). In an effort to include the inherent uncertainty in this kind of estimate, the SCC analysis includes an average of three different integrated assessment models at three distinct discount rates in addition to a 95th percentile at the median discount rate. The 2013 update of the original 2010 SCC analysis (in 2007\$) finds a range from \$11-\$90/t CO_2 avoided (Interagency Working Group on Social Cost of Carbon, 2013). Though the EPA has a potential range of SCC targets to choose from, recent regulation has used a social cost of carbon of about \$30/t CO_2 and the mean value for a 3% discount rate in the 2013 analysis is \$33/t CO_2 in 2010 and \$43/t CO_2 in 2020 (Interagency Working Group on Social Cost of Carbon, 2013). It can be seen that the social cost of carbon is much lower than DOE's estimate of avoided cost, indicating that neither coal- nor natural gas-fired systems with CCS are cost-effective when current SCC estimates are considered.

Though the EPA does not use a cost-benefit analysis as a criterion for determining the BSER, the Regulatory Impact Analysis (RIA) quantifies the monetized benefits for each BSER using the social cost of carbon. The EPA calculates the difference in costs and monetized emissions benefits between a coal CCS technology and the same coal technology without CCS. For pulverized coal without enhanced oil recovery (EOR), the EPA finds a net benefit in 2020 (in 2011\$) of -\$21 to \$16/MWh for partial CCS and -\$44 to \$59/MWh for full capture (varying based on discount rate), relative to a supercritical pulverized coal plant without CCS (U.S. Environmental Protection Agency, 2013b). The range of net benefits given by the EPA showcases the possibility for a positive cost (i.e. negative net benefit) compared to a baseline technology even when incorporating the EPA's social cost of carbon.

In summary, the methods the EPA used to determine whether the implementation costs are reasonable are arbitrary for three reasons:

1. Using the electricity cost metric, natural gas contains less carbon per unit of heating value than coal and therefore the impact on the electricity cost is less for gas than coal. However, even though both coal and natural gas have CCS options in the $80-130/MWh range given by the EPA, this range was only used as a metric for coal with CCS.
2. Using the cost metric of how electricity prices are impacted, gas-fired power with CCS was deemed too expensive. However, coal-fired power plants were deemed affordable primarily because the United States is not planning to build any new ones at this time. Focusing on regulating power plants that will not be built does not seem productive.
3. Using the mitigation cost metric of $/t CO_2 avoided (arguably the proper metric), the costs are about 20-30% greater to apply CCS to gas-fired power plants than coal-fired power plants due to the lower concentration of CO_2 in their respective flue gases, but both are well above the current SCC of $33/t CO_2. However, this metric was not used to determine the BSER, it was only used for the Regulatory Impact Analysis.

3.2.5 Cycling

The EPA states that the addition of "CCS to a NGCC may limit the operating flexibility in particular during the frequent start-ups/shut-downs and the rapid load change requirements. This cyclical operation, combined with the already low concentration of CO_2 in the flue gas stream, means that one cannot assume that the technology can be easily transferred to NGCC without larger scale demonstration projects on units operating more like a typical NGCC. This would be true for both partial and full capture," (U.S. Environmental Protection Agency, 2013a).

Not all natural gas power plants are created equal. Due to their ability to operate flexibly, natural gas-fired power plants can be used to meet peak and intermediate electricity demand loads, but many others are designed to meet more steady base load demands. Base load natural gas-fired systems cycle much less than their peaking counterparts, and this is the category of power plant being evaluated here. After a power plant is built, economic dispatch determines how much a power generator cycles. Even a base load power plant may cycle if there are other power plants generating lower cost electricity at times of low demand. New power plants governed by this rule will be deeper in the base load than existing plants (including coal), making cycling less of an issue than it is for existing plants.

The EPA notes that "while some of these [natural gas] turbines are used to serve base load power demand, many cycle their operation much more frequently than coal-fired power plants. It is unclear how part-load operation and frequent startup and shutdown events would impact the efficiency and reliability of CCS," (U.S. Environmental Protection Agency, 2013a).

Modeling by Howard Herzog's research group at MIT has found that post-combustion carbon capture systems can keep up with cycling base load power plants without impacting the capture of carbon dioxide. "Integration of a carbon capture unit with coal-fired power plants can be successfully operated dynamically to meet the current load following requirements of coal-fired power plants while maintaining 90 percent capture rates," (Brasington, 2012).

Historically, natural gas prices have driven electricity costs higher compared to coal, driving coal to dispatch first and making gas-fired power plants cycle more often. Due to the recent drop in natural gas prices, there has been a shift to dispatching some natural gas before coal, therefore decreasing cycling of natural gas power plants. Figure 7 utilizes data from the EIA to illustrate the impact of fuel prices on dispatch order and cycling. This figure looks at marginal operating costs (which determine dispatch order) from coal steam turbines and natural gas combined cycle systems. Marginal operating costs include fuel costs as well as variable operations and maintenance (O&M) costs (Eide, 2013). The fuel cost of coal was taken from EIA's 2013 rolling monthly average ending in September (U.S. Energy Information Administration, 2013b). To show variation in natural gas fuel price three different natural gas prices were examined: \$3.10/MMBtu is the lowest monthly average price of natural gas seen in the US in April, 2012; \$4.44/MMBtu is the rolling 2013 average cost to electric utilities ending in September, 2013; and \$6.11/MMBtu is the number used by the EPA in their analysis (U.S. Energy Information Administration, 2013c). The range of costs is due to the variation in power plant heat rates and represents 95% confidence limits of US power plants generating more than 300,000 MWh/yr, totaling 347 PC plants and 283 NGCC plants (U.S. Energy Information Administration, 2012). The 300,000 MWh/yr cut-off eliminates peaking units that may have uncharacteristic heat rates. With low gas prices, natural gas-fired power plants can have lower marginal operating costs than coal, pushing them deeper in the base load than coal power plants, resulting in lower cycling rates than the coal plants they displaced.

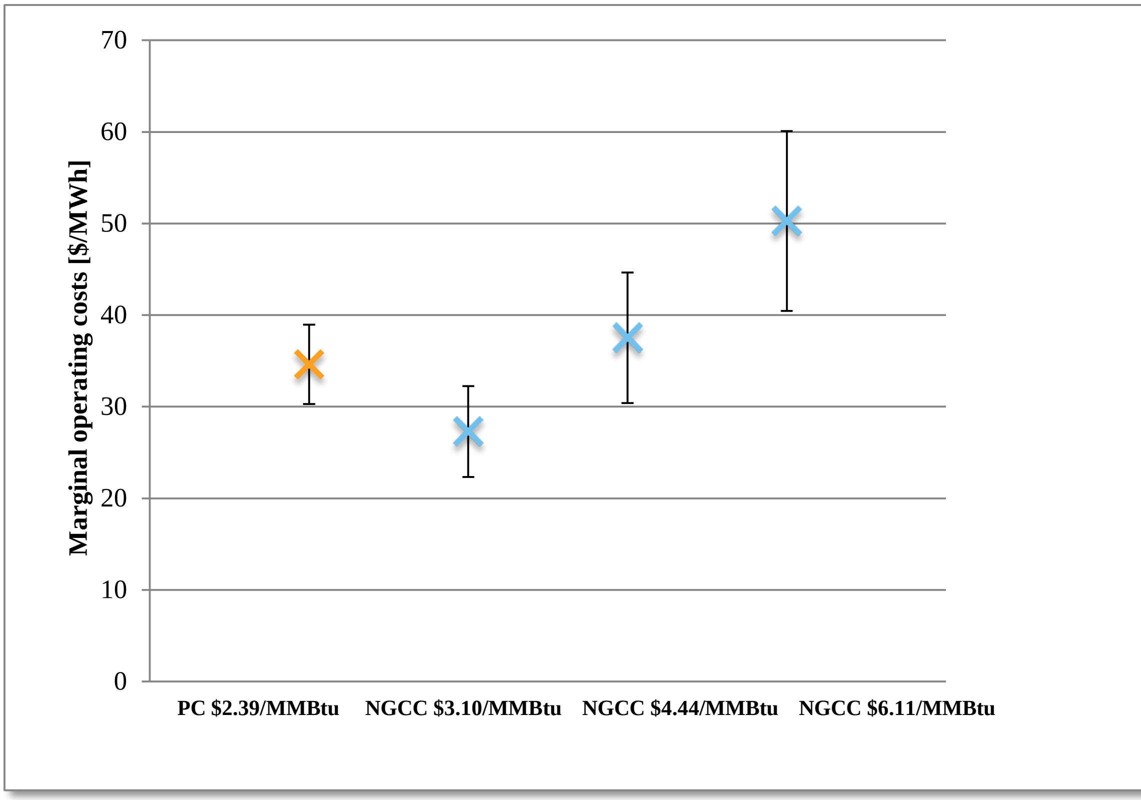

Figure 7: Estimated marginal operating costs from pulverized coal and natural gas combined cycle power plants in the United States

In summary, CCS can load follow on base and intermediate load power plants, which will allow for cycling of either coal or natural gas power plants built to target these electricity demands. Additionally, at current natural gas prices, many natural gas plants are lower in the dispatch order than many existing coal plants and will therefore cycle less often. In conclusion, CCS makes cycling more of a challenge for both coal and natural gas, as both systems may cycle depending on their dispatch order. Though perhaps a greater challenge for natural gas than for coal, both coal and natural gas power plants share this challenge. There is not enough difference that will justify establishing CCS as the BSER for coal but not for natural gas.

3.2.6 Technological development

The EPA's final criterion for determining a BSER is the encouragement of technological development of control technologies. For coal-fired technologies, the EPA suggests that simply requiring efficient new coal technology (such as efficient pulverized coal boilers or IGCC units) would not promote technological development of the control technology, but requiring CCS would further development (U.S. Environmental Protection Agency, 2013a). They base this conclusion on the fact that the only way to meet the performance standard for coal is through the deployment of CCS technologies. However, the EPA ignores another of their assertions that they do not expect any new coal plants to be built for the foreseeable future. Though the EPA projects a small amount of new coal-fired capacity (0.3 GW) to come online in response to incentives for CCS and government funding, they conclude that "the vast majority of new, unplanned generating capacity is forecast to be either natural gas-fired or renewable," (U.S. Environmental Protection Agency, 2013b). Therefore companies are unlikely to invest in control technology for power plants that will not be built. The Congressional Research Service came to the same conclusion, stating: "If the standards won't have any cost or impact, because no new coal-fired capacity subject to them will be built, then they will do little to stimulate the development of CCS technology," (McCarthy, 2013)

The EPA acknowledges that identifying CCS as the BSER for natural gas-fired power plants would promote technological development of control technology, saying, “Although identifying CCS as the BSER [for natural gas power plants] would promote the development and implementation of emission control technology, for the reasons described, the EPA does not believe that CCS represents the BSER for natural gas combustion turbines at this time,” (U.S. Environmental Protection Agency, 2013a).

Requiring CCS on NGCC power plants would not only promote technological development of CCS, but would also promote other low carbon generation options. By allowing what is termed in this thesis as the “NGCC loophole”, just about all capacity issues in the electric power sector will be solved using natural gas as a fuel (with the exception of renewables where they are mandated through portfolio standards and/or subsidized through tax credits). This will result in little to no incentive to invest in low carbon technologies like CCS, renewables, or nuclear power generation systems.

The EPA argues that simply having this new power plant regulation on the books will reduce regulatory uncertainty because it identifies CCS as the BSER for coal and will therefore encourage further research development of CCS technologies (U.S. Environmental Protection Agency, 2013b). The EPA cites the example of American Electric Power (AEP), who cancelled construction of a commercial-size demonstration project in 2011, citing weak policy as a key issue (American Electric Power, 2011). Though this statement is accurate, the context has changed. This AEP project was started when coal was competitive with gas as a low-cost electricity provider, but this is no longer the case. With no coal plants projected in the immediate future, this regulation will act only to increase the cost gap between coal and gas options.

The proposed rule could have the unintended consequence of being a disincentive to some technology development, particularly for the oxy-combustion capture technology pathway. The regulation focuses on partial capture of CO_2, because coal plants only need to get their emissions down to 1100 pounds CO_2/MWh. However, oxy-combustion technology must be applied to the entire flue gas, unlike pre- and post-combustion technologies, which can be more easily adapted for partial capture. The premise of oxy-combustion is to separate out nitrogen from oxygen before combustion, resulting in a flue gas that has high CO_2 concentrations. This approach creates a major cost for oxy-combustion and, therefore, because power plant managers will not be rewarded for exceeding the regulation, oxy-combustion technologies are not likely to see R&D investments if partial capture is the requirement. This seems a particularly perverse outcome given that the largest government subsidy awarded to any CCS demonstration project in the US is $1 billion to FutureGen, which is based on oxy-combustion technology (U.S. Department of Energy, 2010).[3]

3.3 Clean Power Plan

3.3.1 Summary

The EPA released the sister rule of the NSPS for existing power plants, called the "Clean Power Plan" (CPP), on June 2nd, 2014 (U.S. Environmental Protection Agency, 2014b). Unlike the BSER approach taken in the NSPS, the EPA proposed state-specific rate-based goals for CO_2 emission reductions expected to sum to 30% emissions reductions in the power sector by 2030, compared to 2005 levels.

More specifically, the state-specific goals are in the form of "adjusted-output-weighted-average CO_2 emission rates that the affected fossil fuel-fired EGUs located in each state could achieve, on average, through application of the measures comprising the

[3] FutureGen was cancelled in February 2015 (Marshall, 2015)

BSER (or alternative control methods)," that range from 1,763 lb CO_2/MWh for Kentucky to 228 lb CO_2/MWh for Idaho (U.S. Environmental Protection Agency, 2014a). The 2030 goal for each state differs based on current emissions and the EPA's estimation of capacity to achieve reductions in four areas:

1. Improving coal power plant efficiency
2. Increasing generation from less-carbon intensive natural gas power plants in times of excess capacity
3. Increasing the share of generation from renewables and nuclear
4. Increasing end use energy efficiency

The plan emphasizes flexibility to allow each state to meet goals in any way they choose, and will give a year extension on submitting plans if states work towards a regional goal with other states.

3.3.2 Reactions

Initial reactions to the CPP have focused on four main areas: state equity, environmental concerns, legal issues, and over-reliance on natural gas.

Equity is a large concern with this rule, as some states have the task of reducing more than others. There are several reasons for this. One, the baseline year is 2005, and some states have already reduced emissions between 2005 and 2014. The EPA feels that those states have additional capacity to reduce emissions, though those states could argue that they have to now pay additional costs to reduce and that their initial investments are not being considered (Philips, 2014).

