Rethinking CCS – Strategies for Technology Development in Times of Uncertainty

by

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Submitted to the Engineering Systems Division
in Partial Fulfillment of the Requirements for the Degree of
Master of Science in Technology and Policy

at the

MASSACHUSETTS INSTITUTE OF TECHNOLOGY

June 2013

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Abstract

Concerns over climate change and a reliance on CO_2-emitting fossil fuels for a majority of the world's energy supply have motivated the development of carbon dioxide capture and storage (CCS). However, CCS is not yet commercially available, and key technical roadblocks remain. However, the external circumstances for developing the technology, such as weak climate policy and tight public finances, have changed dramatically over the past four years and current RD&D roadmaps are poorly adapted to the new realities. In order to rethink U.S. CCS policy, and to provide a *realistic* roadmap for technology development, this thesis provides an overview of the key technical roadblocks, an analysis of the impact of the new realities on CCS investments, and a novel method for finding the optimal way of allocating scarce public resources to CCS RD&D.

The U.S. has responded to the changing political context in two notable ways. First, Enhanced Oil Recovery (EOR) has received increased attention due to the positive value that EOR storage puts on CO_2. Second, the EPA has proposed a 1000 lbs CO_2/MWh emission standard that would require new coal plants to install CCS. Using a stochastic generation expansion model, this thesis concludes that low natural gas prices make fuel switching rather than CCS investment the most likely compliance method. Moreover, should these standards be gradually tightened, CCS will likely be deployed on natural gas plants before coal plants. More generally, the model highlights the importance of considering uncertainty when analyzing CCS investments, and results differ notably depending on whether probability distributions over parameters are considered or not.

With limited funds available for technology development there is a striking need to ensure that limited resources are allocated strategically. Whereas designing optimal technology RD&D portfolios has traditionally been dealt with qualitatively, this thesis develops a quantitative model for choosing optimal portfolios of demonstration projects. The strength of new model is how it incorporates the different uncertainties associated with CCS, allowing decision makers to observe how different underlying assumptions affect project choices.

Based on my analyses, I make six recommendations for CCS technology development in times of uncertainty, many of which are major departures from current U.S. CCS policy. First, the U.S. should focus more on pilot-scale development of novel capture concepts promising to significantly reduce cost. Second, if gradually tightening emission standards is to be the primary mechanism to reduce power sector CO_2 emissions, then the U.S. should also demonstrate CCS on natural gas plants. Third, granting a limited number of coal plants a higher CO_2 emission standard could help bring CCS plants online in challenging times. Fourth, relying almost exclusively on projects with EOR storage is unlikely to be a sound long-term policy. Because of the significant variability across geologic storage reservoirs, at least some demonstration projects must focus on CO_2 storage in saline formations. Finally, with tightening public finances it becomes increasingly important to coordinate demonstration efforts globally to avoid unproductive overlap.

Thesis supervisors:
Howard Herzog, Senior Research Engineer, MIT Energy Initiative
Mort Webster, Associate professor, Engineering Systems Division

Acknowledgements

My two years at MIT have been beyond all expectations, and there are a large number of individuals to whom I am in great debt for making my time here in Cambridge so rewarding. First among those are my two advisors whose insight and support has taught me invaluable lessons that are valid far beyond my work on CCS.

To Howard Herzog, for your patience, support and direction during my two years working on CCS. I have benefited greatly from your rigor and attention to detail, but more so from your ability to, and passion for, explaining complex issues in a straightforward and understandable manner. To Mort Webster, for providing me with the opportunity to work in a field that was the reason I came to MIT. Your work on decision-making under uncertainty is truly inspiring, and I hope to continue using what I learnt from you in many years to come.

I am very grateful for the financial support of my research by the MIT Carbon Sequestration Initiative, and to the amazing students that were part of the group. To Rob, Anna, Amanda, Cristina and Sadia for so many great conversations, and to Mary for being such a supportive and friendly person.

To TPP for the amazing group of people you bring to the program. To my friends for making my time at MIT not simply academically rewarding, but also so much fun. To the MIT Energy Initiative and the Webster group who provide such an exciting environment for researching the world's most pressing energy challenges.

To the MIT Energy Conference organizers, and particularly Sadia and Jorge for all the long, sometimes frustrating, but eventually extremely rewarding, hours we put into the content of this year's Conference.

To my grandparents, for always showing so much heartfelt enthusiasm and joy over what I do, and for teaching me that all is possible through hard work. To my sister, Mari, for so many great years growing up.

To Kristine, for three amazing years together. Your love, patience and support through many long nights have always kept me up. I am glad this is only the beginning.

Finally I would like to thank my parents for your love and support through all my endeavors. You are a much greater inspiration than you think.

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List of Acronyms

ARRA	American Recovery and Reinvestment Act
Btu	British thermal unit
CCGT	Combined Cycle Gas Turbine
CO_2	Carbon dioxide
CO	Carbon monoxide
CCS	Carbon capture and storage
DOE	U.S. Department of Energy
EIA	U.S. Energy Information Administration
EOR	Enhanced Oil Recovery
EPA	U.S. Environmental Protection Agency
EU	European Union
GCCSI	Global CCS Institute
GW	Gigawatt
IEA	International Energy Agency
IEAGHG	IEA Greenhouse Gas R&D Programme
IGCC	Integrated gasification combined cycle
IPCC	Intergovernmental panel on climate change
kW	kilowatt
kWh	kilowatt-hour
LCOE	Levelized cost of electricity
MEA	Monoethanolamine
MIT	Massachusetts Institute of Technology
MIT CSI	MIT Carbon Sequestration Initiative
MMBtu	Million British thermal units
MT	Megaton
MW	Megawatt
MWh	Megawatt-hour
NCADAC	National Climate Assessment and Development Advisory Committee
NETL	National Energy Technology Laboratory
N_2	Nitrogen
OCGT	Open Cycle Gas Turbine
O&M	Operation and maintenance
R&D	Research and development
RD&D	Research, development and demonstration
RPS	Renewable portfolio standard
UK	United Kingdom
UN	United Nations

Chapter 1 - Introduction

With its promise of nearly CO_2-free electricity from fossil fuels, carbon dioxide capture and storage (CCS) has been viewed as an important option to consider for reducing greenhouse gas emissions. However, CCS is yet to be an “off-the-shelf “ mitigation technology and technology development is still needed before CCS is commercially available. Consequently, over the past decade aggressive roadmaps were laid out for CCS development and deployment. However, it is highly unlikely that the primary driver for investment in CCS projects, namely stringent climate policy, will be in place in the U.S. in the foreseeable future. In addition, public deficits, resulting from heavy stimulus spending and the economic downturn, are putting downward pressure on subsidies for early technology development.

The U.S. government has responded to the lack of climate markets in two notable ways that are changing the drivers for CCS investments. First, the Environmental Protection Agency (EPA) has announced, but net yet finalized, a stringent CO_2 emission standard that in practice bans new coal plants without CCS. Second, the U.S. Department of Energy (DOE) has rebranded their CCS strategy as “CCUS”, Carbon Capture *Utilization* and Storage. In practice, “utilization” means using captured CO_2 for Enhanced Oil Recovery (EOR) to increase oil production.

The realities and dangers of climate change are only becoming more apparent and the need for low-carbon technologies such as CCS is therefore only increasing. At the same time it is clear that the external realities for CCS have changed considerably, and the initial roadmaps for technology development may no longer be feasible. As a result there is considerable confusion about the path forward for CCS technology development. While a limited number of demonstration projects are moving ahead, many others are either being put on hold or cancelled. Even more troubling, there are no programs in place to initiate new demonstration projects after the existing projects run their course. With tight public finance resulting in fewer demonstration projects than initially believed, it is of increasing importance that scarce funds are spent strategically in order to overcome the barriers to commercialization. Unfortunately no such strategic plan for CCS technology development has been announced that takes into consideration the drastically changed external realities.

What is a realistic roadmap for moving CCS technology to commercial readiness despite the new and challenging external circumstances? Answering that question is the objective of this thesis. In order to answer the question, three distinct analyses were conducted:

- *Determine the roadblocks* that need to be overcome in order for CCS technology to be commercial
- *Determine how the short- and long-term outlook for CCS has changed, and what these changes imply for public and private investment in CCS*
- *Determine how to optimally allocate public funds to overcome the roadblocks* to commercialization

The thesis is structured into seven chapters:

Chapter 2 will present an overview of CCS technology and the current state of CCS demonstration projects in the U.S. and worldwide. The chapter will conclude with what the focus should be for a technology development program whose goal is to make CCS commercial as a mitigation technology.

Chapter 3 will present the roadmaps that were initially laid out for CCS commercialization, and will investigate whether the assumptions on which they were based are still valid. The chapter will analyze how the short- and long-term realities have changed in general, and what these changes imply for both public and private investment in CCS.

Chapter 4 will take an in-depth look at how the short-term outlook for CCS investment changes with a CO_2 emission standard for new power plants. A stochastic generation expansion model is employed to determine the effect of different emission standards on investment decisions in new power plants, and how these decisions change with different natural gas and EOR prices. The model is stochastic to allow for an explicit treatment of the uncertainty surrounding the commercial-scale cost and performance of power plants with CCS.

Chapter 5 will investigate whether continued public involvement in CCS technology commercialization is justified despite the new and challenging external realities, and particularly given the lack of short-term incentives for technology deployment.

Chapter 6 will develop a mathematical optimization model for how to optimally invest in CCS demonstration projects in order to overcome some of the roadblocks to commercialization. While quantitative tools exist for aiding decision making under uncertainty, few of them have been applied to develop mathematical tools to aid public investments in CCS. Such tools are of increasing importance when uncertainty over future climate policy and technology performance is large, and when funding is increasingly tight. In order to better inform the path forward for CCS the optimization model is used to help determine the optimal allocation of funds across a portfolio of demonstration projects. Part of the analysis will look at the conditions under which the recent shift by the Department of Energy to focus exclusively on demonstration projects with EOR storage is advisable.

Using the insight of the first six chapters, chapter 7 will propose ways to redesign a realistic U.S. roadmap for CCS technology development in times of uncertainty.

Chapter 2 - CCS today

Carbon capture and storage (CCS) refers to the process of capturing CO_2 from large point sources and injecting it underground for long-term storage. CCS targets the large, stationary sources of CO_2 listed in Table 1. While CCS has been proposed as a technology to reduce CO_2 emissions from industrial sources, power plants represent close to 80% of the total CO_2 emissions from this group (Herzog & Eide, 2013). This chapter and thesis will therefore focus on technologies for applying CCS to power plants.

Table 1: Share of fossil fuel CO_2 emissions appropriate for CCS. Source: Herzog & Eide (2013), adapted from (IPCC, 2005) Table 2.3[7]

Source	Share
Coal-fired power plants	59.7%
Natural gas-fired power plants	11.3%
Other power plants	7.0%
Cement	7.0%
Refineries	6.0%
Iron & Steel industry	4.0%
Petrochemical industry	2.0%
Other	0.6%

The chapter will first address the current state of CCS technology and the barriers to be overcome for CCS to be a commercial climate mitigation technology. It will then give a brief overview of the current demonstration projects underway in the U.S and internationally, and will describe regulatory barriers for CCS that exist in the U.S.

2.1 - CCS technology

2.1.1 - Capture

Capturing CO_2 from power plants can either be done after combustion (post-combustion), before combustion (pre-combustion), or by the burning fossil fuels in oxygen such that the flue gas contains mostly CO_2 and water vapor (oxy-combustion) (IPCC, 2005).

The most common and commercially mature process for CO_2 capture is post-combustion capture using chemical absorption (MIT, 2007). Post-combustion capture using amines was first invented in the 1930s, and commercial units for natural gas separation processes and slip streams from power plants are offered by a number of technology vendors (Rubin et al., 2012). In an absorption-based capture process the CO_2 in the flue gas reacts with a solvent in an absorber. Close to CO_2-free flue gas exits the stack, and the CO_2-rich solvent is directed towards a stripper. In the stripper the absorption reaction is reversed using energy provided by steam that is extracted from the power plant steam cycle. Many types of solvents may be used in the capture process, but the most common has historically been monoethanolamine (MEA) (MIT, 2007).

The biggest challenge with post-combustion chemical absorption is that it requires significant amounts of heat to regenerate the solvent. Heat is required both to break the chemical bond between the solvent and CO_2, but also to raise the temperature of the aqueous CO_2-rich solvent entering the stripper and to produce stripping steam (Oexmann & Kather, 2010). In addition to the significant energy requirements of current amine-based capture processes, the high capital cost of capture units would add significantly to the cost of generating electricity (Rubin et al., 2012).

Pre-combustion capture for coal-fired power plants refers to a capture process where carbon is removed from the fuel prior to combustion in an Integrated Gasification Combined Cycle (IGCC) plant. In IGCC plants coal is first gasified in order to produce syngas (a mixture of CO and H_2). To produce CO_2, the syngas passes through a water-gas shift reactor where CO reacts with steam to produce CO_2 and H_2. CO_2 is then captured and compressed for storage and H_2 is burned to generate electricity in a turbine. The benefit of pre-combustion capture is that the flue gas is at high pressure and has a high CO_2 concentration. Consequently, physical absorption can be used to capture CO_2 rather than chemical absorption, resulting in significantly lower energy requirements. While the capture process itself has a lower cost relative to post-combustion processes, the higher capital costs of IGCC plants is the main barrier to their widespread adoption (MIT 2007, Rubin et al, 2012).

The principal idea behind oxy-combustion is to burn coal in pure oxygen rather than air, eliminating the large concentration of N_2 that is normally present in flue gas. Burning coal in pure oxygen leads to very high combustion temperatures, and parts of the flue gas therefore needs to be recycled into the combustion chamber in order to bring the temperature of the exhaust gases down to acceptable levels (MIT, 2007). Combustion products are CO_2 and water vapor, which can be easily condensed, leaving an almost pure CO_2 stream. While the energy requirement of the capture process is much lower for an oxy-combustion unit, the production of high-purity oxygen requires significant amounts of energy. An air separation unit is required on site to provide enough oxygen for the combustion process and the energy required for the oxygen separation process significantly reduces the power output of the power plant (MIT, 2007).

The high cost of existing post-combustion capture technologies has spurred a significant R&D effort directed at lowering the cost of capture. These R&D pathways can generally be grouped into liquid solvents, solid sorbents and membranes (Rubin et al., 2012).

The first R&D pathway is directed towards developing new types of liquid solvents. These can be chemical solvents, such as MEA, that capture CO_2 through a chemical reaction, or physical solvents. Better solvents are designed to have high CO_2 capacity, fast reaction kinetics, to be less corrosive and less prone to degradation from flue gas impurities as well as have a low cost (Oexmann & Kather, 2010). The amine piperazine, being developed at the University of Texas is one example of a promising new solvent (Rubin et al., 2012).

A second R&D pathway to lower the cost of capture is solid sorbents. Solid sorbents work by fixing CO_2 on the surface of a solid material and then releasing the CO_2 when the pressure or temperature is changed. Solid sorbents offer the benefit of lower energy requirements for regeneration because, among other things, they avoid the need to heat and cool large amounts of water. A key challenge that needs to be overcome in order for solid sorbents to be competitive with liquid solvents is how to handle the large amounts of solids that would have to be processed at a commercial-scale capture facility (Rubin et al., 2012).

A third R&D pathway for lowering the cost of CO_2 capture is to use membranes. Membranes that have a high CO_2-to-N_2 selectivity could separate CO_2 from flue gas without the use of steam or chemicals (Rubin et al., 2012). Unfortunately, membranes work best when the CO_2 partial pressure is high. Membranes are therefore more likely to be applied to pre-combustion capture in IGCC plants where the flue gas is at higher pressure and has a high CO_2 concentration. The low partial pressures of CO_2 in flue gas from traditional fossil fuel-fired power plants would require very large membrane surface areas if used in post-combustion capture (Rubin et al., 2012).

2.1.2 - Transport and storage

There are currently 3,600 miles of CO_2 pipelines in the U.S. that transport CO_2 from natural sources to EOR operations (DOE, 2010). Despite there being a number of questions regarding what a potential future CO_2 pipeline network might look like, "*transport of CO_2 over moderate distances (e.g., 500 km) is both technically and economically feasible*" (Herzog, 2011). CO_2 transport by pipeline is not a key technical barrier to the commercial readiness of CO_2 and will therefore not be treated more in-depth in this thesis.

There are three primary types of geological formations that have been considered relevant for long-term CO_2 storage (MIT, 2007):

- **Oil and gas reservoirs:** Having proven that they can hold oil and gas in place for millions of year, these reservoirs are good candidates for long-term storage.

Active oil reservoirs have also received significant attention due to the prospect of using captured CO_2 in EOR.

- **Deep saline formations:** These formations consist of porous rock filled with brine. A key advantage is their abundance, allowing for large quantities of CO_2 to be stored.
- **Unmineable coal seams**: Layers of coal underground that have been deemed uneconomic to mine could prove a good candidate for long-term storage, yet there is little experience in injecting CO_2 into these types of formations.

In order for CCS to be a viable climate mitigation technology, CO_2 must be safely stored for thousands of years in the reservoirs where it has been injected. For the first years after injection, CO_2 will primarily be prevented from migrating to the surface by low-permeability cap rocks (structural trapping). As time after injection increases, capillary forces in the formation will immobilize more and more of the CO_2 (residual CO_2 trapping). Over longer time horizons (see Figure 1), CO_2 will dissolve in the formation water (solubility trapping), and eventually be converted into carbonate minerals (mineral trapping) (IPCC, 2005). These trapping mechanisms are not yet fully understood, but as noted by MIT (2007), current understanding is sufficient to confidently state that essentially all of the stored CO_2 will remain in place for thousands of years and probably much longer.

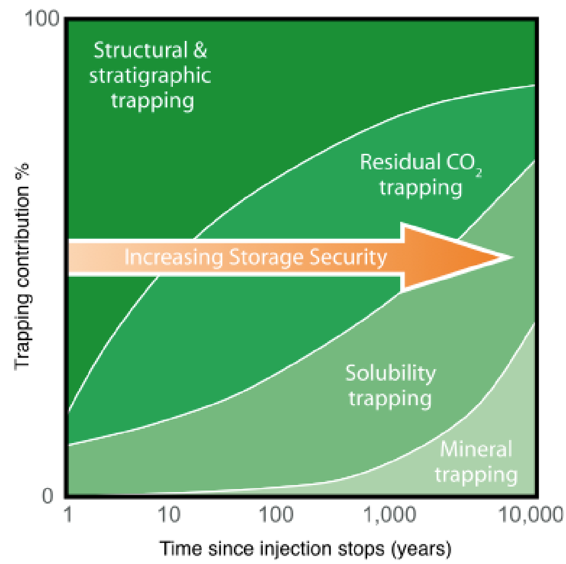

Figure 1: Different storage mechanisms over time. Source: IPCC (2005) fig 5.9

If CO_2 is to contribute to mitigating climate change it will need to operate at a gigaton-per-year scale (Herzog, 2011). Consequently, a significant number of storage reservoirs will be needed to handle the large amounts of CO_2 captured. The exact storage potential for CO_2 in the U.S. is hard to determine, however some argue that there is enough storage capacity for at least a century of emissions from coal-fired power plants (Szulczewski et al., 2012). These estimates are nonetheless very uncertain and show significant variability. Estimates for U.S. storage capacity for example range from 2 gigatons to 3747 gigatons CO_2 (MIT, 2007). The large range is due to the difficulty of confidently assessing the total capacity of heterogeneous reservoirs when site-specific data is limited (MIT, 2007; IPCC, 2005). While there is a large amount of well and seismic data for oil and gas fields, there is limited data for the main type of CO_2 storage formation, namely saline formations (IPCC, 2005). Furthermore, the interplay between the storage mechanisms mentioned above is very complex, and depending on the assumptions made, one obtains different capacity estimates (IPCC, 2005). Narrowing the uncertainty range would require in-depth knowledge of each individual reservoir, through for example well cores that are expensive to obtain, and detailed modeling of the storage mechanisms. Reducing the uncertainty in storage capacity will be important if CCS is to play a role in climate mitigation, and it is particularly important to lower the uncertainty surrounding the lower bounds of current estimates.

Despite successful commercial-scale CO_2 injection at a handful of locations worldwide, including In Salah (Algeria)[1] as well as Snøhvit and Sleipner (Norway), two recent articles have cast doubts about the viability of large-scale CO_2 storage in geologic formations. Zoback & Gorelick (2012) argue that large-scale CO_2 injection would trigger smaller earthquakes in many of the locations currently considered for CO_2 storage in the U.S. The authors worry that even small- and medium-sized earthquakes "*threaten the seal integrity of a CO_2 repository*" and that CCS will therefore "*be an extremely expensive and risky strategy for achieving significant reductions in greenhouse gas emissions*". Ehlig-Economides & Economides (2010) argue that flawed CO_2 storage models have vastly overstated the amount of CO_2 that can be stored in a reservoir's pore space. The authors conclude that *"[CCS] is not a practical means to provide any substantive reduction in CO_2 emissions"*.

While many experts have argued that these concerns are overstated (e.g. Juanes et al. (2012), Dixon & Hovorka (2012), CO2GeoNet (2012)), they do introduce uncertainty about the viability of widespread, long-term CO_2 storage at a gigaton-per-year scale. Addressing the concerns raised by the authors will be critical in ensuring the commercial readiness of CCS as a mitigation technology. In order to do so, large-scale demonstration projects will be important to test the behavior of reservoirs because, as noted by Zoback & Gorelick (2012), smaller scale injection projects do not adequately reflect how reservoirs are likely to respond to large-scale CO_2 injection. Equally important will be to gather real-life experiences on CO_2 behavior from a variety of heterogeneous reservoirs.

2.1.3 - Conclusion

All the necessary components of a CCS system are in commercial use today somewhere in the economy. Commercial CO_2 capture using amines is offered by a number of technology vendors, commercial-scale CO_2 transport has been undertaken for decades and a number of locations worldwide inject CO_2 at million-tonnes-per-year scale (Herzog

[1]In June 2011 In Salah suspended injection. Source: MIT CSI project database

& Eide, 2013). Nonetheless, challenges remain for both capturing and storing CO_2. For capture, the challenge is to scale up current available technologies to commercial-scale power plants (Herzog, 2011), and to develop new and innovative technologies that can substantially lower the cost of capture. For storage, uncertainty still remains over whether or not a sufficient number of reservoirs exist to safely and securely store gigatons of CO_2 a year. While initial field tests provide reason for optimism (i.e. the experiences from Sleipner and Snøhvit), only large-scale testing in a variety of heterogenous reservoirs can provide definite answers.

2.2 - An overview of U.S. demonstration projects

Addressing the technical challenges of CCS has been a research area for close to two decades in the U.S., with the first research needs assessment for CCS being written for the U.S. Department of Energy in 1993 (DOE, 1993). However, it was not until 2009 that significant public funding was committed to a CCS commercial-scale demonstration program. Such a program aimed to reduce costs and would also reduce the uncertainty over commercial-scale performance of capture systems and the ability to store large amounts of CO_2 in geologic formations. The American Recovery and Reinvestment Act (ARRA) allocated $800 million to the Clean Coal Power Initiative (CCPI), $1.52 billion to industrial CCS projects and $1 billion to the FutureGen project[2].

In addition to the stimulus money directed towards demonstration projects, a total of around $184 million was spent on capture and storage R&D projects by the U.S. Department of Energy in 2012, and approximately another $156 million requested for 2013 (DOE, 2012).

The CCS demonstration projects currently underway in the United States can be divided into those capturing CO_2 from industrial sources and those capturing CO_2 from natural or industrial sources. Table 2 shows an overview of ongoing and cancelled projects.

[2] MIT CSI, *The United States CCS Financing Overview*. Retrieved on February 25th 2013 from sequestration.mit.edu/tools/projects/us_ccs_background.html

Two of the large-scale industrial CCS projects, Decatur and Port Arthur are now operating and each project injects approximately one million tonnes of CO_2 per year into geologic formations. Southern Company's Kemper County IGCC plant is currently under construction and is expected to start operation by 2014[3]. Unfortunately, despite these successes, a significant number of projects have been cancelled over the past years, including American Electric Power's (AEP) Mountaineer project.

Table 2: Large-scale U.S. CCS power and industrial projects (> 1 MT CO_2/year). Source: MIT CSI database[4]

Project	Company	Source	CO_2 Fate	Status
U.S. Power Projects				
Kemper County (MS)	Southern	Coal Power	EOR	Under construction
TCEP (TX)	Summit Power	Coal Power	EOR	Under development
WA Parish (TX)	NRG	Coal Power	EOR	Under development
HECA (CA)	SCS	Coal Power	EOR	Under development
Trailblazer	Tenaska	Coal power	EOR	Under development
FutureGen 2.0 (IL)	FutureGen Alliance	Coal Power	Saline	Under development
Mountaineer (WV)	AEP	Coal power	Saline	Cancelled
Antelope valley (ND)	Basin Electric	Coal power	EOR	Cancelled
Taylorville (IL)	Tenaska	Coal power	Saline	Cancelled
Sweeny Gasification (TX)	ConocoPhillips	Coal power	Saline/EOR	Cancelled
Plant Barry (MS)	Southern	Coal power	EOR	Pilot operating, full-scale plant on hold
U.S. Industrial Projects (stimulus money)				
Decatur (IL)	Arthur Daniels Midland	Ethanol Plant	Saline	Operational since Nov 2011
Port Arthur (TX)	Air Products	Hydrogen Plant	EOR	Operational since Jan 2013
Lake Charles (LA)	Leucadia Energy	Methanol Plant	EOR	Under development

The many cancellations over the past two years are challenging CCS technology development, particularly since no new projects have been announced to take the place of those cancelled. However, there is nothing inherent in CCS as a mitigation technology that caused projects to cancel. The primary reason for project cancellation in the U.S. was that the lack of climate policy led to an absence of clear commercial markets. The

[3] MIT CSI project database, *Kemper County Fact Sheet*. Retrieved on February 25th 2013 from http://sequestration.mit.edu/tools/projects/kemper.html
[4] http://sequestration.mit.edu/tools/projects/index.html

Mountaineer project was cancelled due to the uncertain future of U.S. climate policy[5]. The Antelope valley project was shelved in 2010 due to high cost and regulatory uncertainty**[6].** Taylorville's $3.5 billion project was shelved after the Illinois Senate rejected the project in January 2011[7]. ConocoPhillips cancelled its gasification project due to uncertainty over federal climate change legislation[8]. Southern company seemed to have withdrawn its commercial-scale Plant Barry project from the third and final round of funding from the CCPI due to a short deadline from the U.S. Department of Energy regarding commitment to the project[9].

Organizing the projects in Table 2 in a two-by-two matrix by CO_2 source and CO_2 sink shows that there are far fewer ongoing projects with non-EOR storage than there are projects with EOR storage. That is not surprising given that the positive value put on CO_2 in EOR operations lowers the cost of capture. However, if one of the goals of a CCS technology development strategy is to prove the viability of long-term CO_2 storage in geologic formations other than EOR, then the picture presented in Figure 2 is worrisome. With only one operational project, Decatur, and the future of FutureGen highly uncertain, there might not be sufficient experience gathered to address the concerns raised by Zoback & Gorelick (2012) and Ehlig-Economides & Economides (2010).

[5] The New York Times, *Utility Shelves Ambitious Plan to Limit Carbon* (July 3rd 2011). Retrieved on February 25th 2013 from http://www.nytimes.com/2011/07/14/business/energy-environment/utility-shelves-plan-to-capture-carbon-dioxide.html?_r=2&
[6] The Bismarck Tribune, *Basin shelves lignite's first carbon capture project* (December 17th 2010). Retrieved on February 25th 2013 from http://bismarcktribune.com/news/local/a5fb7ed8-0a1b-11e0-b0ea-001cc4c03286.html
[7] The State Journal Register, *Taylorville clean-coal plant gets go-ahead from House committee* (May 30th 2011). Retrieved on February 25th 2013 from http://www.sj-r.com/top-stories/x1293696862/Taylorville-clean-coal-plant-gets-go-ahead-from-House-committee
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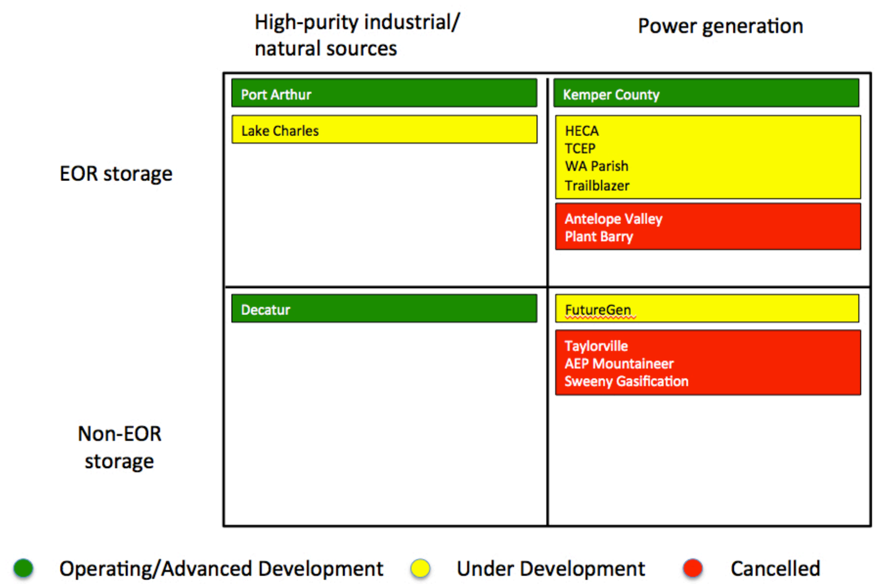

Figure 2: Large-scale U.S. CCS demonstration projects (> 1 MT CO_2/year). Source: MIT CSI Database

2.3 - Regulatory barriers for CCS projects in the U.S.

There are currently three key regulatory barriers facing CCS in the U.S.: the issue of pore space ownership, rules for underground injection, and a mechanism for managing CO_2 reservoirs after injection ceases (Herzog, 2011).

