An Analytical Framework for Long Term Policy for Commercial Deployment and Innovation in Carbon Capture and Sequestration Technology in the United States

By

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B.S., Mechanical Engineering
Georgia Institute of Technology (2007)

Submitted to the Engineering Systems Division
In Partial Fulfillment of the Requirements for the Degree of

Master of Science in Technology and Policy

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Abstract

Carbon capture and sequestration (CCS) technology has the potential to be a key CO_2 emissions mitigation technology for the United States. Several CCS technology options are ready for immediate commercial-scale demonstration, but three obstacles to commercial deployment remain: the lack of a clear legal and regulatory framework for sequestration, the lack of a demonstration phase, and most importantly, the lack of a market for CCS.

A successful demonstration phase will achieve the goal of technology readiness. The demonstration phase should be organized so as to share costs and risks between public and private actors. Project selection responsibility should be assigned to a dedicated private board and project management responsibility to private companies. This analysis recommends a combination of the Boucher Bill proposal for a CCS demonstration phase, as incorporated in the American Clean Energy and Security Act (ACES Act) of 2009, and a continuation of the DOE Clean Coal Power Initiative program. This combined approach can provide productive competition between public and private demonstration programs.

Achieving technology readiness will not on its own lead to commercial deployment of CCS. Two additional policy objectives for the commercial deployment phase are considered: market penetration and cost reduction. Market penetration can be ensured through strong market pull policies, but this may be a very expensive policy approach in the long run. A more prudent goal is long-term cost reduction of CCS. Unlike the market penetration goal, the cost reduction goal will not guarantee that CCS will become a major contributor to carbon emissions mitigation, but it will provide a more cost-effective path. Achieving the cost reduction goal will require strong market pull policies for the short and medium term, together with a focus on technology push policies over the entire period. In the long term, market pull policies for CCS should be eliminated; if CCS is not economically competitive with alternative technologies, it should not be deployed on a significant scale.

The ACES Act provides a good policy framework to achieve technology readiness through a demonstration phase and to pursue the long-term goal of cost reduction for commercial deployment of CCS technology. This approach will provide a cost-effective strategy for ensuring that CCS, a major scalable option for carbon emissions mitigation, is given the best chance of success in the long term.

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1. Introduction

Anthropogenic emissions of CO_2 and other greenhouse gases are contributing to global climate change. Authoritative scientific assessments have concluded that continued high emission rates could lead to significant ecological and economic consequences (Metz *et al.*, 2007). A significant portion of these emissions come from the coal-dominated US power sector. Carbon capture and sequestration (CCS) technology offers a scalable solution to provide carbon emissions mitigation from the power sector. Public policy will have to create a market for low-carbon technologies such as CCS, but it seems increasingly likely that any carbon pricing scheme that is politically feasible will not provide sufficient incentive for private industry to invest in low-carbon technologies such as CCS; therefore, other policy options are being considered so that significant commercial deployment of CCS technology can be achieved.

This thesis seeks to develop a better framework for thinking about the different policies that will be required to make CCS a significant contributor to carbon emission mitigation in the US. This framework will consider the many facets of the innovation system for CCS technology, including the current state of CCS technology, the barriers to CCS investment in the US power sector, and how different policies support innovative activities at different stages in the innovation process. Using this framework, an analysis of policy options for a demonstration phase and for long-term commercial deployment of CCS technology is carried out.

1.1. The Challenge

Anthropogenic emissions of CO_2 and other greenhouse gases are contributing to global climate change. Authoritative scientific assessments have concluded that continued high emission rates could lead to significant ecological and economic consequences (Metz *et al.*, 2007). One illustrative example of the costly consequences of climate change is the potential effect on water supplies in Asia if the Tibetan glacier melts; if this glacier disappears, the primary regulator of water supplies for one third of the world's population will be eliminated, leading to health, environmental, and economic problems in some of the world's poorest nations.

The primary source of anthropogenic CO_2 emissions is the burning of fossil fuels, with more than 45% of these emissions occurring in stationary sources like power plants and industrial facilities. Figure 1.1 shows the number of major point sources of CO_2 worldwide and the amount of CO_2 emissions from these sources.

Process	Number of sources	Emissions ($MtCO_2\ yr^{-1}$)
Fossil fuels		
Power	4,942	10,539
Cement production	1,175	932
Refineries	638	798
Iron and steel industry	269	646
Petrochemical industry	470	379
Oil and gas processing	Not available	50
Other sources	90	33
Biomass		
Bioethanol and bioenergy	303	91
Total	**7,887**	**13,466**

Figure 1.1. Point Sources of CO_2 Worldwide (UN-IPCC, 2005).

Carbon capture and sequestration (CCS) technology can in principle be applied to many of these stationary sources. In CCS operation, CO_2 is removed from the system, compressed, and sent through a pipeline to a permanent storage location, usually in an underground geologic reservoir such as a deep saline formation.

Many billions of tons of CO_2 emissions will have to be prevented if the worst effects of climate change are to be averted. Socolow and Pacala identified several *scalable* "wedges": options that could, if deployed on a large scale, avoid the release of 1 gigaton of carbon (GtC) per year by 2050. Seven of these wedges would be needed if global carbon emissions in 2050 were to remain at today's level, as shown in Figure 1.2.

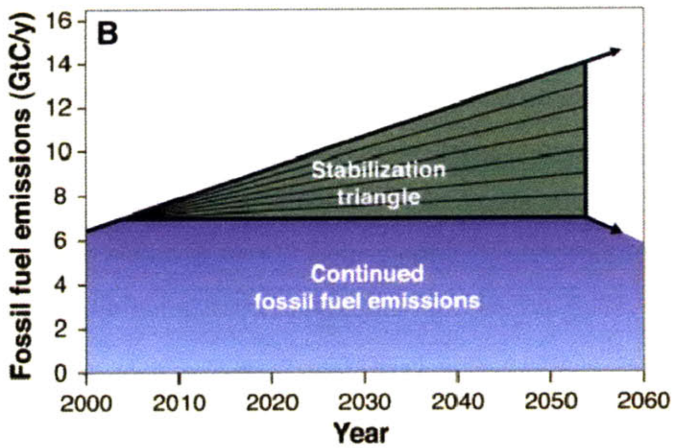

Figure 1.2. The Socolow and Pacala wedges. (Pacala and Socolow, 2004)

Three of the potential fifteen wedges identified by Socolow and Pacala involve CCS in different sectors: coal-burning power plants, hydrogen plants, and synthetic fuels plants (Pacala and Socolow, 2004). This wedge model only accounts for stabilizing carbon dioxide emissions from now to 2050, but according to the IPCC and most experts, worldwide carbon dioxide emissions will need to be *reduced* by 15-25% by 2050 to avoid the most severe effects of climate change, making the scale of the challenge even more severe.