Environmentalists are concerned that the goals are too low to be on track with long term climate policy. The baseline year for the rule is 2005, the highest point of emissions in the US, meaning that low natural gas prices (among other things) have facilitated a 16% drop on carbon pollution from power generation from 2005-2012 (Foran, 2014). The global Copenhagen Accord also uses 2005 as its base year, where the US pledged in 2010 to reduce *overall* emissions 42% by 2030 and 83% by 2050 (Stern, 2010). Considering the scale of emissions from electricity as a large part of overall emissions, critics worry that the proposed rule will achieve only one third of the intermediate 42% goal by 2030, ensuring that the 2050 goal will be missed (Adler, 2014).

The CAA was not designed to regulate GHGs, which means that this proposal will likely be challenged in state and national courts, potentially delaying implementation. The fourth building block, end-use efficiency, is likely to invite the most controversy related to whether the EPA can use Section 111d to govern efficiency programs (Konschnik & Peskoe, 2014).

Both the NSPS and CPP push for a transition from coal to natural gas in the US fleet of power plants. There have been concerns that being overly-reliant on natural gas may lock the US into one energy source with uncertain future prices and availability (Vartabedian, 2014). Other commentary highlights the fact that though natural gas burns much cleaner than coal at a power plant, other emissions from flaring (causing 16.5 million tons of CO_2 emissions in 2013) and methane from escaped gas are not considered, which could drive up long term emissions (Wald, 2014).

3.3.3 CPP and CCS

The Clean Power Plan does not mandate CCS, as can be seen in the 4 building blocks of the plan. In their own words, though CCS retrofits for existing plants "may be a viable GHG mitigation option at some facilities" and could therefore "meet the emission performance level required under a state plan," "the EPA does not propose to find that CCS is a component of the best system of emission reduction for CO_2 emissions from existing fossil fuel-fired EGUs," (U.S. Environmental Protection Agency, 2014a).

The EPA utilizes an Integrated Planning Model (IPM) to "evaluate the economic and emission impacts of prospective environmental policies" and to support the "assessments … regarding the ability of the electricity and natural gas industries to achieve the levels of performance indicated for building block 2 in the state goal computations," (U.S. Environmental Protection Agency, 2014a). A comprehensive study was implemented by Charles River Associates (CRA) and directed by the Clean Air Task Force (CATF) to examine in more detail the assumptions of this IPM related to CCS (Clean Air Task Force, 2014c). The CATF presents modeling that updates assumptions such as 2008 oil prices, outdated EOR well standards, low EOR sequestration capacity estimates, overstated CO_2 transportation costs, and the possibility of partial capture (Clean Air Task Force, 2014c). The CATF and CRA replicated the EPA's modeling in the North American Electricity and Environmental Model ("NEEM") and modified the key assumptions about CCS to evaluate impacts on the availability and cost of new builds and retrofits with CCS. This modeling exercise estimated that CCS implementation was more likely and less expensive than what was found by the EPA (Clean Air Task Force, 2014a). The result of this scenario was 19 retrofits and 2 new builds and 11.9 GW of CCS-equipped units constructed before 2030. CATF also created 4 other sensitivity scenarios with permutations of the new assumptions and the EPA's assumptions. These also found more CCS being added to power plants, mainly retrofits, with results ranging from 4.8 GW to 18.5 GW, leading CATF to conclude that the EPA should include CCS with EOR as part of the state building blocks (Clean Air Task Force, 2014a, 2014b, 2014c). The CATF analysis is subject to a high level of uncertainty, but showcases the importance of assumptions in the analysis undertaken by the EPA.

3.4 Discussion

Two questions were posed for this section: (1) in the NSPS, why was CCS on a coal-fired power plant considered a BSER, but not CCS on natural gas-fired power plant? And (2) will the NSPS and CPP incentivize CCS?

In response to the first question on the NSPS, there is not nearly enough difference to justify saying CCS is the BSER for coal-fired power plants, but not gas-fired power plants. Therefore, the question arises why the EPA came to a different conclusion. Speculatively, it appears that the EPA first decided on what would be a politically palatable new source performance standard (i.e., partial capture for coal-fired power plants, high efficiency only for gas-fired power plants) and then tailored their justifications to support their decision.

As to the second question, this thesis disagrees with the EPA's contention that the NSPS as written will increase investment in CCS. Furthermore, the biggest thing the EPA could do to generate new investments in not only CCS, but nuclear and renewables as well, is to require CCS on new natural gas power plants. The CPP clearly does not incentivize CCS for existing power plants as a way to reduce state-specific emissions in the short term, but may encourage a shift in thinking towards CCS for natural gas.

There will always be differences in how technologies are evaluated to fit criteria like "best system of emission reduction." As long as traditional regulation is used, the legitimate issues highlighted in this chapter will continue to be debated without clear resolution. One benefit of a market-based mechanism (such as a carbon tax) is that these discussions are not needed because the market will decide.

Chapter 4: Cost analysis of successful CCS projects

Two major CCS projects where stranded assets seem to have been critical are the Gorgon LNG project in Australia and the Boundary Dam retrofit power plant project in Saskatchewan, Canada. This section investigates how the fossil fuel assets (natural gas and lignite, respectively) have affected the viability of these projects. For each case, project details are provided and the policy drivers are discussed, and a new metric for bottom-up analysis is introduced. Both cases will be used to answer the questions (1) what role did stranded assets play? And (2) what can we generalize from each analysis?

4.1 Gorgon

The Gorgon project is a large liquefied natural gas (LNG) plant on the northwest shelf of Australia set to produce 15.6 million tonnes of LNG per year starting in 2015. The plant will be operated by Chevron in a joint venture with Shell, ExxonMobil and others. Once operational, Gorgon will inject CO_2 into deep onshore sandstone reservoirs, 2.5 km below Barrow Island (Chevron Australia, 2014b). Chevron aims to capture 0.2 tonnes of CO_2 for every tonne of LNG produced, equating to over 3 million tonnes of CO_2 stored every year when producing at capacity (Chevron Australia, 2005, 2014a).

Australia recently enacted a carbon tax in 2012, only to repeal it in the summer of 2014 (Taylor & Hoyle, 2014). These changes in climate legislation had seemingly no impact on Gorgon, as preparations for CCS at Gorgon have been in progress for over two decades. Instead of a carbon tax, what drove the use of CCS was the fact that a collaborative decision was made by Chevron and the government of Australia to develop resources at Gorgon using CCS (International Energy Agency, 2013a).

Specific project costs for Gorgon are difficult to locate, but two reasons can be documented that explain how the economics worked out at Gorgon:

1. The cost to add CCS was a relatively small fraction of total costs (compared to power plant projects)
2. There are high market prices for the LNG product

Costs of CCS for the Gorgon project were less than 10% of the total capital costs (“Discussions with Chevron Representatives,” 2014). Unlike power plant CCS projects where adding carbon capture is often greater than 50% of the cost (Ball, 2014) (as is the case at Boundary Dam), natural gas processing projects can include carbon capture with a much lower expense in proportion to the project as a whole (“Discussions with Chevron Representatives,” 2014).

The baseline natural gas price in Asia is very high compared to other places in the world. Figure 8 shows that LNG was selling for almost $17/MMBtu in 2012, much higher than in the US or Europe and rising since 2007 (BP, 2013). The Gorgon project clearly benefits from high LNG prices in the area, that leave a sufficient profit margin in spite of the CCS capital cost additions. However, it would be much more difficult for a similar project to be able to compete with local natural gas markets in North America or in Europe.

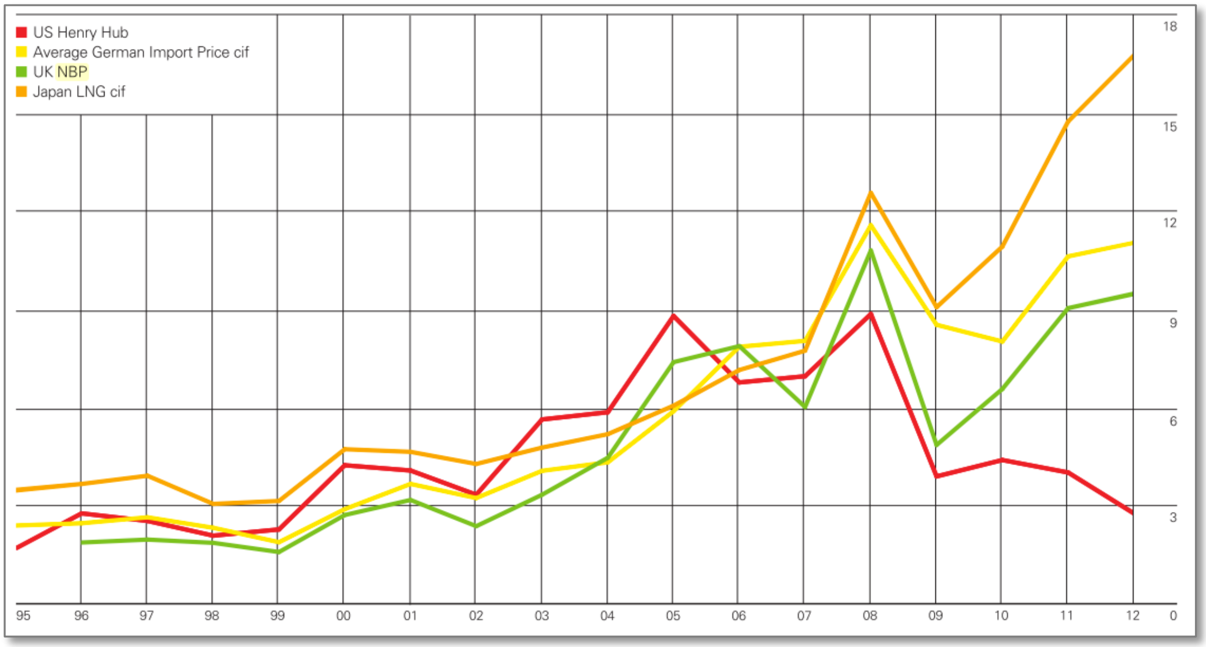

Figure 8: Natural gas prices by regional market and year in US$/MMBtu

4.2 Boundary Dam

SaskPower retrofitted one unit (110 MW) of the Boundary Dam lignite pulverized coal (PC) power plant in Saskatchewan, Canada, aiming to capture one million tonnes of CO_2 per year through post-combustion to sell for EOR to the nearby Weyburn oil field (SaskPower, 2014).

Canada's 2012 update to the Environmental Protection Act requires new coal plants to be compliant with an emissions limit of 420 tonnes of CO_2 emitted per GWh of electricity produced, as well as existing plants when they turn 40 years old (Canadian Ministry of Environment, 2012). Lignite coal has a high emission factor (~1050 t CO_2/GWh for a PC plant[4]), and therefore would not be able to meet this requirement without CCS. This policy left SaskPower only two choices: include CCS in their project

[4] Calculated using average heat rates from US power plants generating more than 300,000 MWh/yr, totalling 347 PC plants (U.S. Energy Information Administration, 2012) and average emission factors from United States lignite (U.S. Energy Information Administration, 2013d).

or allow regulations to strand some of their lignite assets. Saskatchewan has a valuable 300-year supply of coal that SaskPower does not want to be wasted or kept underground (SaskPower, 2012).

SaskPower considered two primary options: retrofit the existing unit with CCS or replace it with a base load natural gas combined cycle (NGCC) power plant. Figure 9 shows the initial gross cost estimates of the Boundary Dam unit retrofit along with the financial instruments that bring the cost down and compares this to the base load NGCC option. The relative electricity costs in Figure 9 were provided by SaskPower, but absolute costs have been estimated and documented in Appendix A (Daverne, 2012). Also included in Figure 9 is the assumption that the CCS addition is 64% of the total capital costs based on the public statement from SaskPower that the CCS addition cost $800 million and that other capital costs added up to $450 million (Monea, 2014).

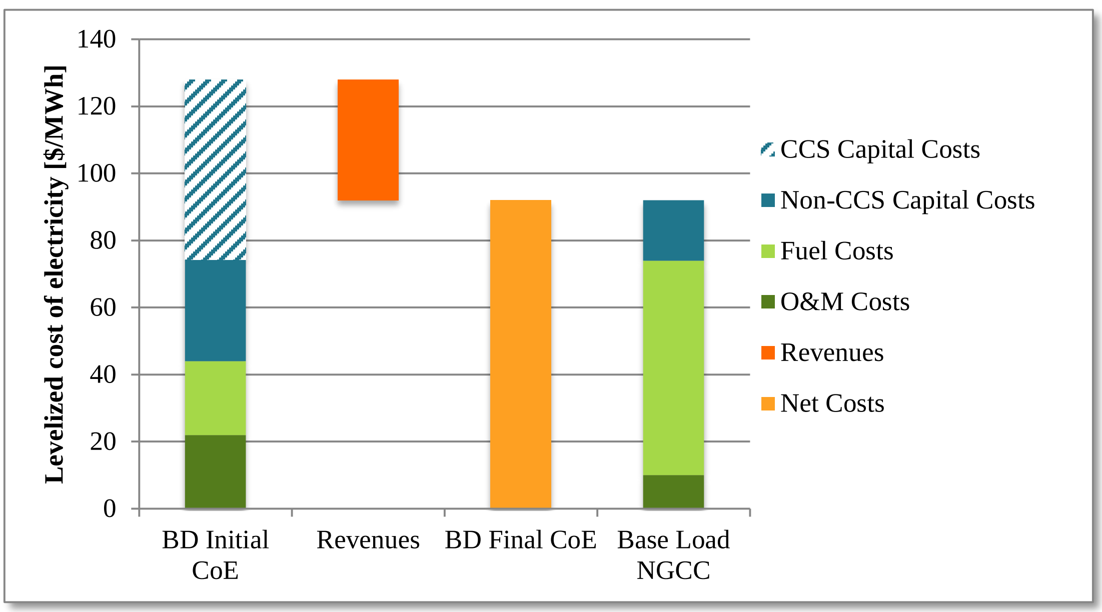

Figure 9: Levelized cost of electricity estimates of the Boundary Dam retrofit by cost category compared to a base load NGCC plant

In addition to the values in the original SaskPower analysis, Figure 10 shows the same graph including an estimate of annualized contribution of the Canadian federal subsidy of $240 million dollars, which was assumed to contribute to capital costs of the system.[5]