In the U.S., as opposed to Europe and Canada, pore space and mineral rights in the subsurface generally resides with the surface owner. For CCS project operators this means that permission is needed from all landowners to whom an underground CO_2 plume might migrate. Providing clear guidance on access to underground rights for CO_2 storage will be important if CCS is to be deployed at scale to mitigate climate change. While obtaining underground storage rights from a number of private landowners complicates the planning of U.S. CCS projects, it also creates potential economic benefits for the population living where storage is to take place. The financial upside might therefore make U.S. landowners, as opposed to Canadian or European, more likely to be positively inclined towards long-term CO_2 storage[10].

Following the Safe Drinking Water Act, the EPA is responsible for regulating most types of underground injections under the Underground Injection Control (UIC) program (Herzog, 2011). There are six classes of wells, of which class II wells (EOR), class V wells (experimental wells) and class VI wells (long-term geologic storage) are of relevance for CCS projects (Herzog, 2011). The creation of class VI geological storage wells in 2010 by the EPA has created a more comprehensive permitting process compared to class II and V wells. With only a limited number of demonstration projects moving forward, some have argued that the regulatory process should be made more flexible so as not to stand in the way of early demonstration projects[11].

Long-term management of CO_2 storage includes both rules for reservoir monitoring, and defining liability for potential CO_2 leaks. Private companies are unlikely to be willing to commit to hundreds of years of monitoring and liability for current reservoirs, and it has therefore been proposed that the government take over responsibility after a certain time period (Herzog, 2011). Currently six states have enacted legislation covering long-term liability for sequestered CO_2: Kansas, Louisiana, Montana, North Dakota, Texas and Wyoming (IEA, 2011). This means that the state takes over the long-term liability of injected CO_2 after an initial time period, usually between 10 and 20 years. Wyoming has chosen to not transfer liability to the state and the operator therefore holds it indefinitely. All six states have enacted liability funds financed by the operators to cover the monitoring costs as well as other potential future costs (Hart, 2011).

Resolving the issues surrounding pore space ownership, permits for underground injection, and rules for long-term storage is critical for the future viability of CCS as a climate mitigation technology. However, with the future of climate policy uncertain, the

[10] Personal correspondence with Ernst van Nierop, C12 Energy, Research Experience in Carbon Sequestration (RECS), June 2012, Birmingham Alabama

[11] Clean Energy Report, *EPA Weighs Resource Needs For CCS Permit Program Absent Projects* (January 14th 2013). Retrieved on February 15th 2013 from http://cleanenergyreport.com/201301142421430/Clean-Energy-General/Public-Stories/epa-weighs-resource-needs-for-ccs-permit-program-absent-projects/menu-id-487.html?s=sm

coming years are unlikely to see significant deployment of CCS technology. Yet, uncertainty over future regulations only compounds the difficulty of bringing CCS projects online, and developing a sound regulatory framework for CCS should remain a priority for policy makers both at the state and the federal level.

2.4 - An international perspective

Table 3 shows a selection of the operating, ongoing and cancelled large-scale CCS projects worldwide. International demonstration projects follow the same trend as U.S. demonstration projects, namely that some have been cancelled and very few are operating. Equally worrying is that no new projects have been announced to take the place of those cancelled. Below follows a brief discussion on what some key countries are doing in terms of CCS demonstration.

The United Kingdom (UK) has been a key player in developing CCS technology and initially had a £1 billion competition to build a coal-fired power plant with post-combustion capture. Unfortunately, the competition ended in 2011 with no awards being made (Gough & Mander, 2012). Nonetheless, the UK government continues to make £1 billion available for demonstration projects and opened a new competition to a wider range of capture technologies in April 2012. The goal is to have projects operational between 2016 and 2020[12]. On March 20th, 2013 the UK government announced that the Peterhead project in Scotland and the White Rose project in England would move forward to the final phase of the competition. In addition to the incentive provided by the competition, the Electricity Market Reform, likely to be enacted in 2013, will provide a guaranteed price of electricity for CCS through a contract-for-differences[13] (Herzog & Eide, 2013).

[12] UK Government, *CCS Commercialization Competition*. Retrieved on February 15th 2013 from https://www.gov.uk/uk-carbon-capture-and-storage-government-funding-and-support#ccs-commercialisation-competition
[13] UK Government, *Supporting detail: Electricity Market Reform.* Retrieved on February 15th 2013 from https://www.gov.uk/government/policies/maintaining-uk-energy-security--2/supporting-pages/electricity-market-reform

In Europe the goal was to have twelve demonstration plants online by 2015. Six demonstration projects were awarded a total of €1 billion in 2008 under the European Union (EU) stimulus plan, and another 8 projects were to receive funding through the NER300 program[14]. Unfortunately, no CCS projects were funded in the NER300 first round of allocations announced on December 18, 2012 as projects failed to meet the requirements by the announcement deadline[15]. While some CCS projects might receive funding in the second round of allocations, it is clear that the EU will fall short of its ambitious targets for CCS demonstration projects. In the current economic and political environment, only a small fraction of the projected 12 projects are likely to come into operation (Herzog & Eide, 2013).

[14] European Commission, *Communication: Realizing the Carbon capture and storage (CCS) demonstration program* (October 2011). Retrieved on February 15th 2013 from http://ec.europa.eu/governance/impact/planned_ia/roadmaps_2012_en.htm
[15] European Commission, *Questions and Answers on the outcome of the first call for proposals under the NER300 programme, 2012*. European Commission MEMO/12/999 (December 18th 2012). Retrieved on April 28th 2013 from http://europa.eu/rapid/press-release_MEMO-12-999_en.htm

Table 3: Selected international large-scale CCS projects (> 1 MT CO_2/year). Source: MIT CSI database

Project	Company	Source	CO_2 Fate	Status
Canadian Projects				
Weyburn	Pan Canadian	Coal gasification	EOR	Operational since 2000
Boundary Dam	SaskPower	Coal Power	EOR	Under construction
Bow city	BCPL	Coal Power	EOR	Under development
Alberta Carbon Trunk Line	Enhance Energy	Refinery	EOR	Under development
Quest	Shell	Steam-methane	Saline	Under development
Fort Nelson	PCOR	Gas processing	Saline	Under development
Swan hills	Swan Hills synfuels	In situ gasification	EOR	Cancelled
Project Pioneer	TransAlta	Coal Power	Saline/EOR	Cancelled
European projects				
Mongstad (Norway)	Statoil	Gas processing	Saline	Operational since 1996
Snohvit (Norway)	Statoil	LNG processing	Depl. Gas	Operational since 2008
ROAD (Netherlands)	E.ON	Coal power	Depl. Oil	Under development
Porto Tolle (Italy)	ENEL	Coal power	Saline	Under development
Belchatow (Poland)	PGE	Coal power	Saline	Under development
Compostilla (Spain)	Endesa	Coal power	Saline	Under development
Goldenbergwerk (Germany)	RWE	Coal power	Saline	Cancelled
Janschwalde (Germany)	Vattenfall	Coal power	Saline	Cancelled
UK projects (Competition)				
White Rose	Alstom	Coal Power	Saline	Awaiting award
Peterhead	Shell and SSE	Gas Power	Depleted Gas	Awaiting award
Longannet	Scottish Power	Coal power	Saline	Cancelled
Rest of the World				
In Salah (Algeria)	BP	Gas processing	Depl. Gas	Operational 2004-11
Ordos (China)	Shenhua group	Liquefaction	EOR/Saline	Under development
Gorgon (Australia)	Chevron	Gas processing	Depl. gas	Under development
Daqing (China)	Alstom & Datang	Coal power	EOR	Under development
GreenGen	GrreenGen	Coal power	Saline	Under development

Capturing CO_2 has been at the center of the Norwegian environmental debate for at least two decades. The world's first commercial CO_2 storage project was Statoil's natural gas processing facility at the Sleipner platform in the North Sea in 1996, and in 2008 CO_2 capture started at the Snøhvit natural gas processing facility. The current government has vested significant amounts of prestige in building a full-scale capture plant at the Mongstad 630 MW cogeneration plant, with the prime minister declaring in his 2007 New Year's speech that capturing CO_2 from a full-scale plant would be Norway's "moon landing".

The Test Center Mongstad cost the government approximately $870 million and was officially opened on May 7th 2012[16]. The investment decision on the full-scale plant has been postponed a number of times and is currently expected in 2016. With cost estimates currently running at $3.3-$4.2 billion[16], a report from the Norwegian Climate and Pollution agency estimate the cost of CO_2 avoided for the first full-scale projects to be between $216-$375/tonne CO_2 (KLIF, 2010). Yet Norway has remarkably strong public finances, as well as a political climate that strongly favors the project. Still, the future of the project will depend on continued support after the 2013 parliamentary elections, as well as on whether or not Statoil decides to continue to operate the refinery at Mongstad.

Australia has shown a strong interest in CCS as a mitigation technology. The current government passed a national carbon tax in November 2011, and starting in July 2012 a charge of approximately $24/tonne CO_2 has been imposed on the country's top 500 emitters. Although an important step, it does not change the economics of power generation enough to pave the way for deployment of CCS on a commercial scale.

Canada also exhibits a very strong interest in CCS. The Weyburn EOR project has been operating for over twelve years and the Boundary Dam post-combustion project is under construction. In addition, another power project and three industrial projects are planned. The projects in Canada are continuing to move ahead despite the setback of Pioneer's cancellation. Shell announced on September 7th 2012 that it had made a positive investment decision for its Quest project[17]. Although the Canadian government recently announced their withdrawal from the Kyoto protocol, support for proving CCS at a commercial scale remains strong. Alberta has stated that CCS will deliver 70% of its abatement to 2050 (GCCSI, 2011), and the state has established a C$2 billion fund to support demonstration projects as well as a C$15/tonne CO_2 tax. Although this tax is far

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[16] Norwegian government whitepaper, *Full-scale CO_2 capture* (March 4th 2011). Retrieved on April 30th 2013 from http://www.regjeringen.no/nb/dep/oed/dok/regpubl/stmeld/2010-2011/meld-st-9-20102011/3.html?id=635119 (in Norwegian)

[17] Shell press release, *Shell to construct world's first oil sands carbon capture and storage (CCS) project* (September 5th 2012). Retrieved on January 24th 2013 from http://www.shell.com/global/aboutshell/media/news-and-media-releases/2012/quest-first-oil-sands-ccs-project-05092012.html

below the levels needed to make CCS commercially viable, it provides a small incentive to reduce emissions.

Home to the largest coal fleet in the world (IEA, 2012), China has received considerable attention as a future market for CCS technology. With considerably lower construction costs, some actors have also seen China playing a leading role in technology development. A number of projects are currently underway in China, most notably Alstom's 350 MW oxy-combustion project in Daqing and the 400 MW GreenGen IGCC plant at Tianjin City. While China will likely be an important player if CCS is to be deployed at scale globally, it is unlikely on its own to foot the bill for CCS technology development. It is unrealistic to expect China to pick up the slack from scaled-back ambitions in the EU and the U.S. If Western electricity consumers are unwilling to foot the bill of funding CCS technology development, is it really realistic to expect the Chinese to be more amenable to the idea? (Herzog & Eide, 2013).

Current austerity measures on both sides of the Atlantic makes it likely that public finances will be tighter in coming years. For demonstration projects that typically require hundreds of millions of dollars of government subsidies, tight finances pose a particular problem. International collaboration could lower the financial burden on individual nations. Yet pooling demonstration funds under either IEA or UN supervision is likely to be politically challenging. The financial support needed for a single commercial project makes it likely that any country committing such funds will require it to be located within their own border. Yet the small group of countries mentioned above could nonetheless agree on a joint demonstration strategy. Each country could demonstrate a different aspect of the technology, and in sum they could develop the knowledge and experience needed for CCS to be a commercial mitigation technology.

Table 4 shows how four countries account for over half the global coal reserves, along with close to three fourths of the coal production and consumption. With a vast majority of generation from coal, their electricity supply would become highly exposed if some sort of global agreement on reducing emissions came into force. These countries have a particular long-term strategic interest in developing CCS, yet as already mentioned, it is unlikely that less-wealthy countries such as China and India will be willing to take the lead in technology development if the West is unwilling to do so.

Table 4: Selected countries with long-term strategic interest in CCS. Source: BP (2012), IEA (2012)

Country	Share of world coal reserves	Share of world coal production	Share of global coal consumption	Coal share of electricity production
United States	28%	14%	14%	45%
China	13%	50%	49%	79%
Australia	9%	6%	1%	78%
India	7%	6%	8%	69%

In conclusion, the U.S., Australia, the U.K., and Norway seem to be the most suited for taking a leading role in together moving CCS forward. Each country has committed significant resources domestically to CCS research and demonstration, and has either a strategic interest in developing low-emission coal plants (U.S. and Australia), or governments with a particularly strong commitment to CCS as a climate mitigation technology (UK and Norway).

2.5 - Conclusion

As shown in the first subsection of this chapter, a number of technical barriers exist for the large-scale deployment of CCS as a climate mitigation technology. The most important are the high cost of the technology, the lack of experience in commercial-scale performance of capture technologies at power plants and the uncertainty over the viability of long-term storage. A CCS development strategy should therefore focus on three key goals:

1. Lower the cost of capture
2. Lower the uncertainty surrounding commercial-scale performance of CO_2 capture at power plants

3. Prove the viability of long-term storage of commercial-scale amounts of CO_2 in geologic formations

Addressing these goals in a CCS technology demonstration program will be challenging in today's political and economic environment. Despite a number of successful projects, the U.S. CCS demonstration program has suffered setbacks through a number of project cancellations. Cancellations have been particularly numerous in the projects intended to demonstrate large-scale injection and storage in non-EOR reservoirs. Internationally, and particularly in the EU, the situation is equally bleak, and only a small fraction of the desired 12 demonstration projects are likely to come into operation. The following chapter will analyze the underlying reasons for the challenging realities of CCS. While the focus is U.S.-centric, many parts of the analysis apply also internationally.

Chapter 3 - The new realities for CCS

The adverse effects of climate change are becoming more apparent (NCADAC, 2013), and in order to limit global temperature increases CO_2 emissions will have to be reduced. Simultaneously, fossil fuel-fired power plants are expected to continue supplying a majority of U.S. and global electricity demand for the foreseeable future (IEA, 2012). As the only technology available to significantly reduce CO_2 emissions from fossil fuel-fired power plants, CCS has therefore been viewed as a key technology in mitigating climate change. Commonly referred to, the IEA projects in its Blue Map scenario that if the world wants to halve global CO_2-emissions by 2050, then CCS should account for 19% of total emissions reductions.

However, as shown in the preceding chapter, CCS is yet to be an "off-the-shelf " mitigation technology and technology development through full-scale demonstration projects is needed before CCS is commercially available. In order to pave the way for large-scale deployment of CCS technology, several organizations have set out roadmaps that describe the path that needs to be taken over the next several years and decades. The IEA states that one hundred CCS projects are needed by 2020, and close to 3500 by 2050 (IEA, 2009). Figure 3 clearly shows the massive buildup that the IEA believes is needed for CCS to fulfill its potential as a mitigation technology. The leaders of the G8 countries pledged in 2008 that twenty large-scale demonstration projects should be launched by 2010 and large-scale deployment should start in 2020[18]. President Obama's goal is to have five to ten commercial scale demonstration plants online by 2016 (DOE, 2010a), and the European Commission in its Energy Roadmap 2050 projects power plants with CCS to account for 19%-32% of power generation in 2050 (European Commision, 2011).

[18] Japanese Ministry of Foreign Affairs. *G8 Hokkaido Toyako Summit Leaders Declaration* (July 8th 2008) Retrieved February 11, 2012 from http://www.mofa.go.jp/policy/economy/summit/2008/doc/doc080714__en.html

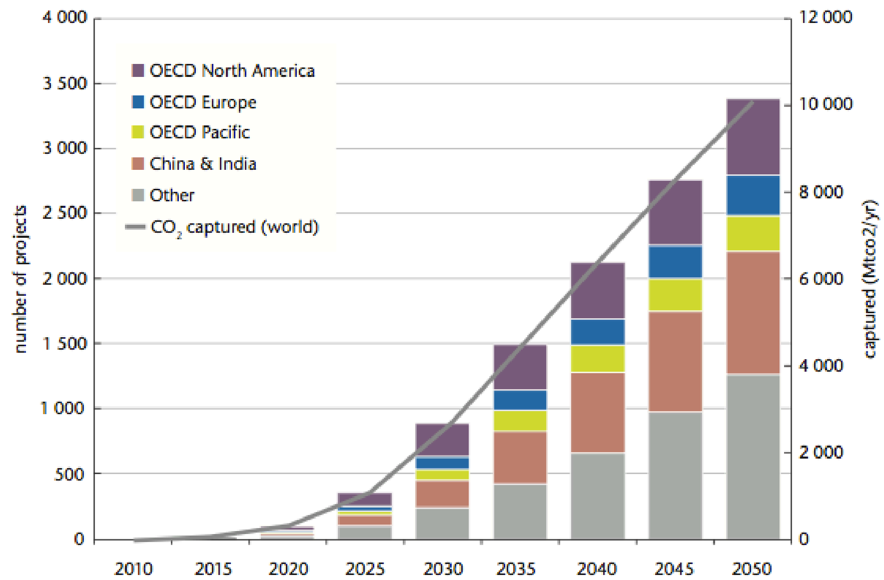

Figure 3: IEA CCS roadmap. Soure: IEA (2009)

Despite these ambitious roadmaps, the political reality for emission reductions in general, and CCS in particular, has changed dramatically over the last four years. The likelihood that global, comprehensive climate policies will be enacted this decade is close to zero. In addition to the lack of climate policies, a number of other factors have complicated the process of moving CCS to commercial readiness. The current roadmaps are therefore poorly adapted to deal with the current political and economic climate. As an example, a recent study concluded that in order to meet the IEA goal of one hundred projects by 2028, around 60 new projects needed to be announced by 2012, in practice making it unattainable (IEAGHG, 2011).

The following two subsections will take an in-depth look at how the realities for CCS have changed, both short-term and long-term.

3.1 - Short-term situation

The short-term need for CCS was based on a belief that strict climate policies would create a demand for technologies that could reduce CO_2 emissions from fossil fuel-fired power plants. With stimulus spending making significant funds available for low-carbon technology development, a CCS demonstration program was deemed a sound investment. However, five short-term factors are all contributing to change the political and economic realities of CCS commercialization, undermining many of the roadmaps described above. In addition to the lack of comprehensive climate policies, the changing economics of U.S. electricity generation, tight public finances and the continued high costs of CCS all pose significant hurdles for bringing commercial-scale CCS projects online. On the other side, high oil prices are opening a large market for anthropogenic CO_2 through EOR. These additional revenue streams could potentially ease the path to commercialization by lowering the cost of capture.

3.1.1 - Climate policy

Investments in CCS technology are dependent on climate policies, and the political environment for climate policy is unwelcoming.

Following the failure of the COP-15 meeting in Copenhagen to produce a successor to Kyoto, the momentum for a legally binding global agreement has slowed, or stopped altogether. Nonetheless, COP-17 in Durban resulted in an agreement where the parties "*decides to launch a process to develop a protocol, another legal instrument or an agreed outcome with legal force*" through a working group *that "shall complete its work as early as possible but no later than 2015 in order to adopt this protocol… and for it to come into effect and be implemented from 2020"*[19]. Although a better-than-hoped-for outcome, the proposed deadline is unlikely to be met given the opposition to a legally binding agreement by India and China, and the lack of enthusiasm for one by the U.S. It is therefore fair to assume that no legally binding agreement covering the major emitters will come into effect in this decade. While the Kyoto protocol was extended in Doha, only Australia, the European Union (EU), Ukraine, Switzerland and Norway agreed to sign on to the new agreement. Major emitters such as Japan, Russia and New Zealand

[19] UN Framework Convention on Climate Change, *Report of the Conference of the Parties on its seventeenth session* (March 15th 2012). Decision 1/CP.17. Retrieved on February 1st 2013 from http://unfccc.int/resource/docs/2011/cop17/eng/09a01.pdf#page=2

refused[20], and Canada had already withdrawn from their commitments. The extended Kyoto protocol therefore only covers a small share of global CO_2 emissions.

An important agreement in Durban was the decision to include CCS projects in the Clean Development Mechanism (CDM). Although important in recognizing the role CCS has to play in developed as well as developing countries, the practical effect on actually incentivizing projects may be limited. This is both due to the stringent monitoring and verification mechanisms of the CDM as well as the very high costs of CCS projects in general. The EU has also signaled that countries such as China will no longer be considered for support after 2013[21].

U.S. Climate policy

The most notable effort to produce comprehensive climate legislation in the U.S. was the American Clean Energy and Security Act of 2009, often referred to as Waxman-Markey. The bill passed the House of Representatives in June 2009, but was never voted on in the Senate[22]. Among other provisions of the bill, it would have introduced a U.S. cap & trade mechanism that aimed to reduce U.S. CO_2 emissions by 83% by 2050 (CRS, 2009).

On February 29th 2012, then-senator and chair of the Energy and Natural Resources Committee, Jeff Bingaman, introduced the Clean Energy Standard Act of 2012 to enact a federal clean energy standard. The bill, which was never voted on, would have required electricity retailers to supply a specified amount of their electricity from clean sources through a credit system. Renewables, nuclear and hydro would gain full credit per unit electricity generated, whereas natural gas and clean coal would get partial credit depending on the carbon intensity of the technology employed (EIA, 2012a). The bill's target was 24% of electricity sales to be clean by 2015, and 84% in 2035. While the bill would increase the share of renewables by 34% relative to baseline, one study concluded

[20] Environmental and Energy Study Institute, *Doha Renews Kyoto Protocol, Postpones Tough Decisions*. Retrieved on January 17th 2013 from http://www.eesi.org/doha-renews-kyoto-protocol-postpones-tough-decisions-13-dec-2012
[21] Point Carbon, *CO2 Caps Not Enough to Save China CDM* (August 9th 2011). Retrieved on February 5th 2012 from http://www.reuters.com/article/2011/08/09/us-china-cdm-point-carbon-idUSTRE7783PE20110809
[22] OpenCongress, H.R. 2454 The American Clean Energy and Security Act of 2009. Retrieved on January 18th 2013 from http://www.opencongress.org/bill/111-h2454/show

that basically no power plants with CCS would come online by 2035, despite the fact that CCS was awarded full credit under the scheme (EIA, 2012a).

There is still significant Congressional opposition to aggressive climate policies, particularly among members of the Republican Party, and President Obama has not announced any major new initiatives for his second term, despite noting the issue's importance in his second inaugural address. It therefore seems unlikely that major climate legislation will pass through the current Congress.

In the absence of Congressional action, the EPA has taken measures to decrease CO_2 emissions through emission standards for vehicles and new fossil fuel-fired power plants. The latter could potentially prove important for incentivizing CCS investments and will be analyzed in-depth in chapter 4.

Despite the lack of comprehensive federal policies, a number of states have adopted measures to promote clean energy. In particular, some version of a Renewable Portfolio Standards (RPS) has gained considerable popularity. All but thirteen states currently have a requirement that a certain percentage of electricity generation be from renewable or clean energy sources[23]. The definition of "clean" or "renewable" varies by state, but only Utah, Pennsylvania and Illinois recognize CCS in their RPS (IEA, 2011). However, it does not seem that an RPS is a determining factor in incentivizing CCS projects given that only Illinois still has an active project.

California has introduced two notable climate measures that could provide incentives for low-carbon energy projects such as CCS. On December 17th 2010 the California Air Resources Board (CARB) voted to adopt a cap & trade mechanism starting in 2013[24]. Although important as the first non-voluntary cap & trade system in the U.S., its impact on CCS projects is likely to be of only secondary importance since the allowance prices are unlikely to reach the levels needed to incentivize investments in power plants with

[23] Database for State Incentives for Renewables and Efficiency. Retrieved on January 22nd 2012 from http://www.dsireusa.org/summarytables/index.cfm?ee=1&RE=1
[24] California Air Resources Board, *California Air Resources Board adopts key element of state climate plan* (October 20th 2011). News release #11-44. Retrieved on April 26th 2013 from http://www.arb.ca.gov/newsrel/newsrelease.php?id=245

CCS. Nonetheless, the cap & trade system could provide additional revenue streams for CCS projects from allowance trading.

The low carbon fuel standard (LCFS) that was effective as of April 15th 2010[25] is designed to reduce the "well-to-wheels" carbon intensity of gasoline and diesel fuels in California by around 7% by 2020. The maximum allowed average carbon intensity for gasoline will decrease from 95.6 gCO_2e/MJ in 2011 to 89.06 gCO_2e/MJ in 2020[26]. The maximum allowed average carbon intensity for diesel will decrease from 94.47 gCO_2e/MJ in 2011 to 88.23 gCO_2e/MJ in 2020[26]. Although the standard has had little direct effect on CCS projects within the U.S., it had a large impact on projects in Alberta. Oil produced from the oil sands could risk to be locked out of a large market due to its significantly higher carbon intensity. However, the future of the fuel standard is in doubt following the U.S. District Court for the Eastern District of California blocking its enforcement on December 29th 2011[27]. The State of California has said it will appeal the ruling, but the enforcement of the fuel standard is currently on hold.

Despite a number of encouraging state policies, the EPA emission standard is the only federal climate policy in effect that could potentially provide the necessary incentives for private investment in CCS technology. With additional climate legislation unlikely to pass through the U.S. Congress, the standard is likely to be the only federal climate policy that can act as a driver for moving CCS demonstration projects forward (see chapter 4).

3.1.2 - Changing economics of U.S. electricity generation

The U.S. power sector is undergoing significant changes, most notably with an unprecedented shift from coal-fired to natural gas-fired power plants. The main reason

[25] California Air Resources Board, *Low Carbon Fuel Standard* (June 14 2010). Retrieved on January 28th 2013 from http://www.arb.ca.gov/regact/2009/lcfs09/lcfs09.htm
[26] California Code of Regulations (CCR), *sections 95480-95490*. Retrieved on April 26th 2013 from http://www.arb.ca.gov/regact/2009/lcfs09/lcfscombofinal.pdf
[27] California Air Resources Board, *Low Carbon Fuel Standard (LCFS) Supplemental Regulatory Advisory 10-04B* (December 2011). Retrieved on April 26th 2013 from http://www.arb.ca.gov/fuels/lcfs/123111lcfs-rep-adv.pdf

for this shift is the dramatic reduction in natural gas prices due to increased natural gas supply from shale formations. In addition, new EPA regulations on air emissions and increased demand for flexible generation are further challenging the economics of coal-fired power plants (Brasington, 2012). The U.S. shifting from coal to natural gas at such a scale was not considered in the current roadmaps for CCS, and the transition poses challenges for a U.S. demonstration program that traditionally only focused on coal-fired power plants.

Advances in horizontal drilling and hydraulic fracturing have dramatically increased the supply of natural gas, doubling U.S. reserves and increasing daily marketable production by a third[28]. The increase in natural gas production from U.S. shale formations has reduced prices and average natural gas price for electricity generation was $4.56/MMBtu[29] in January 2013. Combined with technological advances in turbine technology, the low fuel prices have made generating baseload electricity from natural gas competitive with coal. Moreover, Combined Cycle Gas Turbine (CCGT) plants also offer the advantages of lower capital costs and shorter construction times. Consequently net generation from natural gas has increased 37% from 2007 to 2012, whereas net generation from coal decreased 25%[30].

The EPA has recently enacted or proposed a series of new regulations under the Clean Air Act to reduce pollution from coal-fired power plants, most notably the Cross-State Air Pollution Rule (CSAPR), the Mercury and Air Toxics Standard (MATS), the Clean Water Act 316 (b), and the Coal Combustion Residuals rule (CCR).

The Cross-State Air Pollution Rule was finalized on July 6th 2011 and is designed to significantly reduce emissions of SO_2 and NO_x through a cap & trade mechanism. However, on August 21st 2012 the U.S. Court of Appeals of the D.C. Circuit ruled that

[28] U.S. EIA, *Marketable daily production from January 2005 to October 2012. Reserves from 2005 to 2010*. Retrieved on January 18th 2013 from http://www.eia.gov/naturalgas/data.cfm
[29] U.S. EIA, *Electric Power Price*. Retrieved on April 26th 2013 from http://www.eia.gov/dnav/ng/hist/n3045us3m.htm
[30] U.S. EIA, *Net Generation by Energy Source*. Retrieved on January 18th 2013 from http://www.eia.gov/electricity/data.cfm#generation

the EPA had overstepped its statutory authority, and ordered the rule to be revised[31]. The EPA petitioned for a rehearing en banc of the Court's decision, but on January 24th 2013 the petition for a rehearing was denied. The U.S. solicitor general on March 28th petitioned the U.S. Supreme Court to review the Court of Appeals' decision[32]. The Mercury and Air Toxics Standard is designed to reduce emissions of heavy metals such as mercury as well as acid gases (MISO, 2011). The regulations are in the form of an emission standard, calculated as the average emissions of the 12% best-performing plants (Brasington, 2012). Section 316(b) of the Clean Water Act is designed to reduce the environmental impact of cooling water systems for power plants (MISO, 2011). The strictest interpretation of the rule could result in plants with once-through cooling being forced to retrofit to a closed system, however EPA can take regional considerations by considering system reliability, availability of land and potentially increased local air emissions (Brasington, 2012) The proposed Coal Combustion Residuals rule is designed to regulate coal ash, and could potentially designate it a hazardous waste, significantly altering the way it needs to be treated (Brasington, 2012).

Existing generation units have to comply with the Mercury and Air Toxics Standard by 2015, with the Coal Combustion Residuals rule by 2015 if finalized as is, and with 316(b) by 2016 (MISO, 2011). As mentioned above, the future of the Cross-State Air Pollution Rule is currently uncertain. In order to comply with the new regulations, for many existing units utilities will need to either retrofit with flue gas cleanup, lower capacity factors, refuel with natural gas or shut down (Brasington, 2012). However, combined investments in wet flue gas desulfurization (FGD), selective catalytic reduction (SCR) and fabric filter can easily approach $800/kW (Saha, 2012), close to the capital cost of new CCGT power plants. It is therefore clear that in many cases, the new EPA regulations will accelerate the current shift from coal to natural gas for baseload generation. One analysis estimate that up to 35.5 GW of coal capacity could be retired by

[31] U.S. Court of Appeals of the D.C. Circuit, *EME Homer City Generation LP v. EPA*, No. 11-1302 (August 21st 2012). Retrieved on April 28th 2013 from http://www.cadc.uscourts.gov/internet/opinions.nsf/19346B280C78405C85257A61004DC0E5/$file/11-1302-1390314.pdf
[32] EPA Cross-State Air Pollution Rule website, *What's New*. November 19th 2012. Retrieved on April 28th 2013 from http://www.epa.gov/crossstaterule/

2020, however the modeling assumption was based on the Cross-State Air Pollution Rule coming into force by 2012 (Shavel & Gibbs, 2012).