As a recent paper by Lester and Finan shows, the innovation challenge for low-carbon energy technologies is unprecedented, and no technology option can be excluded (Lester and Finan, 2009). There are relatively few currently available, scalable, low-carbon options for the US power sector, including CCS, wind, solar, nuclear fission, geothermal, and hydroelectric, and each of these comes with its own difficulties in reaching significant commercial scale deployment. The result of their analysis is significant: even with an unprecedented rate of installation of each of these low-carbon electricity options, to maintain a reasonable economic growth rate, the required gains in energy efficiency of the US would be unprecedented and perhaps unattainable. If any one of these technologies were not available, the carbon emission reductions would likely have to come at the price of economic growth foregone. This underscores the importance of pursing a serious effort in innovation in many technology options, so that the odds of being able to meet such emissions reduction targets without large reductions in economic growth are improved.

The United States has two major reasons to support the commercialization of CCS technology. One reason is that CCS is a scalable solution for reducing carbon dioxide emissions from a US power sector that today derives about 50% of annual electricity generation from coal-fired power plants (see Figure 1.3). The technology is highly compatible with the existing coal fuel and water infrastructure, and the potential for retrofitting some existing coal-fired power plants makes CCS a suitable option for application to the US power industry. Additionally, many large industrial sources of CO_2 such as cement, steel, and petrochemical facilities are potential candidates for CCS.

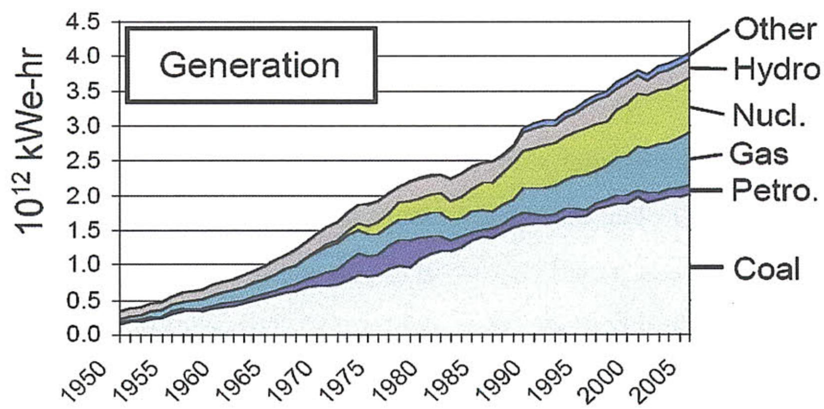

Figure 1.3. Electricity generation in the United States since 1950. Data: (US Energy Information Administration 2008); Figure: (MIT Energy Club Factsheet 2008)

A second major reason for supporting commercialization of CCS is the domestic energy security provided by the hundreds of years of coal reserves known to exist on the North American continent. With a recent history of significantly increasing imports of petroleum for transportation energy supply, the US energy security strategy places a high value on the domestic supplies of traditional oil, gas, and coal resources as well as potential renewable energy resources. CCS can play a vital part in continued energy security in the face of the challenge to drastically reduce carbon dioxide emissions over the next several decades.

To achieve this goal of CCS deployment, a market for the technology must be created by public policy. Whether through simple regulation and pricing of CO_2 emissions, or through a more complex package of regulations, subsidies, and other policies, public policy will be key to creating a market for CCS technology. Through these means, rapid adoption of CCS technology will be made possible at a scale large enough to make a significant contribution to CO_2 mitigation (e.g., > 1 $GtCO_2$/year).

1.2. This Thesis

This thesis explores the possibilities of deploying CCS technology at commercial scale over the next several decades, and presents a framework for analyzing the policy options to achieve this goal. This framework is used to evaluate the options for promoting both demonstration and commercial deployment of CCS in the context of a CCS innovation system, including the presence of a market for the technology, the role of innovation in enhancing this market, and how policies supporting this system can accelerate commercial deployment of CCS.

To achieve this objective, this thesis will:

Explore the current state of CCS technology - Several major approaches to carbon capture technology will be introduced to show the technological variety in CCS. The current cost and future cost outlook for the technology will also be explored. Combined with certain assumptions about an eventual carbon pricing scheme, a cost model will be created to explore the "cost gap" for CCS that is the primary barrier to private investment in CCS, and this model will quantify the level of policy support needed to bridge this cost gap, create the market, and deploy CCS technology at scale.

Explore the obstacles to large-scale deployment of CCS – Three major obstacles to deployment of CCS exist today, including the absence of a clear legal and regulatory framework, the lack of an at-scale demonstration phase, and the absence of a market for CCS technology.

Explore the innovation system for CCS technology– A short study of the history of SO_2 emissions control technology provides the motivation for describing the innovation system for CCS technology. A description of an innovation system is presented, connecting the current state of CCS technology and US power sector, both "market pull" and "technology push" policies, how these policies support different types of innovation, how innovation leads to cost reduction, and how commercial deployment is supported by this system. Finally, this system underscores the primary importance of "market pull" policies in the creation of a market and achieving innovation in CCS, both of which are key to the large-scale commercial deployment of

CCS; additionally, this system underscores the need for a "technology push" strategy for CCS technology as complimentary to innovation after initial commercialization.

Explore the options for organizing demonstration projects, and evaluate the policy proposals to achieve an effective demonstration phase – A framework for thinking about the organization of a demonstration phase is presented, including discussion of cost and risk allocation between public and private actors, as well as project selection and management responsibilities. The current policy proposals for a demonstration phase are considered in the context of this framework, and recommendations are made where prudent. This analysis is supported by evidence from two additional sources: expert feedback on the effectiveness of the policy options for CCS provided at the MIT Expert Workshop on CCS Innovation (see Appendix Section 8.2 for details), as well as several interviews with project managers of current CCS projects.

Explore the potential policy goals for commercial deployment of CCS, and evaluate the combination of "technology push" and "market pull" policies required to achieve each goal in the context of an innovation system for CCS– Achieving the two different goals for commercial deployment of CCS of market penetration and cost reduction will require a different mix of technology push and market pull policy. Using the lessons from the innovation system model, and considerations of economic efficiency, this analysis seeks to conclude which is the best goal to choose, and which policy proposals might best support its achievement.

2. CCS Technology and the Cost Gap

This section explores the current state of carbon capture technology, showing the current range of technologies and the lack of any clear technology winner. The costs of the complete CCS system will then be explored, including a discussion of recent cost escalation and a model of future cost reduction. Finally, a cost model shows the existence and quantifies the magnitude of a "cost gap" for the technology, stemming from the relatively high costs of the technology compared with a politically feasible carbon pricing system for the US. The policy implications of this cost gap are then discussed.