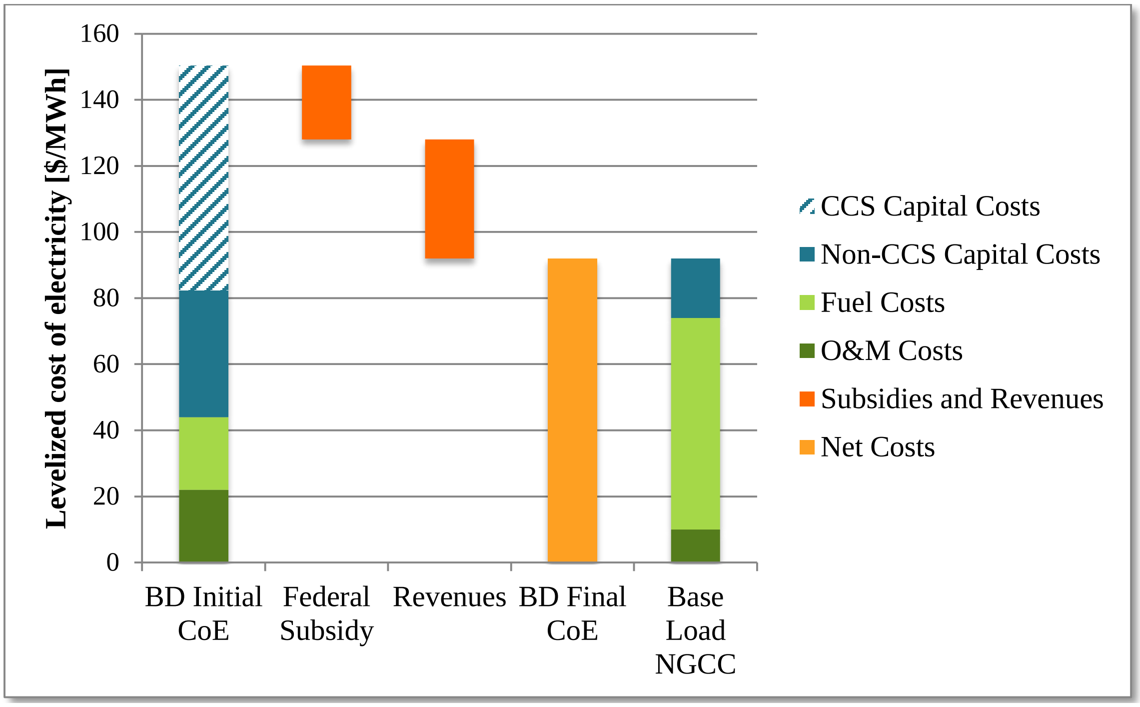

Figure 10: Levelized cost of electricity estimates of the Boundary Dam retrofit by cost category compared to a base load NGCC plant

Figure 10 showcases how Boundary Dam can compete with a base load NGCC plant at current natural gas prices in Canada. Four components played a critical role:

1. There was a substantial federal subsidy from the Canadian government
2. The CO_2 was sold as a by-product for enhanced oil recovery (EOR) for the majority of revenue, along with sulfuric acid and fly ash
3. The fuel cost was significantly lower for lignite than natural gas
4. The project was a retrofit, lowering the capital costs compared to new plant

[5] The annualized cost of the federal subsidy of $22.4/MWh was calculated assuming a 115 MW unit, 0.08 capital recovery factor, and 85% capacity factor

As can be seen, stranded assets played a role, via the fuel cost savings (point 3 above) and reusing existing power plant infrastructure (point 4 above). However, stranded asset considerations alone would not have driven this project.

SaskPower is considering future retrofits of units 4 and 5 of Boundary Dam with CCS, and believes that the experience of retrofitting unit 3 can reduce future capital costs by up to 30% (Ball, 2014; SaskPower, 2013). The federal subsidy is estimated to account for 20-30% of total capital costs (see Appendix A), so the expected reductions would negate the need for future subsidies. SaskPower will be gathering data at unit 3 for two years (2014-2016) to evaluate the viability of replicating CCS retrofits at Boundary Dam before making investment decisions starting in 2017 (Ball, 2014).

The value of the lignite assets and the value of the existing power plant infrastructure are clearly factors in the decision to construct this project. However, just as important was the possibility to sell the CO_2 for EOR. It should also be emphasized that policy was in place that forced SaskPower to make the choice of utilizing CCS or forgoing the lignite assets. It remains to be seen whether the successful experience at unit 3 can be replicated at other units at Boundary Dam, let alone other locations.

4.3 Bottom-up metrics

Gorgon and Boundary Dam had to be profitable after taking into consideration CCS costs. Table 5 highlights the tradeoffs in costs to include CCS compared to the price of the commodity for each project.

Table 5: Relative cost comparison of project output and CCS addition costs for Boundary Dam and Gorgon

	Commodity market price	CCS costs
Boundary Dam	COE for NGCC	High, but mitigated by federal subsidy and EOR revenues
Gorgon	LNG market price	Low percent of project capital costs

New metrics are needed to illustrate these dynamics quantitatively, so a bottom-up calculation was done to understand how the cost of CCS is related to the value of the fossil assets. The two assets of interest are coal and natural gas, as those two resources are most likely to see CCS additions going forward and they provide a meaningful comparison in the Boundary Dam and Gorgon projects.

For this analysis a new metric was defined, termed the "CO_2 Normalized Fuel Price" to compare the carbon impact of different assets. The CO_2 Normalized Fuel Price (in \$/t CO_2) is defined simply as the fuel price (in \$/MMBtu) divided by the emission factor (in t CO_2/MMBtu, see Table 6) for that fuel.

Table 6: Emission factors and heat rates used in bottom-up analysis

Fuel	Emission factor[6] [t CO_2/MMBtu]	Heat rate for PC and NGCC[7] [Btu/kWh]
Lignite coal	0.097	**10825**
Natural gas	**0.053**	**7638**

Figure 11 plots the CO_2 Normalized Fuel Price for various prices of lignite coal and natural gas. Lignite coal is used as the example since this is the type of coal used at

[6] US national averages for lignite coal and natural gas are used. Natural gas average equates to higher heating value of 1029 Btu/scf (U.S. Energy Information Administration, 2011).
[7] Averages of US power plants over 300,000 MWh annual output (U.S. Energy Information Administration, 2012)

Boundary Dam. Results for other coals (i.e., bituminous or subbituminous) may vary by up to 5% based on emission factor (U.S. Energy Information Administration, 2011).

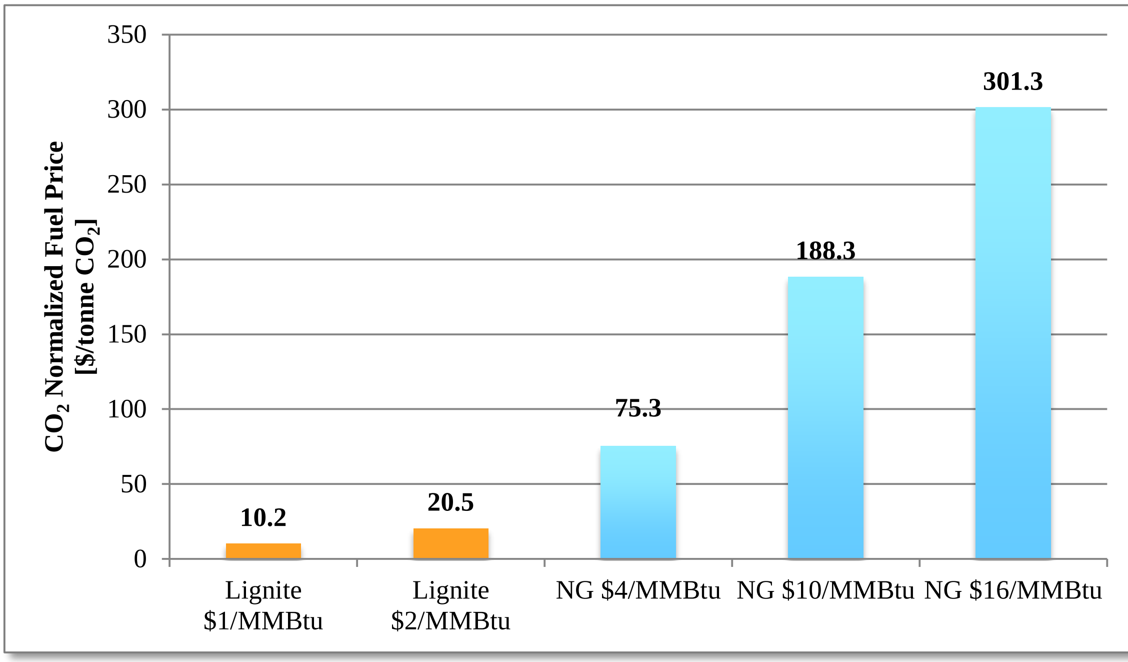

Figure 11: CO_2 Normalized Fuel Price of lignite coal and natural gas at different market fuel prices

It is clear that natural gas has a higher CO_2 Normalized Fuel Price compared to coal because of both a higher fuel price and a lower emissions factor. The higher the CO_2 Normalized Fuel Price, the more flexibility there is within a project to absorb CCS costs and still have an economically viable project. For example, Gorgon benefits from high fuel prices equivalent to the bar on the far right in Figure 11of about $300/tonne CO_2, meaning that it is easier to incorporate CCS for Gorgon at CCS costs on the order of 10% of the CO_2 Normalized Fuel Price.

Figure 11 also shows that lignite has much lower $/tonne CO_2 estimates for all market prices. Boundary Dam has coal prices closest to the far left bar in Figure 11. However, unlike Gorgon that is selling natural gas directly, Boundary Dam is not selling coal, but electricity generated from coal. Therefore, another metric is needed: CO_2 Normalized Electricity Price. This is calculated by dividing a target levelized cost of electricity (LCOE) by the heat rate and emission factor (see Table 6). For this exercise a target LCOE of $90/MWh is used. This particular target electricity price was chosen because that is the likely baseline cost of electricity for Boundary Dam in Saskatchewan. The results are shown in Figure 12.

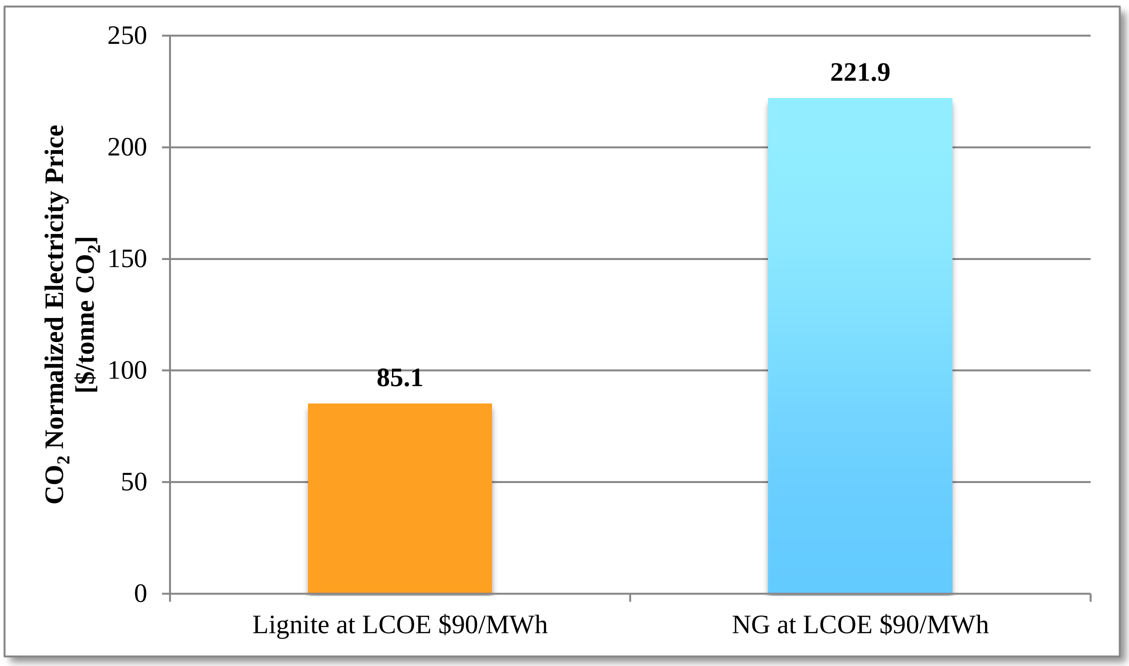

Figure 12: CO_2 Normalized Electricity Price generated by pulverized lignite coal and NGCC power plants at a $90/MWh LCOE

Carbon capture and compression on a coal-fired power plant cost more than $50/t CO_2 (Hamilton & Herzog, 2009), which is a substantial component of the CO_2 Normalized Electricity Price for lignite in Figure 12. In order for SaskPower to have a viable project, it needed additional EOR revenues, the ability to use existing infrastructure, low fuel prices, and a substantial government subsidy. This analysis shows that all else being equal, natural gas has more flexibility than does coal for adding CCS to a project. However, to understand the full picture, one must also take into account the differences in capital costs, fuel costs, and costs of adding CCS.

It is important to point out an additional difference between Boundary Dam and Gorgon. At Gorgon, only the CO_2 from the production of fuel is captured, not the CO_2 from final end use. At Boundary Dam, the CO_2 released during coal combustion is captured, resulting in a much higher fraction of the lifecycle CO_2 emissions of the fossil fuel being mitigated.

It is clear that stranded assets played a role in the decision to pursue projects at Boundary Dam and Gorgon, though additional financial mechanisms and circumstances were necessary for those projects to be viable. At Boundary Dam, CO_2 revenue and a federal subsidy allowed SaskPower to rescue valuable lignite resources. At Gorgon, a voluntary agreement for CCS allowed Chevron to develop valuable natural gas resources.

More broadly, it can be concluded that it is easier for stranded assets to be a driver in projects where CCS costs are a small portion of total capital costs and in projects where CO_2 is being captured from processing the fuel (such as at Gorgon) rather than combusting the fuel (such as Boundary Dam).

Chapter 5: Integrated assessment models: scenarios of CCS rescuing stranded assets

Chapter 4 looked at how stranded assets related to two specific projects. This chapter will estimate the overall scale and significance of stranded assets by utilizing top-down assessments.

5.1 IPCC

In their latest assessment report, Working Group III of the Intergovernmental Panel on Climate Change (IPCC) selected over 50 climate-consistent scenarios from various top-down energy-economic models to be compared based on their different mix of technologies that help them achieve a variety of CO_2 targets in 2100 (2014). Assuming a global carbon price, these top-down models found a significant increase in total mitigation costs if they excluded CCS as a portfolio option on power plants (Intergovernmental Panel on Climate Change, 2014). The IPCC found that excluding CCS from a mitigation technology portfolio would increase discounted mitigation costs 138% when trying to reach a 450 ppm climate target (39% for 550 ppm) over the time period of 2015-2100 (Intergovernmental Panel on Climate Change, 2014). This increase in mitigation costs includes the cost of stranding valuable fossil fuel assets.