With increasing penetrations of intermittent renewables there will be a higher demand for flexible generation that can smooth variable output from sources such as wind and solar (MIT, 2011). Whereas coal plants traditionally have ramping rates of 1-3% per minute, CCGT plants traditionally are able to ramp up to about 8% per minute (IEC, 2012). The newest GE FlexEfficiency 60 turbine can even ramp up to two thirds of capacity in 10 minutes[33]. Intermittent technologies such as solar and wind are expected to generate 10% of U.S. electricity by 2035, up from around 2% today (IEA, 2012). Consequently the demand for flexibility will be even higher in the future, giving an additional competitive advantage for natural gas based generators due to the limited ramping capabilities of coal plants.

As already mentioned, the U.S. CCS demonstration program has traditionally focused on coal-fired power plants, but with current power market trends it is unlikely that many new coal-fired power plants will be built in the coming years. Although CCGT plants release significantly less CO_2 than coal-fired power plants, shifting from coal to natural gas would not by itself achieve the gigatons of emissions reductions needed to mitigate climate change. The changing economics of U.S. power generation might therefore suggest a need to refocus part of the U.S. demonstration portfolio towards natural gas-fired power plants (see section 4.5).

3.1.3 - Public finances

The economic downturn that followed the 2008 financial crisis had a profound impact on the U.S. economy, and the budget deficit for fiscal year 2013 is estimated at $845 billion (Edward et al., 2013). Consequently there have been increased calls to substantially lower spending, and pressure will likely remain on cutting costs.

[33] General Electric (GE) website, *FlexEfficiency 60 Portfolio.* Retrieved on January 30th 2013 from http://www.ge-flexibility.com/solutions/flexefficiency-60-portfolio/index.html

The increased focus on deficit reduction will put the existing subsidies for low-carbon technologies under pressure. The automatic spending cuts that were agreed on in the 2011 federal debt-ceiling negotiations were in January 2013 extended until March 2013[34]. Since no agreement could be made between Democrats and Republicans, the cuts, often referred to as "the sequester", came into effect on March 1st (Lerner, 2013). They will likely have a profound impact on federal R&D spending, but the exact effects are not yet clear. One report estimates that total federal non-defense R&D spending could be cut by between $21.9 billion and $50.8 billion by 2017, depending on whether or not defense-related spending is shielded (Hourihan, 2012). The cuts would be significant, representing between 7.4% and 17.2% of total non-defense R&D. For the Department of Energy's energy programs the effect could be total cuts of $854 to $1977 million, or between $170 million and $400 million per year. The cuts are equivalent to a 7.6% and 17.5% reduction, and the lower end is about a third of the Department of Energy's Fossil Energy R&D program (Hourihan, 2012). As mentioned in chapter 2, the annual CCS R&D budget was $184 million in 2012. One cannot yet determine the exact effect of the budget cuts on CCS funding, but the magnitude of the cuts considerably worsens the probability of increased financial support in the future. Moreover, while $3.4 billion was made available for CCS demonstration projects in the 2009 American Recovery and Reinvestment Act, the funding will be returned to the Treasury if not spent by September 30th 2015[35].

The worsened outlook for financial support is particularly unfortunate given that demonstrating the feasibility of CCS on commercial-scale power plants is highly dependent on government support. As Obama's Task Force states in its final report, "*CCS technologies will not be widely deployed in the next two decades absent financial incentives that supplement projected carbon price*" (DOE, 2010a). With a carbon price off the table in the short-term, private funding for CCS technology development will

[34] Federal Times, *Sequestration Delayed Two Months* (January 2nd 2013). Retrieved on January 30th 2013 from http://www.federaltimes.com/article/20130102/AGENCY01/301020001/Sequestration-delayed-two-months
[35] U.S. Department of Energy, Office of the General Counsel, *Eligibility determinations under EECBG, SEP, or WAP*. Retrieved on January 18th 2013 from http://energy.gov/gc/action-center-office-general-counsel/faqs-related-recovery-act/eligibility-determinations-under

likely be limited. Although venture capital serves the role of providing the initial financial support in many other industries that experiences rapid innovation, it is unlikely to play the same role for CCS due to both the size of the investments (billions of dollars) as well as the technological and political risks involved (Lester, 2011).

3.1.4 - High cost despite years of development

Despite significant investments in technology development over the last decade, the cost of power plants with CCS is still high, and it has yet to be proven on a commercial scale.

Many studies over the past years have tried to determine the cost of CCS on both coal- and natural gas-fired power plants. However, the predictions are often based on data from pilot-scale projects and front-end engineering & design (FEED) studies. The actual costs of the first commercial-scale projects may be significantly different. The two most important cost metrics for CCS are generally the Levelized Cost of Electricity (LCOE) and the cost of CO_2 avoided. The LCOE measures the theoretical price per kWh a utility must receive during a plant's lifetime to pay for investment costs, operating costs, interest and a competitive return to investors. The cost of CO_2 avoided calculates the cost of avoiding one tonne of CO_2 being released to the atmosphere. It is different from the cost of capture since the latter does not take into account the additional CO_2 emissions associated with the energy penalty of CCS. Care must be shown when comparing costs across studies as boundary conditions and methodology vary considerably.

Finkenrath (2011) compares a number different techno-economic studies of post-combustion CO_2 capture using amine solvents for both coal-fired and natural gas-fired power plants. The projections have large variations, but the study nonetheless provide a useful range for n-th of a kind costs:

- CCS on new pulverized coal (PC) power plants would increase LCOE by 38%-77% and have a cost of CO_2 avoided ranging from $40-$74/tonne

- CCS on new natural gas-fired CCGT power plants would increase LCOE by 27%-46% and have a cost of CO_2 avoided ranging from \$60-\$128/tonne.

The variance of the estimate of the cost of capture is shown in Figure 4 and clearly shows the uncertainty in the cost of CCS at both coal- and natural gas-fired power plants. The red line represents the mean value, the blue box the 10th and 90th percentile and the black lines the outliers. However, the sample size is small and the percentiles are only showed to highlight the range of uncertainty.

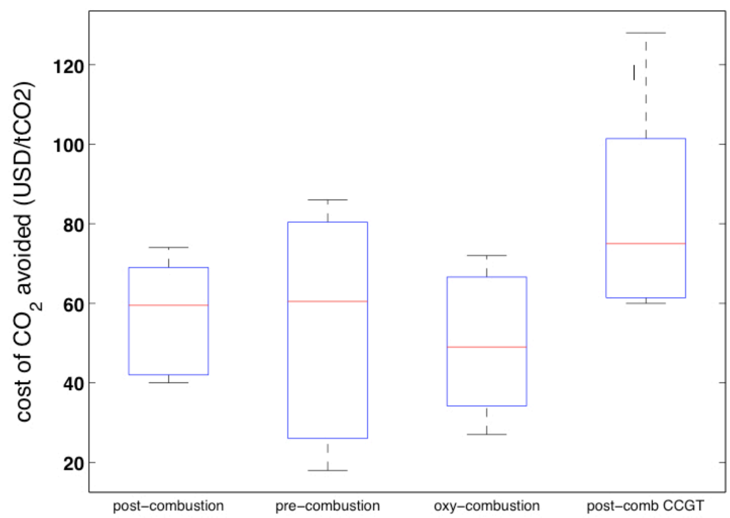

Figure 4: Cost of CO_2 avoided (\$/tonne CO_2) for different capture technologies (N=13 for post-combustion, N=10 for pre-combustion, N=10 for oxy-combustion, N=9 for CCGT). Source: Finkenrath (2011)

The variance in the LCOE is showed in Figure 5.

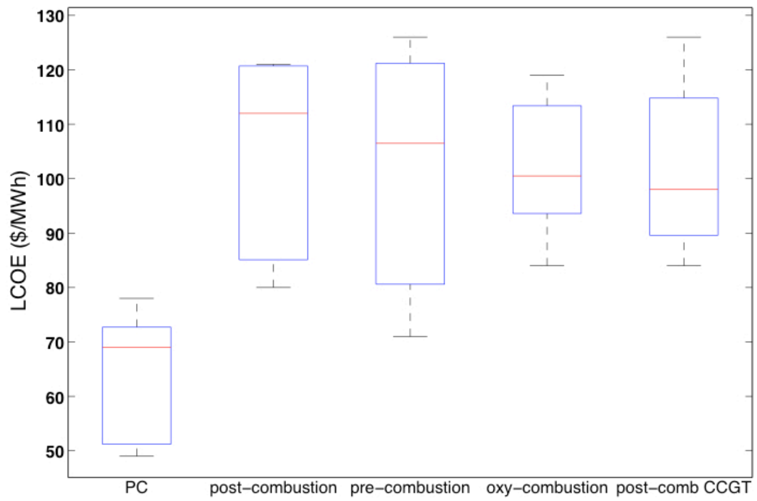

Figure 5: LCOE for different capture technologies (N=13 for PC, N=13 for post-combustion, N=10 for pre-combustion, N=10 for oxy-combustion, N=9 for CCGT). Source: Finkenrath (2011)

It is important to note that CCS technology is still in its infancy, and experiences from similar technologies, such as SO_2 scrubbers, suggest there are likely to be important cost reductions when cumulative installed capacity increases (Rubin et al., 2004). Nonetheless, the cost of CCS is still too high to be commercially deployed in the absence of policies significantly penalizing CO_2 emissions. Given the current uncertainty regarding the future of climate policy, private investors will find it challenging to fund the large investments needed to bring CCS to commercial readiness (see Raveendran (2013) for more in-depth analysis of how different incentive mechanisms impact the competitiveness of power plants with CCS).

3.1.5 - High oil prices and the rise of EOR

Exact data is hard to retrieve on the price received for CO_2 used in EOR operations since, as opposed to for example oil or natural gas, it is not traded openly on commodity markets. However, historical prices are believed to be in the range of $10-15/tonne (NETL, 2010). Recently, high oil prices have led to a rising demand for CO_2, and oil companies have begun to search for additional supplies beside natural CO_2 sources. CO_2

captured from fossil fuel-fired power plants could be one way of meeting the demand. Currently a rule of thumb in the industry is to use 2% of the price of oil (in \$/bbl) as the price paid for CO_2 (in \$/Mcf). Current oil prices of around \$100 a barrel therefore yields a price estimate of CO_2 delivered to the field of \$2/Mcf, or approximately \$36/tonne CO_2. Depending of the distance between the field and the CO_2 source, \$5-10/tonne would be subtracted to cover transportation costs. However, investment decisions in the oil & gas sector are not based on such high oil prices. Long-term planning is generally based on more conservative estimates, and an oil price of \$60 per barrel would for example yield a CO_2 price of approximately \$22/tonne delivered to the field.

Due to the energy penalty associated with CCS, power plants capturing CO_2 will have higher fuel consumption for the same net power output[36]. The net and gross amount of CO_2 captured will therefore be different. For climate mitigation it is the net amount of CO_2 captured that matters, whereas for EOR purposes it is the gross amount. As a consequence, the "cost of capture" is different depending on whether one considers the net or gross amount of CO_2 capture. For EOR purposes it is the latter that is relevant, and the cost of capture from an N-th of a kind coal-fired pulverized coal plant with amine capture ranges from \$29-53/tonne using the costs reported in Finkenrath (2011). Field operators are therefore unlikely to be willing to pay the very high CO_2 prices that are needed to make power plants with CCS economically viable without considerable public subsidies of some kind. Furthermore, investors might not invest in CCS projects even if a combination of EOR revenues and subsidies cover the entire cost of capture. The simple reason is that first-of-a-kind costs are likely to be significantly higher than N-th-of-a-kind costs. Consequently the magnitude of any government incentives will be very high in order to get private investors interested in pursuing early stage demonstration projects in absence of climate policy.

Advanced Resources International (ARI) estimate that 136 billion barrels of domestic oil may be technically recoverable using today's state-of-the-art EOR technology (ARI,

[36] Converting from tonnes of CO_2 avoided to tonnes of CO_2 captured is done by dividing by $\left(1-\frac{energy\ penalty}{capture\ percentage}\right)$. For an energy penalty of 25% and 90% capture this is equivalent to dividing by a factor of 0.72. Therefore, 100 tonnes avoided is equivalent to 139 tonnes captured. Also \$100/tonne captured equals \$72/tonne avoided.

2011). This would require approximately 46 gigatons of CO_2, or the 30-year emissions from close to 250 coal-fired power plants (assuming each is 1 GW). One report estimates the worldwide demand for CO_2 for EOR to be around 310 gigatons, mostly situated in the Middle East and in the former Soviet Union (ARI, 2011). Nonetheless, considerable uncertainty exists around such global estimates, and even the higher estimates are small compared to the cumulative storage potential of many of the other types of storage formations. As an example, DOE (2010b) estimate the storage potential in saline formations to range from 1,653 to 20,213 gigatons.

The key factor that is common for the U.S. demonstration projects described in section 2.2 that are still active is that they are situated in regions with a large oil & gas industry (see Figure 6). Moreover, all of the currently ongoing U.S. CCS power projects, with the exception of FutureGen, are planning to use EOR as an additional revenue source. There are four principal ways in which EOR storage can act as driver for moving CCS projects forward:

1. Access to additional revenue streams result in lower costs and reduced subsurface uncertainty
2. Regulatory agencies and lawmakers in states with EOR are more familiar with geologic injection
3. Access to existing pipeline infrastructure for CO_2
4. Public familiarity with underground CO_2 injection

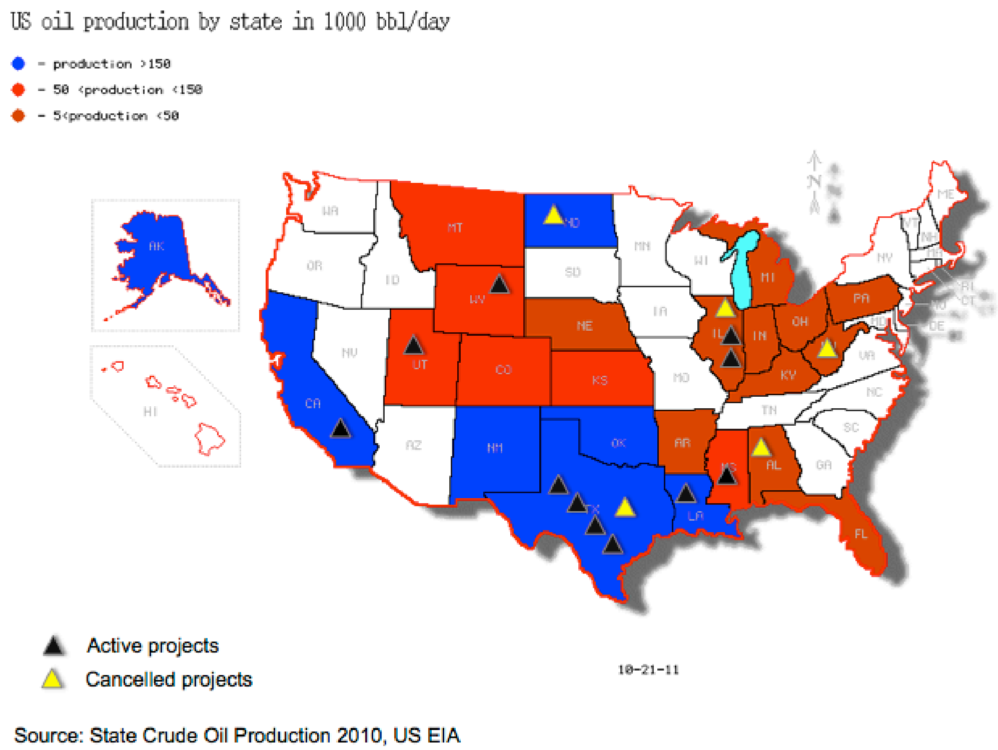

Figure 6: Location of large-scale (>1 MT CO_2/year) U.S. CCS demonstration projects

While there are obvious benefits to project economics of receiving additional revenue streams, projects in areas with prior exposure to oil & gas operations also benefit from a better understanding of the relevant subsurface formations. This prior knowledge could result in important reductions in sequestration risks. As noted by the Global CCS Institute: "*[EOR projects can] draw upon a wealth of developed geological data to help identify and characterize the storage site*" (GCCSI, 2011). Furthermore, EOR is a well-tested technology compared to storage in saline formations, despite the fact that traditional EOR operations are designed to maximize oil recovery, not safely store CO_2 indefinitely. This does produce some technical challenges, but the uncertainties surrounding EOR storage are still considerably smaller compared to developing a new greenfield saline storage site.

Regulators are likely to be more familiar with regulating key aspects of the CCS value chain, most particularly transport and injection, in states that are familiar with oil & gas operations. Consequently, regulators have a better starting point for developing sound regulation for CCS. Having already developed the institutional capabilities needed for permitting some types underground injection, it will be easier to transition to permitting and monitoring the safe injection and storage of CO_2.

There are currently 3,600 miles of CO_2 pipelines in the United States, mostly around Texas, and the pipelines transport around 50 millions tons CO_2 per year from natural sources to EOR operations (DOE, 2010a). With increasing demand for CO_2, it is possible that current pipeline infrastructure can be used to transport anthropogenic CO_2 from CCS projects. If compared to the overall project cost of a commercial-scale power plant with CCS, transport costs are small. Herzog (2011) believes for example that transport and storage would add around $10/tonne to the cost of CO_2 avoided. However, they are not negligible, and avoiding them and their associated risk could, as was seen with the UK's Longannet project[37], theoretically be the "tipping point" for a private company deciding whether or not to go forward with a project.

Lack of public support proved to be an important factor for Vattenfall putting on hold their CCS project at the Jachswalde power plant in Germany[38]. If CCS would be deployed at a large scale, it is likely that much stronger opposition will form if CO_2 storage is to take place close to more heavily populated areas that have little experience with drilling and CO_2 injection. In states that currently have EOR operations the public is already somewhat accustomed to underground injection of CO_2, and it might be less likely that project developers run into the same difficulties as Vattenfall.

Siting CCS demonstration projects in areas with EOR operations can provide a number of benefits. EOR could provide additional revenue streams and lower injection risk. State regulators would be more familiar with underground CO_2 injection, thereby streamlining the permitting process. Finally, existing pipelines could be used to transport capture CO_2 to storage sites, and the public is likely to be less hostile to injection and long-term storage of CO_2. While additional revenues from EOR might somewhat improve project

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[37] BBC online, *Longannet Capture Scheme Scrapped* (October 19th 2011). Retrieved on January 21st 2013from http://www.bbc.co.uk/news/uk-scotland-north-east-orkney-shetland-15371258

[38] MIT CSI Project database, *Vattenfall Janschwalde factsheet.* Retrieved on January 18th 2013 from http://sequestration.mit.edu/tools/projects/vattenfall_janschwalde.html

economics, the cost of capture is simply too high for EOR on its own to make CCS power projects profitable. Consequently, public subsidies are likely to be needed to incentivize the first commercial-scale projects. However, as will be addressed in chapter 6, focusing exclusively on demonstration projects with EOR storage might not be the optimal long-term strategy if CCS is to be used for large-scale climate mitigation.

3.2 - Long-term situation

The primary long-term justification for public investment in CCS technology development is that the gravity of climate change, the increasing demand for energy, and the continued reliance fossil fuels created a demand for a technology that could provide low-carbon electricity from fossil fuels. This section explores whether these three justifications continue to be valid.

3.2.1 - Climate change

First discovered in 1824 and validated in 1850, the greenhouse effect is a process in which the heat radiated from the Earth is absorbed by heat-trapping gases in the atmosphere. These greenhouse gases then reradiate some of the heat back to the surface, making the Earth significantly warmer than would otherwise be the case (NCADAC, 2013). In recent decades, atmospheric concentrations of greenhouse gases such as CH_4, N_2O and CO_2 have increased significantly and are believed to be the main driver behind the increasing global temperatures shown in Figure 7.

The recently released draft report for the Third National Climate Assessment Report concluded that the global climate is changing, and that the changes in the past 50 years are mostly due to human activities. Average U.S. temperatures have increased by about 0.83°C (1.5°F) since 1895, and close to 80% of the increase happened over the past three decades (NCADAC, 2013). Furthermore, there is mounting evidence that more frequent and severe extreme weather is the consequence of human activities. In recent decades, more heavy downpours, more severe droughts, and prolonged stretches of excessively high temperatures have occurred with increasing frequency (NCADAC, 2013).

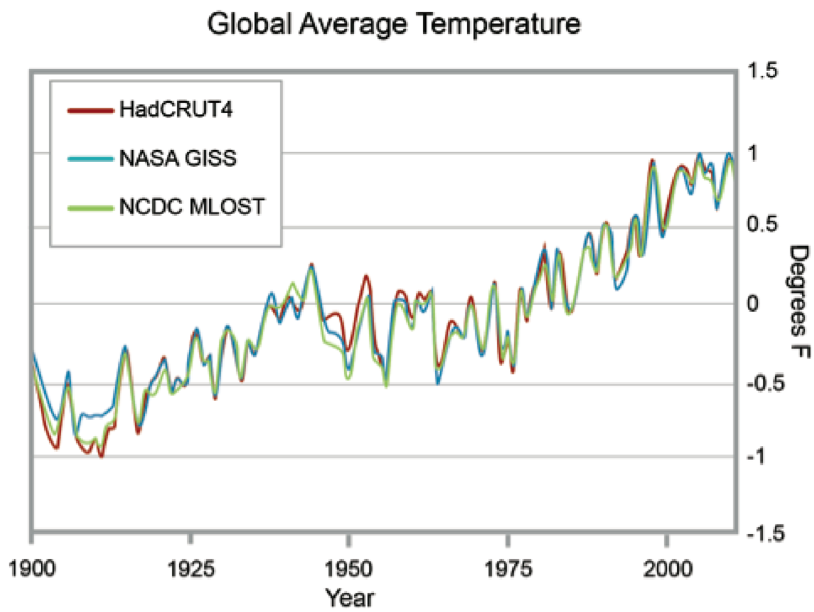

Figure 7: Global average temperature relative to average temperatures 1961-1990
Source: NCADAC (2013)

While there is great uncertainty regarding future greenhouse gas emissions and concentrations, a number of scenarios can be used to represent what *could* happen if current trends persist. For example, the IEA has projected that the world is on track for a long-term temperature increase of 3.6°C relative to pre-industrial levels if pledged policies are acted on. If current policies are continued, the IEA believes the world is on track for a 5.3°C long-term temperature increase (IEA, 2012). In studying the impacts of human activity on the climate, NCADAC refers to two IPCC emission scenarios, one with high emissions and one with low emissions. Figure 8a shows the high emission scenario (A1fi), where global carbon emissions continue to increase towards 30 GtC by the end of the decade. The low emission scenario (B1) is one where global carbon emissions continue to increase slowly before decreasing significantly in the second half of the century. As shown in Figure 8b, the high emission scenario could result in significant temperature increases, compared to more moderate increases in the low emission scenario.

(a)

(b)

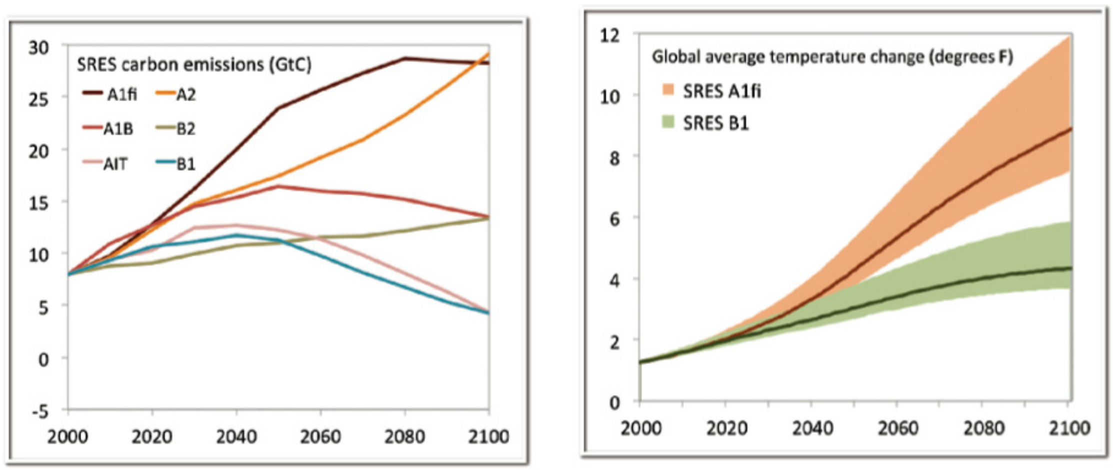

Figure 8: (a) SRES emissions scenarios (b) Corresponding temperature increases (degrees F). Source: NCADAC (2013)

A number of different models are used to study the effects of human activity, and particularly greenhouse gas emissions, on the climate. The outcome of such studies may vary, yet as the NCADAC notes, the overwhelming conclusion is that with current trends, the world is on track for a warmer Earth with a changing climate. However, determining the exact consequences of higher temperatures is challenging. The highly complex and chaotic nature of the Earth's climate make accurate predictions difficult. For example, melting ice sheets will result in more heat being absorbed by the ocean, further accelerating the melting process. However, the processes that govern the melting of ice sheets are not properly described in most climate models (NCADAC, 2013). Nonetheless, a consensus on a number of potential effects of higher temperatures has emerged: tropical cyclones and hurricanes are likely to become stronger, freshwater supplies will come under increasing stress and the oceans will become warmer and more acidic. Sea levels are expected to rise between 1 and 4 feet by the end of the century, threatening about 5 million Americans currently living within 4 feet of the high tide lines (NCADAC, 2013). The most immediate impact of rising waters could be the increasing severity of storms, and the probability of experiencing a *"100-year flood"* could double by 2030 according to one risk-assessment (NCADAC, 2013).

CO_2 is by far the most important greenhouse gas, representing about 84% of U.S.

greenhouse gas emissions in 2010[39]. If CO_2 emissions continue to increase, the adverse effects of climate change will only accelerate further (NCADAC, 2013). While CO_2 emissions decreased by 2.4% in 2011 relative to 2010 due to slower economic growth and a shift from coal to natural gas[40], the reductions are not sufficient to mitigate climate change. The most recent climate change research, summarized in the draft National Climate Assessment Report, therefore shows that climate change continues to pose a significant threat. Rising CO_2 emissions are a significant danger to the planet, and efforts to reduce emissions continue to be of great importance.

3.2.2 - Future energy demand

Global energy demand is growing rapidly, driven by rising incomes and a more populous planet (IEA, 2012). As seen in Figure 9, total energy demand grew 45% from 1990 to 2010, and is projected to grow by another 35% by 2035 according to IEA's New Policies Scenario[41]. The increased demand for energy is particularly striking in the electricity sector, with generation expected to increase 70% between 2010 and 2035. To meet the demand, global capacity is expected to expand from 5429 GW in 2011 to 9340 GW in 2035 (IEA, 2012).

[39] U.S. EPA website, *Overview of greenhouse gas emissions*. Retrieved on January 21st 2013 from http://www.epa.gov/climatechange/ghgemissions/gases/co2.html
[40] U.S. EIA, *Energy-related carbon dioxide emissions down in 2011* (September 10th 2012). Retrieved on January 21st 2013 from http://www.eia.gov/todayinenergy/detail.cfm?id=7890
[41] The New Policies Scenario considers a conservative implementation of existing and pledged policy commitments

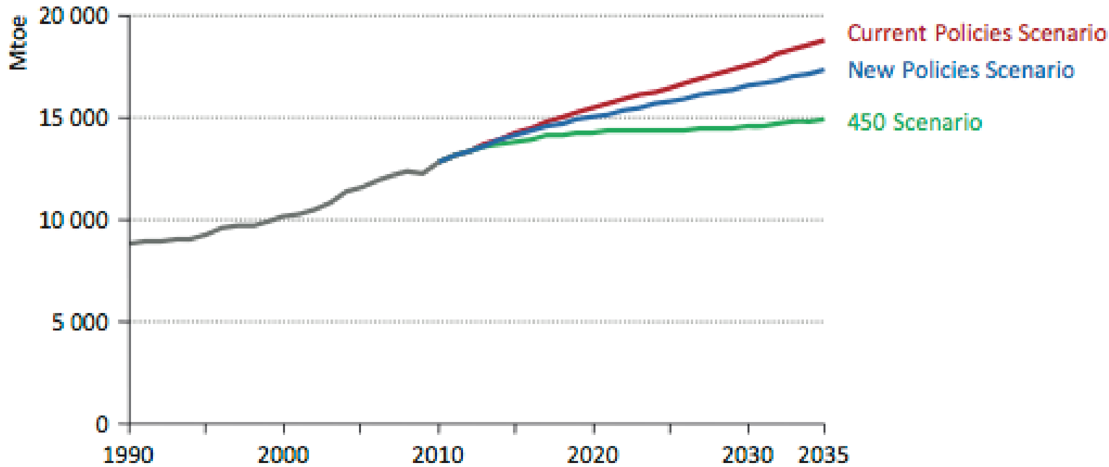

Figure 9: World primary energy demand according to IEA modeling scenarios. Source: IEA (2012)

Most of the increased demand is likely to come from emerging economies, and the IEA expects that China and India will be responsible for over half of the growth in worldwide energy demand. In both countries electricity demand has already grown rapidly, and as an illustration China added 327 GW of coal capacity between 2005 and 2011 (IEA, 2012), more or less the same as the size of the entire U.S. fleet of coal-fired power plants. The growth is likely to continue, and the IEA's New Policies Scenario shows that Chinese electricity generation could grow by over 130% from 2010 to 2035. India's growth rate could be even greater, at over 240%, but from a smaller base.