2.1. Capture Technology Overview

Conceptually, the task of avoiding emissions of CO_2 from power plants is straightforward: collect the hot flue gas emitted by the plant, compress it, and inject it into permanent geological storage. The flue gas from a traditional coal plant consists mostly of N_2, with CO_2 concentrations in the range of 10-15%. The major problem with compressing and storing this untreated flue gas is the prohibitively expensive energy requirement for compressing such massive volumes of gas to the high pressures suitable for deep geological storage. The engineering solution to this problem is to separate out the CO_2 at some point during the plant process. The three main technological approaches to CO_2 separation are: post-combustion capture, which is primarily a N_2-CO_2 separation process added to the back-end of a pulverized coal (PC) or natural gas combined cycle (NGCC) plant, pre-combustion capture, which is an H_2-CO_2 separation process embedded in an integrated gasification combined cycle (IGCC) plant, and oxy-fuel combustion, which is an O_2-N_2 separation to provide high-purity oxygen for combustion to avoid the dilution of the flue gas by nitrogen.

2.1.1. Post-Combustion Capture

Post-combustion capture technology is an approach that is potentially suitable for many industrial applications, including both new and existing pulverized coal power plants, cement factories, oil refineries, steel plants, and natural gas power plants (UN-IPCC, 2005). As the name indicates, the goal of this type of system is to capture the CO_2 after the fossil fuel has been burned. A diagram describing this approach as applied to a pulverized coal power plant is shown in Figure 2.1.

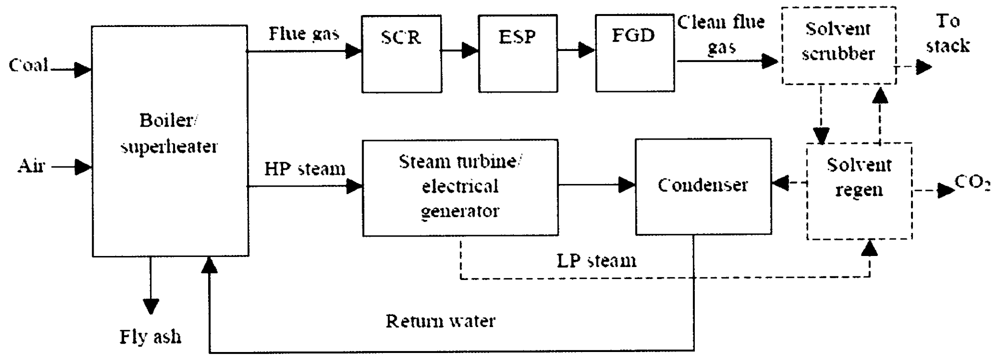

Figure 2.1. Process flow diagram for post-combustion capture on a pulverized coal plant[1]. (Bohm, 2006)

Before entering the carbon dioxide scrubber, the flue gas is cleaned of particulate matter, nitrogen oxides, and sulfur oxides to comply with existing environmental regulations and to minimize contamination of the CO_2 capture system. The leading approach for the post-combustion CO_2 capture system is chemical absorption using a liquid solvent (UN-IPCC, 2005). This approach is shown in Figure 2.2.

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[1] SCR – Selective Catalytic Reduction NO_x removal technology; ESP – Electrostatic Precipitator particulate matter removal technology; FGD – flue gas desulfurization SO_x removal technology.

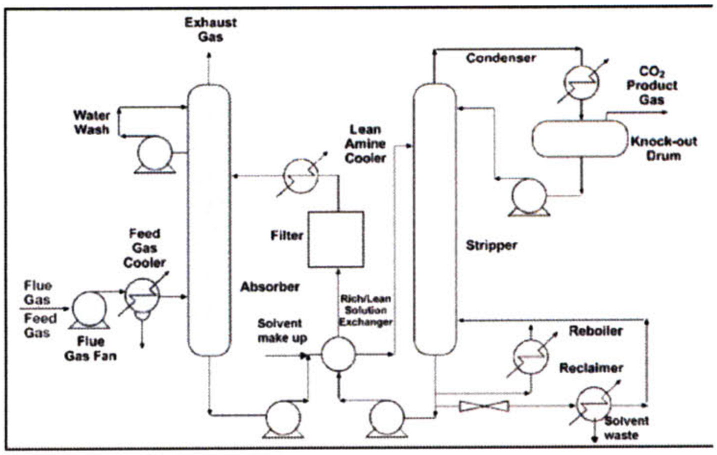

Figure 2.2. Post-combustion solvent capture system (UN-IPCC, 2005)

The flue gas in post-combustion systems is typically between 3 and 15% CO_2, with the higher fraction typical of coal combustion and the lower fraction in a natural gas combined cycle plant (UN-IPCC, 2005). A CO_2-lean solvent is allowed to contact this CO_2-rich flue gas, and this solvent chemically reacts with the CO_2, removing it from the flue gas stream. The CO_2-depleted flue gas is then sent to the plant stack, and the CO_2-rich solvent is sent to a regeneration unit. A large amount of thermal energy is required to release the CO_2 from the CO_2-rich solvent, since the regeneration is a temperature-swing process. This energy is usually supplied by diverting a portion of the steam that would normally be used by the steam turbines in the power block. The released CO_2 then exits in a fairly pure form, and can then be compressed, dehydrated, and transported for sequestration (UN-IPCC, 2005). The resulting CO_2-lean solution is recycled to the absorber.

2.1.2. Pre-combustion Capture

Pre-combustion CO_2 capture is typically used in facilities processing a hydrocarbon fuel into a synthesis gas for further processing. In a power plant configuration, such a plant is called an integrated gasification combined cycle (IGCC) plant, since the fuel is first gasified to produce synthesis gas, which is then burned in a gas turbine as shown in Figure 2.3.

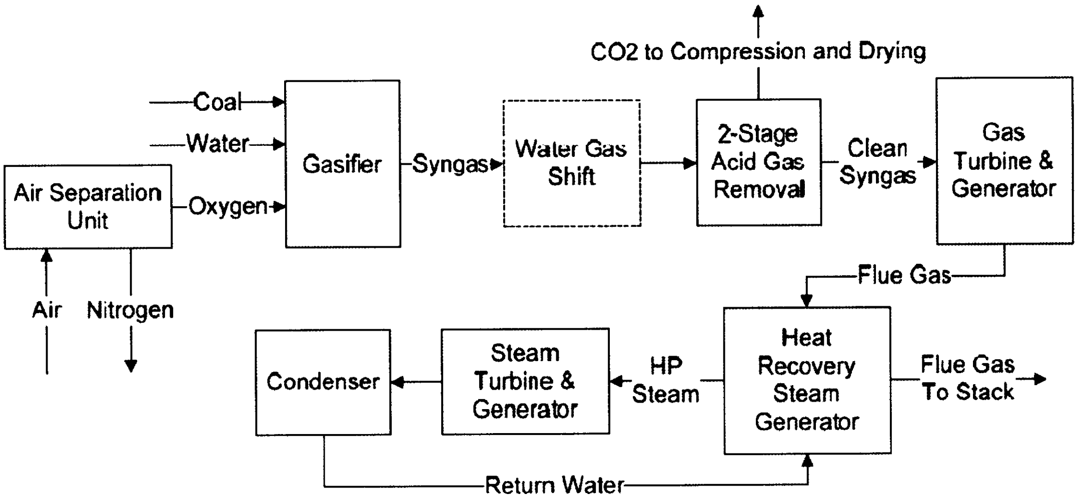

Figure 2.3. Process flow diagram for IGCC plant with pre-combustion capture. (Bohm, 2006)