5.2 AMPERE

To quantify this further, this section will evaluate the results of specific top-down integrated assessment models.[8] To ensure that the compared models would have

[8] Note that previous work completed by the author of this thesis looked at the MESSAGE model runs completed for the 2012 Global Energy Assessment (GEA) (Clark & Herzog, 2014). This thesis has expanded to look at the AMPERE study to be able to compare top-down results from more models with differing assumptions.

consistent assumptions, the collaborative modeling effort AMPERE was used, which ran from 2011 to 2014. AMPERE had five work packages each with a specific objective. Work package 2 focused on limited technology scenarios. This package was chosen for a more detailed analysis because each model ran a scenario with technology portfolios that prohibit CCS in addition to a scenario run with a full portfolio of mitigation technologies (Riahi, Kriegler, Johnson, Bertram, den Elzen, Eom, et al., 2015). Similar to the IPCC cost summary above, the restricted CCS scenario represents potential stranded assets that would result from policy decisions that limit or restrict entirely the use of CCS.

5.2.1 Participating models

Nine models participated in working group 3 of the AMPERE study.

DNE21 +. DNE 21+ is a linear programming model that projects world energy systems out to 2050 and is developed by the Research Institute of Innovative Technologies for the Earth (Sano, Akimoto, Homma, Oda, & Wada, 2012).

GCAM. GCAM is developed by the Joint Global Change Research Institute at the Pacific Northwest National Laboratory and is a dynamic-recursive model with technology-rich representations of the economy, energy sector, land use and water linked to a climate model that can be used to explore climate change mitigation policies including carbon taxes, carbon trading, regulations and accelerated deployment of energy technology (Edmonds et al., 1997).

IMACLIM. IMACLIM is an energy economic integrated assessment model developed by the Centre International de Recherches sur l'Environnement et le Développement in France (Ghersi, 2014).

IMAGE. IMAGE integrates changes in climate, society, and biodiversity, and more so than other models in the study, focuses on environmental complexity over economic complexity. IMAGE is developed by the PBL Netherlands

Environmental Assessment Agency (PBL Netherlands Environmental Assessment Agency, 2014).

MERGE-ETL. MERGE-ETL is a partial equilibrium model with endogenous technological progress (ETL) developed at Stanford (Kypreos & Bahn, 2003).

MESSAGE-MACRO. The MESSAGE model is a dynamic linear programming optimization model developed by the International Institute for Applied Systems Analysis (IIASA) (Messner & Strubegger, 1995).

POLES. POLES is a general equilibrium model developed by Enerdata (formerly IEPE – Institute of Energy Policy and Economics) in France (Enerdata, n.d.).

REMIND. REMIND is a dynamic economic model that takes a hybrid approach, developed at the Potsdam Institute for Climate Impact Research (Bauer, Baumstark, & Leimbach, 2011).

WITCH. The WITCH model takes a general equilibrium approach and is developed by Fondazione Eni Enrico Mattei in Italy (Bosetti, De Cian, & Sgobbi, 2009).

5.2.2 Amount of CCS on coal and natural gas

In the AMPERE study, three of the nine models could not meet a 2 degree climate target in 2100 without including CCS (Riahi, Kriegler, Johnson, Bertram, den Elzen, & Eom, 2015; Riahi, Kriegler, Johnson, Bertram, den Elzen, Eom, et al., 2015).[9] Four models within the AMPERE study converge on an optimal pathway to 2 degrees Celsius without CCS over the time period of 2010-2100: GCAM, MERGE-ETL, MESSAGE-MACRO, and REMIND (Riahi, Kriegler, Johnson, Bertram, den Elzen, Eom, et al.,

[9] All models could converge on a 3-degree climate scenario without CCS.

2015). DNE21+ runs from 2010-2050 with a successful scenario without CCS, but the results are not compared in this text to the other four models due to the different time frame. IMACLIM did not run a scenario without CCS for a 450 ppm target (Riahi, Kriegler, Johnson, Bertram, den Elzen, & Eom, 2015).

Figure 13 displays relevant results from these four models of two scenarios constrained by a climate target of two degrees Celsius, one excluding CCS and the other with a full portfolio of mitigation options. The graphs to the left (a) represent the primary energy in ExaJoules (1 EJ = 10^{18} J = 1 billion GJ) used across all sectors if CCS is not allowed as a mitigation option over the time period 2010-2100. The right graphs (b) represents the primary energy used when CCS is allowed to be deployed widely starting in 2015 (Riahi, Kriegler, Johnson, Bertram, den Elzen, Eom, et al., 2015).[10]

[10] AMPERE scenario assumptions and results are freely available online at https://secure.iiasa.ac.at/web-apps/ene/AMPEREDB/dsd?Action=htmlpage&page=about

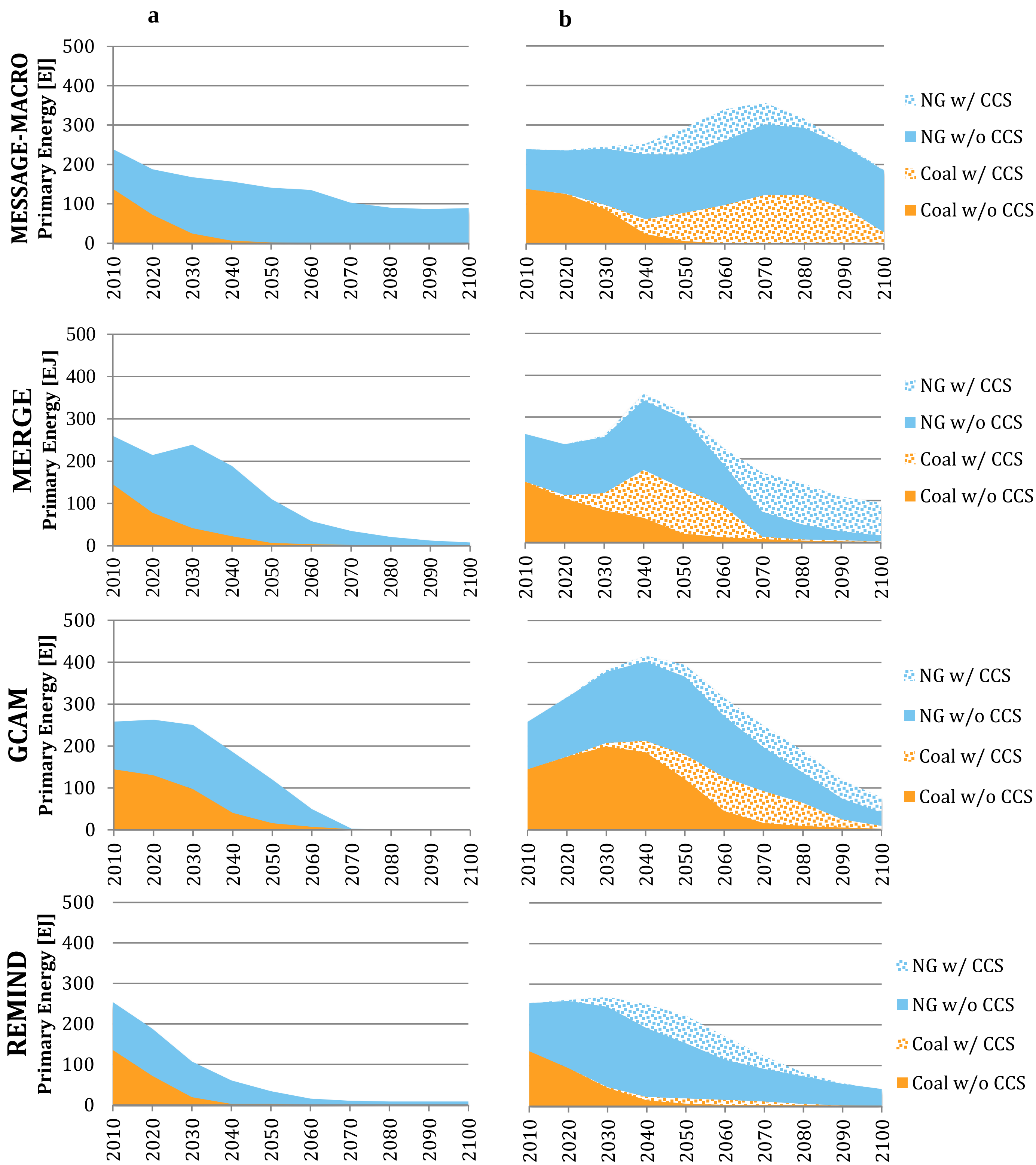

Figure 13: Annual primary energy of coal and natural gas consumed in scenarios where (a) policy prohibits the use of CCS on power plants and (b) where a full portfolio of supply side technologies including CCS is available to reach a 2°C climate target

5.2.3 Modeling assumptions

It is important to take a step back and contextualize the results from the models included in AMPERE. All scenarios assume that CCS technologies will be ready for large-scale deployment before 2020 without consideration for geographic siting or policy constraints and assume a single global carbon price that begins in 2010. The results of these models are not what is expected to happen, just a possible story of how the future energy and emissions trajectories could proceed under the defined assumptions. The results shown in this chapter represent rescued fossil assets for a 2°C (consistent with 450 ppm) target, but any less stringent target would result in fewer (but not zero) stranded assets, as illustrated by the larger 3°C climate budget in Figure 2.

Perhaps the largest consideration for these models is the inclusion of bioenergy with CCS, or BECCS. Figure 13 showed all CCS on coal and natural gas systems, which is the CCS technology expected by the international community and the technologies relevant to stranded fossil fuel assets, but BECCS is also a key player in these models. The important assumption about BECCS is that it creates the opportunity for *negative emissions*. Unlike a coal power plant, where 90% of the emissions can be stored underground, a biomass power plant can theoretically store 90% of emissions underground and still plant new energy crops to recapture future emissions. The way these top down models operate, without an explicit constraint, most models will choose to build out huge amounts of biomass with CCS because the cost per tonne of CO_2 saved is much lower than other technologies. Figure 14 shows the amount of BECCS present in each of these models compared to the CCS on coal and natural gas power plants.

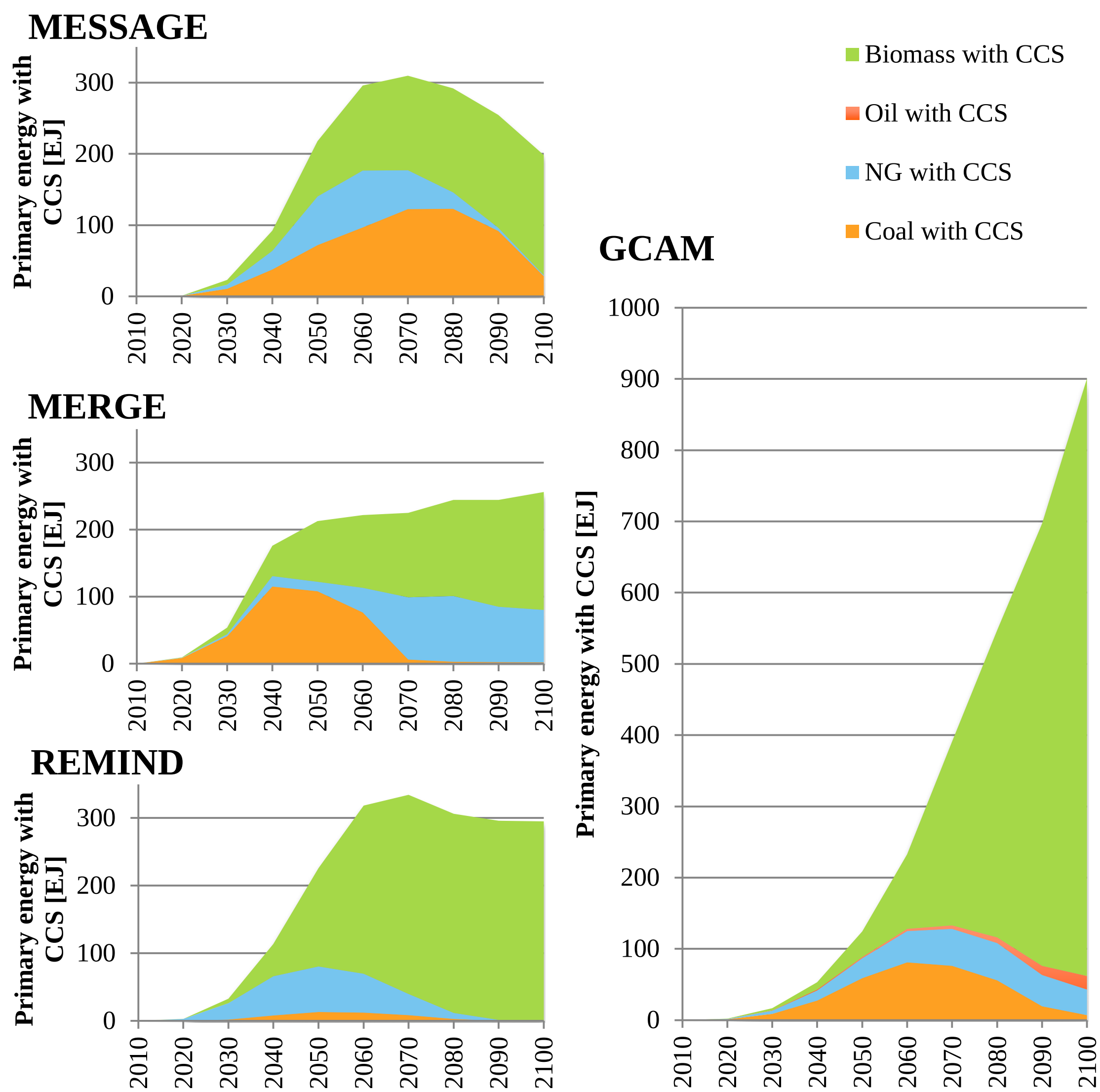

Figure 14: Primary energy with CCS by fuel source in four AMPERE models in a 450ppm scenario

Figure 14 showcases the differences in prediction by each of these models of the total amount of CCS in addition to timing and proportion of biomass in the CCS mix. The IPCC points out that bioenergy with CCS "might, during the course of this century, become globally important," but that there are huge uncertainties centering on the extent of bioenergy conversion and the potential of dedicated energy crops, so it is difficult to know the real potential of BECCS (Intergovernmental Panel on Climate Change, 2005).