The IEA's modeling results should not be considered predictions about the future, but rather as providing useful insights about what could happen if current trends persist. Their key conclusion is that world energy demand is increasing, and shows no sign of slowing. Unfortunately, energy demand is increasing at the same time as the need for emissions reductions are apparent. How the energy demand will be met will in large part determine whether CO_2 emissions continue to rise, and whether CCS continues to be a relevant mitigation technology.

3.2.3 - The future energy mix

Although renewables are likely to play an important role in the future, they are unlikely to overtake the role of fossil fuels in the near future. As the IEA notes in its 2012 World Energy Outlook, *"across the scenarios several fundamental energy trends persist…[one of them being that] fossil fuels meet most of the world's energy needs"*. Fossil fuels supply around 85% of the world's energy primary energy needs, and depending on the scenario considered, the IEA assumes they will continue to supply from 63% to 80% in 2035 (IEA, 2012).

In the New Policies Scenario, non-hydro renewables are projected to increase their share of electricity generation in the U.S., from 2% today to slightly over 12% in 2035 (IEA, 2012). Nonetheless, the IEA projects that coal and natural gas will continue to play a major role in electricity generation for decades to come. Coal-fired power plants, which currently supply 41% of the world's electricity, and are responsible for 43% of global CO_2 emissions, could still generate a third of the world's electricity in 2035 (IEA, 2012). Currently 78% of China's electricity is coal-based, compared to around 43% of India's, and despite large investments in renewables, coal is likely to retain a large share of electricity generation. Figure 10 clearly shows how Chinese and Indian electricity generation from coal (and by extension, emissions) will soon overtake that of the EU and the U.S. While coal's share of total electricity generation might somewhat decrease in the future, there are no signs that it will become a negligible part of the electricity supply.

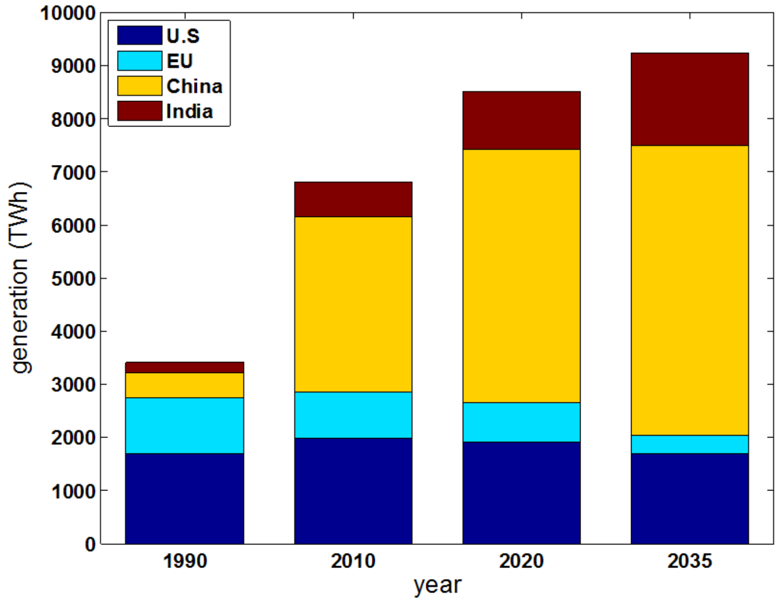

Figure 10: Electricity generation from coal in select regions. Source: IEA (2012)

Increased generation from nuclear reactors used to be viewed as one of the ways to reduce CO_2 emissions. However, the Fukushima accident in March 2011 significantly cooled the worldwide enthusiasm for more reactors. In the wake of the accident, Germany announced that they were phasing out their nuclear plants by 2022 and Switzerland decided not to extend the lifetime of their existing fleet (IEA, 2012). Yet the U.S. Nuclear Regulatory Commission recently issued its first license in a generation for a new reactor for Southern Company's Vogtle plant. Nonetheless, it is unlikely that there will be a large number of new nuclear plants coming online given the strong opposition in many communities to new reactors as well as the significant costs and risks involved in their construction. The IEA also reduced their projected growth in nuclear capacity up to 2035, but not by much. China in particular is projected to soon lift their moratorium on new reactors, and 59 GW of new capacity is expected to come online between 2010 and 2020 (IEA, 2012).

Even if renewables such as wind and solar experience much more rapid growth than projected, without breakthroughs in grid-scale storage technologies, their intermittency will require some form of flexible electricity generation, most likely from natural gas. Furthermore, public attitudes toward nuclear energy make it unlikely that nuclear on its own will overtake the role of fossil fuels to serve significant portions of global and U.S. energy needs. It seems safe to assume that fossil fuels will continue to play an important role for the foreseeable future in meeting a growing energy demand. If society chooses to take decisive action to mitigate climate change, it seems fair to conclude that there continues to be a need for technologies such as CCS that can produce low-carbon electricity from fossil fuels.

3.3 - Conclusion

The short-term argument for CCS used to be that strict climate policies would create a demand for low-carbon technologies. With the U.S. relying on coal for a majority baseload generation there was a particular need for technologies that could reduce CO_2 emissions from coal-fired power plants. With no climate policy in sight, and natural gas-fired power plants increasingly displacing coal-fired ones, the main short-term justification for CCS is no longer valid. Furthermore, persistent high cost of the technology along with tight public finances suggests that the short-term situation for CCS has worsened considerably. Additional revenue streams through EOR are unlikely to significantly change the situation due to the high cost of CO_2 capture from power plants.

The long-term need for CCS nonetheless remains unchanged. Climate change continues to be a significant threat, and recent research suggests the challenge is growing more serious, not less. Simultaneously, worldwide energy demand, particularly in emerging economies, is growing rapidly. Much of the current, and future, demand for energy will continue to be supplied by fossil fuels, further increasing atmospheric CO_2 concentrations. Consequently, there is still a long-term need for technologies that can generate low-carbon electricity from fossil fuels. In other words: only the short-term, but not the long-term, need for CCS has changed. However, moving CCS to commercial readiness will be challenging in the current political and economic environment.

The U.S government has responded to the new realities for CCS in two notable ways:

- A stronger focus on projects with EOR storage

- An announced 1000 lbs CO_2/MWh emission standard for new power plants

The first change came in July 2011[42] with the confirmation of Charles McConnell as assistant secretary for fossil energy at the U.S. Department of Energy. Mr. McConnell, who resigned in early 2013[43], rebranded the DOE's CCS strategy as CCUS (Carbon Capture, *Utilization* and Storage), where *utilization* in practice meant using captured CO_2 for EOR purposes. While EOR storage does provide a number of benefits to projects, section 3.1.5 showed how it is unclear if EOR revenues on their own will be sufficient to cover the high cost of capturing CO_2 from power plants.

The second change came on April 13th 2012 when the EPA announced a CO_2 emission standard for new power plants that practically banned any new coal-fired power plants without some sort of CO_2 capture (EPA, 2012).

An analysis of what the imposition of a CO_2 emission standard and the presence of additional EOR revenues imply for CCS investments and U.S. CCS policy is the focus of the next chapter.

[42] Michael Moore, *CCS to CCUS – U.S. CO_2-EOR Developments.* RECS presentation June 2012, Birmingham, Alabama. Retrieved on January 15th 2013 from http://www.scribd.com/doc/96532947/CCS-to-CCUS-U-S-CO2-EOR-Developments

[43] Oil & gas journal, *McConnell resigns as DOE's fossil energy chief* (January 31st 2013). Retrieved on May 6th 2013 from www.ogj.com/articles/2013/01/mcconnell-resigns-as-does-fossil-energy-chief.html

Chapter 4 - CO_2 emission standards and CCS investment

On April 13th 2012 the EPA announced its proposed New Source Performance Standard (NSPS) that would limit CO_2 emissions from new fossil fuel-fired power plants to 1,000 lbs/MWh. The emission standard is an important milestone in shaping the future of CCS because it requires coal-fired power plants to partially capture CO_2 in order to have approximately the same emissions as an uncontrolled natural gas-fired power plant.

In this chapter, a stochastic generation expansion model is employed to determine the effect of different emission standards on investment decisions in new power plants, and how these decisions change with different natural gas and EOR prices. The model is stochastic in order to appropriately model the inherent uncertainties surrounding the commercial-scale performance of CCS.

The analysis in this chapter is critical to inform the future path of U.S. CCS policy. The chances of a comprehensive climate policy bill passing through the U.S. Congress are slim. In the near future, the EPA's emission standard may therefore be the only major federal carbon-reducing policy affecting U.S. fossil fuel-based generators. Consequently, understanding how emission standards affect investments in the electricity sector will be important for rethinking U.S. CCS policy.

The chapter is structured in six sections. First, the EPA's emission standard is presented. Second, the stochastic generation expansion model is described along with the necessary input parameters. The third section develops an approximation for CCS costs as a function of the capture percentage. The fourth section develops the expression for the necessary CO_2 capture percentage to meet an externally imposed emission standard. The fifth section presents the results and the last section discusses their impact on U.S. CCS policy.

4.1 - The EPA New Source Performance Standard

On April 13th 2012 the EPA announced a proposed rule under section 111 of the Clean Air Act that would limit CO_2 emissions from new fossil fuel-fired power plants to 1,000 lbs/MWh[44]. Under the rule, coal-fired power plants can choose to operate for the first ten years with higher emissions, as long as the 30-year average meets the above target. Given current emissions rates of around 1765 lbs/MWh for new supercritical pulverized coal power plants (NETL, 2011), the new regulations will effectively ban any new coal-fired power plants without carbon capture of some sort over the life of the plant. The regulations only apply to new plants, and would not force older plants undergoing significant retrofits to comply with other EPA regulations to simultaneously meet the CO_2 emission limit (Brasington, 2012).

The emission standard has been met with strong opposition from certain industry groups, and on June 11th 2012 Las Brisas Energy Center filed suit for judicial review of the rule. The company argued that the 1000 lbs/MWh emission standard should only apply to natural gas-fired power plants, not fossil fuel-fired power plants in general. However, on December 13th 2012 the U.S. Court of Appeals for the D.C. circuit dismissed Las Brisas' challenges since the proposed regulation was not yet a final rule[45].

The EPA's action on greenhouse gases follows the 2009 Supreme Court Decision in *Massachusetts v. EPA* granting the EPA the authority to regulate emissions of such gases under the Clean Air Act. The subsequent 2009 EPA endangerment finding stated that greenhouse gases might reasonably "*threaten the public health and welfare of current and future generations"*[46] and were therefore subject to regulation under the Act. In order to avoid the burdens of regulating all major stationary sources of CO_2 emissions, the EPA issued its Tailoring rule. The rule is such that the EPA will initially only target the largest

[44] Based on a 12-month annual average
[45] U.S. Court of Appeals for the D.C. Circuit, *Las Brisas Energy Center, LLC* v. *Environmental Protection Agency*, No. 12-1248 (December 13th 2012). Retrieved on April 28th 2013 from http://op.bna.com/env.nsf/id/fwhe-92xr5k/$File/lasbrisas.dismiss.pdf
[46] U.S. EPA website, *Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act*. Retrieved on January 16th 2013 from http://www.epa.gov/climatechange/endangerment/

stationary sources, those emitting more than 75,000 (modified units) or 100,000 (new units) tons CO_2-equivalent per year[47].

The EPA's actions in regulating greenhouse gases in general have drawn significant criticism from certain industry groups, and the agency's actions have been challenged in court in *Coalition for responsible regulation v. EPA*. However, on June 26th 2012 the U.S. Court of Appeals for the D.C. circuit upheld the 2009 endangerment finding along with the tailoring rule[47]. The court thereby validated the key underpinnings of the EPA's approach to regulating greenhouse gases under the Clean Air Act.

A final ruling on the New Source Performance Standard was expected by the EPA in April 2013, but has now been delayed[48]. While one cannot predict the future of the final rule, this chapter will explore how CO_2 emission standards for power plants could impact the development and implementation of CCS technology.

4.2 - Model description

The effect of CO_2 emission standards on power plant investments is analyzed through a stochastic generation expansion model. The objective of the model is to determine, under a given emission standard, the portfolio of power plants that minimize the expected cost of meeting demand over a pre-defined planning horizon. The model, and the corresponding solution method, is described in detail in Appendix A. Due to the stochastic nature of the problem, a large number of realizations of random variables will be generated. As a result, solving the optimization problem with conventional methods would require prohibitively long solution times, and classic Benders decomposition algorithm is therefore implemented.

[47] U.S. Court of Appeals for the D.C. Circuit, *Coalition for responsible regulation Inc. v. Environmental protection agency*, No. 09-1322 (June 26th, 2012). Retrieved on April 28th from http://www.cadc.uscourts.gov/internet/opinions.nsf/52AC9DC9471D374685257A290052ACF6/$file/09-1322-1380690.pdf
[48] Power Engineering, *EPA delays finalizing New Source Performance Standard regulations* (April 15th 2013). Retrieved on April 18th 2013, from http://www.power-eng.com/articles/2013/04/epa-delays-finalizing-new-source-performance-standard-regulation.html

Whereas a deterministic analysis could be undertaken with simpler methods, for example in a spreadsheet model, Appendix B shows that explicitly modeling the uncertainty produces notable differences in outcomes. The stochastic optimization employed for this analysis can only be solved utilizing some of the more advanced mathematical optimization tools for decision-making under uncertainty

4.2.1 - Deterministic parameters

The generation expansion model uses the hourly electricity demand in ERCOT for the year 2010 to model demand. While considering demand variation over the year is important in order to appropriately choose generation technologies, modeling each of the 8760 hours in a year would make the optimization problem prohibitively large, particularly if some parameters are considered uncertain. Demand is therefore represented through a load duration curve shown in Figure 11 where the hours are stacked according to decreasing demand. To approximate the load duration curve, the year is separated into five load blocks shown in the figure. These load blocks are the basis for modeling demand in the generation expansion model.

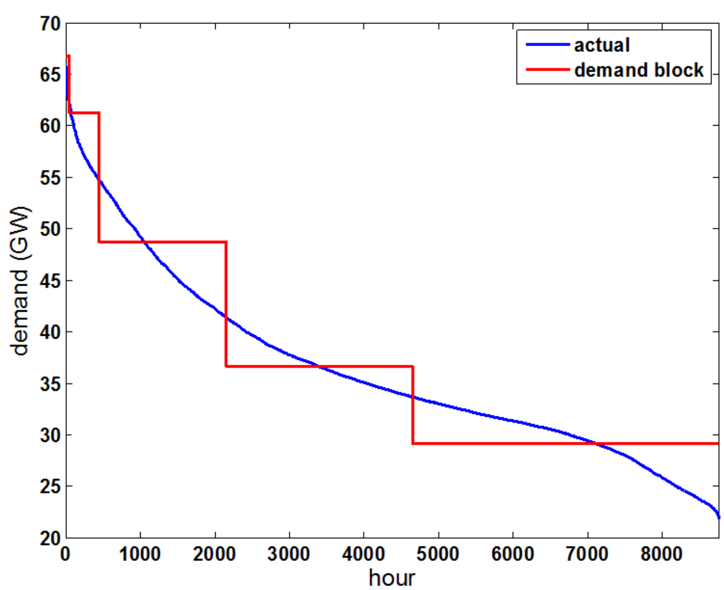

Figure 11: 2010 ERCOT load duration curve and corresponding load blocks used to model demand

The technologies that are modeled, and the accompanying cost assumptions are shown in Table 5. Due to the long planning periods involved in commissioning new nuclear plants, the number of new nuclear plants has been capped at three. Moreover, since the model does not consider the intermittency of renewables, wind penetration is limited to less than 30% in order to avoid having to consider high integration costs for very high wind penetrations (e.g. through a need for large spinning reserves).

Table 5: Model assumptions

	Variable O&M	Overnight cost	Net Plant Efficiency
Technology assumptions	**$/MWh**	**$/kW**	**%**
Nuclear	12.87	3382	
Coal (PC)	8.76	2108	39
CCGT	3.61	969	54
OCGT	4.41	649	40
Wind	8.63	1973	100
CCGT-CCS (90% capture)	5.69	calculated	calculated
Coal-CCS (90% capture)	11.31	calculated	calculated

General assumptions	
Fuel price coal ($/MMBtu)	2.3
Nuclear fuel cycle cost ($/MWh)	9.33
Discount rate (%)	10%
Capital charge (%)	15%
non-EOR storage cost ($/tonne)	15
New nuclear plant limit	3
Planning horizon (T)	30
Maximum wind penetration (% of total demand)	30%

	Demand period				
	1	**2**	**3**	**4**	**5**
Wind capacity factor (%)	20	24	20	23	22
Demand (MW)	66,812	61,240	48,729	36,672	29,183
Duration (hours)	50	400	1700	2500	4110

4.2.2 - Uncertain parameters for power plants with CCS

Current estimates of the overnight cost of power plants with CCS and the energy penalty associated with capturing CO_2 are based on pilot plants and Front-End Engineering and Development (FEED) studies. There is considerable uncertainty regarding their actual value for commercial-scale plants, and the results reported in Finkenrath (2011) provide a good example. The report is a summary of 13 major CCS cost studies, and the overnight cost for a pulverized coal power plant with post-combustion CO_2 capture was on average 1.8 times higher than the overnight cost of a pulverized coal power plant without CO_2 capture. However, in the studies surveyed this overnight cost multiple ranges from 1.5 to 1.96. Similarly, the average energy penalty was 25.6%, with values ranging from 20% to 29%.

To properly model the uncertainty in the overnight cost of power plants with CCS and their energy penalty, the parameters are sampled from probability distributions. The uncertainty in the overnight cost of power plants with CCS is represented as an uncertainty in the overnight cost multiple for a capture percentage of 90% (i.e. how many times higher is the overnight cost of a power plant with 90% CO_2 capture relative to the same power plant without CO_2 capture). The energy penalty will be sampled from a uniform distribution and the overnight cost multiple will be sampled from a lognormal distribution. Both probability distributions for coal-fired power plants with CCS are shown in Figure 12.

Since Finkenrath (2011) was first published better numbers for the energy penalty have been reported (e.g. in Rubin et al. (2012)). The energy penalty of coal-fired power plants with CCS is therefore sampled from a uniform distribution ranging from 18% to 25%. The distribution of overnight cost multiples for coal-fired power plants with CCS uses the same mean value as Finkenrath (2011), i.e. 1.8, but is skewed rightward to account for the possibility that actual overnight costs may end up being higher than those reported today. The distribution of overnight cost multiples has a minimum value of 1.6, and is chosen to have a one-sided 95% confidence interval of 2.1, and a one-sided 99% confidence interval of 2.4.

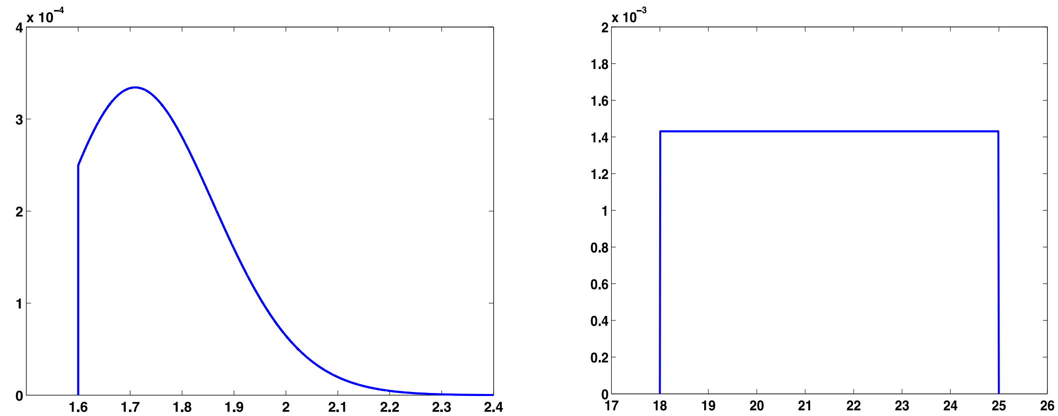

Figure 12: (a) Probability distribution for overnight cost multiple of coal-CCS power plant relative to the same power plant without CCS (b) Probability distribution for energy penalty of coal-CCS power plant

The energy penalty and the overnight cost of coal-fired power plants with CCS and natural gas-fired power plants with CCS are different, but closely correlated. The most rigorous way of representing the likelihood of different scenarios would therefore be through a joint uniform probability distribution in the case of the energy penalty, and a joint lognormal probability distribution in the case of the overnight cost multiple. However, sampling from these joint distributions is rather complicated. For the sake of this analysis the energy penalty and overnight cost multiple for natural gas-fired power plants with CCS are calculated as a function of the energy penalty and overnight cost multiple for coal-fired power plants with CCS. The model assumes that the energy penalty of natural gas-fired power plants with CCS is 75% of the energy penalty of coal-fired power plants with CCS. The overnight cost multiple of natural gas-fired power plants with CCS is considered to be 105% of the overnight cost multiple of coal-fired power plants with CCS. Future extensions of this work will use joint distributions rather than calculate one parameter as a function of the other.

4.3 - CCS costs as a function of capture percentage

Different emission standards would require different CO_2 capture levels from coal- and natural gas-fired power plants, and a number of CCS cost parameters will depend on the CO_2 capture percentage. Higher capture percentages mean that larger solvent volumes are needed in order to capture the increased quantities of CO_2. Consequently, more energy will be needed to regenerate the larger solvent volumes and a higher capture percentage will therefore result in a higher energy penalty. Similarly, a higher capture percentage means that larger capture equipment, e.g. absorbers and strippers, are needed, thereby increasing capital and O&M costs. The net plant efficiency, the variable O&M cost, and the overnight cost will therefore depend on the capture percentage, but unfortunately, most CCS cost studies report cost data only for a capture percentage of 90%.

4.3.1 - Net plant efficiency and variable O&M cost

The model will approximate the net plant efficiency and the variable O&M cost for coal-fired power plants with CCS as a linear function of the capture percentage. The constants of the linear functions will be derived using data for 0% and 90% CO_2 capture. The net plant efficiency at 90% CO_2 capture is calculated from the initial efficiency at 0% CO_2 capture as well as the energy penalty sampled from the uniform distribution described in section 4.2.2.

The linear approximation is based on the results in NETL (2011), where an Aspen Plus model of a supercritical pulverized coal plant with post-combustion capture is used to run simulations for different levels of CO_2 capture[49]. The black boxes in Figure 13 show the resulting variable O&M costs and net plant efficiencies whereas the red line is the linear interpolation using only two capture percentages. Although approximating the O&M cost and net plant efficiency as a linear function of the capture percentage is not entirely accurate, it yields results within reasonable bounds.

[49] The NETL plant model uses 550 MW net power plant with Fluor's Econamine FG Plus capture process with 30% by weight MEA solvent, and fires Illinois #6 medium sulfur bituminous coal

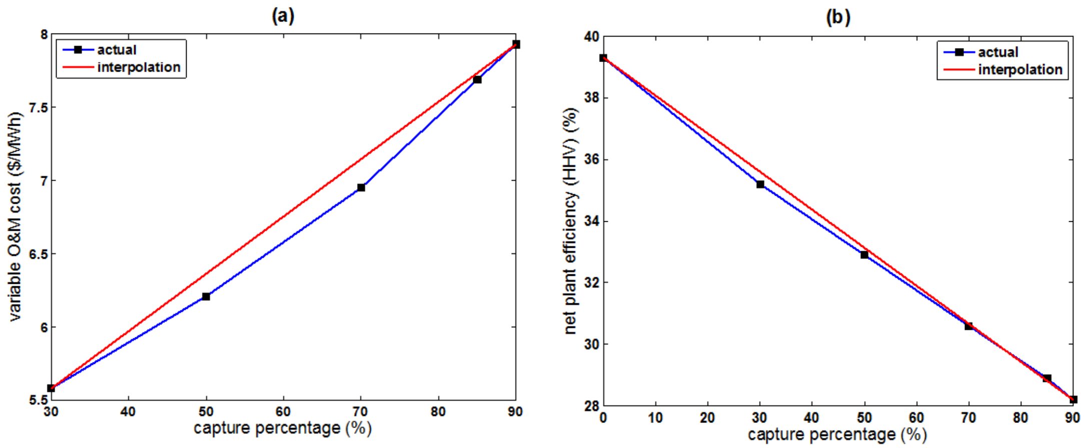

Figure 13: (a) Variable O&M cost reported in NETL (2011) compared to linear interpolation between 30% and 90% CO_2 capture (b) Net plant efficiency reported in NETL (2011) compared to linear interpolation between 0% and 90% CO_2 capture.

Natural gas-fired CCGT power plants will need to capture CO_2 for emission standards below 1000 lbs/MW, but studies similar to NETL (2011) for partial CO_2 capture on CCGT power plants could not be found. Post-combustion capture on natural gas-fired power plants is different from coal-fired power plants, most notably due to lower CO_2 concentrations and smaller amounts of pollutants that could degrade the solvent. However, it is assumed that the variable O&M cost and the net plant efficiency of natural gas-fired power plants with CCS can continue to be approximated as linear functions of the capture percentage.

4.3.2 - Overnight cost

The overnight cost of a power plant with CCS capturing 90% of its CO_2 is calculated using the overnight cost multiple sampled from the lognormal distribution described in section 4.2.2. However, interpolating linearly between 0% and 90% CO_2 capture, as is shown in Figure 14 for overnight costs in NETL (2011), might not be entirely accurate. There can for example be notable nonlinearities in the overnight cost of CO_2 capture equipment for small capture percentages (e.g. due to the fact that there is a minimum size of the absorber and the stripper).

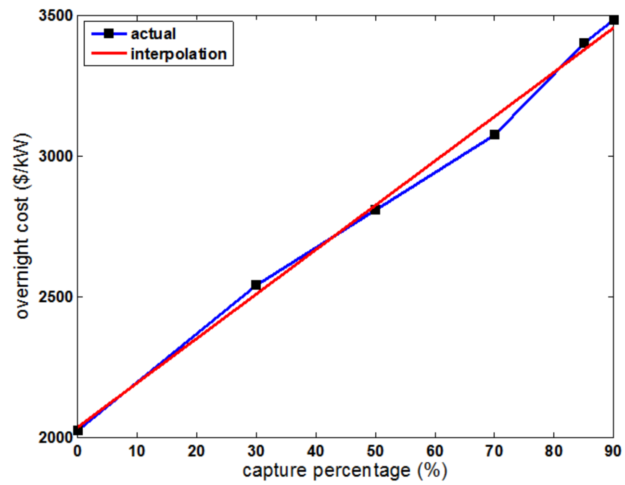

Figure 14: Overnight cost of coal-fired power plants with CCS for different capture percentages. Source: NETL (2011)

These nonlinearities at capture percentages less than 30% are apparent in Figure 15 from Hildebrand (2009). A linear interpolation of the overnight cost is a reasonable approximation for higher capture percentages (i.e. higher than 30%), but in order to account for the nonlinearities at a lower capture percentages a piecewise linear approximation is needed.

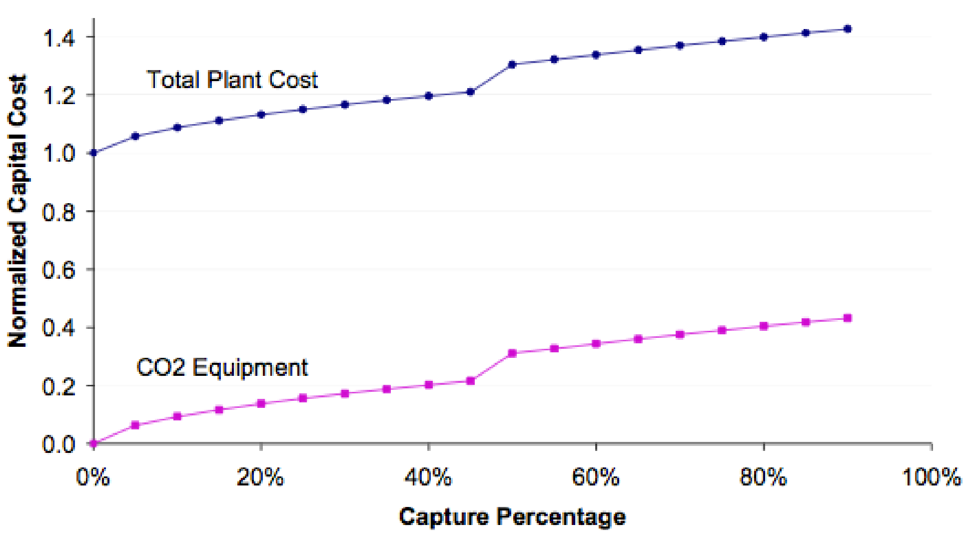

Figure 15: Total plant cost and CO_2 capture equipment cost as function of capture percentage for a pulverized coal plant with post-combustion capture. Source: Hildebrand (2009)

The blue line in Figure 16 shows the shape of the cost functions that are used to approximate the overnight cost for coal and natural gas-fired power plants with CCS. The piecewise linear approximation of the nonlinearity is apparent for capture percentages less than 30%.