The pre-combustion capture system consists of both an initial reactor stage, the gasifier, followed by a gas separation step. The gasifier produces a hot, high-pressure synthesis gas consisting mostly of H_2 and CO. The CO in the synthesis gas is further converted to H_2 and CO_2 by reaction in a water-gas shift reactor, after which the remaining gas is mostly H_2 and CO_2. This gas is then treated in the CO_2 capture process, which commonly involves physical solvent absorption, rather than the chemical solvent absorption used for post-combustion capture. This pre-combustion capture system requires significantly less energy than a post-combustion chemical absorption system. Since the partial pressure of CO_2 in the pre-combustion gas is two orders of magnitude greater than in the post-combustion flue gas, a reversible physical reaction using pressure-swing regeneration is employed rather than an energy-intensive chemical reaction requiring a temperature-swing regeneration (UN-IPCC, 2005). Note that even though the CO_2 separation process is significantly less energy-intensive for an IGCC plant compared to a PC plant, the water-gas shift reactor requires a significant energy input in the form of steam. This leaves the IGCC plant with pre-combustion capture with only a modest energy efficiency advantage when compared to a PC plant with post-combustion capture.

2.1.3. Oxy-fuel Combustion

The oxygen-fired or "oxy-fuel" combustion approach refers to a variety of combustion processes where the separation system is in the oxygen plant, where an O_2-N_2 separation occurs, and the high-purity oxygen is used for combustion in the power system, therefore reducing the dilution effect of nitrogen in the resulting flue gas. One major oxy-fuel approach is the modified pulverized coal power plant, which burns coal in high-purity oxygen instead of air. This process is shown in Figure 2.4.

The oxygen comes from an air separation unit, sometimes called an oxygen plant, to create a high-purity stream of oxygen. Many oxy-fuel systems will use a boiler that is very similar to a traditional air-fuel pulverized coal boiler. When the coal is burned in oxygen instead of air, the heat transfer characteristics in the boiler change, so a flue gas recirculation stream is sometimes used to modify the heat transfer and avoid abnormally high boiler-wall temperatures (Bohm, 2006). The flue gas is then treated for environmental pollutants such as SO_2 in the FGD unit and particulate matter in the ESP unit[2], and since the remaining gas contains mostly steam and carbon dioxide, the compression step will condense most of the steam leaving high-purity CO_2gas ready for transportation and sequestration.

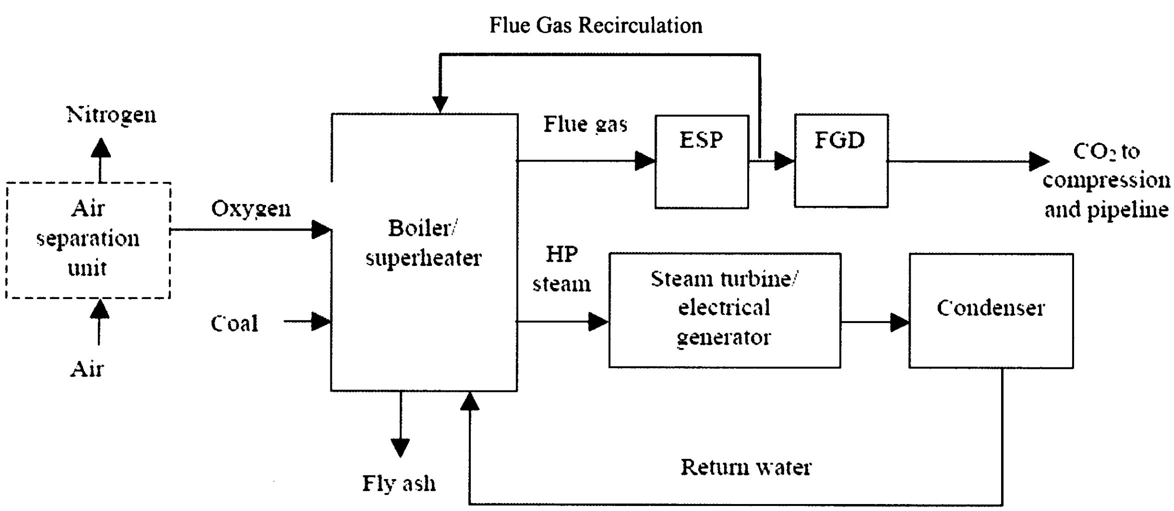

Figure 2.4. Process diagram for oxy-fuel combustion[2]. (Bohm, 2006)

[2] ESP – Electrostatic Precipitator particulate matter removal technology; FGD – flue gas desulfurization SO_x removal technology.

2.1.4. Comparison of Three Major Capture Approaches

Comparing the three leading carbon capture approaches above, there is no clear technology winner from a cost, performance, or reliability perspective. These latter factors may prove to differentiate CCS technology, but the differences are not apparent today:

- **Cost:** The cost estimates for each of these capture technologies vary widely and often overlap when including reasonable uncertainty bounds (see Section 2.2).
- **Performance:** All technologies can achieve 85%+ emissions reduction versus reference, though some differences in net plant efficiency may exist (UN-IPCC, 2005).
- **Reliability:** All three capture technologies have little operations experience, making comparison difficult. However, there is much more experience with PC plants than IGCC plants, and early experience for IGCC demonstrations has shown availability problems for the technology (Javetski, 2006).

Long-term cost, performance, and reliability differences may well appear, and commercial-scale demonstration projects will be useful in revealing these differences; as of today, there is no evidence of a clear carbon capture technology winner. Additionally, the market for CCS will be heterogeneous (due to different coal types or geographic locations), so multiple technologies could be "winners", depending on the specific nature of the plant.