Table 7 highlights results in 2100 for total primary energy, primary energy from CCS, and contribution of BECCS for each of the contributing models that run from 2010-2100. The models in blue are those that converged to quantitatively assess how much stranded assets CCS can rescue; those in orange are those that reported a scenario without CCS was infeasible; the IMACLIM model did not run a scenario without CCS. The table highlights the trend that the higher primary energy demand scenarios seem to also have a higher BECCS contribution. This highlights the fact that if BECCS is not deployed widely, CCS on coal and natural gas becomes much more important, especially in high-demand scenarios.

Table 7: Relevant results in 2100 from full technology portfolio scenario in AMPERE models

	Model	Total energy demand [EJ]	Total CCS [EJ]	% of CCS on bioenergy
Models that converge for "No CCS" scenario	GCAM	1360	900	93%
	MERGE-ETL	789	256	69%
	MESSAGE-MACRO	987	198	85%
	REMIND	981	295	100%
Models where "No CCS" scenario is infeasible	IMAGE	896	485	28%
	POLES	886	333	49%
	WITCH	535	204	51%
"No CCS" scenario not run	IMACLIM	709	357	20%

5.2.4 Global stranded assets

The increase in cumulative primary fossil energy in full technology scenarios compared to scenarios that restrict CCS represent the stranded assets that can be "rescued" by the use of CCS under stringent climate policy over this time period. The results are shown in Figure 15 for the MESSAGE-MACRO model. CCS on coal-, gas-, and biomass-fired electricity also rescues oil assets due to the fact that these are economy-wide models.

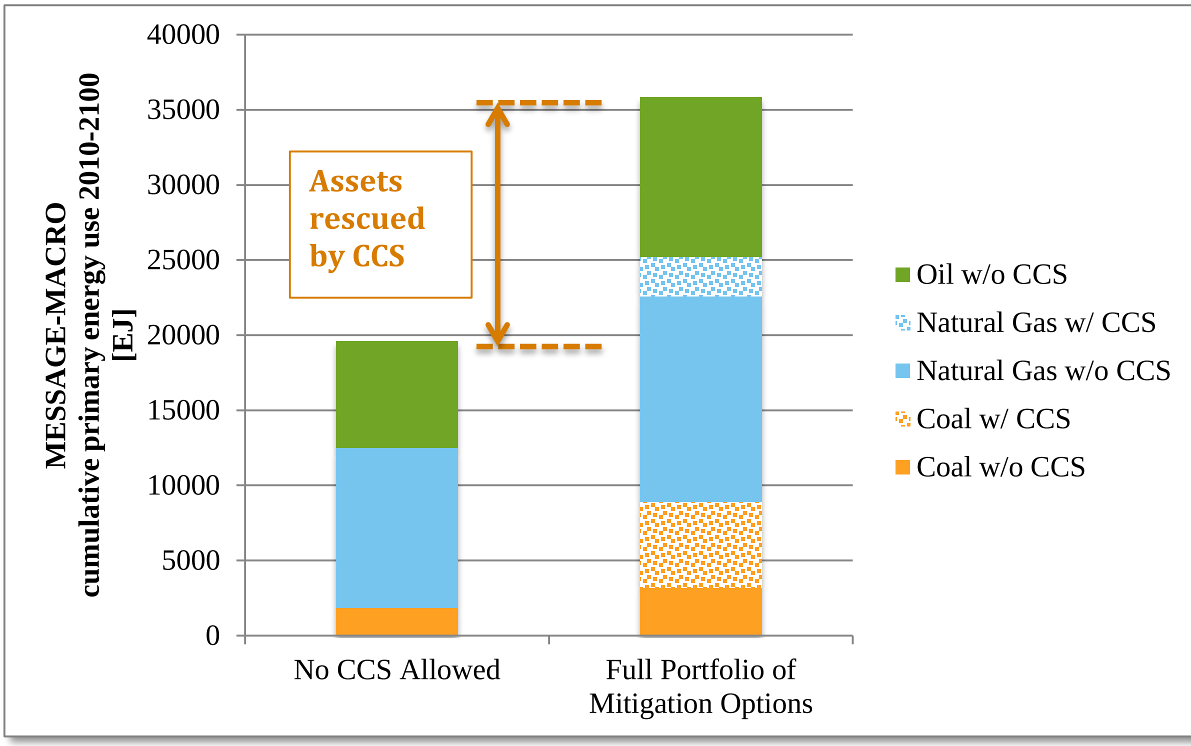

Figure 15: Total primary energy use from 2010-2100 from fossil fuels in all sectors for AMPERE MESSAGE scenarios where policy prohibits the use of CCS on power plants (left) and where CCS is included in a full portfolio of supply side technologies (right) to reach a 2°C climate target

Using the methodology visualized in Figure 15, the total amount of rescued assets for each model was calculated; results are displayed in Table 8. These AMPERE scenarios show that CCS increased fossil fuel utilization 80-120% with no increase in CO_2 emissions. Results from the AMPERE model are given every 10 years, so in order to calculate cumulative emissions in every year, this analysis assumes a linear interpolation between each given value.

Table 8: Rescued fossil fuel assets through the availability of CCS in top-down models

"Rescued" Assets by CCS 2010-2100 [EJ]	MESSAGE-MACRO	MERGE-ETL	REMIND	GCAM
Coal	7100	4900	1200	8000
Natural Gas	5600	4800	9000	7500
Oil	3500	3000	3900	6500
Total	**16200**	**12700**	**14100**	**22000**
% Increase	**83%**	**82%**	**95%**	**121%**

5.2.5 Embedded emissions

IEA and the Carbon Tracker Initiative have looked at the ability of CCS to increase allowable carbon budgets in the near and long term. They conclude that CCS can increase allowable carbon budgets, but disagree on the extent. The AMPERE model results provide an opportunity to quantify an increased carbon budget from the use of CCS on power plants.

The quantity of stranded assets in ExaJoules can be converted to embedded emissions. For each fuel, a single emissions factor from the EPA was applied to get a sense for the scale of the increased carbon budget, as shown in Table 9. Emission factors used were 95, 53, and 75 kg CO_2/MMBtu for coal, natural gas, and oil, respectively.[11]

[11] These emission factors were estimated averages from http://www.epa.gov/climateleadership/documents/emission-factors.pdf

Table 9: Increased carbon budget for fossil fuel assets [Gt CO_2]

	MESSAGE-MACRO	MERGE-ETL	GCAM	REMIND
Coal	637	444	717	105
Natural Gas	284	241	379	453
Oil	251	213	465	279
Total	1172	898	1562	838
2 Degree CO_2 Budget[12]	975	975	975	975
% Increase in CO_2 budget	**120%**	**92%**	**160%**	**86%**

The results of the AMPERE modeling effort indicate that CCS may be able to rescue between 800 and 1600 Gt of embedded CO_2 in coal, natural gas, and oil reserves while still meeting a 2-degree emissions target. Figure 16 shows that 1000 Gt CO_2 would approximately double a carbon budget for 2-degrees, but would still leave about 40% of carbon reserves in the ground, and approximately 85% of carbon stocks in the ground. This means that CCS can rescue substantial fossil fuels, but many countries will have to prepare for the implications of some quantity of stranded assets.

[12] As estimated by the Carbon Tracker Institute (2013)

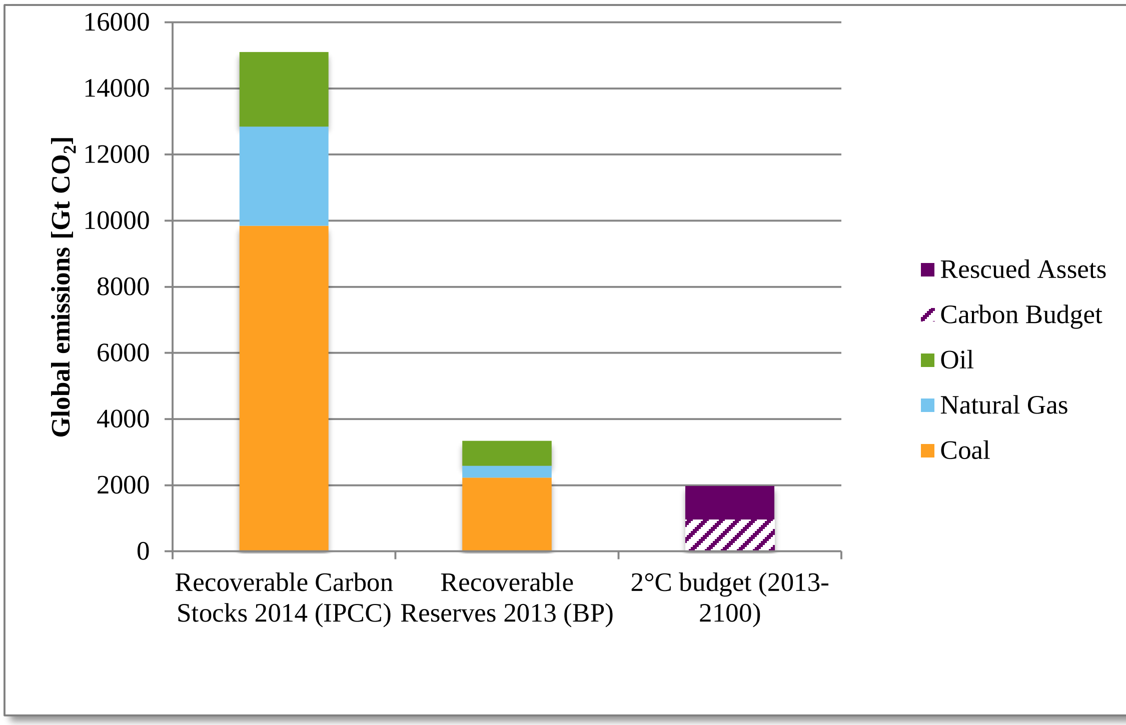

Figure 16: Stranded assets with 1000 Gt rescued assets compared to estimates of reserves and stocks of fossil fuels

5.2.6 Value of stranded assets

The next logical question is what is the value of these stranded assets? There is more than one way to answer that question. Two approaches are used here: overall mitigation costs between scenarios and valuation of rescued assets. The methodology for mitigation costs between scenarios is comparable to the analysis done by the IPCC discussed in section 5.1. For the four models explored, the AMPERE study calculates mitigation costs through two distinct methodologies depending on the model: loss in GDP and area under the marginal abatement cost curve (MAC curve). Total costs by these methodologies find that the availability of CCS can decrease mitigation costs by anywhere from 35-108% compared to a scenario without CCS, as shown in Table 10.

Table 10: Policy costs by methodology for all AMPERE models in trillion $2005 over the period of 2010-2100

	Full portfolio	No CCS	% Increase in mitigation costs
GDP loss			
MESSAGE	$436	$907	**108%**
MERGE	$835	$1129	**35%**
REMIND	$616	$956	**55%**
Area under MAC curve			
GCAM	$486	$654	**35%**

The utilization of CCS in these scenarios also rescues fossil assets that have value to the global energy market. Using the quantity of rescued assets and the projected fuel prices from the full portfolio scenario from each model, an estimated value of the rescued coal, oil, and gas can be calculated.

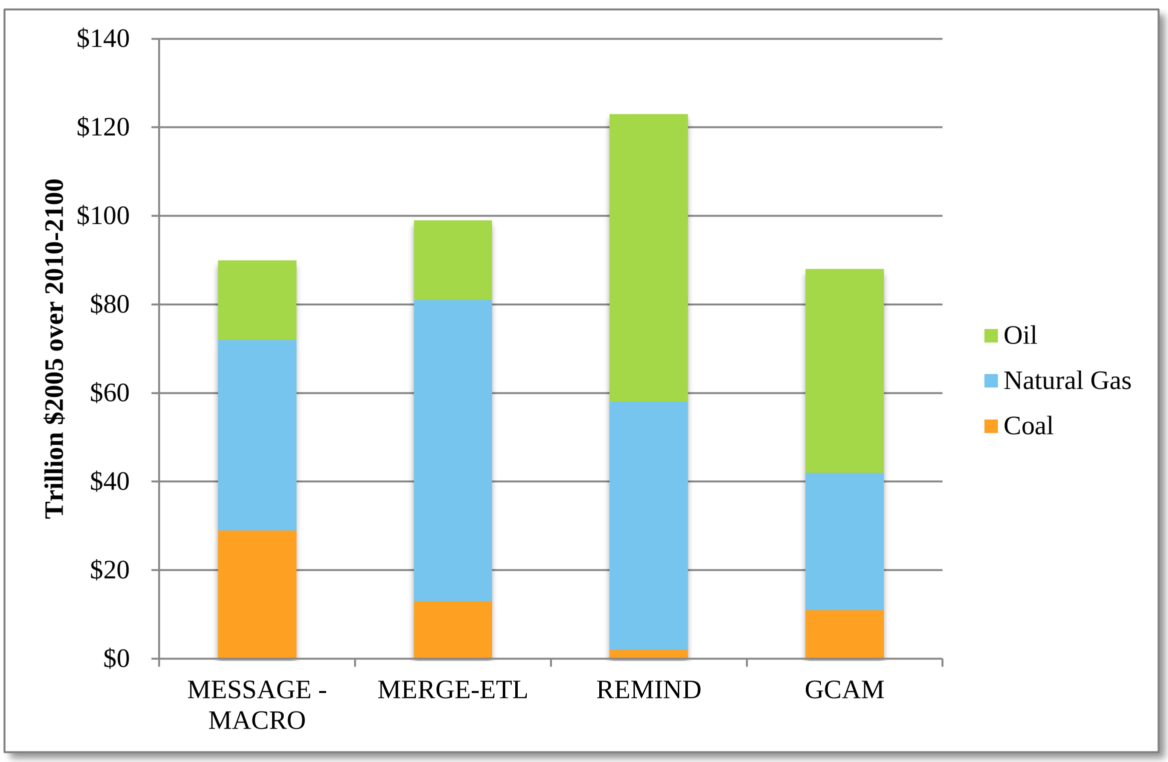

Figure 17: Cumulative value of rescued assets in trillion $2005 over the period 2010-2100 by AMPERE model

Figure 17 highlights the fact that the majority of the value of rescued assets comes from the projected market value of crude oil and natural gas. Table 11 shows the value of rescued assets as a percent of total decreased mitigation costs, calculated as the difference in mitigation policy costs in the Full Technology scenario and the No CCS scenario (see Table 10). Ranging from 19% for MESSAGE to 52% for GCAM, the value of rescued fossil fuel can make a significant contribution to lowering mitigation costs over the next century.