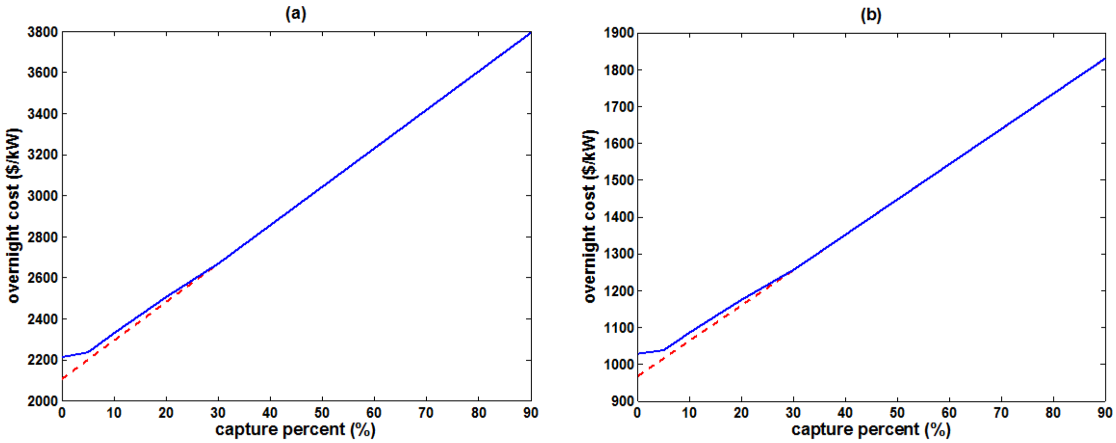

Figure 16: (a) Overnight cost for coal-fired power plants with CCS (b) Overnight cost natural gas-fired power plants with CCS

4.4 - Deriving expression for required capture percentage for CCS units

The energy penalty associated with capturing CO_2 will result in a power plant with CCS having higher fuel consumption for the same net power output compared to a similar power plant without CCS. As a result, gross CO_2 emissions of CCS power plants increase with increasing energy penalty. This effect can be shown analytically, where the gross CO_2 emissions are a function of the energy penalty for a given capture percentage, $ep(cap)$, and the emissions of a reference plant without capture, R_0:

$$gross\_emissions(cap) = \frac{R_0}{1 - ep(cap)} \qquad (1)$$

The energy penalty for a certain capture percentage is the relative decrease in power plant efficiency η as a result of capturing CO_2:

$$ep(cap) = \frac{\eta_0 - \eta(cap)}{\eta_0} = 1 - \frac{\eta(cap)}{\eta_0} \qquad (2)$$

The net plant efficiencies and the net CO_2 emissions reported in NETL (2011) can be used as input values to calculate gross CO_2 emissions using expressions (1) and (2). The resulting gross CO_2 emissions are plotted in Figure 17 as a function of the capture percentage. The energy penalty is superimposed to show how increasing capture percentages result in higher energy penalties, which in turn lead to higher gross emissions.

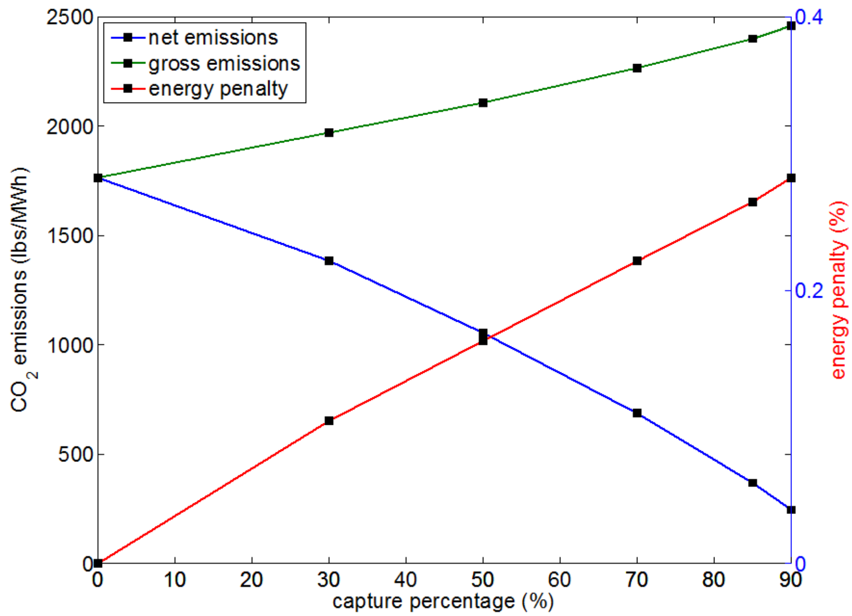

Figure 17: Net and gross CO_2 emissions from a 550 MW supercritical pulverized coal plant as a function of CO_2 capture percentage. Net emissions are those reported in NETL (2011). Energy penalties are calculated using expression (2) and the gross emissions are calculated using expression (1) . Both calculations use input parameters from NETL (2011).

In order to meet a certain emission standard, the net emissions will have to equal the emission standard. In reality, emissions will be higher due to shutdown, startup, load following, etc., but for simplicity this effect will be ignored for the analysis in this chapter.

The net CO_2 emissions of power plants with CCS will simply be a function of the gross emissions and the capture percentage. From expression (1) we therefore have that

$$net\_emissions(cap) = (1 - cap)\frac{R_0}{1 - ep(cap)} \qquad (3)$$

Using expression (2) for the energy penalty, the net emissions can be expressed as

$$net\_emissions(cap) = (1 - cap)\frac{R_0}{1 - \left(1 - \frac{\eta(cap)}{\eta_0}\right)} \qquad (4)$$

As showed in section 4.2, the plant efficiency for a given capture percentage, $\eta(cap)$, can be approximated as a linear function of the capture percentage:

$$\eta(cap) = \alpha * cap + \beta \qquad (5)$$

Consequently, by combining expression (4) and (5), the capture percentage required to meet a certain emission standard can be seen as a function of the initial plant efficiency η_0, the reference emissions R_0, the emission standard ES and the interpolation parameters α and β:

$$cap = \frac{1 - \beta\frac{ES}{R_0\eta_0}}{1 + \alpha\frac{ES}{R_0\eta_0}} \qquad (6)$$

Table 6 shows an example of the necessary capture levels using expression (6) for three different CO_2 emission standards.

Table 6: Capture percentage needed to meet emission standard

	Coal-fired plant	Gas-fired plant
No standard	0%	0%
1000 lbs CO_2/MWh standard	53%	0%
500 lbs CO_2/MWh standard	79%	43%

4.5 - Results

The results of the optimization model are shown as a function of the natural gas price above which coal-fired power plants with CCS enter the portfolio of optimal generation technologies. Figure 18 shows how this natural gas price changes with EOR prices for the EPA's proposed emission standard. With CO_2 emissions capped at 1000 lbs/MWh, coal-fired power plants would be forced to incur significant costs to install CO_2 capture equipment, whereas natural gas-fired ones could comply without installing additional equipment. In the absence of EOR revenues, natural gas prices would need to be above \$13.5/MMBtu before coal-fired power plants with CCS enter the generation mix. As is expected, once captured CO_2 becomes a valuable commodity through EOR, the competitiveness of coal-fired power plants with CCS increases. Yet as long as natural gas prices remain below \$8/MMBtu then power plants with CCS do not enter the generation mix even at very high EOR prices. The kink in the curve at an EOR price of \$0 is due to the fact that when EOR is not available CCS power plant operators have to incur a cost of \$15/ton for CO_2 transport and storage (see Table 5).

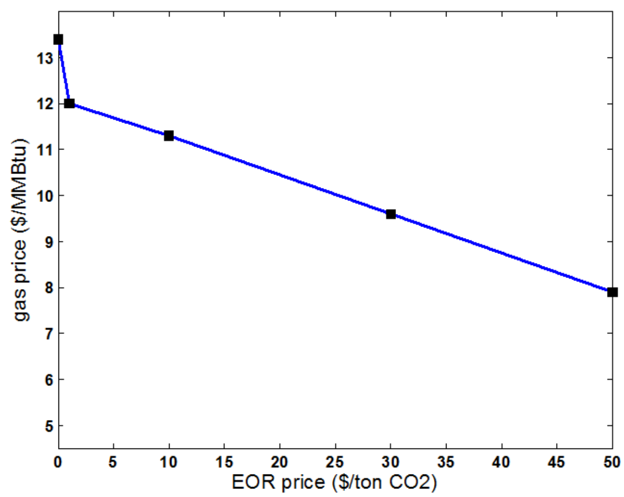

Figure 18: Natural gas price where coal-fired power plants with CCS enter the generation mix for 1000 lbs CO_2/MWh emission standard

Figure 19 shows the natural gas prices above which coal-fired power plants with CCS enter the generation mix as a function of the CO_2 emission standard. Four interesting effects are seen in the graph:

First, if one assumes no EOR revenues, loosening EPA's proposed emission standard, for example from 1000 lbs/MWh to 1500 lbs/MWh, would result in coal-fired power plants with CCS entering the generation mix earlier, i.e. at a lower natural gas price. This can be explained by the simple fact that less stringent emission standards means less CO_2 needs to be captured and consequently costs for the coal-fired power plants with CCS is lower.

The lower costs make them competitive with natural gas-fired power plants at lower natural gas prices.

Second, if EOR revenues are available, the effect described above is significantly less pronounced (i.e., the slope of the line is less negative). Less stringent emission standards require a lower capture percentage, which reduces the cost of capture. However, a lower capture percentage also reduces EOR revenues since lower overall volumes of CO_2 are being captured. Consequently, while a lower capture percentage results in lower costs for coal-fired power plants with CCS, it simultaneously results in lower revenues, which results in a lower net cost saving. At high enough EOR price the lost revenue equals or exceeds the cost savings from lower capture percentages. As a result the slope of the line will be positive above a certain EOR price.

Third, if the EPA's emission standard is tightened, for example from 1000 lbs CO_2/MWh to 500 lbs CO_2/MWh, and natural gas prices remain at current levels, then CCS technology will be applied to natural gas-fired power plants before it is on coal-fired power plants. The reason for why natural gas-fired power plants with CCS are preferred over coal-fired power plants with CCS is due to their lower initial CO_2 emissions. Consequently smaller amounts of CO_2 will need to be captured in order to comply with an emission standard. The lower capture percentage results in lower costs than coal-fired power plants as long as natural gas prices remain at current levels.

Finally, the slope of the curves for tighter emission standards is rather interesting. First, they are downward sloping from 1000 lbs/MWh (going toward 0) because the marginal cost of CO_2 capture from natural gas-fired power plants is higher than for coal-fired power plants. However, the steepness of the line decreases with increasing EOR revenues. At first this seems counterintuitive given that the larger volumes of CO_2 captured from coal-fired power plants should bring in more EOR revenue for coal-fired power plants than natural gas-fired ones, causing the slope to get steeper. However, as EOR revenues increase, the natural gas price at which coal-fired power plants with CCS enter the generation mix decreases, which also decreases the marginal cost of capture from natural gas-fired power plants, as shown in Figure 20. The effect of lower fuel prices will counterbalance the higher marginal revenue increase from EOR for coal-fired power plants and result in the slope of the curve decreasing at higher EOR prices.

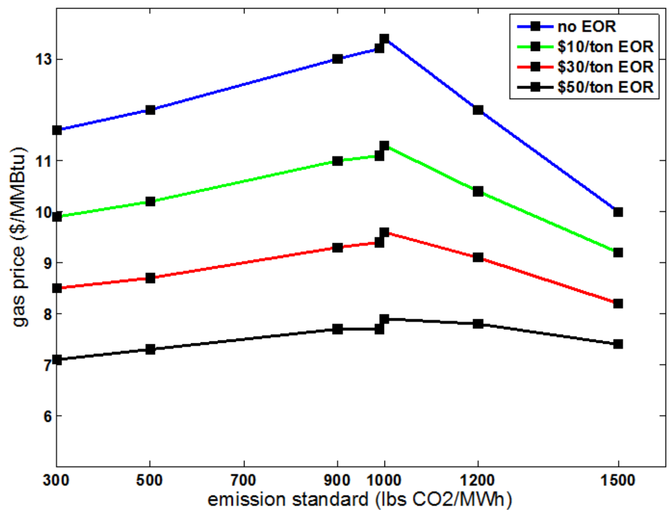

Figure 19: Natural gas price above which coal-fired power plants with CCS enter the generation mix for different emission standards and EOR CO_2 prices

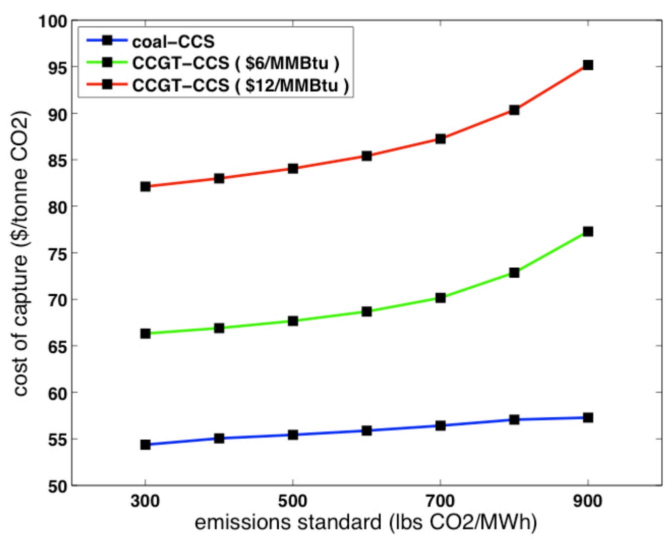

Figure 20: Cost of CO_2 capture for different emission standards and natural gas prices

4.6 - Conclusions and policy implications

Current EOR prices are believed to be in the range of $10-15/ton, and while they may rise in the future, a doubling or tripling seems unrealistic. Moreover, given the EIA's predictions for natural gas prices for power generation in Figure 21, it seems likely that prices will remain below $8/MMBtu for the foreseeable future.

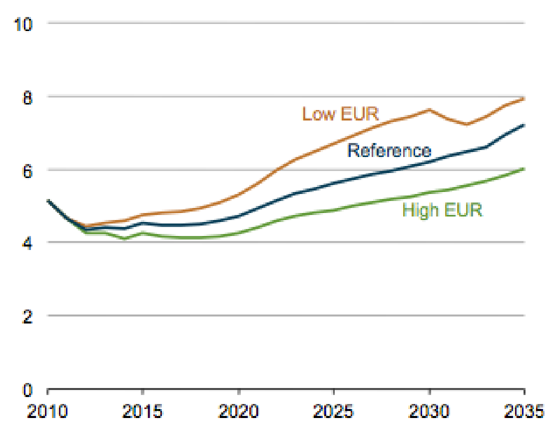

Figure 21: EIA electric power natural gas price predictions. EUR= Estimated Ultimate Recovery. Source: EIA (2012b)

Two key conclusions can therefore be drawn from the results of this stochastic generation expansion model:

1. Implementing EPA's proposed CO_2 emission standard is more likely to result in a shift from coal to natural gas rather than incentivize investment in CCS, even at very high EOR prices. A fairly dramatic departure from current price predictions would be needed for the EPA's proposed emission standard to incentivize investment in power plants with CCS.
2. Imposing a slightly looser emission standard, for example 1500 lbs CO_2/MWh, is more likely than the currently proposed standard to incentivize investment in CCS technology. Even increasing the annual average emissions to 1200 lbs/MWh notably lowers the natural gas price where coal-fired power plants with CCS enter the generation mix.

3. Natural gas-fired power plants are likely to remain the lowest-cost option for electricity generation even if a strict enough emission standard was imposed that also required natural gas-fired power plants to reduce CO_2 emissions. However, as opposed to the currently proposed emission standard, a stricter standard would indeed encourage investment in CCS technology.

As described in chapter 2, all of the U.S. demonstration projects are focusing on coal-fired power plants. In the case of continued political gridlock on climate policy, CO_2 emission standards may become one of the only major federal policies forcing fossil fuel-fired power plants to reduce CO_2 emissions. It is therefore not impossible that one might see even stricter standards than those already proposed sometime in the future. While there are currently no announced plans for strict enough emission standards that also force natural gas-fired power plants to capture CO_2, the results of this analysis should nonetheless caution against a coal-only demonstration program.

In light of the challenging economic and political realities for CCS, even getting a small number of power plants with CCS operational would be important if we are to continue developing the technology. Granting a limited number of coal-fired power plants a higher CO_2 emission standard of for example 1200 lbs/MWh or 1500 lbs/MWh could potentially be one way of achieving this. The lower capture percentages needed to comply with these higher emission standards would result in lower costs, which in turn could make up for the lack of generous incentives or stringent climate policy. While government incentives are likely to still be needed, even at high EOR prices, it could reduce the magnitude of the incentives needed to bring power plants with CCS online. Reducing the magnitude of the necessary government incentives is particularly important given the tightening public finances. The additional CO_2 emissions from these plants would have negligible impacts on climate change, but the technology development they would facilitate could be important in the future if more stringent climate policies were enacted. Yet allowing certain power plants to have higher emissions than others is challenging, and will likely run into both legal and political obstacles. Exactly how such a higher emission standard for a limited number of coal-fired power plants would be enacted is nonetheless beyond the scope of this thesis. The analysis in this chapter only suggests that if incentivizing investment in CCS is a goal of U.S. policy makers then a looser standard, as opposed to the one currently proposed by the EPA, might be the best option.

An important reservation regarding these results is that they treat only new-builds since the proposed EPA standard only applies to new units. Section 111 (d) of the Clean Air Act requires the EPA to issue binding "guidelines" for emissions from existing sources once a New Source Performance Standard has been issued [50]. While the analysis in this chapter referred to new plants, there is no reason to believe that the insight gained from analyzing new-builds does not also apply to retrofits, i.e. that shifting to natural gas is preferred over partial CO_2 capture from coal-fired power plants.

There are naturally many limitations to this modeling approach, as this simplified model does not properly capture many of the key dynamics of power markets that affect an investment's attractiveness. The analysis for example does not consider the effect of the grid, location-specific costs, or the higher heat rates during start-up, shutdowns and ramping. Most importantly, the model does not consider dispatch and reserve markets. Particularly at high natural gas prices there are considerable amounts of wind entering the generation mix, and modeling the effect of intermittency would be critical in order to determine the lowest-cost way of meeting demand. A more sophisticated electric power sector model would likely have been far superior in assessing profitability of different generation technologies. Nonetheless, the results in this chapter are meant more for illustrative purposes, not for rigorous in-depth capacity-expansion planning.

In conclusion, the EPA' emission standard will not be a driver for private investment in CCS, even if significant EOR revenues are available. This lack of short-term incentives for private investment poses significant challenges for CCS technology development. With no clear future markets for the technology, there will likely be fewer demonstration projects, and those that remain will rely increasingly on public funding. The following

[50] U.S. EPA website, *Background on Establishing New Source Performance Standards (NSPS) Under the Clean Air Act*. Retrieved on January 24th 2013 from *www.epa.gov/carbonpollutionstandard/pdfs/111background.pdf*

chapter will analyze whether continued public investment in CCS development is justified given the challenging external realities.

Chapter 5 - The role of government in CCS technology development

Given its perceived importance in mitigating climate change, significant public funds have been made available for CCS technology development in recent years. The most notable commitment was the $3.4 billion allocated for demonstration projects in the 2009 American Recovery and Reinvestment Act. However, as shown in previous chapters, worsened external realities have resulted in there being no short-term market for the technology. This chapter will therefore examine whether government spending on CCS technology development continues to be justified despite the new and challenging realities.

The chapter will first treat the role of government in supporting low-carbon technologies in general before moving on to the appropriateness of government support for CCS in particular.

5.1 - Government support for low-carbon technology development

With its significant externalities, economies of scale, and high barriers to entry, the electricity sector has always seen significant government involvement in technology development and commercialization, both in the U.S. and abroad. For example, the 1990 amendments to the Clean Air Act that put in place a cap & trade mechanism for SO_2 emissions created a large demand for flue gas desulfurization technologies.

Rising concerns over the negative externalities of CO_2 emissions has spurred considerable interest in the development of new, low-carbon energy technologies. The main rationale for government funding for developing such technologies has been the absence of a mechanism penalizing CO_2 emissions. When there is no cost to emitting CO_2 it makes no economic sense for private companies to invest in cleanup. Moreover, electricity is generally considered a non-differentiable good, i.e. suppliers only compete on price, and generators are unlikely to be able to charge a significant premium for "clean" energy (Norberg-Bohm, 2000).

If society decides to act decisively to mitigate climate change then cheaper "clean" energy technologies would drastically reduce the cost of emissions reductions. The fact that most low-carbon technologies are at the top of their learning curve makes it likely that significant technology improvements and cost reductions are attainable. Yet with policy mechanisms penalizing emissions lacking, these benefits are unlikely to be realized. With the negative effects of CO_2 emissions becoming more apparent, as noted for example by NCADAC (2013), it is clear that society has an interest in developing low-carbon technologies as an insurance policy against the effects of climate change. When private investors are unwilling to shoulder the cost due to the uncertainty over future climate policy, the government should take up part of the slack.

A big challenge with low-carbon technologies is that any benefits from cleaner ways to generate electricity are likely to be long-term and diffuse. They are diffuse because actors beyond the individual technology developer would benefit, and they are long-term because the major benefits are likely to be felt decades from today. Beneficiaries could for example include citizens of low-lying coastal regions that face lower risk of flooding, or farmers that experience less-frequent droughts. Yet the upfront investment needed to realize these benefits will be short-term and largely concentrated with the company incurring the significant development cost of low-carbon technologies.

One could argue that utilities have an incentive in developing low-carbon generation technologies as an insurance against potential stringent climate policies in the future. However, with the future of climate policy being so uncertain it is unlikely that any individual utility, or technology provider, will incur the large upfront investment cost of technology development. The capital requirements for technology development are high, and while many industries are capital-intensive without relying on large government incentives, e.g. the oil & gas industry, the low profit margins of electricity generation reduce the risk appetite.

The benefits of low-carbon energy technology should be regarded like a public good, along the lines of the benefits of a good infrastructure system. Consequently, support for their development should be regarded a legitimate government endeavor. Their long-term and diffuse benefits, but short-term and concentrated development cost, makes for a solid rationale for government funding for low-carbon technology development.

5.2 - Legitimacy of government policies for CCS development

The goal of this subsection is not to give a thorough treatment of the benefits and disadvantages of CCS relative to other low-carbon energy technologies, but simply to point out that the preliminary promise of CCS as a mitigation technology warrants efforts to reduce uncertainty about its true potential.

Despite the uncertainty regarding the stringency of future climate policies there is an option-value in looking into potential mitigation technologies. CCS is naturally not the only mitigation technology available, yet a number of studies have shown it could have significant importance in future technology portfolios. McJeon et al. (2011) for example show how the availability of CCS reduces the probability of very high future stabilization costs. Cost studies are nonetheless uncertain, and modeling results should therefore be treated with caution. Actual costs of CCS may end up being considerably higher than those anticipated today, and other disruptive technologies are hard to incorporate in models. Technical progress is generally modeled as evolutionary rather than revolutionary, and will always be based on today's technologies. In the future, one may develop a highly efficient, low-cost solar panel made from readily available materials. In that case CCS would be obsolete, and any money spent on technology development would have been "wasted". Similarly, a break-through in CO_2 capture technologies could dramatically reduce the cost of emissions reductions, in which case money spent on technology development would have been considered a very valuable investment. The main benefit of investing in CCS is nonetheless that it increases the number of potential technologies to mitigate climate change. If future technical breakthroughs in renewables fail to materialize, CCS could still allow us to have close to CO_2-free electricity from fossil fuels.

Although CCS refers to a number of capture and storage technologies, post-combustion capture could be of particular importance if society sometime in the future decides to quickly reduce emissions. Post-combustion capture is the only technological option that allows for substantial reduction of emissions from existing fossil fuel-fired power plants, absent closure. China added 327 GW of coal capacity between 2005 and 2011 (IEA, 2012), more or less the same as the size of the U.S. coal fleet. With a lifetime of up to forty or fifty years, new coal or natural gas-fired power plants represent a large lock-in of future emissions. Exploring options that could mitigate this lock-in could be a good hedge against the risks laid out by NCADAC (2013).

Some actors have argued that while CCS carries some initial promise, the technology is immature and scarce public resources should rather be devoted to technologies with a proven track record, such as renewables. Joseph Romm from the Center for American Progress has voiced this concern, and argues that CCS is merely an excuse for the continued use of fossil fuels at the expense of renewables. He argues that CCS will not reach the scale necessary to mitigate climate change for many decades, and given the urgency of climate change we should focus on short-term emission reductions. His main point is that one could achieve significant emission reductions with existing technologies, be it energy efficiency or renewables, and aggressive rollout of these technologies should get priority over technologies that are not yet commercially available. The Sierra Club has also voiced similar skepticism about the role of CCS in climate mitigation, and they are particularly concerned with the safety and viability of long-term storage in geologic formations. Arguing that the U.S. cannot rely on CCS alone to reduce emissions, they believe, along with Romm, that immediate rollout of commercially available technologies such as energy efficiency and renewables should have priority.

The key challenge with both arguments is that scaling non-hydro renewables from less than 1% of the electricity supply to overtake the role of fossil fuels is a momentous challenge. Although renewables such as wind and solar have undergone significant technological development in recent years, they are still much more expensive than traditional sources of electricity. They are therefore unlikely to reach a significant scale absent pricing mechanisms for CO_2 emissions, and the future of climate policy is unfortunately highly uncertain. Furthermore, the intermittency of wind and solar is a significant challenge for the power system if they are deployed at scale. Absent batteries capable of grid-scale energy storage, it will be challenging for intermittent renewables on their own to supply a majority of the demand for electricity.

Decarbonizing the electricity sector with existing technologies is not as straightforward as Romm and the Sierra Club suggest. While immediate rollout of existing technologies would be beneficial for the climate, one has to also acknowledge the lack of political support for immediate enactment of comprehensive climate policies. In the absence of commercial markets for low-carbon technologies the appropriate public policy is a broad portfolio of research efforts that expands the number of mitigation technologies. Most cost-studies estimate that electricity from power plants with CCS is generally cheaper than electricity from offshore wind or solar PV (Abellera & Short, 2011), and exploring one technology path does not necessarily exclude others. According to the IEA, subsidies to renewables will grow to about $185 billion by 2020, and solar and wind alone received $46 billion in subsidies in 2011 worldwide (IEA, 2012). A global CCS demonstration program with a cost of only a fraction of this does not seem an unreasonable investment to diversify risks. While the Sierra Club is right in that guaranteeing the safety of long-term storage will be critical for the future of CCS as a climate mitigation technology, this should be an argument for more research rather than less. CCS technology's initial promise of dispatchable, low-carbon electricity from fossil fuels warrants efforts to reduce uncertainty. Consequently, although there is uncertainty pertaining to when or if climate policy gets enacted, there is a value in developing CCS so that it is safe, publicly accepted, and "off-the-shelf" if society decides to act decisively to mitigate climate change.

5.3 - Conclusion

The large positive externalities of low-carbon electricity, and the market failures inherent in the power sector make for a legitimate role for government involvement in commercialization of new low-carbon energy technologies in general and CCS in particular.

While the short-term future of climate policy might be uncertain, it is still beneficial for society to have off-the-shelf technologies that are safe and easily scalable if aggressive emission reduction measures are enacted in the future. By diversifying the portfolio of potential future mitigation technologies, government involvement in CCS development would be a good insurance policy against high future climate mitigation costs. CCS is not the only mitigation technology available for reducing CO_2 emissions from power generation, but its initial promise warrants exploration of its actual performance as a mitigation technology.

Despite the challenging short-term situation, public spending on CCS technology development is indeed a legitimate use of scarce public funds. The following chapter will analyze how to optimally spend these scarce resources.

Chapter 6 - Designing a CCS RD&D portfolio

Limited funds for technology development make it critical to ensure that scarce public resources devoted to CCS development are strategically allocated to achieve the highest return. This chapter will therefore employ a stochastic dynamic programming framework to analyze what an optimal portfolio of CCS projects look like, and the key assumptions that such a portfolio depends on. Due to the high cost of demonstration projects, typically hundreds of millions of dollars, the analysis will focus entirely on the optimal mix of demonstration projects. Consequently, the optimal portfolio of R&D efforts will not be treated.

The biggest benefit of the analysis in this chapter is not to generate a detailed allocation of R&D funds, but to help policy makers better understand how to think about CCS technology development through demonstration projects, and thereby gain valuable insights for making budget allocation decisions.

Governments generally invest in RD&D and demonstration projects to gain knowledge, and it therefore seems fair to assume that policy-makers want to invest in a way that maximizes knowledge acquisition. Knowledge is of course a vague term, and can include better physical understanding of reservoirs (e.g., regarding reservoir leakage), ways to reduce costs, developing new technologies, etc. However, as “knowledge” is hard to model quantitatively, the model will assume that reducing uncertainty correlates to acquiring knowledge. Moreover, reducing uncertainty is a convenient objective given that two of the three goals of a CCS technology development program described in chapter 2 are aimed at reducing uncertainty (i.e. reducing the uncertainty around commercial-scale performance of capture technologies and reducing the uncertainty surrounding the viability of large-scale CO_2 storage).

The knowledge acquisition problem is simplified by just modeling the uncertainty in cost, with cost being a proxy for a wide range of technical and economic issues. Policymakers will therefore need to determine the optimal allocation of a given amount of money across a portfolio of demonstration projects that minimizes the uncertainty in the cost of

CCS. Given the almost exclusive focus in the U.S. on demonstration projects with EOR storage, the model will seek to gain insights about whether such EOR projects are conducive to increasing knowledge about CCS, and if so, under what conditions?

Arguably this is a very complex problem, not least because there are no accurate ways of determining the effect of any demonstration project on the acquisition of knowledge or the reduction of uncertainty. However, by using a number of simplifying assumptions, a quantitative optimization model of project selection under uncertainty is developed. Specifically, a dynamic programming framework with Bayesian learning is employed to assess how different carbon capture and storage demonstration projects reduce uncertainty about CCS as a mitigation technology. The focus is not to contribute to the state of the art of mathematical portfolio analysis, but rather to apply the methods in an illustrative example to provide new insight about the future path of CCS policy in the U.S. and globally.

The structure of the chapter is as follows. Section 1 provides a brief overview of the relevant literature. In section 2, the decision problem is framed and the modeling methodology is described. The modeling results are presented in section 3 and the last section concludes with a discussion of the insights of the model for U.S. CCS policy.

6.1 - Background

This chapter builds on two distinct areas of study in assessing the optimal path for CCS development: energy and climate economics, and operations research and dynamic portfolio optimization. The model in this chapter draws on research from number of fields, and Eide et al. (2012) provide a more in-depth overview of the relevant literature.

Incorporation of technological learning into a modeling framework generally distinguishes between learning-by-doing and learning-by-searching (R&D-based approaches). Learning-by-searching models of the R&D process typically rely on the concept of “knowledge capital” in their representation of endogenous learning. Learning-by-doing focuses on reductions in technology cost that occur as a function of cumulative investment or cumulative production during the commercial phase of technology development. Neither concept is utilized in this chapter since the objective of the model is to minimize uncertainty, not minimize costs.