2.1.5. Retrofit Application

Most of the cost analyses for CCS performed over the past several years have focused on the application of CCS technology to new plants, but there is a large potential for retrofit of existing coal-fired power plants using post-combustion capture technology. If deep cuts in US carbon emissions are to become a reality, either retrofitting CCS to existing coal plants or decommissioning them will be necessary, since the existing fleet of US coal power plants emits nearly 2.4 $GtCO_2$ annually (Dalton, 2008). Some experts believe that perhaps 60% of the current US coal fleet could be potentially retrofitted with post-combustion CO_2capture, but to date, no exhaustive analysis of the retrofit potential on actual commercial plants has been performed (MIT Expert Workshop, 2009). Coal power plants in the US have traditionally been built by engineering, procurement, and construction contractors as one-off projects with every project slightly different from the next. The Electric Power Research Institute (EPRI) has noted some of the important issues in determining the retrofit applicability to an existing plant (Dalton, 2008):

- **Space**: Perhaps 6 additional acres will be needed to retrofit a 500 MW plant. Has the installation of other environmental control technologies like flue-gas desulfurization (FGD) and selective catalytic reduction (SCR) left enough space for a capture plant?
- **Steam**: Can the low-pressure steam for solvent regeneration be accessed and transported where needed?
- **Lost Capacity**: How will the generating capacity sacrificed to power the capture system be offset?
- **Cost**: How much more will CCS retrofit cost than a CCS installation on a new plant? It is worth noting that retrofit FGD systems cost 1.2-1.8 times more than new plant FGD systems.
- **CO_2 Storage**: Can the CO_2 be transported and sequestered? The existing plant may be located quite far from suitable sequestration geology, thus increasing the cost of transport significantly.

This thesis will not focus on policy mechanisms specifically dealing with existing power plants such as retrofit CCS or retirement of older coal power plants. Some of the policy mechanisms analyzed are valid for either new plants or retrofits.

2.1.6. CCS for Other Industrial Sources

As shown above in Figure 1.1, there are many large stationary sources of CO_2 outside of the power sector where CCS could potentially be applied. The main industrial sources for CCS are natural gas sweetening operations, steel plants, cement plants, and petrochemical refineries (UN-IPCC, 2005). In some parts of the world, natural gas comes out of the ground with a high percentage of CO_2, and must be "sweetened" to make the gas pipeline-quality. A carbon capture process is used to clean the gas of CO_2. In fact, several large carbon sequestration projects are currently using natural gas sweetening as the CO_2 source. These include projects such as Statoil-Hydro's Sleipner and BP's. In Salah which are two of the major carbon sequestration projects in the world today. In steel production, CO_2 capture potential exists for both traditional blast furnace plants as well as electric-arc mini-mill plants. This would help reduce the emissions from the steel industry from the estimated 1400 $MtCO_2$ emitted annually worldwide in 1995. In cement production, fossil fuels are used to drive the energy-intensive limestone calcination process, producing a flue gas potentially suitable for a post-combustion CO_2 capture approach. In the petrochemical processing industry, oil refineries and ethylene and ammonia plants are major sources of CO_2 emissions, and a large carbon capture potential also exists here. While these industrial CCS approaches are not the major focus of this report, they will be considered in later sections of this thesis where they are relevant to the public policy discussion.

2.2. CCS Costs

This section explores the current costs of CCS and presents a model of future reductions in CCS cost through technological learning.

2.2.1. The Cost of CCS Today

2.2.1.1. Recent Cost Volatility

The cost of power plant technologies has increased significantly since the year 2003, although there are recent signs that this trend has leveled off. This cost escalation has mostly affected capital costs, but fuel costs have also risen. To account for this recent cost escalation, this work updates the CCS cost estimates originally presented in *The Future of Coal* (Moniz and Deutch, 2007). Figure 2.5 shows several cost and price indices from 2000 to 2009 to illustrate this recent price volatility.

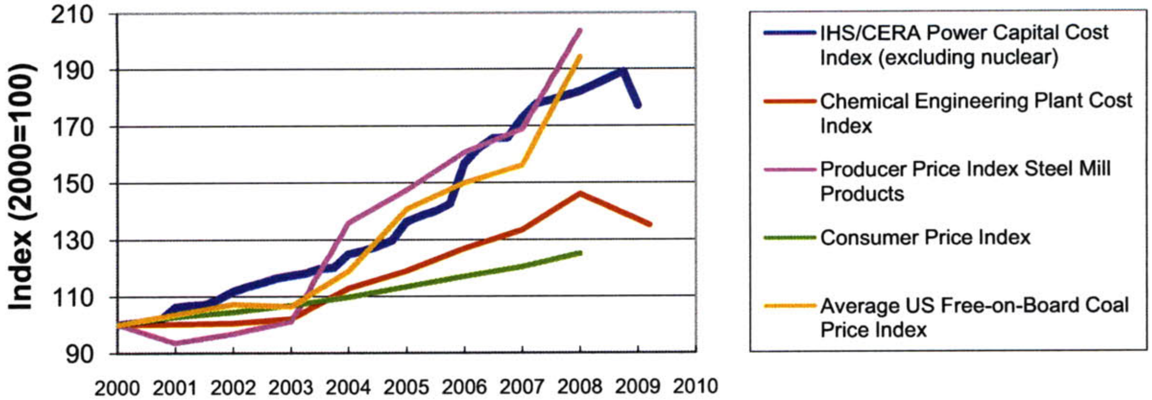

Figure 2.5. Cost and Price Indices since 2000. (Bureau of Labor Statistics, 2008b, Bureau of Labor Statistics, 2008a, Chemical Engineering Magazine, 2000-2009, Energy Information Administration, 2008, IHS/CERA, 2008)

There are several reasons for the recent escalation in capital and fuel costs (Chupka and Basheda, 2007):

- **Capital -**
  - Increasing global demand for the raw materials, such as steel, cement, copper, and nickel, required to build new plants.
  - High global demand for plant components, such as turbines, boilers, and scrubbers, has increased prices due to vendor capacity limitations.
  - Engineering, labor, and construction costs have increased as well. Engineering, procurement, and construction (EPC) contractor backlogs became more common during this period.
- **Fuel -** Coal fuel price has almost doubled since 2000, and continues to increase in the US, probably as a result of increasing demand under rail shipping capacity constraints and increased US coal exports.

The MIT *Future of Coal* report, published in March 2007, includes a cost estimate for new coal plants (Moniz and Deutch, 2007). This original cost estimate was derived from an extensive review of plant design studies from 2000-2004, then standardized for capacity factor, capital charge rate, and fuel price, and then updated to 2005$ using the consumer price index (CPI).

This information was combined with expert opinion and reviewed by technology providers and others to arrive at a final cost estimate. Cost escalation since 2000 was acknowledged in the original report, but was not accounted for in the final cost estimate.

2.2.1.2. *Update of MIT Post-combustion CCS Costs*

This cost update focuses on post-combustion CCS on a supercritical pulverized coal (SCPC) plant, since the recent literature and discussion with industry experts support these new estimates. Because of a lack of raw data, new cost estimates for pre-combustion capture on an IGCC plant and oxy-fuel combustion technology are not presented here. Significant uncertainty about this updated cost estimate must be acknowledged; while this update attempts to account for recent cost escalation in a transparent manner, this attempt is akin to trying to hit a moving target; the market remains highly volatile and costs are constantly changing.