Table 11: Value of rescued assets compared to total decreased mitigation costs enabled by deployment of CCS in trillion $2005 over the period of 2010-2100

	Decreased mitigation costs	Value of rescued assets	Contribution of rescued assets [%]
MESSAGE	$471	$90	**19%**
MERGE	$294	$100	**34%**
REMIND	$340	$122	**36%**
GCAM	$168	$88	**52%**

Chapter 6: Policy discussion and implications

The objective of this thesis is to explore how climate policies can help incentivize CCS and whether the specter of stranded fossil assets can help drive CCS deployment. Current policies do not seem to be driving CCS deployment, but the consensus from the international community is that CCS is critical to meeting 450 and 550 ppm climate targets at reasonable mitigation costs. In light of this, this chapter will discuss policy recommendations for the international community.

6.1 Type of policy to incentivize CCS

CCS projects must be driven by policy, but this thesis has shown that the type of policy, whether carbon pricing, performance requirements, or CCS-specific incentives, can have a very large impact on the extent of encouragement for CCS deployment. To incentivize CCS, policies must create situations where CCS projects can obtain the necessary financial support.

Carbon pricing

The benefits of an economy-wide carbon price are that it signals the importance and value of emissions reductions across all sectors and allows the market to decide where to cut emissions. Because it will always be cheaper to emit CO_2 than capture it, putting a price on carbon is one way to level the economic playing field between a power plant or industrial process without CCS and one with CCS.

The most important element of carbon pricing is to have a price high enough to incentivize CCS. As of January 2015, the carbon price in the EU ETS was hovering below \$10/tonne CO_2, and carbon prices in other regional and national markets were in the range of \$3-\$13/tonne CO_2 (Climate Connect Ltd., 2015; Neslen, 2015). All the top-down AMPERE models internally calculate a carbon price to be consistent with CO_2 stabilization, averaging $43/tonne CO_2 in 2020 and $437/tonne CO_2 in 2050.[13] It is clear that carbon prices set by current markets are falling short of the carbon prices calculated by models to reach climate stabilization scenarios. Carbon prices as low as $15/tonne CO_2 may begin to incentivize gas processing projects with CCS, but abatement costs for power plants will be higher, likely between $40 and $80/tonne CO_2 (International Energy Agency, 2013b; Kulichenko & Ereira, 2011). With low carbon prices, emitters can absorb the added cost and will pay the tax to continue to emit CO_2 with conventional technologies. An alternative example is the carbon tax in Norway, introduced at a price of $51/tonne in 1991, which was high enough to incentivize Statoil to include CCS on its Sleipner and Snøvit projects (International Energy Agency, 2013b).

The takeaway here is that though carbon pricing has huge potential to incentivize CCS, there is a minimum price required for the policy to be successful or carbon pricing must be coupled with other mechanisms.

Performance requirements

Performance standards, usually a result of command and control policy, allow the government to promote and encourage specific technologies to meet specified emissions limits, especially when economy-wide carbon pricing is not an option. This kind of policy is effective at meeting emissions limits, but because the incentive is so narrowly focused, it may not provide the lowest cost policy or the proper incentives for long-term mitigation targets (International Energy Agency, 2012).

[13] In 2020, all 8 AMPERE models with a 2010-2100 time frame calculate carbon prices ranging from $13/tonne to $112/tonne. In 2050, the range grows to $60 to $1706.

Proposed US EPA power plant regulations and Canadian coal power plant emissions limits are examples of this. As discussed in Chapter 3, the de facto exclusion of some technologies from emissions limits has the potential to change the incentive structure. For example, the US EPA proposes CCS for newly built coal-fired power plants, but not gas-fired power plants, creating a loophole for natural gas. In this case, a policy that specifically requires CCS will likely not result in any new CCS-equipped facilities.

To succeed, command and control policy must avoid creating loopholes for other technologies that might undermine the stated objective.

CCS-specific incentives

CCS-specific financial mechanisms directly incentivize CCS, but current experience highlights that they must be well designed. Examples of these incentives include capital grants in the EU through the NER300 and the UK CCS Commercialisation Competition, and US stimulus money for CCS RD&D projects.

Of the eight candidates for the first round of the NER300, no CCS projects were awarded funds, while renewable energy projects were given €1.2 billion in funding. Compared to renewable projects, CCS demonstrations are more complex and require much higher amounts of co-funding. The NER300 seems to be falling short mainly due to insufficient funding and lack of flexibility for CCS projects (Lupion & Herzog, 2013). The second round of funding will support a single CCS project, White Rose in the UK, for up to €300 million (Alstom, 2014; European Commission, 2015).

The UK CCS Commercialisation Programme seems to be operating more successfully than the NER300. The competition also failed to award money in its first round in 2011, but the second round selected both White Rose and Peterhead projects as preferred bidders in 2013 with up to a total of £1 billion available in capital grants (Lupion & Herzog, 2013).

US federal stimulus money has funded many CCS deployments in the US over the last five years, but some of these federally-supported projects have failed to be completed. Most recently, FutureGen was cancelled because there wasn't enough time to complete the project before the September 2015 stimulus fund deadline (Marshall, 2015).

In the US, two additional mechanisms are proposed within President Obama's budget for 2016. First, refundable investment tax credits summing to $2 billion will be available to new and retrofitted power plants with CCS. This mechanism attempts to fund a variety of technologies but is likely to promote more CCS on coal than natural gas due to the constraint that at least 70% of the credits must go to coal-based projects. The second mechanism focuses on carbon sequestration – a tax credit of $10/tonne stored CO_2 through EOR and $50/tonne for all other geologic storage (US Office of Management and Budget, 2015). Time will tell if these two incentives will deliver successful CCS deployment.

Direct financial support may be the best incentive for CCS, but the NER300 and US federal stimulus packages show that design is crucial to the success of these policies.

For financial support to be successful, incentives must provide sufficient funds, flexible terms designed specifically for CCS projects, and reasonable timelines to complete projects.

6.2 The role of stranded assets

The discrepancy between total fossil fuel reserves and carbon dioxide budgets highlights the importance of stranded assets. Stranded assets have played a role in project finances at Gorgon and Boundary Dam. Top-down assessments highlight the vast global scale of potential stranded assets. Fossil fuel assets have real value, which is why CCS plays an important role in these projects and in top-down models.

A key question is how much is an electric utility or a country willing to spend to rescue stranded assets? This will depend on the availability of substitutes for the asset in question, which in turn will depend on the sector and ownership of the asset. Fossil fuels in the transportation sector will be much harder to replace, while substitutes for electricity generation may be easier to find. In terms of US EPA policy, coal resources are threatened to become stranded assets because of the natural gas loophole. But it seems that stranded coal assets are not a significant concern due to the availability of natural gas as a suitable substitute for coal and due to the abundance of shale gas in the United States. This substitution reduces the value of coal as a stranded asset. Alternatively, one would expect that society would be willing to pay much more to rescue petroleum products for transportation rather than coal for electricity generation because of the lack of viable substitutes in the transport sector.

In the case of Boundary Dam, the coal was owned by SaskPower, so though natural gas is a substitute for electricity generation in Canada, SaskPower wanted to find a way to use their lignite asset or they would lose their investment. In the case of a private asset you would expect the owner to have additional incentive to rescue those assets because they will suffer a financial loss should that asset become stranded. Lignite coal is especially likely to be stranded, due to the difficulty moving the fuel (and therefore a lack of a market for exports) and common utility ownership of the fuel. It is telling that though lignite is a small portion of total coal reserves, a large number of demonstrations have been proposed on lignite coal. It seems no coincidence that Boundary Dam, Schwarze Pumpe, and Kemper all operate on lignite, and it therefore seems likely that other utilities with lignite reserves will angle for CCS under restrictive climate policy.

6.3 Fuel use vs. fuel production

The bottom-up assessments in Chapter 4 showcased the fact that financing of CCS was easier at Gorgon, a natural gas processing operation, than it was at the Boundary Dam power plant. But what conclusions can be drawn for other projects? First, it is important to distinguish between two broader types of projects: fuel use projects and fuel production projects.

- **Fuel use** projects are those where a fuel is used to produce another product, such as a power plant or cement processing operation. Here the CO_2 captured is from the input fuel, but a different commodity is produced with no further emissions.
- **Fuel production** projects are those where a fuel is input, processed, and then produced as a commodity, such as natural gas processing or oil refining. In these projects, CO_2 is captured from the fuel during processing, but additional CO_2 will be released when the final commodity (natural gas or oil) is consumed at its end use.

In fuel use projects, up to 90% of the CO_2 embedded in the fuel is captured, usually resulting in CCS additional costs being a high percentage of total capital costs. This makes power plants harder to finance and makes ownership of a fuel a clear driver, again pointing back to lignite.

Oil and natural gas processing operations produce a fossil fuel commodity, meaning the CCS on processing operations captures a much smaller percent of the CO_2 associated with the fuel, making the technology addition a much smaller percent of the total project capital costs than is seen at a power plant.

In the short term, fuel processing operations with CCS are being driven by environmental concerns. Specifically, companies want to reduce the carbon footprint associated with their fuel. For example, the controversial Keystone XL pipeline that would bring heavy oil from Canada to Texas has made the environmental footprint of oil sands a public concern. Environmental groups have pointed out that burning all of Alberta's oil sands could cause an additional 0.4 degrees Celsius of warming (Biello, 2013). The oil sands are among the largest emitters in Canada, and therefore are required to reduce their emissions intensity by 12% or face a \$15/t CO_2 emitted above their required reduction (Alberta Environment and Sustainable Resource Development, 2015). Also, Canada is the largest oil supplier to the US. Therefore, the California Low Carbon Fuel Standard (LCFS), which set limits on the carbon content of imported transportation fuels, was an additional driver for CCS in oil sands operations (Carlifornia Energy Commision, 2012).

These environmental concerns were a driver for Alberta's Quest project to capture 35% of the CO_2 from the processing of bitumen to synthetic crude oil from Canada's oil sands (Global CCS Institute, 2014b). While the details are somewhat different, concern about the carbon footprint was also a driver for the inclusion of CCS in the Gorgon LNG project. Without CCS, Gorgon would be a significant percentage of Australia's national emissions. This helps understand why Chevron agreed to include CCS in the project.

6.4 Role of BECCS

As illustrated in Table 7 in section 5.2.3, bioenergy with CCS is relied on very heavily in recent top-down models to meet two-degree emissions targets, but is a much less demonstrated technology than coal or natural gas with CCS. Biomass used for power generation without CCS is limited in its application due to availability of energy crops, high fuel price, and low conversion efficiencies leading to higher costs compared to coal or natural gas. Due to these factors, biomass-fired electricity generation is orders of magnitude less demonstrated than coal or natural gas. In 2013, electricity generated from woody biomass amounted to 40 TWh compared to 1125 TWh and 1581 TWh generated from natural gas and coal, respectively (U.S. Energy Information Administration, 2013a). Bioenergy with CCS has the benefit of avoiding CO_2 emissions by burning biogenic carbon and then decreasing emissions further by storing that CO_2 underground, providing twice the carbon benefit of other mitigation technologies. BECCS has higher costs than coal and natural gas with CCS, but at the high carbon prices assumed in AMPERE scenarios, models will choose to deploy BECCS widely due to the additional emissions reductions. Even if such a high carbon price was realistic, the widespread deployment of BECCS assumes a dramatic scale up of a technology with a small market share today. Overusing BECCS in these scenarios clouds the role of CCS in meeting climate targets. The inclusion of CCS on bioenergy is likely displacing CCS on coal, natural gas, and industrial operations. This means that the AMPERE scenarios likely overstate the role of BECCS but underestimate the role of coal and natural gas with CCS.

Therefore, the huge role of BECCS likely overemphasizes the ability of CCS to rescue stranded assets, but scenarios with less BECCS would likely have more CCS on coal and natural gas. A scenario with mainly conventional CCS would still rescue large amounts of coal and natural gas, but would likely not have such huge gains in saved mitigation costs.

6.5 Geographic distribution of CCS

Another potentially interesting facet of results is the regional distribution of CCS deployment and stranded assets. Figure 18 shows regional results of CCS deployment from all AMPERE models in the full technology scenario with a 450 ppm target. Note that all graphs have a different scale of total CCS deployed in primary energy units in order to highlight the distribution of CCS. Figure 18 includes CCS installed on coal, natural gas, and bioenergy facilities. Though the scenarios disagree to some extent on the breakdown of CCS installations by region, there does seem to be a prediction that CCS will play a large role in China, the Middle East, Africa, and Latin America (mainly Brazil). India and the United States play a large role in some but not all of the model forecasts.

Most CCS demonstrations have been located in industrialized countries, but widespread deployment will require the majority of implementation to be in emerging economies, as predicted by AMPERE scenarios. This will be especially true for power plants, where current demonstrations are moving forward in the US and EU before they will be implemented in emerging economies. Any delay in implementation in industrialized nations will further delay deployment in other parts of the world, putting more pressure on the US and EU for near-term deployment and making it more difficult to reach climate targets in the long run.