As the model objective is to determine the optimal set of projects that minimize uncertainty, the problem is very similar to that described in the literature on optimal experimental design (see Eide et al. (2012) for a closer comparison). However, a dynamic programming formulation of the problem is nonetheless chosen to allow for greater flexibility in modeling knowledge overlap between different types of CCS projects, e.g. the "learning overlap" between CO_2 storage in EOR reservoirs and CO_2 storage in saline formations.

6.2 - Methodology

In order to determine the optimal CCS RD&D portfolio a stylized decision problem is constructed. Consider a decision maker that can invest in a number of CCS demonstration projects in a number of time periods, with a fixed budget every period. The objective is to reduce the uncertainty in project costs (the proxy used for gaining knowledge). Some projects cost more, but result in more useful information for reducing the uncertainty in CCS costs. Also, the cost of each individual project is variable relative to the average cost, which reduces the information learned from a single project. After observing the cost of the chosen projects, the decision-maker again chooses new projects to invest in for the next period, and the process repeats. The decision problem in any period is how to allocate funding across project types in order to maximize the reduction in cost uncertainty by the final period.

The decision maker wants to predict the cost of one project ahead of time and the prediction relies on his or her understanding of the average cost of all projects. Yet the resulting cost estimate for a single project will be uncertain for two very distinct reasons. First there is uncertainty regarding the average cost due to a lack of knowledge and experience. In the model, this is referred to as "uncertainty", and it will decrease as more knowledge is gained from demonstration plants. Second, although one can use the average cost to predict the cost of individual projects by considering site-specific factors, all the heterogeneities of individual projects cannot be accounted for ahead of time. Individual project costs will therefore vary around the average, even if one has tried to account for project-specific heterogeneities. In the model this is referred to as "variability", and it will persist even when there is enough knowledge to determine the average cost with confidence. For example, when building a refinery, site-specifics such as tax rate, land cost, labor cost etc. can be factored into the cost ahead of time. Yet even if there are decades of experience and data on the average cost, individual project costs can still be a bit lower or a bit higher than anticipated due to the variability that can be associated with the heterogeneities of specific projects.

Below, the model of this decision problem is formalized and the assumptions made for this illustration are described.

6.2.1 - Modeling uncertain costs

To formalize the problem, a Bayesian approach is used to model uncertainty and learning. The cost of any CCS project, *C*, is modeled as following a Gaussian distribution:

$$C \sim N(\mu, \sigma) \qquad (7)$$

Where μ is the mean or average cost and σ is the standard deviation, which represents the variability of projects. The mean cost of a CCS project, μ, is uncertain and also follows a Gaussian distribution such that

$$\mu \sim N(m, s) \qquad (8)$$

Where *m* is the mean, or current "best-guess" for the average cost, and *s* is the standard deviation, which represents the current uncertainty in the average cost of CCS projects. After each new CCS investment, the actual cost for that project will be observed, and updating *m* and *s* according to Bayes rule reduces the uncertainty in future CCS project costs (see Appendix C).

To capture the key features of the current debate over whether to invest in demonstration projects that capture CO_2 from high-purity sources and/or use the captured CO_2 for EOR, the costs of each CCS project is further disaggregated into the sum of two components: the cost of capture C_c and the cost of storage C_s.

$$C = C_s + C_c \tag{9}$$

The uncertainties in the capture cost and the storage cost are represented separately, and each observed cost from an investment updates both uncertainties:

$$\begin{aligned} C_c &\sim N(\mu_c, \sigma_c) \\ C_s &\sim N(\mu_s, \sigma_s) \end{aligned} \tag{10}$$

$$\begin{aligned} \mu_c &\sim N(m_c, s_c) \\ \mu_s &\sim N(m_s, m_s) \end{aligned} \tag{11}$$

6.2.2 - Dynamic Programming Formulation

A decision maker could improve the estimate of the parameters *m* and *s* by investing in a broad range of possible projects, where the “return” from each project is uncertain. The decision problem is therefore framed and solved using stochastic dynamic programming. Dynamic programming provides a structure for solving multi-stage sequential decision problems under uncertainty. Rather than solve the entire problem at once, which is generally prohibitively large, the problem is decomposed into separate decision stages and solved iteratively for the optimality conditions at every decision stage.

The range of possible CCS demonstration projects is simplified into four possible types (see Figure 22). The CO_2 capture can occur within a high-purity industrial process or within an electricity generation facility. The CO_2 can then be used for EOR, or sequestered in a non-EOR reservoir such as a saline formation. The four possible project types are high-purity capture and EOR storage (HP-CCUS), high-purity capture with non-EOR storage (HP-CCS), power plant capture with EOR storage (CCUS), or power plant capture with non-EOR storage (CCS). However, if the ultimate goal is to use CCS for climate mitigation, then power generation capture and non-EOR storage will need to play major roles. It is therefore assumed that policy makers are most interested in reducing the uncertainty in this capture and storage method. The cost of capture from a high-purity source is assumed to be deterministic and less than capture in a power plant.

$$C_{HP} \leq C_c \tag{12}$$

and the cost of storage for EOR is assumed to be deterministic and less than non-EOR storage

$$C_{EOR} \leq C_s \tag{13}$$

	High-purity capture	Power generation capture
EOR storage	**HP-CCS** **Learning:** - Less learning about capture - Less learning about storage **Cost** - Least expensive	**CCUS** **Learning:** - Learn about capture - Less learning about storage **Cost** - Expensive
Non-EOR storage	**HP-CCS** **Learning:** - Less learning about capture - Learn about storage **Cost** - Less expensive	**CCS** **Learning:** - Learn about capture - Learn about storage **Cost** - Very expensive

Figure 22: Carbon capture project types

In formalizing the dynamic programming decision problem the decision-maker's objective is to minimize the uncertainty in CCS costs by the terminal period *T*:

$$\min_{a_{t,1},a_{t,2}} s_T \tag{14}$$

Assuming that the capture and storage costs are independent, the total uncertainty can be expressed as a function of the capture and storage cost uncertainty:

$$\min_{a_{t,1},a_{t,2}} \sqrt{s_{c,T}^2 + s_{s,T}^2} \tag{15}$$

To simplify the example here, it is assumed that the decision-maker can only choose up to two projects in each period *t*:

$$a_{t1}, a_{t2} \in \{HP - CCUS, HP - CCS, CCUS, CCS\} \tag{16}$$

The state variable, which fully captures all relevant information about the evolution of the system up to period *t*, are the parameters that describe the cost uncertainties based on all projects observed up to this point. For this problem, the state variable x_t at period *t* is the vector:

$$x_t = \{m_{t,c}, s_{t,c}, m_{t,s}, s_{t,s}\} \tag{17}$$

The state transition equations describe how the state evolves as a function of the actions chosen and the random variation that occurs. When the next set of two projects is chosen, the capture and storage costs for each project are drawn randomly from the current probability distribution. The observed costs of capture and sequestration, c_c and c_s, from each project are then used to update the parameters according to the following transition equations derived in Appendix C:

$$\begin{aligned} s_{t+1}^2 &= \frac{\sigma^2 s_t^2}{\sigma^2 + s_t^2} \\ m_{t+1} &= \frac{\sigma^2 m_t + s_t^2 c}{\sigma^2 + s_t^2} \end{aligned} \tag{18}$$

The future expected mean cost is uncertain, and future expected costs could be either higher or lower than in the current period. If the future expected cost end up being higher in consequent time periods, some portfolios that are within the budget limit today may be infeasible in the future due to financing constraints.

To solve this problem using dynamic programming, backward induction is used to recursively solve the Bellman value function:

$$V_t = \min_{a_{t,1},a_{t,2}} E\left[s_T^2 | a_{t,1}, a_{t,2}, x_t\right] \tag{19}$$

For the example shown below, a finite horizon problem with two periods, $t = \{1,2\}$, is used, each period representing 10 years. More periods could potentially be used, but would not provide any additional qualitative insights.

The final aspect of the model is that the observed cost of capture from a high-purity project is less useful for reducing the uncertainty in capture costs from power plants, and that the observed cost of storage from an EOR project is less useful in reducing the uncertainty in non-EOR storage costs. This reduced learning is modeled by using a weighting vector $[w_c, w_s] \in [0,1]^2$. w describes how much of the learning obtained should actually be considered in the updated posterior distributions. For example w_s will be 0 if it is assumed that there is no transferable learning from EOR to non-EOR storage. If it assumed that half the learning is transferable w_s will be 0.5.

The reward function for this example depends solely on minimizing the uncertainty in the final period T, and does not consider any time-value of learning. In some situations the value functions of two decisions might be very close, and a filter is therefore used such that if the relative difference in value between two decisions is less than ε, with ε=1%, the optimal portfolio is the one with lowest expected cost.

6.2.3 - Cost Assumptions

Flyvbjerg et al. (2003) showed that costs are generally underestimated for large and complex infrastructure projects, and there is reason to be similarly cautious for CCS projects. The cost assumptions described below should therefore be regarded as more of a representation of a stylized type of project, highlighting differences between the four quadrants in Figure 22, rather than an accurate prediction of what future costs will be. In this model capture costs are reported in \$/tonne avoided whereas storage costs are reported in \$/tonne captured.

The cost of capture from power plants has been referenced thoroughly in the literature. Finkenrath (2011) examined 13 different cost studies with avoided costs ranging from \$40-\$69/tonne CO_2 for pulverized coal plants with post-combustion capture. Given the inherent uncertainty of cost estimates the model nonetheless considers a greater range of uncertain costs, particularly for demonstration projects. The first of a kind avoided costs at Norway's Mongstad project was estimated by one report at being between \$228-\$395/tonne CO_2 (Klif, 2010). Although these costs are probably not representative of likely future average N^{th} of a kind costs, they do highlight the significant uncertainty that surrounds the cost of demonstration projects. The Gaussian probability distribution that might reflect this range of uncertainty is one with mean values ranging from \$40-\$160/tonne CO_2 avoided, and a maximum standard deviation of \$15/tonne (equivalent to a 2σ confidence interval of $\pm$\$30/tonne).

The symmetric Gaussian distribution may not necessarily be the most appropriate choice for modeling uncertain costs for large engineering projects. Actual costs are probably more likely to be higher than anticipated, rather than lower. A more appropriate model of cost uncertainty would therefore be some positively skewed distribution with a right-hand "tail" for very high average costs, similar for example to the one used in chapter 4. As more projects are realized, the "tail" of the distribution would shrink, and the distribution would converge on the actual mean cost. However, due to the limited data available data with which to regress distributions and model parameters Gaussian distributions are used for simplicity. The Gaussian distribution is also used to be transparent about the lack of empiric data for determining exact distributions that uncertain CCS parameters will follow.

Data from Alstom (2011) suggests a non-EOR storage cost of around \$10/tonne CO_2 captured for onshore storage, with an additional \$5/tonne CO_2 captured for transport. Yet due to lack of experience with large-scale injection and long-term storage, it is more appropriate to use a range of storage costs. Eide et al. (2012) reviewed a number of papers showing how geologic heterogeneity has a high impact on the cost of storage, notably how the cost is highly sensitive to changes in the estimate of the average permeability. Maybe equally important is the uncertainty in the cost of insuring against the impacts of potential future leaks (one example showing how to potentially monetize the effect of leaks is given in Bielicki et al. (2012)). As there is little experience with actual insurance costs, or lack of willingness to insure, it is hard to monetize the insurance cost. Nonetheless, the model in this chapter assumes there is significant uncertainty in the cost of insurance, and this uncertainty is distinct from the uncertainty surrounding geologic properties of reservoirs.

To try to incorporate the uncertainty surrounding the total lifetime cost of storage the model considers storage costs up to an additional \$40/tonne CO_2 to account for any contingencies related to long-term monitoring and potential mediation of leaks. The Gaussian probability distribution that is used to reflect this range of uncertainty is one with mean values ranging from \$10-\$55/tonne CO_2 captured, and a maximum standard deviation of \$7.5/tonne CO_2 (equivalent to a 2σ confidence interval of ±\$15/tonne CO_2). As with capture cost, some positively skewed distribution is likely a better choice to represent cost uncertainty, but due to the limited data available data with which to regress distributions and model parameters Gaussian distributions are used for simplicity.

The cost of high-purity capture is assumed to be \$16/tonne CO_2 captured (equivalent to \$22/tonne CO_2 avoided), similar to the OPEX costs at Sleipner reported in IEA (2008). EOR storage cost is set at negative \$15/tonne CO_2 captured[51] since the operator now receives revenue for captured CO_2.

Demonstration projects are likely to cost more than future expected Nth plant costs. The results presented in section 6.3 therefore use a base case of an expected mean cost of capture of \$100/tonne CO_2 avoided and an expected mean cost of storage of \$25/tonne CO_2 captured. These costs are significantly higher than the numbers in Finkenrath (2011),

[51] Assuming 2% of oil price at \$70/bbl in Mcf, 18 ton/Mcf, subtracting \$10/ton for transport.

but a conservative cost estimate, rather than a too optimistic one, should be the basis of CCS policy.

The total lifetime cost of a CCS project is calculated using a 10% discount rate and an assumption that 2.36 megatons is avoided annually for an average coal-fired power plant[52].

The degree of variability in capture and storage costs is hard to determine *ex-ante*, as one has not yet observed how far from the average the cost of individual projects will be. It nonetheless seems fair to assume that there will be significant variability in the cost of capture from project to project. However, a lot of this variability can be accounted for, such as differences due to land cost, coal type, labor cost etc. Consequently, the model assumes that the variability that *cannot be accounted for* will be small. For storage costs, it is likely to be harder to account for project heterogeneities. Site-specific particularities of geologic formations could impact costs in unpredictable ways, and consequently there will be a lot of variability in storage cost that cannot be account for. To illustrate the difference in capture and storage variability the model will use a capture cost standard deviation of \$4/tonne CO_2 avoided (equivalent to a 2σ-interval of ±\$8/tonne CO_2) and a storage cost standard deviation of \$8/tonne CO_2 captured (equivalent to a 2σ-interval of ±\$16/tonne CO_2). As Heath et al. (2011) points out, there is considerable uncertainty regarding the geologic properties of many of the saline formations that could be targeted for CO_2 injection since they are less explored than for example reservoirs used for oil production. It therefore seems likely to assume that it will be hard to characterize all of the heterogeneities of individual reservoirs *prior* to injection, and consequently the variability in cost that cannot be accounted for can be high. It is important to acknowledge the lack of empiric data to test these assumptions. Nonetheless, as the modeling approach is meant for illustrative purposes, the variability above is used to illustrate the effect of the hypothesis that the variability cannot be accounted for will be greater for storage cost than for capture cost.

[52] Cost are calculated based on a 500 MW net supercritical coal plant with an emissions rate of 1830 lbs CO_2/MWh without CCS. Assuming a relatively high 25% energy penalty this results in an emission rate of 2441 lbs CO_2/MWh for the CCS plant. The higher energy penalty is chosen due to the fact that projects are first-of-a-kind demonstration projects. With 90% capture and a 75% capacity factor a total of 3.27 megatons of CO_2 will be captured annually, although the amount of CO_2 avoided will only be 2.36 megatons.

Although the effect of different budget levels per period will be analyzed in the results section a baseline budget of $8 billion per investment period is used. This amount counts both public and private funds made available for CCS demonstration. With a total of around $184 million spent on capture and storage projects by the DOE in 2012, and another $156 million requested for 2013 (DOE, 2012), it seems that the estimate of public funds available per decade is reasonable.

6.2.4 - The relative roles of uncertainty and variability

An analytical solution to a stylized version of the decision problem described in section 6.2.2 is given in Appendix D. An important insight is that both the variability and the uncertainty play a key role in determining optimal project portfolios. Consider for example the case where the uncertainty in the cost of capture is twice the uncertainty in cost of storage, but the variability in the cost of capture is half that of the variability in the cost of storage. At first sight the optimal decision seem to be to invest exclusively in capture projects, yet Appendix D shows that investing in both capture and storage projects is almost always preferred to a capture-only portfolio. The result holds true as long as the ratio of storage uncertainty to storage variability is above a certain threshold.

The reason for why it sometimes is beneficial to invest in projects with lower absolute uncertainty, as was the case in the example above, is due to the interesting effect that variability has on how much you learn from a single cost observation. As described in section 6.2.2, after the realized cost of a project is observed, the revised uncertainty in average costs, s_{t+1}, expressed as a standard deviation, is given by:

$$s_{t+1} = \sqrt{\frac{\sigma^2 s_t^2}{\sigma^2 + s_t^2}} \qquad (20)$$

Where the variability of any individual project relative to the mean cost of projects is noted as σ. Reorganizing (20) yields

$$\frac{s_{t+1}}{s_t} = \frac{1}{\sqrt{1 + \left(\frac{s_t}{\sigma}\right)^2}} \tag{21}$$

Because $(s_t/\sigma)^2$ will always be greater than zero, (21) is a monotonically decreasing function. Furthermore, the expression shows that s_{t+1} is always less than s_t, which is intuitive given that it represents the updated knowledge. When the ratio s/σ is small, representing that the uncertainty in average costs is small relative to a large variability in any individual project, the learning effect will be small. Similarly, when this ratio is large, representing that the uncertainty in average costs is large while the individual variability is small, each observation will yield significant uncertainty reduction. If the distribution from which samples are drawn exhibits little variability (i.e., σ is small) then any sample drawn will likely be very close to the actual mean of the distribution and learning will be significant. On the other hand, if samples are drawn from a distribution with significant variability, more samples will be needed to obtain a reasonable estimate of the mean. Each individual observation provides less information, and more samples will be needed in order to reduce the uncertainty. As illustrated graphically in Figure 23, learning decreases with increasing variability (σ). A subtlety to be understood is that this treatment assumes that the entity observing the costs will know beforehand whether the variability is large or small. The representativeness of any observation of cost for the average value depends on the variability.

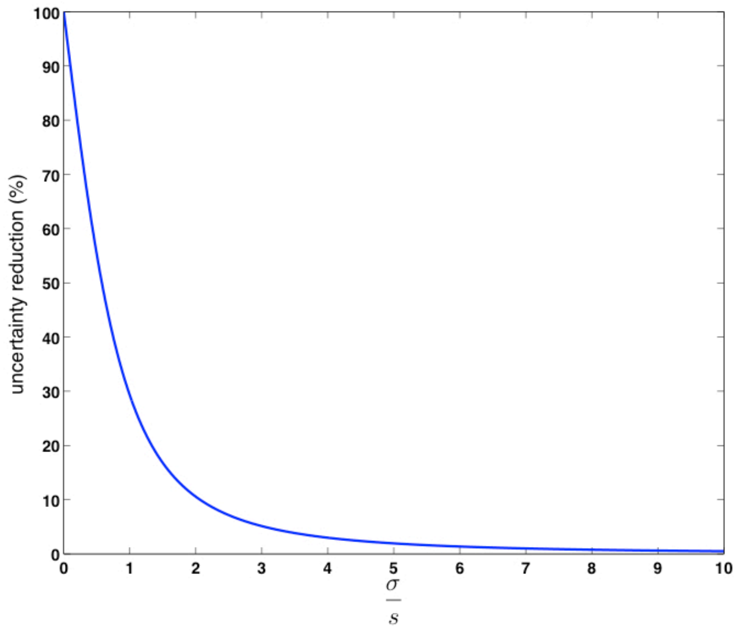

Figure 23: Relative uncertainty reduction (%) from one cost observation as function of the variability (σ) for a constant uncertainty (s)

The reason why investing in both capture and storage projects is preferred over a capture-only portfolio in the stylized problem described above is therefore due to the difference in variability. If capture variability is small relative to storage variability, then the amount you learn from the first capture cost observation is large. But, as a result, the learning from a second cost observation is small. The total reduction in uncertainty will therefore be greater if funds are spent also on learning about storage, which has lower initial uncertainty, but where learning is harder.

6.3 - Results

The total demonstration budget plays a key role in determining the optimal portfolio of projects. If the budget is too low, only project with high-purity CO_2 capture will be undertaken due not enough funds being available for power sector projects. If the budget is unlimited, only CCS projects will be undertaken due to their maximization of learning. The interesting dynamic nonetheless occurs from the situation in between these two extremes, where not enough money exists to only do CCS projects, but not so little as to rule them out completely. Also, for the results shown here, it is assumed that the variability in storage costs is greater than the variability in capture costs. This assumption is based on the hypothesis that developing accurate cost estimate models for geologic storage is harder than developing accurate cost estimate models for power plants.

For a first analysis, it is assumed that EOR storage does not reduce storage uncertainty and that high-purity capture does not reduce capture uncertainty (i.e. CCUS projects only reduce capture uncertainty, and HP-CCS projects only reduce storage uncertainty). Figure 24 shows the optimal investment strategy in the first time period as a function of the absolute uncertainty in capture and storage costs. The axes are labeled for a two-sigma confidence interval. Current proposals to shift investments to solely EOR storage (CCUS) are only optimal for relatively low uncertainty in storage costs, (green region along bottom). For slightly higher uncertainty in storage costs, the optimal strategy is a mix of one CCS and one CCUS project (blue region). For increasing uncertainty in storage costs, the preferred portfolio is one CCS project and one HP-CCS project (red region).

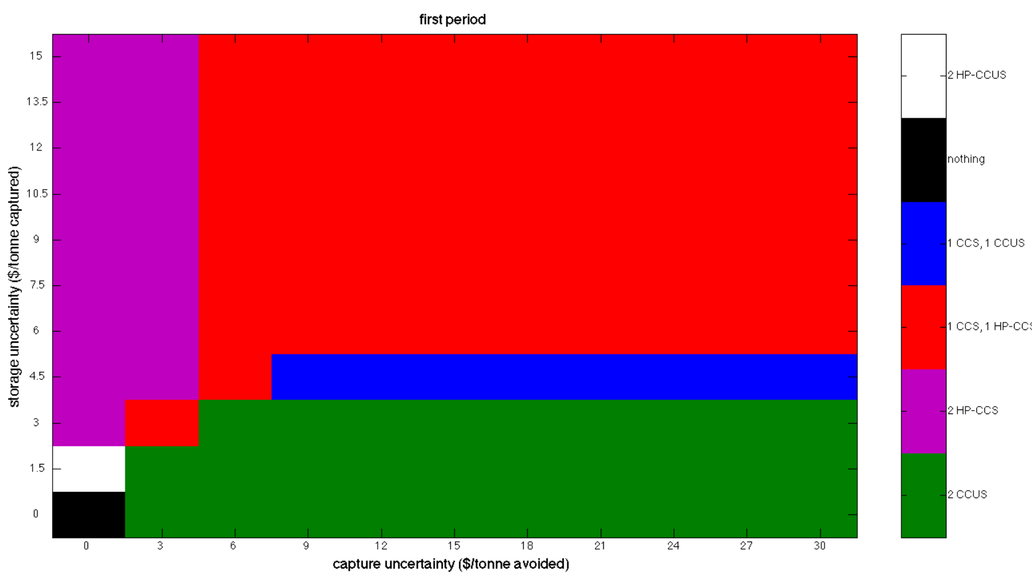

Figure 24: Optimal project portfolios for large storage variability (σ_s=$8/tonne) and low capture variability (σ_c=$4/tonne). Expected capture cost (m_c) is $100/tonne CO_2 avoided. Expected storage cost (m_s) is $25/tonne CO_2 captured.

An interesting effect is that for the second (and last) period, the blue region is "tilted" upwards, meaning that the (CCUS, CCS) portfolio is preferable for a greater number of situations. What this means is that if there are no future periods left in which to reduce the uncertainty, one might get most "value for money" by investing where learning is easy. However, if there is more time until deployment, (i.e. in the first period), it might be preferred to invest more in projects that are harder to learn about. The expectation about the time of deployment will therefore have a significant impact on what the optimal portfolio is. Consider for example the case where the storage uncertainty is ±\$7.5/tonne CO_2 captured. If the decision maker believes that there is around two decades until deployment, the first-period decision would be the portfolio (CCS, HP-CCS). However, if he or she believes there is only one decade left until deployment, the optimal portfolio is (CCS, CCUS).

Next it is assumed that EOR storage reduces storage uncertainty and that high-purity capture reduces capture uncertainty (i.e. CCUS projects will reduce both storage and capture uncertainty, and HP-CCS projects will also reduce both capture and storage uncertainty). This is modeled with the weighted approach described in section 6.2. If EOR projects reduce the uncertainty in storage costs (with a weight of 0.6), both the portfolios (2 CCUS) and (CCS, CCUS) are optimal for a greater number of situations (Figure 25a). If high-purity projects reduce the uncertainty in capture costs, a (CCS, CCUS) strategy is optimal over a smaller range of storage cost uncertainty Figure 25b). In general, the degree to which this boundary between portfolios moves depends on how close the learning weight for EOR (HP) is to 1, and how close the learning weight for HP (EOR) is to zero. A key result is that even if the learning weight for EOR storage is 0.6, a portfolio consisting exclusively of CCUS projects is advisable only if storage uncertainty is low.

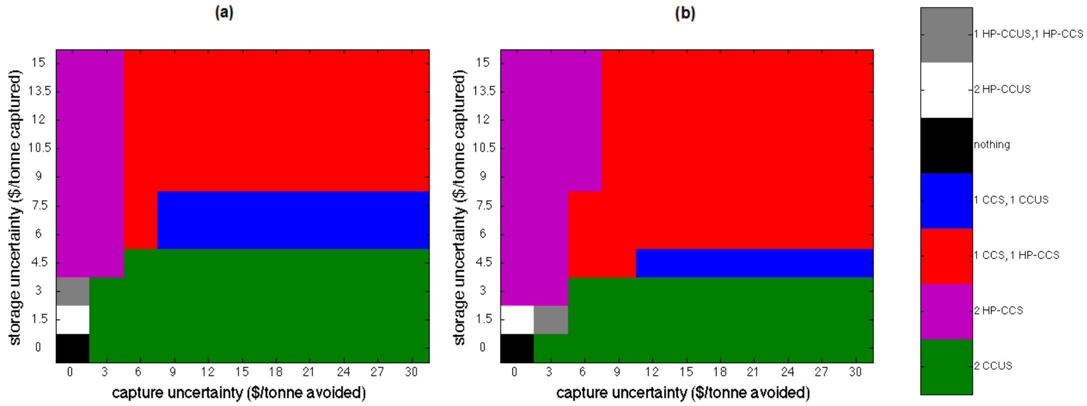

Figure 25: (a) Effect of learning from EOR with weight of 0.6 (b) Effect of learning from high-purity capture with weight of 0.6. Both cases assume large storage variability (σ_s=$8/tonne) and low capture variability (σ_c=$4/tonne). Expected capture cost (m_c) is $100/tonne CO_2 avoided. Expected storage costs (m_s) is $25/tonne CO_2 captured.

Figure 26 shows a sensitivity analysis on the effect of cost variability and learning weights for a given storage and capture cost uncertainty. It is clear that the optimal portfolio is highly sensitive to the assumptions of the storage and capture cost variability (Figure 26a). However, given the discussion in section 6.2.4 on the importance of variability this insight is somewhat intuitive. More interesting is the fact that when assuming high storage variability and low capture variability, the optimal portfolio does not include CCUS unless the learning weight for EOR is above 0.4 (Figure 26b). Furthermore, relying exclusively on CCUS is optimal for the sole case where the learning weight is equal to 1, i.e. learning is the same from EOR as non-EOR storage.

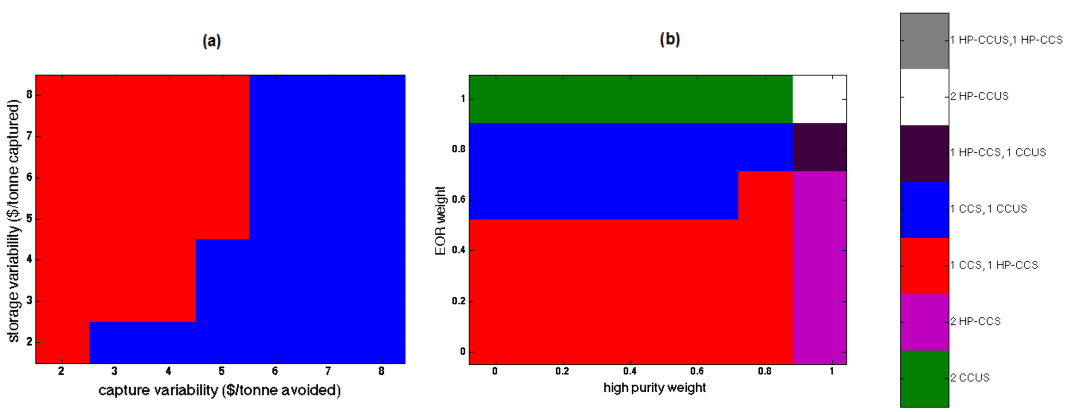

Figure 26: (a) Sensitivity on capture and storage variability assuming learning weights are zero (b) Sensitivity on EOR and high-purity learning weights assuming high storage variability (σ_s=$8/tonne captured) and low capture variability (σ_c =$4/tonne avoided). Both (a) and (b) show optimal first-period decisions for high capture uncertainty (s_c =$15/tonne) and medium storage uncertainty (s_s =$3.25/tonne). Expected capture cost (m_c) is $100/tonne CO_2 avoided. Expected storage costs (m_s) is $25/tonne CO_2 captured.

6.3.1 - Forward simulation

Through Monte Carlo methods one can simulate possible paths a demonstration program can take. By doing so, insights can be gained about how decisions are made over time, and how the optimal policy derived above is likely to yield different outcomes compared to a CCUS-only portfolio.

A forward simulation is run for a scenario where the actual cost of capture is 25% higher than initially anticipated and the actual cost of storage is 25% lower than initially anticipated. For 100,000 model runs Figure 27 shows the relative accuracy in the final average CCS cost estimate. The initial error is displayed to show how any demonstration program narrows the uncertainty range. The optimal portfolio yields an average cost estimate that is 2.85% from the true value, compared to an average cost estimate error of 5.71% for the CCUS-only portfolio. The relative attractiveness of the optimal portfolio increases when the true cost of storage is significantly different from the initial estimate, and decreases when the initial guess is more accurate.