The estimate of costs for an Nth-of-a-kind[3] (NOAK) SCPC power plant, both with and without post-combustion CCS, has been updated to a 2007$ basis according to estimates of recent escalation in capital, operating, and fuel costs. The updated cost estimate is shown in Table 2.1.

[3] NOAK means the Nth plant built where N is less than 10; this assumes significant cost reduction through technological learning in design, construction, and operation.

Table 2.1. Updated Costs for Nth Plant SCPC Generation[4]

Reference Plant		Units	SCPC
Total Plant Cost (1)[5]		\$/kWe	1910
CO_2 emitted		kg/kWh	0.830
Heat Rate (HHV)		Btu/kWh	8868
Thermal Efficiency (HHV) (2)			38.5%
LCOE	Capital (3)	\$/MWh	38.8
	Fuel	\$/MWh	15.9
	O&M	\$/MWh	8.0
	Total	\$/MWh	62.6
Post Combustion CO_2 Capture Plant			
Total Plant Cost (1)		\$/kWe	3080
CO_2 emitted @ 90% Capture		kg/kWh	0.109
Heat Rate (HHV)		Btu/kWh	11652
Thermal Efficiency (HHV) (2)			29.3%
LCOE	Capital (3)	\$/MWh	62.4
	Fuel	\$/MWh	20.9
	O&M	\$/MWh	17.0
	Total	\$/MWh	100.3
\$/tonne CO_2 avoided			
vs. SCPC (4)		\$/tonne	52.2

The capital costs were escalated with the IHS/CERA Power Capital Costs Index (PCCI) for Coal Power (IHS/CERA, 2008). The original values were deflated from 2005\$ to 2002\$ using a CPI index as reported in Table A-3.C.5 in The Future of Coal (Moniz and Deutch, 2007). The values were then escalated to 2007\$ using the CERA PCCI, from 112 in 2002 to 177 in 1st quarter of 2009. This represents an increase of 44% in capital costs as compared to the original data.

The fuel costs for bituminous Illinois #6 coal have also increased from \$1.50/MMBtu delivered cost to \$1.79/MMBtu in 2007. This data was collected from the quantity-weighted average price of delivered coal from the Illinois basin in 2007 from FERC Form 423 data. This represents an increase of 19% in fuel price as compared to the original data.

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[4] Cost Estimate Details: 500 MWe plant net output; 85% capacity factor; Illinois # 6 coal (61.2% wt C, 10,900 Btu/lb HHV, \$1.79/MMBtu); for Oxy-PC CO_2 for sequestration is high purity; for IGCC, GE radiant-cooled gasifier for no-capture case and GE full-quench gasifier for capture case; 20-year payback period.

[5] Table 1 Notes: (1) Assume Nth plant where N is less than 10 (assumes significant cost reduction from learning in construction/operation); (2) Efficiency = 3414 Btu/kWe-h /(Heat rate in Btu/kWe-h); (3) Annual carrying charge of 15.1% from EPRI-TAG methodology, based on 55% debt @ 6.5%, 45% equity @ 11.5%, 38% tax rate, 2% inflation rate, 3 year construction period, 20 year book life, applied to total plant cost to calculate investment charge; (4) Does not include costs associated with transportation and injection/storage.

The operations and maintenance (O&M) costs were scaled by the CPI index from 195.3 in 2005 to 207.3 in 2007. The CPI data is from the US Bureau of Economic Analysis. This represents an increase of 6% in O&M costs since 2005.

2.2.1.3. *Capital Cost Comparison*

Table 2.2 compares this updated capital cost estimate with several publicly available sources, including design studies as well as actual plant estimates from recent press releases and PUC filings from 2007 and 2008. The capital cost numbers are presented in $/kW on a total plant cost (TPC) basis where possible, except for the actual plant estimates which are on an unknown cost basis.

The following general conclusions were drawn from the cost estimation study:

- This updated cost estimate for SCPC is within the range of recently reported design studies, but is consistently lower than each of the actual plant estimates, which is expected since this estimate is for an NOAK design.
- Our updated cost estimate is generally lower than the S&P and CERA estimates, but higher than the NETL estimate. Note the large variance in the cost data within each plant type; this variance supports the fact that there is no current consensus on power plant costs.
- With few exceptions, the actual plant estimates report costs significantly higher than the design study estimates.

Table 2.2. Current costs for new fossil power projects.

Fuel Type	Estimate Type	Estimate Name	Date	SCPC	SCPC w/CCS	IGCC	IGCC w/CCS	Oxy-PC
				Total Plant Cost ($/kW) (where possible)				
Bituminous	Design Studies	MIT Update		$1,910	$3,080			
Bituminous	Design Studies	CERA (Jones, 2008)[6]	Mar 2008	$2,300	$4,150	$2,800	$4,230	$4,230
Bituminous	Design Studies	NETL (2007)	May 2007	$1,575	$2,870			$2,895
Bituminous	Design Studies	S&P (Venkataraman, 2007)[7]	May 2007	$2,216	$3,071	$2,541	$2,950	
Bituminous	Design Studies	NETL GE (2007)	May 2007			$1,813	$2,390	
Bituminous	Design Studies	NETL Conoco Phillips (2007)	May 2007			$1,733	$2,431	
Bituminous	Design Studies	NETL Shell (2007)	May 2007			$1,977	$2,668	
Bituminous	Actual Plant Estimates (Wilson, 2008)	Duke - Cliffside, NC	May 2007	$3,000				
Bituminous	Actual Plant Estimates (Wilson, 2008)	Duke - Edwardsport, IN	May 2008			$3,730		
Bituminous	Actual Plant Estimates (Wilson, 2008)	AEP - Mountaineer, WV	June 2007			$3,545		
Bituminous	Actual Plant Estimates (Wilson, 2008)	Tampa Electric - Polk Co., FL	July 2007			$2,554		
Sub-bituminous	Design Studies	EPRI (2006)	Oct 2006	$1,950	$3,440	$2,390	$3,630	
Sub-bituminous	Design Studies	BERR/CPCC (2007)[8]	Mar 2007	$2,618	$4,445			$4,586
Sub-bituminous	Design Studies	S&P (Venkataraman, 2007)	May 2007			$2,659	$3,068	
Sub-bituminous	Actual Plant Estimates (Wilson, 2008)	AEP/SWEPCO -Hempstead,	Dec 2006	$2,800				
Sub-bituminous	Actual Plant Estimates (Wilson, 2008)	Sunflower - Holcomb, KS	Sep 2007	$2,572				
Sub-bituminous	Actual Plant Estimates (Wilson, 2008)	AMP Ohio - Meigs Co. OH	Jan 2008	$3,300 – note uses both bit. and PRB coal				
Sub-bituminous	Actual Plant Estimates (Wilson, 2008)	Tenaska - Sweetwater Co., TX	Feb 2008		$5,000			
Sub-bituminous	Actual Plant Estimates (Wilson, 2008)	Southern Co. - Kemper Co.,	Dec 2006			$3,000		

The actual plant estimates for SCPC generally show much higher costs than the design study estimates, which is perhaps unexpected. These plants use mature technology with significant construction and operating experience, and EPC contractor guarantees for cost and performance are common. Despite this, it would seem that the effects of materials cost escalation and high market demand for new plant construction have outstripped estimates of cost escalation published in even the most recent studies.