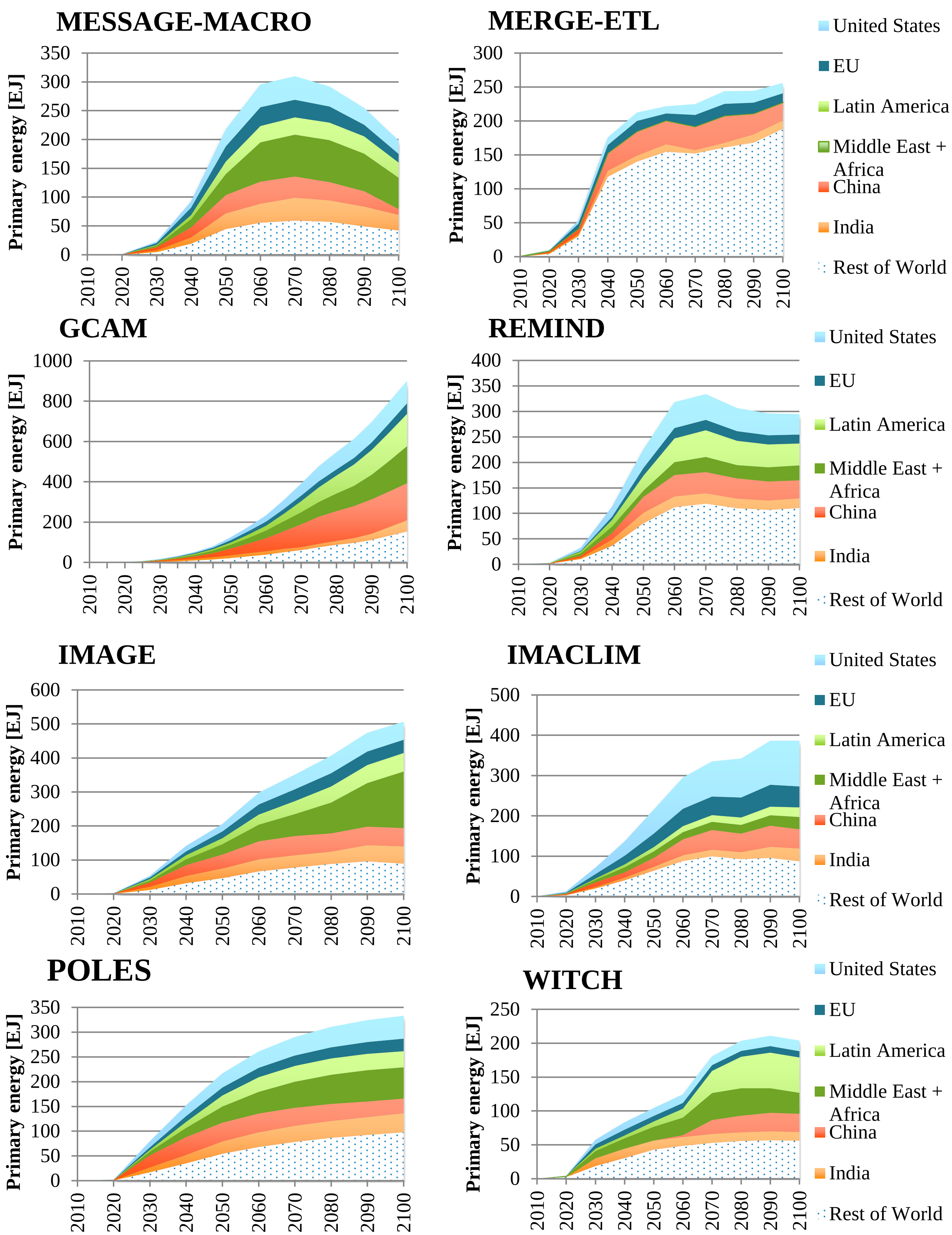

Figure 18: Regional primary energy installed with CCS over 2010-2100 by model[14]

The IEA echoes this expectation, estimating that non-OECD countries will need to account for 70% of CCS implementation by 2050 to meet a 2°C emission target (International Energy Agency, 2012b). If this is the case, emerging economies will certainly want financial assistance from the developed world to help develop CCS. A World Bank report estimates that widespread CCS deployment in the developing world could cost $220 billion between 2010 and 2030 (Kulichenko & Ereira, 2011). It is not clear how to bridge the gap between the need for deployment in developing countries and the need for financing from industrialized countries, but it is clear that this will need to be addressed for CCS to be deployed on a large scale.

The next step would be to analyze the location of stranded assets in scenarios with and without CCS, because those are the areas that one would expect to see potential additional drivers for CCS. The AMPERE model is not well suited to this calculation, as a regional analysis of primary energy will show where fuels are consumed, not where they are extracted and produced.

A different study published in early 2015 created a new analysis in the TIAM-UCL model to compare to IPCC AR5 model runs (McGlade & Ekins, 2015). This modeling effort compares production of coal, oil, and gas between 2010 and 2050 in scenarios with and without CCS. In their 2-degree scenario, they find that without CCS, 88% of coal, 52% of gas, and 35% of oil remains unburnable globally. The largest reserves of stranded coal are in the US, China, India, and former Soviet Union countries. Stranded natural gas is predicted to mainly occur in the Middle East and former Soviet

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[14] It appears that the MERGE-ETL model does not separate out Latin America, the Middle East, and Africa as the other models do, making the "Rest of World" category more substantial.

Union countries. As is to be expected, over half of all stranded crude oil is expected to be in the Middle East, with substantial additional stranded oil in Africa, Canada, former Soviet Union countries and Central and South America (McGlade & Ekins, 2015).

6.6 Possibilities for future work

The top-down analysis done as a part of this thesis started with robust modeling completed by the AMPERE study. This has given a good introduction into quantifying the global scale of stranded fossil fuel assets and the ability of CCS to rescue coal, natural gas, and oil reserves. However, there are opportunities for further refinement and research.

First, all the top-down models explored in this thesis assume a global carbon price starting in 2010, not unusual for the IPCC and other global climate modeling exercises. A good next step would be to recreate the kind of analysis undertaken in this thesis with more realistic scenarios of delayed or fragmented climate action combined with CCS-restricted scenarios. Understanding how alternative policy pathways impact stranded assets could lead to new insights into the role of CCS.

Second, scenarios with limited and no BECCS need to be evaluated for mitigation costs and stranded assets with implications for CCS on coal and natural gas. In 450 ppm AMPERE scenarios, anywhere from 28-100% of all CCS was on bioenergy. Though it may be feasible in the future to have such widespread bioenergy, scenarios with limited bioenergy with CCS must be explored considering the uncertainty about BECCS deployment. Scenarios with limited BECCS will make ambitious climate targets more difficult to reach, but will make CCS on coal and natural gas, along with other low carbon options, much larger players in the mitigation mix. Widespread use of BECCS likely also underrepresents global mitigation costs, so limited bioenergy scenarios will highlight the extent to which that is or is not true.

Third, and finally, multiple modeling efforts make claims about the ability of CCS to increase the use of fossil fuels, including the McGlade & Ekins paper mentioned above, all making different claims ranging from huge to negligible impacts. There must be more work done to bring transparency to these studies to make them comparable in a way that can help policymakers make sense of how to incentivize CCS and other low-carbon technologies.

Chapter 7: Conclusions

This thesis explores the extent to which various types of policy incentivize CCS and whether CCS deployment can be helped by concerns of stranded fossil fuel assets. It is clear that technology-specific regulations in the US are not incentivizing CCS and in Canada they are only incentivizing CCS due to the risk of stranded lignite and financial help from subsidies and by-product revenues. It seems stranded assets may have also played a role in project finances at Gorgon along with favorable natural gas markets in Asia. Top-down assessments highlight the vast global scale and value of potential stranded assets. From these analyses, five key conclusions are drawn.

1. CCS has the potential to rescue 12,000-22,000 EJ (equivalent to 800-1600 Gt CO_2) of coal, natural gas and oil stranded by climate policy and has the potential to reduce global mitigation costs 35-100% compared to a scenario without CCS over the timeframe of 2010-2100. It is therefore more important than ever that policies incentivize the near-term deployment of CCS to unlock the potential to rescue stranded assets and reduce long-term mitigation costs.
2. In light of the fact that current policies are not incentivizing CCS at the scale modeled in climate stabilization scenarios, it is clear that the design of policy is crucial. Carbon pricing mechanisms must have a price high enough to incentivize CCS; command and control policies must not create loopholes by excluding certain technologies; and financial incentives must provide sufficient funds, flexibility, and time to complete projects.
3. The role of bioenergy with CCS (BECCS) in top-down climate stabilization scenarios needs to be better understood to clarify the role of CCS on coal and

natural gas. Current modeling seems to be overly optimistic regarding BECCS, which results in overemphasizing the decrease in mitigation costs of CCS and underestimating the quantity of CCS on coal and natural gas.

4. On an individual project level, stranded assets have the most value when there is no viable substitute available (e.g., transportation fuels) or when the fuel user also owns the asset (e.g., utility-owned lignite).
5. CCS on fuel production processes (e.g. oil refining and natural gas processing) are easier to finance than fuel utilization processes (e.g. power generation and cement production), but power plants remain the biggest potential market for CCS if it is to become a major climate mitigation technology.

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Appendix A. Boundary Dam economics

The purpose of this appendix is to expand on the economics of the Boundary Dam project included in Chapter 4.

A.1. Given data

Figure A1 is an original figure from SaskPower that shows the scale of electricity costs by category, but no absolute numbers as it was originally displayed (Daverne, 2012).

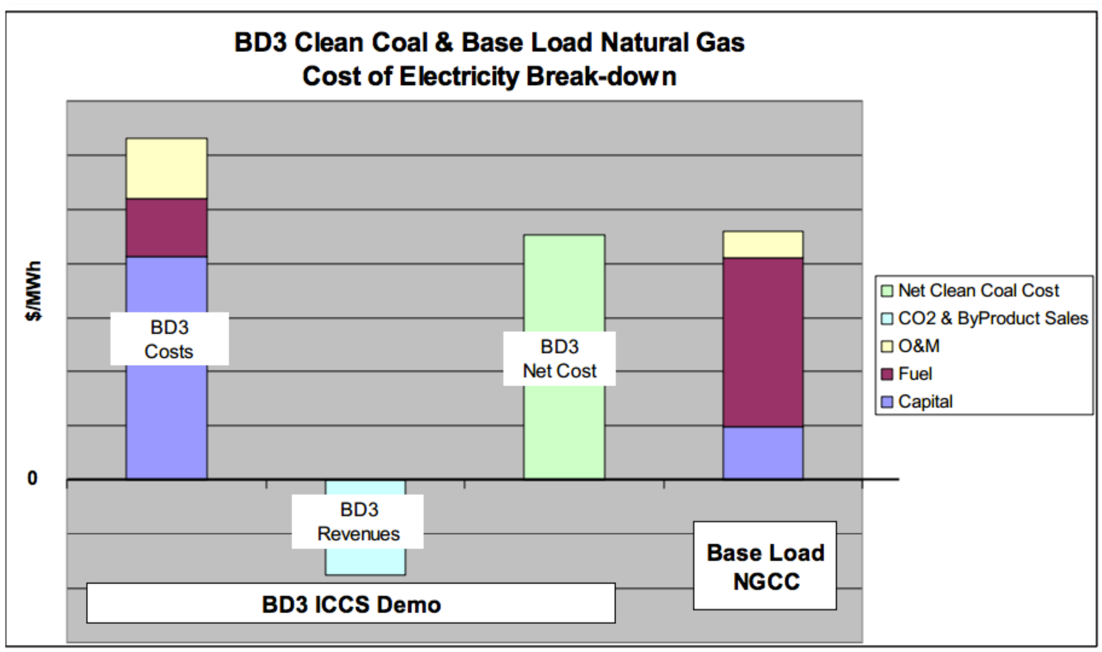

Figure A1: SaskPower scale estimate of Boundary Dam cost of electricity by category [$/MWh]

A.2. Updated analysis

To estimate the absolute value of these costs, relative values were multiplied by different potential options for the scale of each line. In Table A1 two reasonable possibilities are estimated: the horizontal grid lines being $10/MWh or $20/MWh.

Table A1: Quantitative estimates of Boundary Dam cost of electricity

	Capital	Fuel	O&M	Revenue	Total Cost
Grid lines=$10/MWh					
Boundary Dam	42	11	11	-18	46
NGCC	9	32	5	0	46
Grid lines=$20/MWh					
Boundary Dam	**84**	**22**	**22**	**-36**	**92**
NGCC	**18**	**64**	**10**	**0**	**92**

Each cost category is then back calculated to a reasonable value for each set of costs. The second set of numbers (equivalent to grid lines equaling $20/MWh) is the only reasonable option, which will be shown below in the results of each category exercise. In addition to believing that the costs in each category are reasonable, the total cost of $92/MWh is in line with SaskPower's statement that their target final cost of electricity was between $70 and $90/MWh (Monea, 2014). Figure A2 incorporates the assumption that the scale lines are equal to $20/MWh.

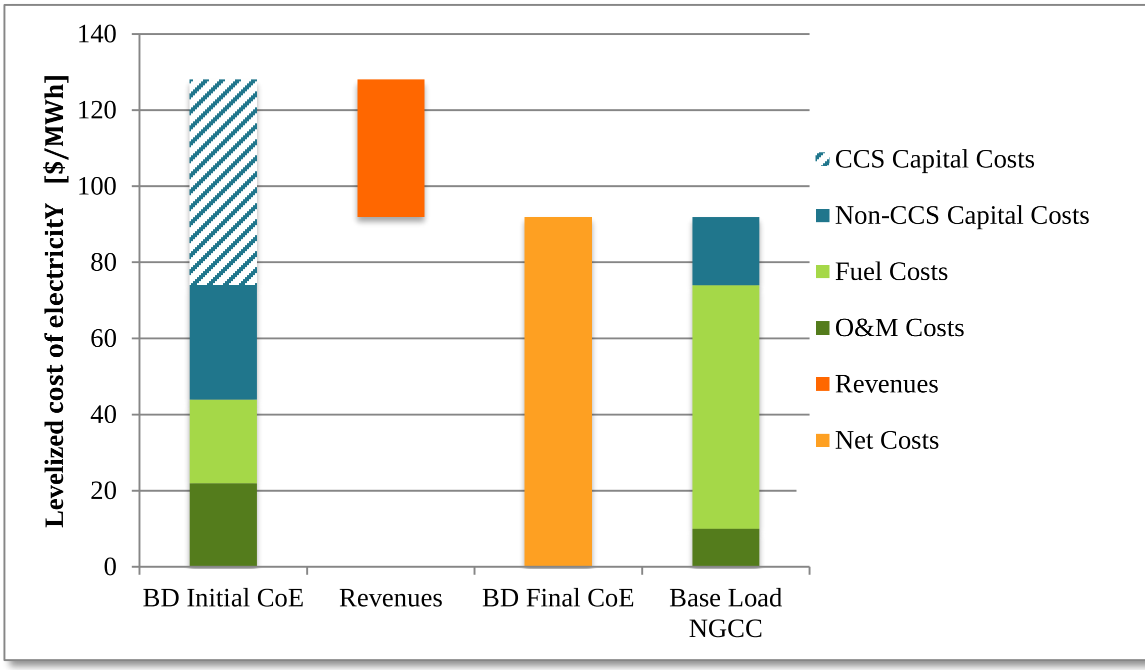

Figure A2: Recreation of original SaskPower graph with additional analysis from this appendix

A.1.1. Capital costs

Originally, capital costs were estimated at $1.1 billion, with a $240 million subsidy from the Canadian government. At a size of 110 MW, this means that Boundary Dam had capital costs of $10,000/kW (includes interest during construction) before the subsidy, which is more than two times the $3,570/kW overnight capital cost estimate (excludes interest during construction) from US DOE (U.S. Department of Energy, 2013).[15]

Electricity costs (in $/MWh) are equal to overnight capital costs plus interest during construction (in units of $/MW) multiplied by a CCR and divided by active hours the power plant operates in a year (equivalent to the capacity factor multiplied by the total hours in a year). If it is assumed from Table A1 that levelized cost of electricity

[15] All LCOE estimates from DOE are reported in $2007

(LCOE) associated with capital costs is $84/MWh, either a capacity factor (CF) or a capital charge rate (CCR) can be estimated and the other value can then be calculated (see Table A2).