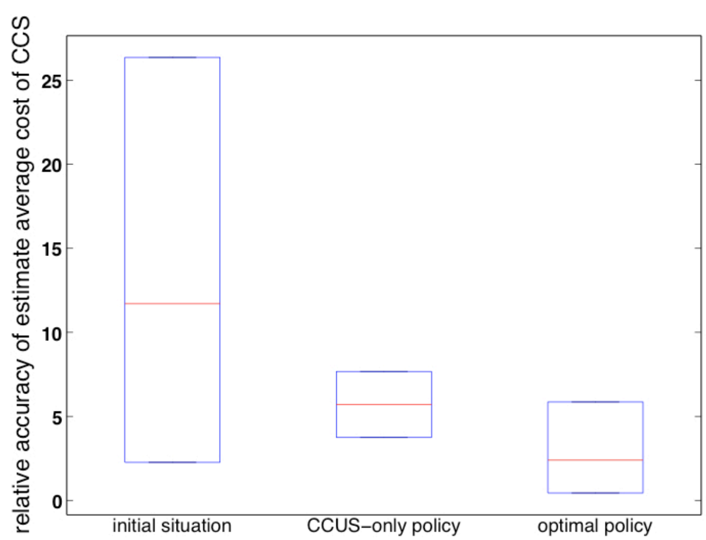

Figure 27: Comparing the relative accuracy in the average cost of a CCS project for the optimal portfolio and a CCUS-only portfolio for high initial capture and storage uncertainty. Red line shows average values and blue edges of box show 10th and 90th. Assumptions: $(m_{0,c}, m_{0,s})=(100,25)$, $(\sigma_c, \sigma_s)=(4,8)$, $(w_c , w_s)=(0,0)$.

The project choices in the first period following the optimal portfolio are always one HP-CCS project and one CCS project given the initial assumptions. However, the second-period choices depend on the realized cost of capture and storage. Nonetheless, 90% of the time the decision maker chooses the same projects as in the first period, i.e. a (CCS, HP-CCS) portfolio. In the remaining cases, the second-period expected cost is low enough for the decision maker to choose only CCS projects (i.e. power plant projects with non-EOR storage).

As shown in Figure 27 it is clear that both a CCUS-only portfolio and the optimal portfolio significantly reduces the uncertainty. Nonetheless, the optimal portfolio yields a final cost estimate that is on average around 50% more accurate than the CCUS-only portfolio (of course, if CCUS projects teach important lessons about storage in non-EOR reservoirs, then the difference is smaller). Furthermore, the average cumulative cost of a demonstration program that follows the optimal portfolio is $12 billion, whereas the CCUS-only portfolio on average costs $12.6 billion. The optimal portfolio therefore yields both more accurate cost predictions and is on average $600 million cheaper.

6.4 - Conclusion

The key insight of this model is that if the near-term objective of policy makers is to gain knowledge and reduce uncertainty then the relative amounts of uncertainty and variability in capture and storage will have a significant impact on determining optimal CCS demonstration project portfolios. The more variability there is, the harder it is to reduce uncertainty in the average cost.

With public funding likely to be limited in coming years, the simple, stylized example presented here provides three important insights about the optimal allocation of funds across different CCS demonstration projects.

The first insight is that if storage variability is high, then a CCUS-only approach (investing exclusively in power projects with EOR storage) to developing CCS as a mitigation technology would only advisable if there was little uncertainty regarding non-EOR storage. Given the lack of experience with large-scale injection of CO_2 in for example saline formations, this condition is unlikely to be true. U.S. policy makers should therefore be cautious about a CCUS-only approach to CCS development.

The second insight is that the time until deployment will impact optimal choices today. If deployment is delayed and you have more time for demonstration, then it is preferable in early periods to invest more in projects that are harder to learn about. If the variability in non-EOR storage cost is high, that means investing more in non-EOR storage projects. Yet even with the prospect of imminent deployment, a CCUS-only approach to developing CCS is unadvisable if non-EOR storage variability is high.

The third insight is that a portfolio consisting of a mix of CCS and CCUS projects is an effective strategy to gain knowledge if EOR storage can provide significant knowledge about non-EOR storage. It might indeed be plausible that some experience with EOR storage would reduce uncertainty in non-EOR storage, but more research is needed to determine exactly how learning overlaps between the two types of storage.

In conclusion, if the U.S. is to rely on CCUS projects to improve knowledge about CO_2 capture, then there is a striking need to ensure that simultaneous effort are aimed at learning about the safety and viability of non-EOR storage, for example in saline formations. The current U.S. policy of relying almost exclusively on projects with EOR storage does not seem to be an effective strategy to ensure that scarce public resources are spent where they yield the highest return.

Chapter 7 - Policy implications and conclusions

All of the necessary components of a CCS system are in commercial use today somewhere in the economy, and the main challenge for CCS to be commercially viable is to integrate and scale up these components. CO_2 capture from coal-fired power plants is for example currently undertaken at the pilot-scale at a handful of locations. Similarly, injection of large volumes of CO_2 into both EOR and non-EOR reservoirs has been undertaken at a number of locations worldwide. However, something that works on a 25 MW pilot plant might not work similarly at a 500 MW commercial-scale power plant, where the size of the equipment involved could change the way a technology operates. An even bigger concern is how to integrate the power plant and the capture system, since the large steam extraction can affect power plant flexibility and operability. Understanding how a technology functions under the real-time operation of power plants is critical to provide utilities with sufficient information to lower commercial risk to an acceptable level. Moreover, the current cost of capture is still prohibitively high and recent scientific articles, such as Zoback & Gorelick (2012), on the risks surrounding geologic CO_2 storage have introduced uncertainty around the viability of long-term storage.

Much work therefore remains to be undertaken before CCS will be a commercial mitigation technology. Yet, while there are many issues that need to be addressed before CCS can operate at a gigaton-per-year-scale, many of these are typical "engineering challenges" that can be overcome once there is a market for the technology. The goal of U.S. policy on the other hand should be to address the main questions and potential showstoppers facing CCS as a mitigation technology. Chapter 2 concludes that overcoming these roadblocks can be summarized as three key goals:

1. Lower the cost of capture
2. Lower the uncertainty surrounding commercial-scale performance of CO_2 capture at power plants

3. Prove the viability of long-term storage of commercial-scale amounts of CO_2 in geologic formations

In early 2009, with the election of Barack Obama and optimism for the COP-15 meeting in Copenhagen, there was a strong belief that stringent climate policies would be enacted both in the U.S. and globally. However, the political and economic realities have changed considerably over the past four years, worsening the prospects for low-carbon technologies in general, and CCS in particular. Addressing the goals above for a CCS technology demonstration program will therefore be far more challenging in today's political and economic environment. As an example, despite a number of successful projects, the U.S. CCS demonstration program has suffered setbacks through a number of project cancellations.

The most notable of the altered external circumstances are the following:

1. ***Lack of comprehensive climate policies.*** CCS is ultimately dependent on climate policies to create a market for it, and the political environment for climate policy is unwelcoming. The future of a global, legally binding emission reductions agreement is uncertain, and no comprehensive climate bill is likely to pass through the current U.S. Congress. While some markets exist for the utilization of CO_2 (i.e. for EOR), they are much smaller than markets needed to abate climate change.
2. ***Tight public finances as a result of large budget deficits***. While companies may support some CCS development efforts, given the lack of imminent climate policy, their support will be limited. CCS demonstration projects are therefore highly dependent on government incentives, and austerity measures are a serious threat to technology development.
3. ***The persistent high cost of CCS demonstration projects.*** While the cost of CCS was also considered to be high in 2009, four years of development has failed to significantly lower costs. Most studies estimate that CCS would still add 40-80% to the cost of electricity from coal and cost from \$40-70/tonne CO_2 avoided. The

economics are made worse in that first-of-a-kind demonstration projects are significantly more costly than the projected N^{th} plant costs. In the absence of climate policy and with tight public finances, these high costs are an additional barrier to technology development.

While the short-term justification for CCS (i.e., the implementation of strict climate policies that would create a demand for low-carbon energy) is no longer valid, the long-term potential need for CCS remains unchanged. Climate change continues to be a significant threat, and worldwide energy demand is growing and will likely continue to be supplied mainly by fossil fuels. In order to avoid ever increasing atmospheric CO_2 concentrations, CCS continues to be a key mitigation option that will need to be available if large emission reductions are required in the future.

Nonetheless, the absence of climate policy creates a lack of short-term commercial markets for low-carbon technologies in general, and CCS in particular. EOR revenues are not high enough to cover the cost of capture from power plants, and EPA's CO_2 emission standard is more likely to accelerate the shift from coal to natural gas rather than incentivize investment in CCS. Even with very high EOR prices U.S. natural gas prices would have to double in order for coal plants with partial CO_2 capture to be preferred over natural gas-fired CCGT units. Consequently, there are no short-term incentives for private investment in the development of CCS technologies.

Moving CCS to commercial readiness when short-term incentives for private investment are lacking will be challenging. With the future of climate policy uncertain it is unlikely that the positive externalities of low-carbon technologies will be realized without government intervention. The costs to private companies of developing low-carbon technologies are short-term and high, but any future benefits are long-term and diffuse. Moreover, the near-term costs are certain whereas long-term benefits are uncertain since we cannot predict the stringency of future climate policies. Although there might be some value for a private company in betting on developing a technology that might be indispensable in the future, the risks are simply too high, benefits too far out and immediate costs too high for any private company to develop the technology on their own. Consequently, the U.S. government cannot rely exclusively on private investors to take responsibility for first-stage commercial development. If the government does not take an active role in providing some of the funds necessary for developing and demonstrating innovative low-carbon technologies, they are unlikely to move forward. This is particularly true for CCS.

The absence of short-term commercial markets actually leaves time for developing CCS to full commercial readiness. Chapter 5 showed that there is a strong precedent for government policies promoting technologies with potentially large positive externalities, and CCS is one such technology. While it is not the only low-carbon technology available to mitigate climate change, its initial promise of dispatchable, low-carbon energy from fossil fuels warrants efforts to develop the technology further. While RD&D efforts can always fail, be it in renewables or CCS, the benefit of investing in CCS is that it diversifies the portfolio of potential future mitigation technologies. Chapter 5 therefore concludes that public funding of CCS technology development is a good insurance policy against high future climate mitigation costs. Given that solar and wind alone received $46 billion in subsidies in 2011 worldwide, a global CCS demonstration program with a cost of only a fraction of the subsidies given to other renewables does not seem an unreasonable investment.

While government funding of technology development continues to be a legitimate use of scarce public funds, the changed circumstances have highlighted the increased need to ensure that limited resources are strategically allocated. In order to achieve the best use of scarce public funds, **this thesis makes six key recommendations for how U.S. CCS policy** should respond to the new political and economic realities:

1. The U.S. should focus more on pilot-scale development of novel capture concepts promising to significantly reduce cost
2. The U.S. should move away from coal-only demonstration program and also demonstrate the feasibility of CCS on natural gas-fired power plants

3. The U.S. should impose a slightly higher emission standard than that currently proposed by the EPA for coal-fired power plants that agree to use CCS
4. The U.S. should renew and strengthen its focus on long-term, large-scale CO_2 storage projects in saline formations
5. The U.S. should move away from an EOR-only demonstration program
6. The U.S. should encourage stronger international coordination of CCS technology development. To limit unproductive overlap a number of key countries should agree on the main pillars of a global CCS strategy

Each of the recommendations are discussed further below:

1) More pilot-scale development projects

As mentioned above, the two key challenges with current capture technologies are the need to prove their commercial-scale operation and the need to lower cost. The latter has become increasingly important given the near-term political infeasibility of imposing stringent restrictions on CO_2 emissions. Consequently, unless the cost of capture goes down, there is a real risk that the technology will never be adapted in the marketplace. Chapter 6 showed that while there is significant uncertainty surrounding commercial scale performance (i.e. cost) of capture, the ability to account for project-specific heterogeneities (i.e. low variability) makes it likely that only a small number of commercial-scale projects are needed to sufficiently reduce the uncertainty to acceptable levels. However, any cost reductions from such demonstration projects are likely to be evolutionary as opposed to revolutionary. Given the striking need for large cost reductions U.S. CCS policy should therefore focus on development of novel capture processes and capture methods that hold the promise for significant cost reductions. As the time window for large-scale commercial CCS deployment is pushed further into the future, there is also more time to develop such breakthrough technologies. The high-risk nature of such a strategy nonetheless means there is a high probability of failure of an individual project, and consequently a portfolio of projects is needed. However, funding is limited and commercial-scale demonstration of new capture technologies on power plants is very expensive. The effort to develop breakthrough concepts should therefore focus more on pilot-scale development. The lower cost of such projects (less than $100 million) would allow for a wider span of technologies to be explored and developed, thereby significantly increasing the chance for success of one or a few of them.

2) Increased focus on CCS on natural gas-fired power plants

At current natural gas prices the imposition of CO_2 emission standards would have the effect of favoring natural gas-fired power plant over coal-fired ones for baseload generation. Given Congressional gridlock on climate policy, these standards may become a primary policy instrument for reducing CO_2 emission standards from large, stationary sources. If strict emission standards are enacted in the U.S., the results in chapter 4 suggests that if deployed at all in the U.S., CCS might be cheaper to deploy on natural gas-fired power plants as opposed to coal-fired power plants. While there are currently no announced plans for strict enough emission standards that also force natural gas-fired power plants to capture CO_2, the results of this analysis should nonetheless caution against a coal-only demonstration program. CCS on coal-fired plants is likely to play a key role to reduce emissions internationally, but if emission standards are envisioned to gradually become tighter, then the U.S. should allocate a portion of their demonstration project portfolio towards also demonstrating the feasibility of CCS on natural gas-fired power plants.

3) Higher CO_2 emission standards for coal-fired power plants with CCS

Granting a limited number of coal-fired power plants a higher CO_2 emission standard of for example 1200 lbs/MWh or 1500 lbs/MWh could potentially be one way of bringing CCS power plants online in challenging times. At the very least it could lower the need for very large incentives. The lower capture percentages needed to comply with higher CO_2 emission standards would result in lower costs, which in turn could make up for the lack of generous incentives or stringent climate policy. The additional CO_2 emissions from these plants would have negligible impacts on climate change, but the technology development they would facilitate could be important in the future if more stringent climate policies were enacted. However, this does not replace the need for commercial-scale demonstration plants with 90% CO_2 capture, but should rather be considered a way of scaling ambitions to political reality.

4) Increased number of large-scale storage projects in saline formations

More observations are likely needed to reduce the uncertainty surrounding CO_2 storage in saline formations than are needed to reduce the uncertainty surrounding commercial-scale performance of capture technologies at power plants. Consequently more storage demonstration projects than capture demonstration projects are needed to fully develop CCS as a viable mitigation option. The reason for this is because accounting for project-specific heterogeneities in geologic storage is harder than accounting for project-specific heterogeneities in capture plants. While scaling up current capture technologies from pilot-scale to commercial-scale is not trivial, the results in chapter 6 suggest that one only needs a small number of observations to actually reduce the uncertainty to acceptable levels. On the other hand, multiple observations of commercial-scale non-EOR storage projects are likely needed before the uncertainty is reduced to similar levels. U.S. CCS policy should therefore focus resources where knowledge acquisition is hardest. A balanced approach, with commercial-scale demonstration of capture as well as storage, is likely the most appropriate path forward for CCS policy.

5) Departure from EOR-only demonstration program

For the reasons described in the paragraph above, the results presented in chapter 6 caution strongly against an EOR-only CCS demonstration program. EOR will play an important role in making CCS commercially viable, and EOR markets could be viewed as niche markets that allow for initial development of capture technologies at lower cost. Yet it is important to remember that EOR is not the endpoint, but rather a stepping-stone, and the cumulative storage potential in EOR fields is small compared to that of saline formations. Consequently, if CCS is to operate at a gigaton-per-year scale, most of the captured CO_2 will therefore likely be stored in saline formations. Moreover, projects with EOR-storage will likely contribute little to learning about large-scale storage in saline formations. The results in Chapter 6 therefore suggest that the current U.S. CCS policy of relying almost exclusively on EOR storage is unlikely to be a sound long-term strategy for developing CCS as a climate mitigation technology.

6) Increased international coordination of CCS development efforts

Recent developments suggest that there is a need for much stronger coordination of demonstration efforts. With limited public funds available, international coordination could lower the financial burden on individual nations, and avoid unproductive overlap between demonstration programs. However, pooling demonstration funds in some sort of international fund is likely to be politically challenging. A small group of countries could nonetheless agree on a joint demonstration strategy. Each country could for example commit to a specific aspect of CCS, and in aggregate they could explore the different aspects that are needed for commercial scale power generation with CCS.

The goal of policy makers worldwide used to be to pave the way for large-scale deployment of CCS on power plants by 2020, but having unrealistic ambitions that do not consider the political realities could threaten the future of CCS rather than help it. This thesis has concluded that the changed external circumstances should warrant a considerable change in U.S. CCS policy. These changes include stronger focus on pilot-scale demonstration of high-risk, high-payoff capture technologies, a shift to CCS on natural gas-fired power plants, a higher emission standard for coal plants that agree to using CCS, stronger international coordination, and most importantly: a significant effort to demonstrate the safety and viability of CO_2 storage through long-term, commercial-scale storage projects in saline formations.

CCS holds tremendous promise as a climate change mitigation technology, and climate change is too much of a challenge to ignore. By following the recommendations in this thesis U.S. policy makers can ensure that we continue to move forward, despite the challenging realities

Afterword

On April 10th President Obama released his budget for fiscal year 2014, and a number of notable changes were made in the Department of Energy's carbon capture and storage R&D program.

The most notable changes were:

- Funding for CO_2 capture R&D is increased by slightly more than 60% compared to 2012 (+$43 million)[53]
- Funding for CO_2 storage R&D is reduced by close to 50% (-$54 million)[53]
- CO_2 capture R&D will increasingly focus on scale-up of breakthrough concepts developed through ARPA-E[53]
- $25 million is allocated to fund preliminary work for commercial-scale carbon capture at a natural gas-fired power plant[53]

The significant reorientation of priorities within the Department of Energy's CCS program follows the recommendations in this thesis on two points: an increased focus on breakthrough concepts and a commitment to demonstrate the commercial-scale performance of CCS on natural gas-fired power plants.

Nonetheless, the dramatic reduction in funding for CO_2 storage R&D is worrying, particularly since there is no change in the demonstration program's overwhelming focus on projects with EOR storage.

Should a leak occur from a commercial-scale CCS project due to incomplete understanding of the geologic formation, even if the damage is small or negligible, then building more will prove politically difficult, if not outright impossible. Local opposition

[53] Walters M, Angielski S. (2013). *The President's FY 2014 Fossil Energy Budget Request.* Coal Utilization Research Council memorandum April 11, 2013.

to CO_2 storage in Germany have only given us a first glimpse of the significant opposition CCS projects can run into unless the public is convinced that large-scale CO_2 is safe.

As noted in chapter 7, CCS holds tremendous potential as a mitigation technology, yet without certainty that captured CO_2 can be safely stored for hundreds of years, it does not matter how low the cost of capture becomes. The Department of Energy’s shift away from research on geologic storage is therefore both unfortunate and highly unadvisable.

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Appendix A - Generation expansion model

Nomenclature

$C_i^{fix}(w)$	[$]	Total fixed costs for technology *i* for scenario *w*
$C^{CO2}(cap, w)$	[$]	Total cost of CO_2 storage for scenario *w* and capture percentage
$C_{CCS}^{penalty}(cap, w)$	[$]	Difference between initial and actual total fixed costs for CCS for given capture percentage and scenario *w*
$C^{storage}$	[$/tonne]	CO_2 sequestration cost
$C_i^{TOC}(w)$	[$/kW]	Overnight cost for technology *i* for scenario *w*
$C_{i\in K,ccs}(\mathrm{w})$	[$/kW]	Overnight cost of CO_2 capture equipment for technologies using CCS for a given scenario *w*
$C_{i\in K}^{TOC,penalty}(cap, w)$	[$/kW]	Difference between initial and actual overnight cost for technologies using CCS for a given capture percentage and scenario *w*
$C_{i\in K}^{TOC}(cap, w)$	[$/kW]	Overnight cost for technologies using CCS for a given capture percentage and a given scenario *w*
$C_{i\in K,0}^{TOC}$	[$/kW]	Overnight cost for technologies using CCS at 0% CO_2 capture
$C_i^{var}(w)$	[$/MWh]	Variable costs for technology *i* for scenario *w*
$cap_{i\in K}(\mathrm{w})$	[%]	CO_2 capture percentage for technologies using CCS for scenario *w*
D_j	[MW]	Demand in load block *j*
dur_j	[hrs]	Duration of load block *j*
em_i	[lbs/MWh]	Net CO_2 emissions from technology *i*
$ep_{i\in \boldsymbol{K}}(cap)$	[%]	Energy penalty of technologies using CCS for given capture percentage
$E\mathrm{S}$	[lbs/MWh]	CO_2 emission standard
F_i	[$/MMBtu]	Fuel price of technology *i*
HR_i	[Btu/kWh]	Heat rate of technology *i*
I		Set of available generation technologies
J		Set of demand blocks
K		Set of generation technologies using CCS
$p(w)$	[%]	Probability of scenario *w*
$R_{0,i\in \boldsymbol{K}}(cap, w)$	[lbs/MWh]	Gross CO_2 emissions of technologies using CCS for given capture percentage and scenario *w*
r	[%]	Yearly discount rate
T	[years]	Length of planning horizon
$X_{i,j}$	[MW]	Power generated by each technology *i* in each demand block *j*
Y_i		Number of plants built of technology *i*
$\chi_{i\in K}(w)$		Overnight cost multiple for technologies using CCS for given scenario *w*
$\delta(r, T)$		Net present value constant
$\theta(Y, w)$	[$]	Recourse function for investment vector Y and scenario *w*
$\sigma_{i\in \boldsymbol{K}}^{l}(w)$	[$/MW]	Dual multiplier of stochasticity of CCS overnight costs for technologies using CCS
$\pi_{i,j}^{l}(w)$	[$/MW]	Dual multiplier of capacity constraint for each technology *i* in demand block *j*
ϵ	[%]	Tolerance for Bender's decomposition
γ	[%]	Capital charge

Generation expansion model

The effect of CO_2 emission standards on CCS investment is analyzed through a stochastic generation expansion model. The objective of the model is to determine, under a given emission standard, the vector **Y** of new capacity additions that minimizes the expected sum of fixed costs, variable costs, and CO_2 storage costs over a pre-defined planning horizon. Total cost for each technology is its fixed cost plus the sum of the variable cost multiplied by the generation, i.e. power output multiplied by duration, for all demand periods in the set *J*. The total system cost is the expected sum of total costs over all available technologies defined in the set *I* plus the cost of CO_2 storage. K is the set of plants that can be outfitted with CCS, i.e. {coal-CCS, CCGT-CCS}.

In order to model the uncertainty surrounding the commercial-scale cost of CCS a number of cost scenarios *w* are generated, each with a corresponding probability *p(w)*. For simplicity, only the energy penalty and the total overnight cost of power plants with CCS are considered uncertain. Since the amount of CO_2 captured is closely related to the energy penalty, as was shown in section 4.4, the cost of CO_2 storage will also be uncertain and depend on the scenario *w*. The level of capture from each CCS unit, $cap_i(w)$, will depend on the energy penalty of the scenario *w*, and is set so that net emissions from the CCS plant is equal to the emissions standard (see section 4.3 for more detail on determining the capture percent).

Mathematically, the optimization problem can be formalized as minimizing the expected sum of fixed costs, variable costs and CO_2 storage costs:

$$\min_{\boldsymbol{Y}} \sum_{W} p(w) \left[\sum_{I} \left(C_i^{fix}(w) Y_i + \sum_{J} C_i^{var}(w) X_{i,j} dur_j \right) + C^{CO2}(w) \right] \qquad (22)$$

Subject to:

$$X_{i,j} \le Y_i S_i \qquad \forall i \in I, \forall j \in J \qquad (23)$$

$$\sum_I X_{i,j} \geq D_j \qquad \forall j \in J \qquad (24)$$

$$em_i \leq ES \qquad \forall i \in I \qquad (25)$$

$$X_{wind,j} \leq Y_{wind} S_{wind} * CF_{wind,j} \qquad \forall j \in J \qquad (26)$$

$$0.7 * 0.22 Y_{wind} S_{wind} \leq 0.3 \sum_{I \setminus \{wind\}} 0.85 S_i Y_i \text{ [54]} \qquad (27)$$

Constraint (23) ensures that electricity generation remains below the installed capacity, and constraint (24) ensures that demand is met in each demand period. Constraint (25) ensures that emissions of each technology is lower than the given emission standard ES. In addition, wind generation cannot exceed the installed capacity multiplied by the average capacity factor for the given demand period j (26). The assumptions for wind capacity factors are treated in section 4.3.

The model will not contain a detailed unit commitment model for dispatch, and consequently cannot treat the intermittent nature of wind generation. A maximum constraint on installed wind capacity is therefore imposed to limit the average annual wind penetration to less than 30% (27). It is here assumed that the annual average capacity factor of wind is 22%, and 85% for all other technologies.

$C_i^{fix}(w), C_i^{var}(w)$ and $C^{CO2}(w)$ are calculated as follows,

$$C_i^{fix}(w) = C_i^{TOC}(w) S_i \gamma \delta(r,T) 10^3 \qquad (28)$$

$$C_i^{var}(w) = [OM_i + HR_i(w) F_i * 0.001] \delta(r,T) \qquad (29)$$

$$C^{CO2}(w) = \sum_{i \in K} \sum_{J} dur_j X_{i,j} R_{0,i}(cap_i, w) cap_i(w) C^{storage} * 0.00045\, \delta(r,T) \qquad (30)$$

54 $\frac{0.22 Y_{wind} S_{wind}}{0.22 Y_{wind} S_{wind} + \sum_{I \setminus \{wind\}} 0.85 S_i Y_i} \leq 0.3$

Where $\delta(r,T) = \sum_{t=1}^{T} \frac{1}{(1+r)^{t-1}}$ is a multiplying constant to obtain the net present value of future costs. r is the discount rate in percent, and T is the length of the planning horizon in years.

In (28), $C_i^{TOC}(w)$ are the total overnight costs, in \$/kW, of technology i and S_i is the default size in MW of technology i. γ is the capital charge in percent and the multiplication by 1000 is done to obtain overnight costs in \$/MW.

In (29), OM_i are the variable O&M costs of technology i in \$/MWh, HR_i its heat rate in Btu/kWh and F_i the price of the fuel in \$/MMBtu. The fixed O&M costs are incorporated into the variable O&M costs following the method described in IEA (2010).

In (29), $C^{storage}$ is the sequestration cost in \$/tonne CO_2, and will be negative in the case of EOR. $R_{0,i}(cap_i, w)$ is the gross emissions of the CCS plant in lbs/MWh, dur_j is the duration in hours of load period j, and $cap_i(w)$ is the capture percentage. 0.00045 is the number of metric tonnes in a pound.

Calculating overnight costs of power plants with CCS

There are two notable reasons for why CCS overnight costs are higher relative to similar plants without CO_2 capture. The first is the derating of the power plant due to lost power output, and the second is the overnight cost of the capture equipment.

The overnight cost of power plants with CCS for a given scenario w as a function of the capture percentage can therefore be calculated as the sum of two terms:

$$C_{i\in K}^{TOC}(cap,w) = \frac{C_{i\in K,0}^{TOC}}{1 - ep_{i\in K}(cap_{i\in K}, w)} + C_{i\in K,ccs}(w) * \frac{cap_{i\in K}}{0.9} \tag{31}$$

Where $C_{i\in K,ccs}$ is the overnight cost of CO_2 capture equipment at 90% CO_2 capture. $C_{i\in K,0}^{TOC}$ is the overnight cost of the corresponding power plant without capture (i.e. a pulverized coal plant for coal-CCS and a CCGT plant for CCGT-CCS). $ep_{i\in K,}(cap_{i\in K,}, w)$ is the energy penalty for a given capture percentage and scenario *w*.

The overnight cost of capture equipment, $C_{i\in K,ccs}$, for a power plant with CCS is found by considering the total overnight cost at 90% capture:

$$C_{i\in K}^{TOC,cap=90\%}(w) = \frac{C_{i\in K,0}^{TOC}}{1 - ep_{i\in K,cap=90\%}(w)} + C_{i\in K,ccs}(w) * 1 \tag{32}$$

Which can be rearranged as:

$$C_{i\in K,ccs} = \left(C_{i\in K}^{TOC,cap=90\%}(w) - \frac{C_{i\in K,0}^{TOC}}{1 - ep_{i\in K,cap=90\%}(w)}\right) \tag{33}$$

As mentioned in section 4.2, the overnight cost of power plant with CCS is modeled as a multiple, $\chi_{i\in K}(w)$, of the overnight cost of the same plant without CCS. Expression (33) therefore becomes:

$$C_{i\in K,ccs}(w) = \left(\chi_{i\in K}(w) C_{i\in K,0}^{TOC} - \frac{C_{i\in K,0}^{TOC}}{1 - ep_{i\in K,cap=90\%}(w)}\right) \tag{34}$$

Solution method

Because some of the parameters that determine CCS cost are uncertain we need to generate a set of possible realizations of them, each corresponding to a specific scenario. As the number of scenarios increases, a standard linear programming formulation would have a very large number of variables. As a result, the solution time would be prohibitively long. In order to reduce the solution time, a Bender's decomposition formulation of a stochastic generation expansion problem (e.g. in Bloom, 1982) is adopted. The minimization problem in (22) is split into two separate problems: the first, referred to as the master problem, is deterministic and minimizes the investment cost. The second, referred to as the sub problem, loops over all the possible scenarios *w* and minimizes the expected operating and CO_2 storage costs given the investment decisions.

Uncertain overnight costs for CCS are modeled with one deterministic element, $C_{i \in K}^{TOC}$, that is part of the master problem, and one stochastic element, $C_{i \in K}^{TOC,penalty}(w)$, which is part of the sub problem. The term $C_{i \in K}^{TOC,penalty}(w)$ will simply be the difference between the initial assumption for overnight costs and the actual overnight costs for a given scenario.