6 Adjusted downward from all-in capital cost (which includes owner's costs, etc.) assuming all-in cost is 30% greater than total plant cost per EPRI TAG methodology.

7 Adjusted downward from all-in capital cost assuming all-in cost is 10% greater than engineering, procurement, and construction (EPC) cost (assumed to be equivalent to TPC)

8 Adjusted downward from total capital requirement (TCR) assuming TCR is 10% greater than TPC

2.2.1.4. *Representative Costs for CCS*

Given the high uncertainty surrounding CCS cost estimation, two recent CCS cost studies have provided likely ranges for CCS costs, both for first-of-a-kind[9] (FOAK) plants and Nth-of-a-kind (NOAK) plants (2008, Al-Juaied and Whitmore, 2009).

The first study is from the Harvard Kennedy School's Energy Technology Innovation Policy program. The avoided cost for FOAK plants is estimated to be approximately \$120-\$180/tCO_2 in 2008\$, and the estimated avoided cost for NOAK plants are much lower at \$35-70/tCO_2. [10] These estimates do not include the costs of transportation and storage of CO_2, which are estimated here as \$10/tCO_2 avoided. This is within the range estimated by the IPCC Special Report on CCS and the MIT Future of Coal Study.

The second study from McKinsey and Company also presents some representative costs of CCS. These costs include capture, transportation, and permanent geological storage and are shown in Figure 2.6. This thesis assumes the demonstration phase estimate is essentially a FOAK estimate, and the early commercial phase cost is essentially a NOAK estimate.

[9] A FOAK costs estimate includes costs faced by first movers due to initial errors and miscalculations in building engineering projects; as several iterations of the technology are built, these first-mover costs come down significantly, eventually reaching the NOAK cost level.
[10] This thesis will define all references to a ton to mean a "metric" ton and all references will be to CO_2 and not C alone.

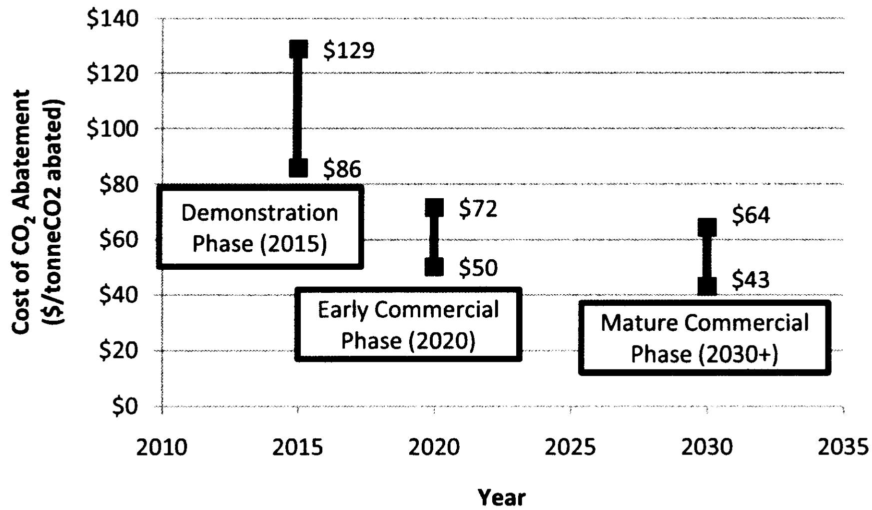


Figure 2.6. Representative Costs of CCS from McKinsey paper. Adapted[11] from (2008).

In summary, the FOAK and NOAK cost estimates are shown in Table 2.3.

Table 2.3. First- and Nth- of-kind CCS cost estimates in $/t$CO_2$ avoided.

	McKinsey		Harvard[12]		Representative Cost
	Lower	Upper	Lower	Upper	
FOAK	$86	$129	$130	$190	$126
NOAK	$50	$72	$45	$80	$63

Using the MIT Cost Estimate from Table 2.1, along with the context of the data from the McKinsey and Harvard studies, a representative cost of CCS was chosen to be $52.2 (from the MIT post-combustion CCS cost-estimate in Table 2.1) + $10 (additional for transportation and storage of CO_2) = $63 for the NOAK cost and, double this quantity, $126 for the FOAK cost. These representative costs will be combined with the following section on future CC cost reduction as an input to the cost model presented in Section 2.3.

[11] The costs reported in EUR were converted to USD by the multiplier 1.43189 from www.xe.com on 8/24/2009.
[12] Includes an additional $10/t$CO_2$ avoided for transportation and storage of CO_2.

2.2.2. A Model for Future CCS Cost Reduction

This section uses the current costs of CCS along with empirical estimations of technological learning to develop a model for future CCS cost reduction.

In the past, costs for other major energy and environmental control technologies have shown an initial increase followed by a decrease in costs. The costs increase as pre-commercial technology studies are updated to reflect increasing knowledge about limitations on design or performance of the technology. These costs increase to some peak known as a first-of-a-kind (FOAK) cost.[13] This peak is then followed by cost reduction in two phases; an initial quick cost reduction phase after building a few facilities reduces costs to the nth-of-a-kind (NOAK) cost level followed by some slower rate of continued cost reduction as the installed capacity of the technology increases. The cost reductions following the FOAK cost peak come from experience in design, construction, and operation; collectively these cost reductions are known as technological learning, which include "learning-by-doing" and "learning-by-using" (these mechanisms for cost reduction are explored further in Section 4.3.1). The initial peak and subsequent reduction of cost through technological learning are evidenced by the major differences in FOAK and NOAK costs presented in Section 2.2.1.2. Additionally, Figure 2.7 shows the historical capital and operation costs for wet FGD SO_2 reduction technology; the costs increase initially due to underestimation in pre-commercial studies, followed by a cost peak after commercial projects are built, and continued reduction of costs over time due to technological learning.

[13] Due to the high uncertainty and lack of retrospect in current CCS cost estimates, we cannot know if current pre-commercial cost estimates, such as what is presented in Section 3.1, can be truly representative of FOAK or NOAK CCS costs. Despite this, it is the best attempt we can make at this time.