Table A2: Estimates for capacity factor and capital charge rate for the Boundary Dam project

LCOE	$84/MWh	$84/MWh	$84/MWh
Capacity Factor	0.80	**0.85**	0.9
CCR	0.075	**0.08**	0.85

Table A2 leads to the estimation that the capacity factor for Boundary Dam calculations is likely to be 85%. US DOE estimates that the capacity factor for a pulverized coal unit with 90% capture of CCS to be 85% (U.S. Department of Energy, 2013). Moreover, it is unlikely that a higher estimate would have been used for capacity factor, and it is equally unlikely that a lower number would have been used for capital charge rate.

SaskPower has publicly stated that with the increase in total costs from $1.1 to $1.3 billion, $800 million was for CCS costs and $450 million was for other costs (Monea, 2014). This ratio of costs is represented in Figure A3, however, the total cost increase is not represented in the cost of electricity analysis presented in this appendix. Based on conversations with SaskPower representatives, capital costs do not include CO_2 transportation, storage, and monitoring.

A baseline NGCC power plant, on the other hand, is estimated by Table A1 at $18/MWh for capital costs. Comparing this to estimates from DOE, a $718/kW overnight capital cost at the same CCR and CF is equivalent to $7.7/MWh, significantly lower than SaskPower's estimates. Besides needing to add in interest during construction, a higher cost structure at SaskPower due to the remote location and high costs from competition with oil sands operations, can help explain the difference.

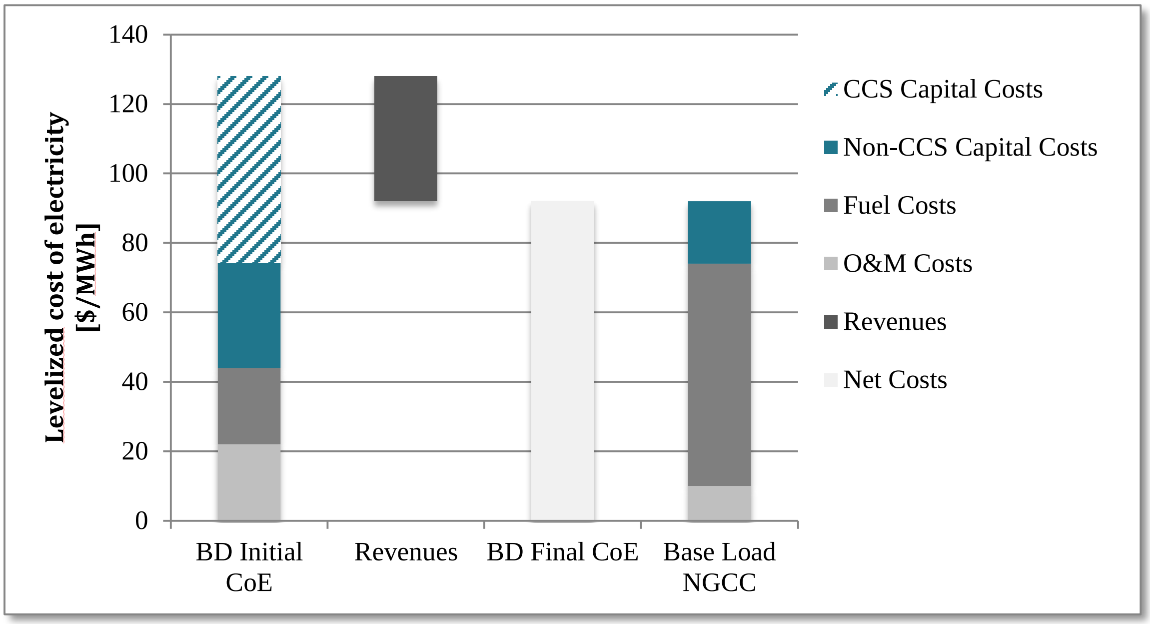

Figure A3: Levelized capital cost estimates from Boundary Dam

A.1.2. Fuel costs

If it is assumed from Table A1 that fuel cost estimates are $22/MWh for pulverized coal with CCS and $64/MWh for baseline NGCC, the original fuel costs can be back calculated in $/MMBtu. To calculate the fuel cost in $/MMBtu the original electricity cost from fuel can be taken from Table A1 and divided by a heat rate. Results are given in Table A3.

Table A3: Assumptions and calculations for lignite coal and natural gas for Boundary Dam and a baseline NGCC plant

	Electricity Cost from fuel [$/MWh]	Heat Rate [Btu/kWh]	Fuel cost [$/MMBtu]
Pulverized Coal	22	12002	1.83
NGCC	64	6798	9.41

For coal, this means that local lignite costs to SaskPower are about $1.83/MMBtu, which is a reasonable low cost for lignite that does not need to be transported. Natural gas, on the other hand, is estimated to be quite expensive at $9.41/MMBtu. One explanation for this high estimate is the fact that SaskPower has stated that they used a 30-year time horizon as the basis for their fuel cost (Monea, 2014). A higher estimate assumes that current low-natural gas prices are an unrealistic expectation for the next 30 years.

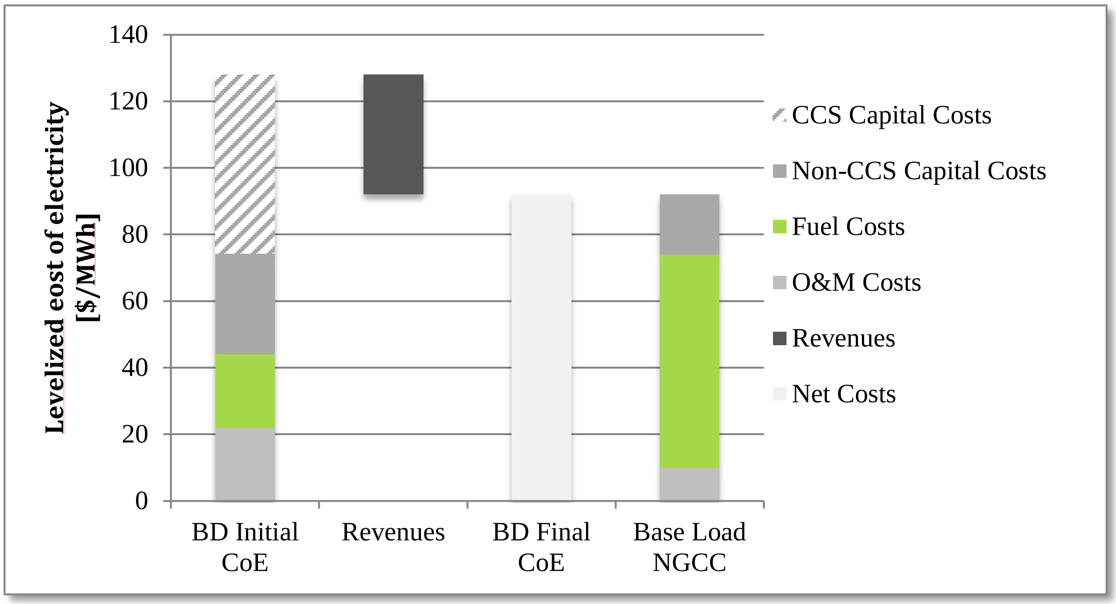

Figure A4: Levelized fuel cost estimates from Boundary Dam

A.1.3. O&M costs

Operations and maintenance (O&M) costs are typically broken up into a fixed cost (a set cost each year) and variable cost (based on amount of electricity generated). To check the estimates from Table A1, DOE performance parameters were used for a typical SCPC plant with CCS and a typical NGCC plant, with the comparison shown in Table A4. It looks like SaskPower assumes a lower O&M estimate for coal, and a higher

O&M estimate for NGCC, coincidently the skew that would most favor using lignite at Boundary Dam.

Table A4: Comparison of SaskPower and DOE estimates for O&M costs of electricity

	SCPC with CCS	NGCC
DOE	**27.5**	**5.5**
Fixed	16.5	3.8
Variable	11	1.6
SaskPower	**22**	**10**

Figure A5 highlights the O&M portion of costs by SaskPower estimates of total cost of electricity.

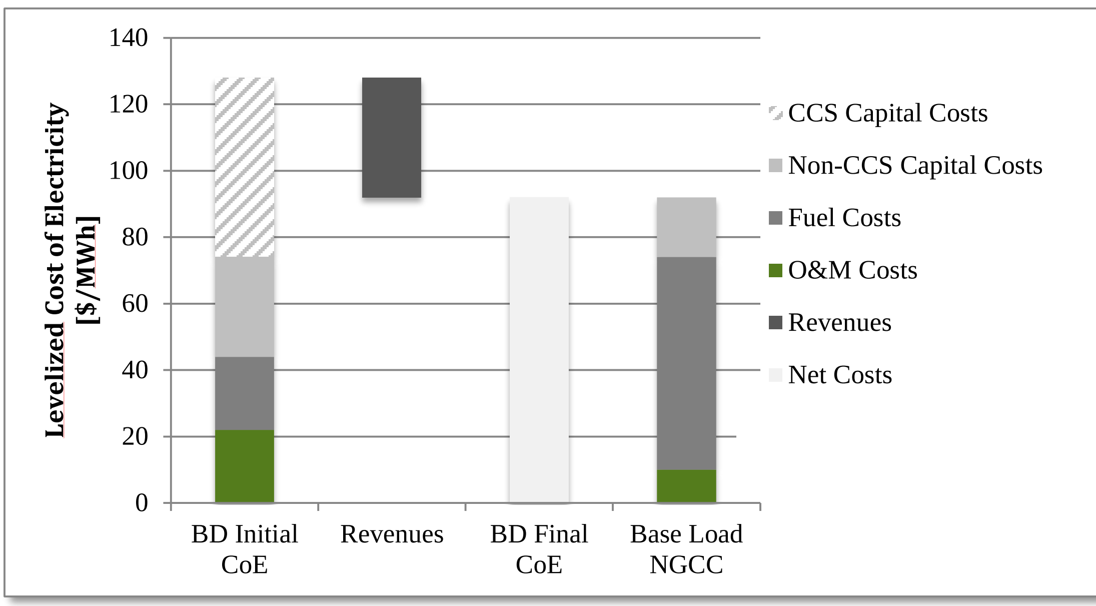

Figure A5: Levelized O&M cost estimates from Boundary Dam

A.1.4. Revenue

Table A1 highlights the fact that total revenue is estimated at $36/MWh. Revenue is divided between three categories: CO_2 sold for EOR, sulfuric acid sold for industrial purposes and fertilizer, and fly ash sold for concrete production (Monea, 2014). The goal in this section is to estimate the CO_2 price that SaskPower is including in their calculations by first calculating the revenue from sulfuric acid and fly ash.

To calculate prices of sulfuric acid and fly ash, a simple mass balance was completed and used ash and sulfur content estimates from MIT's Future of Coal Study for North Dakota lignite (Massachusetts Institute of Technology, 2007). Finally, cost estimates for sales of both by-products were included to find the final price per tonne of CO_2 produced. It is assumed that there is approximately 1 tonne CO_2 released per MWh of electricity generated.

Table A5: Estimates of all revenue sources at Boundary Dam

	Price $/tonne		**Price [$/t CO_2]**	
	Low estimate	High Estimate	Low Estimate	High Estimate
Sulfuric Acid	$60[16]	$300[17]	$0.77	$8.90
Fly Ash	$6[18]	$45[19]	$0.31	$4.37
CO_2	-	-	**$34.90**	**$22.70**
Total Revenue	-	-	$36.00	$36.00

This means that CO_2 is being sold for between $23 and $35/tonne from Boundary Dam, compared to the $10-16/tonne CO_2 historical average for EOR in the Permian Basin, expert estimates of $15-30/tonne CO_2, and DOE hopeful scenarios of $45/tonne CO_2 (Carter, 2011; Intergovernmental Panel on Climate Change, 2005; National Energy Technology Laboratory, 2008). Figure A6 visualizes revenue sources from Boundary Dam utilizing the average of the high and low estimates from Table A5.

[16] Spot prices from CFR US Gulf from December 2013 as quoted in Figure 7 SaskWind analysis (Glennie, 2015)
[17] Wholesale prices from South Africa for fertilizers, available online: http://www.alibaba.com/product-detail/Sulfuric-acid-sulphuric-acid_180704223.html
[18] $5.68/tonne from a coal power plant report (Great River Energy, n.d.)
[19] $20-45/tonne for "concrete quality fly ash" from American Coal Ash Association

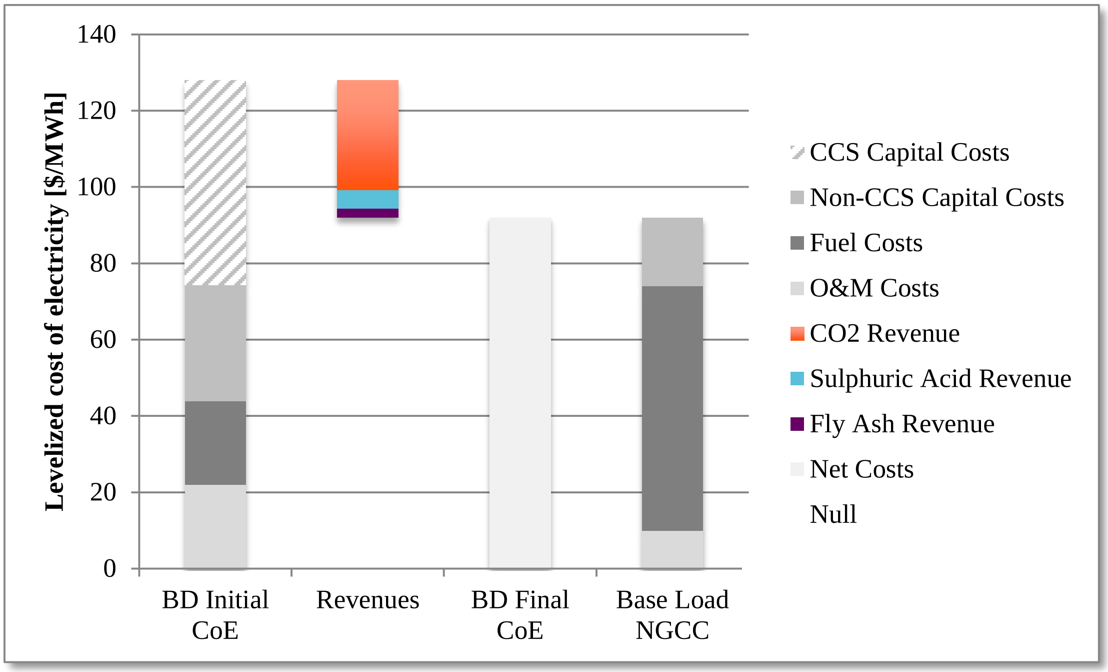

Figure A6: Levelized revenue estimates from Boundary Dam