A recourse function $\theta(Y)$ is included in the master problem to approximate the future costs given the investment decisions. Since some of these costs are uncertain, and depend on the scenario *w*, the expected value of the recourse function is needed, i.e. $\mathrm{E}[\theta(Y, w)]$. From duality theory it is known that the dual multipliers of the constraints of an optimization problem provide an estimate of how much the objective function would improve with a one-unit increase in the decision variable. For a Bender's decomposition, these duality multipliers are of great interests, in particular the constraints of the sub problem that are functions of the master problem decisions. These constraints and their corresponding duality multiplier can be used to obtain a point-and-slope approximation of the future cost as a function of the master problem decision. For the capacity expansion model described above one could obtain an approximation of the future uncertain costs as a function of the investment decisions. For each iteration that has a different investment decision, a different point-and-slope approximation of the future cost function is obtained, and by combining them one obtains an increasingly accurate piecewise linear approximation of the future cost.

In the case of this capacity expansion model, there are two parts of the sub problem that are functions of the master problem investments. The first is the capacity constraint, i.e. constraint (23) and (26), with the latter only regarding wind generators. The second is the stochasticity of CCS overnight costs. The stochastic part of CCS overnight costs is not a constraint per se, but it can be transformed into one by simply setting $C_{CCS}^{penalty}(w)$ greater or equal to its actual value. $\mathrm{E}[\theta(Y, w)]$ can therefore be estimated from the dual multipliers of the capacity constraints and the stochasticity "constraint", where the latter will be zero for all $i \notin K$.

The solution method is iterative, and on the Kth iteration there will be a total of K-1 different point-and-slope estimates of $\mathrm{E}[\theta(Y,w)]$, where the recourse function for each iteration can be calculated as the expected value of $\left[f^l(w) - \sum_I S_i(Y_i^l - Y_i)\left(10^3\gamma\delta(r,T)\sigma_i^l(w) + \sum_J \pi_{i,j}^l(w)\right)\right]$. Here, Y_i^l denotes the l^{th} master problem decision, and $f^l(w)$ denotes the l^{th} solution of the sub problem. Moreover, $\pi_{i,j}^l$(w) denotes the l^{th} duality multiplier of the capacity constraint of technology i at demand period j for the scenario w. $\sigma_i^l(w)$ denotes the l^{th} duality multiplier of the stochastic CCS costs for scenario w. As mentioned above, $10^3\gamma\delta(r,T)$ is a constant term that gives the total discounted lifetime costs for a given capital charge, discount rate and length of planning horizon.

A Bender's formulation of the stochastic generation expansion is therefore the following master problem:

$$\min_Y \left(\sum_I C_i^{fix} Y_i + \mathrm{E}[\theta(Y,w)]\right) \tag{35}$$

subject to

$$em_i \leq ES \qquad \forall i \in I$$

$$0.7 * 0.22 Y_{wind} S_{wind} \leq 0.3 \sum_{I \setminus \{wind\}} 0.85 S_i Y_i \qquad \forall i \in \{wind\}$$

$$\mathrm{E}[\theta(Y,w)] \geq \sum_W p(w)\left[f^l(w) - \sum_I S_i(Y_i^l - Y_i)\left(10^3\gamma\delta(r,T)\sigma_i^l(w) + \sum_J \pi_{i,j}^l(w)\right)\right] \qquad \forall i \in I \quad \forall j \in J \quad l = 1, \dots, K-1$$

And the following sub problem:

$$\min_X \sum_W p(w)\left[C^{CO2}(w) + \sum_I \sum_J C_i^{var}(w) X_{i,j}\, dur_j + C_{CCS}^{penalty}(w)\right] \tag{36}$$

subject to

$$\sum_{I} X_{i,j} \geq D_j \qquad \forall j \in J$$

$$X_{i,j} \leq Y_i S_i \qquad \forall i \in I$$

$$X_{wind,j} \leq Y_{wind} S_{wind} * CF_{wind} \qquad \forall i \in \{wind\}$$

$$C_{CCS}^{penalty}(w) \geq \sum_{i \in K} C_{i \in K}^{TOC,penalty}(w) S_i Y_i \gamma \delta(r,T) 10^3 \qquad \forall i \in K$$

The optimization algorithm is iterative. First, the master problem is solved, yielding a lower bound on the cost. Second, the sub problem is solved given the master problem investments. The sum of the objective function in the master and sub problem minus the recourse function yield an upper bound on the total cost. In addition, as mentioned above, a point and slope approximation of the expected recourse function $\mathrm{E}[\theta(Y,w)]$ is found by considering the dual variables of the complicating constraints. The master problem is then solved again incorporating the recourse function approximation from the previous solution, and the procedure repeats. The algorithm stops when the relative difference between the lower and upper bounds are less than a pre-defined limit ε

Appendix B - Comparing stochastic and deterministic results

A similar analysis to the one undertaken in chapter 4 can be done deterministically, using only the expected value of each distribution, i.e. 21.5% for the energy penalty and 1.8 for the overnight cost multiple.

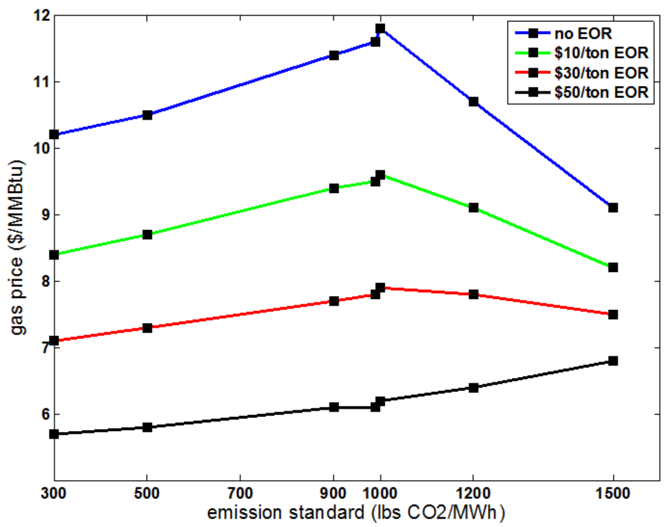

Figure 28: Results using deterministic analysis: natural gas price above which coal-fired power plants with CCS enter generation mix for different emission standards and EOR CO_2 prices

The same trends are apparent whether input parameters are stochastic or deterministic. However, as shown in Figure 29a, the effect of considering the expected value of the uncertain parameters, rather than their probability distributions, is significant. The natural gas prices where coal-fired power plants with CCS enter the generation mix is notably shifted downward when the overnight cost and energy penalty are deterministic. Moreover, as shown in Figure 29b, the effect of modeling or not modeling uncertainty seems to be independent of whether or not EOR revenues are available.

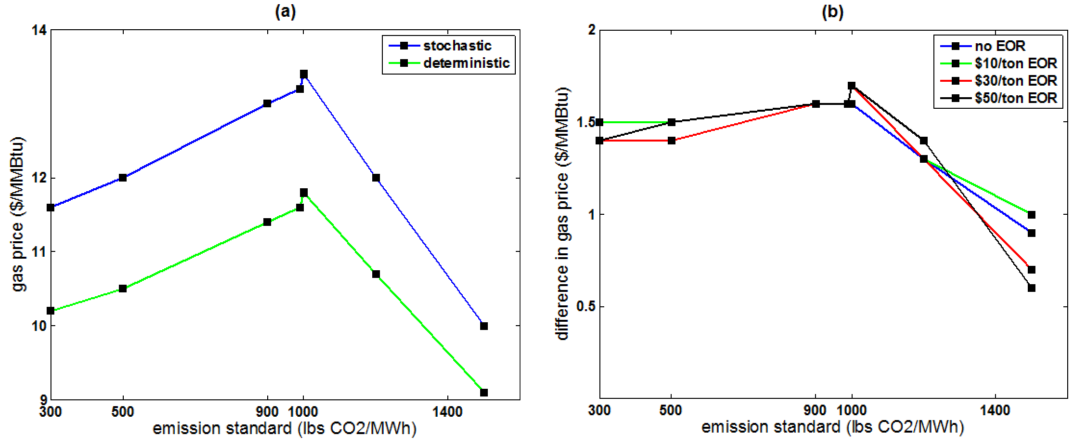

Figure 29: (a) Stochastic and deterministic result of capacity expansion for 1000 lbs/MWh emission standard (b) Difference in stochastic versus deterministic determination of natural gas price where coal-fired power plants with CCS enter generation mix

The distance between the stochastic and deterministic curves is at its largest for the EPA's proposed emission standard, and is at its smallest for the higher emission standards. Both effects are to be expected. The "unattractiveness" of a coal-CCS investment relative to a natural-gas fired CCGT investment is at its maximum for an emission standard of 1000 lbs/MWh. Adding uncertainty to the actual costs of coal-fired power plants with CCS, while keeping the cost of natural gas-fired ones deterministic, is therefore likely to only increase the gas price where coal-fired plants with CCS are the preferred option. As the emission standard is loosened, the monetary effect of uncertain costs decreases since lower capture percentages result in lower overall capture costs. When both coal-fired *and* natural gas-fired generators are required to capture CO_2 they are both subject to the cost uncertainty, but the greater capture percentages of coal-fired power plants result in the monetary effect of the uncertainty being greater for these units, thereby shifting upwards the point where coal-fired power plants with CCS enter the generation mix.

The difference between the stochastic and deterministic results highlights the importance of considering parameters to be stochastic as opposed to deterministic when modeling investments in technologies whose commercial-scale performance is uncertain. Whereas an equivalent deterministic analysis could be undertaken with more simple methods, for example in a spreadsheet model, the stochastic optimization could only be done utilizing some of the more advanced mathematical optimization tools for decision-making under uncertainty.

Appendix C - Derivation of learning expressions

Given two Gaussian probability density functions g and f, where f is the pdf of cost and g is the pdf of the mean of f, the density functions can be expressed as:

$$g(\mu|m_t) = \frac{1}{s_t\sqrt{2\pi}} e^{-\frac{1}{2s_t^2}(\mu-m_t)^2} \tag{37}$$

$$f(c|\mu) = \frac{1}{\sigma\sqrt{2\pi}} e^{-\frac{1}{2\sigma^2}(c-\mu)^2} \tag{38}$$

One can use a realized cost c to update the parameters m and s for g through Bayes theorem:

$$g(\mu|c) = \frac{g(\mu)f(c|\mu)}{\int g(\mu)f(c|\mu)d\mu} \tag{39}$$

Using equation (37) and (38) and ignoring any constants yields

$$g(\mu)f(c|\mu) = e^{-\frac{1}{2}\left[\frac{(\mu-m_t)^2}{s_t^2}+\frac{(c-\mu)^2}{\sigma^2}\right]} = e^{-\frac{1}{2\sigma^2 s_t^2/(\sigma^2+s_t^2)}\left[\mu-\frac{\sigma^2 m_t+s_t^2 c}{\sigma^2+s_t^2}\right]^2} \tag{40}$$

In other words:

$$g(\mu|c) \sim N(m_{t+1}, s_{t+1}^2) \tag{41}$$

$$s_{t+1} = \sqrt{\frac{\sigma^2 s_t^2}{\sigma^2 + s_t^2}} \tag{42}$$

$$m_{t+1} = \frac{\sigma^2 m_t + s_t^2 c}{\sigma^2 + s_t^2} \tag{43}$$

Starting with an initial guess of the parameters of g, and knowing σ, (42) and (43) provide an analytical expression for updating *(m, s)* for each cost c that is observed. Assuming that probability distributions for capture and storage costs are independent and identically distributed, the mean and standard deviation of the convoluted total cost function will be

$$s_T = \sqrt{s_{c,T}^2 + s_{s,T}^2}$$
$$m_T = m_{c,T} + m_{s,T} \tag{44}$$

Appendix D - Analytical Decision Model

This appendix provides an analytical expression of a more general version of the optimization problem formalized in section 6.2.2, before providing an actual analytical solution to a simple and stylized version of the same problem.

Consider a technology whose average cost is the sum of N uncertain components, each of which follows a Gaussian distribution with a mean expected cost of μ_i and standard deviation σ_i, $i \in \{1, \dots, N\}$. Each of the mean expected costs are uncertain, but follows a Gaussian probability distribution defined by parameters $s_{0,i}$ and $m_{0,i}$. One can improve the knowledge about the parameter μ_i by investing in a technology demonstration that reveals one realization of the cost of component i.

Noting as $m_{1,i}$ the mean expected cost of component i after one cost realization c_i, and $s_{1,i}$ the uncertainty in the estimate. $m_{0,i}$ and $s_{0,i}$ are the initial expected cost and corresponding uncertainty. The results in Appendix C show that after one cost realization c_i

$$s_{1,i} = s_{0,i} \sqrt{\frac{1}{1 + \left({s_{0,i}}/{\sigma_i} \right)^2}} \tag{45}$$

$$m_{1,i} = \frac{\sigma_i^2 m_{0,i} + s_{0,i}^2 c_i}{\sigma_i^2 + s_{0,i}^2} \tag{46}$$

Assuming that the N components are independent, then the expected total cost $m_{1,T}$ and the total uncertainty $s_{1,T}$ after investments in technology demonstrations can be written as

$$s_{1,T} = \sqrt{\sum_{i=1}^{N} \frac{s_{0,i}^2}{1 + n_i \left({}^{s_{0,i}}/_{\sigma_i} \right)^2}} \tag{47}$$

$$m_{1,T} = \sum_{i=1}^{N} \frac{\sigma_i^2 m_{0,i} + n_i s_{0,i}^2 c_i}{\sigma_i^2 + n_i s_{0,i}^2} \tag{48}$$

Where n_i is and indicator function that is 1 if one invests in component i, and 0 otherwise.

Assuming there are two periods in which to invest in technology demonstration. If there is one cost observation in each period then

$$s_{2,i} = s_{1,i} \sqrt{\frac{1}{1 + \left({}^{s_{1,i}}/_{\sigma_i} \right)^2}} = s_{0,i} \sqrt{\frac{1}{1 + 2\left({}^{s_{0,i}}/_{\sigma_i} \right)^2}} \tag{49}$$

The total uncertainty then becomes

$$s_T = \sqrt{\sum_{i=1}^{N} \frac{s_{0,i}^2}{1 + n_i \left({}^{s_{0,i}}/_{\sigma_i} \right)^2}} \tag{50}$$

Where n_i is and indicator function that is 2 if one invests in component *i* in both periods, 1 if one invests only once and 0 otherwise.

However, in the second period, one can only observe an additional cost realization if the total mean expected cost in that period is below a certain threshold m_{max}. From expression (48) it is clear that the future mean expected cost, $m_{1,i}$, is stochastic and depend on the observed cost, where $c_i \sim N(m_{0,i}, \sigma_i)$. If $m_{1,T} > m_{max}$ there is only one observation, but otherwise there are two. In other words, if $m_{1,T} > m_{max}$ then $s_{2,i} = s_{1,i}$, but if $m_{1,T} \leq m_{max}$ then $s_{2,i} = s_{1,i} \sqrt{\frac{1}{1+\left({}^{s_{1,i}}/_{\sigma_i} \right)^2}}$.

The total uncertainty at the end of the second period is therefore stochastic, and can be expressed as the probability weighted sum of the total uncertainty in each scenario:

$$\mathrm{E}[\,s_T] = \sqrt{\sum_{i=1}^{N} \frac{s_{0,i}^2}{1 + n_i \left({}^{s_{0,i}}/_{\sigma_i} \right)^2}}\, \mathbb{P}\left(\sum_{i=1}^{N} m_{1,i} \le m_{max} \right) + \sqrt{\sum_{i=1}^{N} \frac{s_{0,i}^2}{1 + I_i \left({}^{s_{0,i}}/_{\sigma_i} \right)^2}} \left[1 - \mathbb{P}\left(\sum_{i=1}^{N} m_{1,i} \le m_{max} \right) \right] \qquad (51)$$

Where I_i is and indicator function such that

$$I_i = \begin{cases} n_i & if\ n_i < 2 \\ n_i - 1 & if\ n_i = 2 \end{cases}$$

The objective of policymakers is to find the portfolio **p** of demonstration projects that minimizes the overall uncertainty in a technology's cost

$$\min_{\boldsymbol{p} \in \mathcal{P}} \mathrm{E}[\,s_T] \qquad (52)$$

Where $\mathcal{P}$ is the set of feasible portfolios such that $\boldsymbol{m_o^T p} \le m_{max}$. With $\boldsymbol{p} = [n_1, \dots, n_N]$ and $n_i \in \{0,1,2\}$.

As the elements of **p** are integers, there is no closed form solution to the minimization problem in (52). To examine how the analytical solution to the minimization problem above behaves, the simple case of a technology that consists of only two components (i.e. N=2) is considered. To further simplify the range of possible investments, the budget limit is set such that it only allows for one investment in each period. A policy maker can therefore choose between three portfolios, one that invests solely in the same technology in both periods, or one that invests first in one and then in the second.

Consider that these two components are capture and storage and denote as p_1 a portfolio investing in only capture projects, and p_2 a portfolio investing in both capture and storage. For simplicity a portfolio investing exclusively in storage is not considered. The objective now becomes to determine the situation for which a diversified portfolio is preferred over one that invests exclusively in one component. Mathematically, this results in finding the situations for which

$$\mathrm{E}[s_T \mid p_2] \leq \mathrm{E}[s_T \mid p_1] \tag{53}$$

For portfolio p_2 that invests in both capture and storage the expected 2nd period total uncertainty is deterministic such that

$$\mathrm{E}[s_2|p_2] = \sqrt{s_{2,c}^2 + s_{2,s}^2} = \sqrt{s_{0,c}^2 \frac{1}{1+\left(\frac{s_{0,c}}{\sigma_c}\right)^2} + s_{0,s}^2 \frac{1}{1+\left(\frac{s_{0,s}}{\sigma_s}\right)^2}} \tag{54}$$

For portfolio p_1 that invests exclusively in capture the expected 2nd period total uncertainty is stochastic such that

$$\mathrm{E}[s_2|p_1] = \mathbb{P}(m_{1,c} \leq m_{max}) \sqrt{s_{0,s}^2 + s_{0,c}^2 \frac{1}{1+2\left(\frac{s_{0,c}}{\sigma_c}\right)^2}} + \left[1 - \mathbb{P}(m_{1,c} \leq m_{max})\right] \sqrt{s_{0,s}^2 + s_{0,c}^2 \frac{1}{1+\left(\frac{s_{0,c}}{\sigma_c}\right)^2}} \tag{55}$$

In order for $m_{1,c} \leq m_{max}$ the observed capture cost needs to be such that $c_i \leq c_{max}$ with $c_{max} = \frac{\sigma_c^2 + s_{0,c}^2}{s_{0,c}^2} m_{max} - \frac{\sigma_c^2}{s_{0,c}^2} m_{0,c}$[55]. Observed costs are stochastic and follow a Gaussian distribution *f* with mean $m_{0,c}$ and standard deviation σ_c. Noting as *F* the Gaussian cumulative distribution function, the expected total uncertainty given portfolio p_1 is therefore

$$\mathrm{E}[s_2|p_1] = \int_{-\infty}^{c_{max}} \sqrt{s_{0,s}^2 + s_{1,c}^2 \frac{1}{1+\left(\frac{s_{1,c}}{\sigma_c}\right)^2}} f_{m_{0,c},\sigma_c}(c)dc + \int_{c_{max}}^{+\infty} \sqrt{s_{0,s}^2 + s_{0,c}^2 \frac{1}{1+\left(\frac{s_{0,c}}{\sigma_c}\right)^2}} f_{m_{0,c},\sigma_c}(c)dc$$

$$\mathrm{E}[s_2|p_1] = \sqrt{s_{0,s}^2 + s_{1,c}^2 \frac{1}{1+\left(\frac{s_{1,c}}{\sigma_c}\right)^2}} F(c_{max}; m_{0,c}, \sigma_c) + \sqrt{s_{0,s}^2 + s_{0,c}^2 \frac{1}{1+\left(\frac{s_{0,c}}{\sigma_c}\right)^2}} (1 - F(c_{max}; m_{0,c}, \sigma_c))$$

Noting as $p = \mathbb{P}(m_{1,c} \leq m_{max})$, the expression $\mathrm{E}[s_T \mid p_2] \leq \mathrm{E}[s_T \mid p_1]$ can be rewritten as

$$p\sqrt{s_{0,s}^2 + s_{0,c}^2 \frac{1}{1+2\left(\frac{s_{0,c}}{\sigma_c}\right)^2}} + (1-p)\sqrt{s_{0,s}^2 + s_{0,c}^2 \frac{1}{1+\left(\frac{s_{0,c}}{\sigma_c}\right)^2}} - \sqrt{s_{0,c}^2 \frac{1}{1+\left(\frac{s_{0,c}}{\sigma_c}\right)^2} + s_{0,s}^2 \frac{1}{1+\left(\frac{s_{0,s}}{\sigma_s}\right)^2}} \geq 0 \tag{56}$$

[55] Since $m_{1,c} = \frac{\sigma_c^2 m_{0,c} + s_{0,c}^2 C}{\sigma_c^2 + s_{0,c}^2}$

The first two terms above can be downwards bounded by the first term, so that if expression (57) is valid, then expression (56) is as well:

$$\sqrt{s_{0,s}^2 + s_{0,c}^2 \frac{1}{1 + 2\left(\frac{s_{0,c}}{\sigma_c}\right)^2}} - \sqrt{s_{0,c}^2 \frac{1}{1 + \left(\frac{s_{0,c}}{\sigma_c}\right)^2} + s_{0,s}^2 \frac{1}{1 + \left(\frac{s_{0,s}}{\sigma_s}\right)^2}} \geq 0 \tag{57}$$

Now assuming σ_c and $s_{0,c}$ to be proportional to σ_c and $s_{0,s}$. (I.e. $\sigma_c = a\sigma_s$ and $s_{0,c} = bs_{0,s}, a, b \in \mathbb{R}^+$). Denoting as *r* the ratio of storage uncertainty and storage variability[56] (57) can be rewritten as

$$\sqrt{1 + \frac{b^2}{1 + 2r^2\left(\frac{b}{a}\right)^2}} - \sqrt{\frac{1}{1 + r^2} + \frac{b^2}{1 + r^2\left(\frac{b}{a}\right)^2}} \geq 0 \tag{58}$$

As mentioned in section 6.2.3 it seems reasonable to assume that the uncertainty in capture cost is greater than the uncertainty in storage costs, and that the variability you cannot account for is greater for storage costs than they are for capture costs. This can be modeled in expression (58) by considering b>1, and *a* to be inversely proportional to *b*. Expression (58) then becomes

$$\sqrt{1 + \frac{b^2}{1 + 2r^2b^4}} - \sqrt{\frac{1}{1 + r^2} + \frac{b^2}{1 + r^2b^4}} \geq 0 \tag{59}$$

Whether a diversified portfolio is better than a capture-only portfolio will depend on whether the learning from a first storage observation is higher than from a second capture observation. Figure 30 shows the relative difference in final uncertainty of the two portfolios as a function of the ratio *r*. It is clear that when the ratio of storage uncertainty to storage variability increases, the diversified portfolio fares increasingly better relative to the capture-only portfolio. This can be explained by two mechanisms:

1. The ease of learning about capture increases with r since $\sigma_c/s_{0,c} = b^2 r$. Consequently, the amount of learning from the first capture cost observation increase with r. However, as described in section 6.2.4, the additional learning

[56] I.e $\frac{s_{0,s}}{\sigma_s} = r$ and $\frac{s_{0,c}}{\sigma_c} = \frac{b}{a} r$

from a second capture cost observation will decrease if you learned a lot from the first observation. Therefore the additional learning from a second capture observation decreases with *r*.

2. The ease of learning about storage increases with r since $\sigma_s/s_{0,s} = r$. As a result, the learning from the first storage observation increases with increasing values of *r*.

Furthermore, the relative performance of the diversified portfolio increases when the proportionality constant *b* increases. This can be explained by considering that since $\frac{s_{0,c}}{\sigma_c} = b^2 r$, increasing the value of *b* will further increase the amount of learning from the first capture cost observation, and correspondingly decrease the amount of learning from the second capture cost observation.

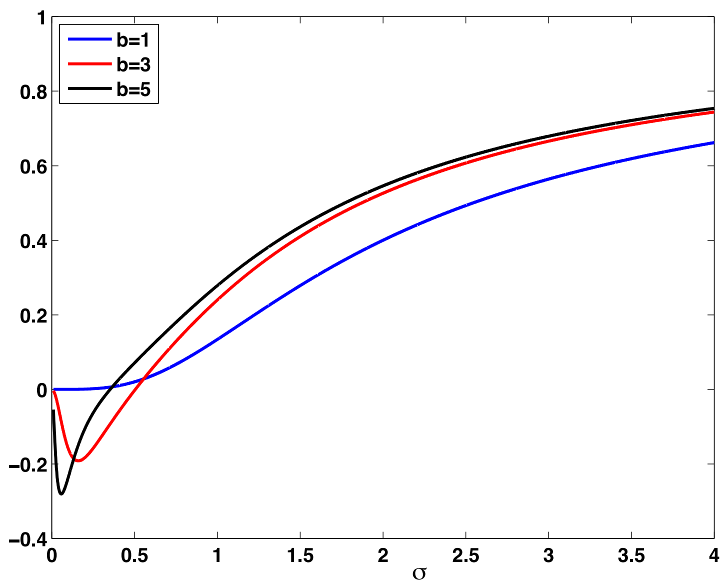

Figure 30: Relative performance of diversified portfolio over capture-only portfolio[57]

The minimum ratio of storage uncertainty to variability necessary for the diversified portfolio to be preferred can be found through expression (59). By rearranging and setting it equal to zero we have that:

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[57] $\left(\sqrt{1+\frac{b^2}{1+2r^2b^4}} - \sqrt{\frac{1}{1+r^2}+\frac{b^2}{1+r^2b^4}}\right) \Big/ \sqrt{1+\frac{b^2}{1+2r^2b^4}}$

$$\frac{1}{1+\ r^2}-\frac{b^6}{(1+2r^2b^4)(1+r^2b^4)}=0 \tag{60}$$

Which can be rewritten as the following polynomial:

$$2r^4b^8-(1+\ r^2)b^6-3r^2b^4+1=0 \tag{61}$$

The roots of which are

$$r=\begin{bmatrix} \frac{1}{2b^2}\sqrt{\sqrt{(b^2+1)(8b^4-7b^2+1)}+b^2-3} \\ \frac{-1}{2b^2}\sqrt{\sqrt{(b^2+1)(8b^4-7b^2+1)}+b^2-3} \\ \frac{1}{2b^2}\sqrt{-\sqrt{(b^2+1)(8b^4-7b^2+1)}-b^2+3} \\ \frac{-1}{2b^2}\sqrt{-\sqrt{(b^2+1)(8b^4-7b^2+1)}-b^2+3} \end{bmatrix} \tag{62}$$

As $r \in \mathbb{R}^+$, the second and fourth root can be discarded. Furthermore, the expressions within the square roots need to be greater than zero in order to avoid complex solutions. For b>1, the first solution yields a positive real solution, and therefore

$$r=\frac{1}{2b^2}\sqrt{\sqrt{(b^2+1)(8b^4-7b^2+1)}+b^2-3} \qquad \forall b\geq 1 \tag{63}$$

Figure 31 shows expression (63) for different values of *b*. When *b* increases, i.e. when capture uncertainty increases relative to storage uncertainty, then the ratio of storage uncertainty to variability above which the diversified portfolio is preferred decreases.

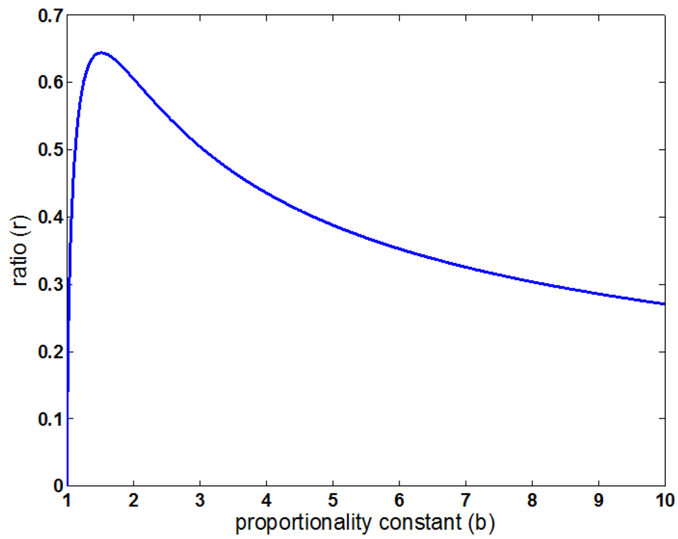

Figure 31: Ratio of storage uncertainty to variability above which a diversified portfolio is preferred

For the particular situation where b=2, i.e. capture costs are twice as uncertain as storage, the inequality $\mathrm{E}[s_T \mid p_1] - \mathrm{E}[s_T \mid p_2] \geq 0$ can be rewritten as

$$\sqrt{1+\frac{4}{1+32r^2}} - \sqrt{\frac{1}{1+r^2}+\frac{4}{1+16r^2}} \geq 0 \qquad (64)$$

Since b>1, the expression can be solved as

$$r = \frac{\sqrt{\sqrt{505}+1}}{8} \approx 0.6056 \qquad (65)$$

In conclusion, if $\sigma_c = \frac{1}{2}\sigma_s$ and $s_{0,c} = 2s_{0,s}$ then

$$\mathrm{E}[s_T \mid p_2] \leq \mathrm{E}[s_T \mid p_1] \qquad (66)$$

If

$$\frac{s_{0,s}}{\sigma_s} \geq \frac{\sqrt{\sqrt{505}+1}}{8}$$

In other words: if the uncertainty in the cost of capture is twice the uncertainty in cost of storage, but the variability in the cost of capture is half that of the variability in cost of storage, it can be shown analytically that the diversified portfolio is always the preferred option as long as $\sigma_s/s_{0,s} \geq 0.6056$. Since the assumption for storage uncertainty is such that $s_{0,s} \in [0,7.5]$, and $\sigma_s = 8$, then the diversified portfolio is preferred as long as $s_{0,s} > 4.84$.