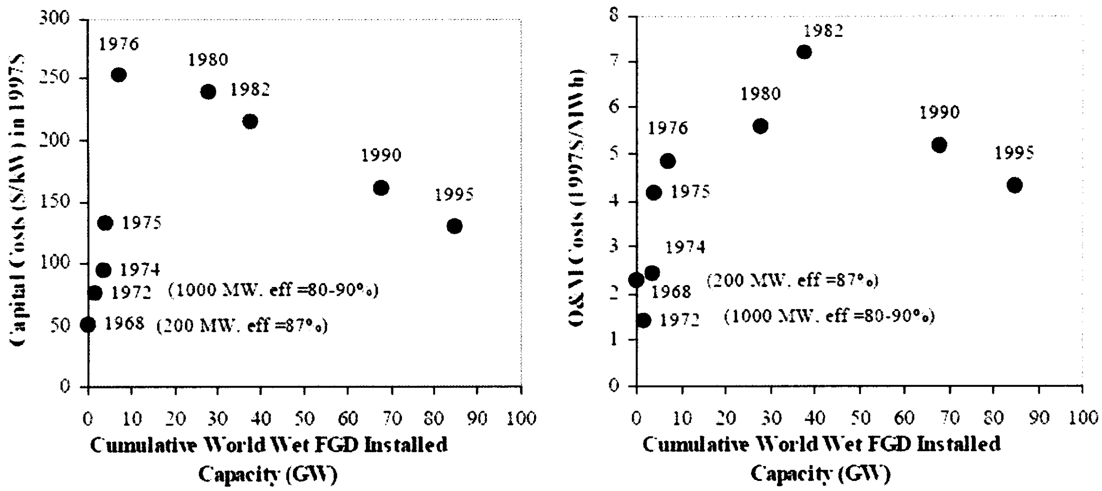


Figure 2.7. Example of learning-by-doing cost reduction in Wet FGD SO_2 reduction technology (IEA Greenhouse Gas R&D Programme, 2006).

Ignoring the initial cost increases from pre-commercial studies (see footnote 13 for explanation), this thesis assumes that CCS technology will show similar cost reductions through technological learning over time, given that the technology in this case is similar to these mature technologies.

A study by the IEA Greenhouse Gas R&D Programme and Carnegie Mellon University quantitatively estimated technological learning for CCS systems through empirical experience curves, such as the data shown in Figure 2.7 (IEA Greenhouse Gas R&D Programme (IEA GHG), 2006). The experience curves for seven relevant technologies, for both capital cost and operations and management (O&M) cost, were calculated from empirical data. Table 2.4 shows the seven relevant technologies and which part of the CCS system they are relevant to.

Table 2.4. Relevant technologies used for estimation of technological learning. Adapted from (IEA Greenhouse Gas R&D Programme (IEA GHG), 2006).

Technology	Relevance to CCS System
Flue gas desulfurization (FGD)	Post-combustion capture
Selective catalytic reduction (SCR)	Post-combustion capture
Pulverized coal (PC) boilers	Oxy-fuel combustion
Natural gas combined cycle (NGCC)	Pre-combustion capture
Liquefied natural gas (LNG) production	CO_2 liquefaction
Oxygen production	Oxy-fuel and pre-combustion capture
Steam methane reforming (SMR)	Pre-combustion capture

The authors then considered the three main CCS capture approaches: post-combustion capture on a PC plant, pre-combustion capture on an IGCC plant, and oxy-fuel combustion. Here we assume that the model for post-combustion capture on a PC plant is representative of CCS technology.

First, the plant's capital and O&M costs were split up by the relative contribution of each plant subsystem to the overall cost. Each plant subsystem was then assigned an empirically-derived learning rate for the relevant existing technology. The costs were then aggregated to estimate an aggregate plant learning rate and experience curve. The log-linear experience curve model is shown as Equation 2.1:

$$\text{Technology Cost} = \text{Starting Cost} * (\text{Installed Capacity})^{-b} \qquad (2.1)$$

And the learning rate, the estimated cost reduction for each doubling of installed technology capacity, is defined as Equation 2.2:

$$\text{Learning rate} = 1\text{-}2^{-b} \qquad (2.2)$$

The important results from the IEA GHG study are shown in Table 2.5.

Table 2.5. Learning curves for post-combustion capture.

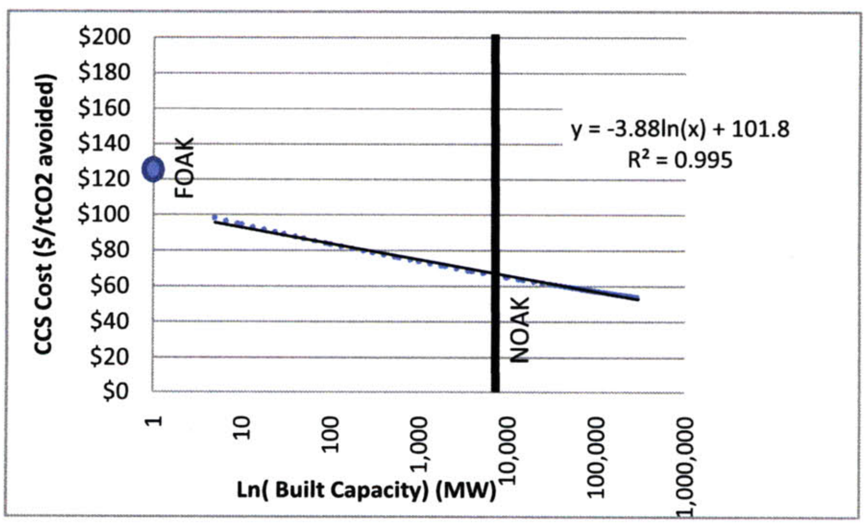
	COE No Capture ($/MWh)	COE With Capture ($/MWh)
b	-.018	-.04
Learning rate	1.2%	2.7%
Starting cost	$71.5	$133.39

The two learning curves were then combined to yield a learning curve best-fit equation for cost as a function of built capacity for the post-combustion capture case; this best fit-equation will be the primary model for CCS cost and technological learning in the cost model. Equation 2.3 shows the formula for calculating the avoided cost per tonne CO_2 of CCS technology:

$$\text{Avoided Cost} = \frac{\text{COE}_{\text{capture}} - \text{COE}_{\text{no capture}}}{\text{emission rate}_{\text{no capture}} - \text{emission rate}_{\text{capture}}} \tag{2.3}$$

Where COE is the cost of electricity in \$/MWh (represented by the learning curve from Table 2.5) and emission rates are the CO_2 emission rates in tCO_2/MWh as presented in the MIT post-combustion CCS cost update in Table 2.1. The avoided cost of CO_2 was then calculated as a function of built capacity. The regression of the avoided cost as a function of built capacity yields a logarithmic learning curve, or technology cost curve, the result of which is shown as Figure 2.8.

Figure 2.8. Plot of technology cost curve with logarithmic regression.



This technology cost curve is used as the basis for the cost input in the cost model constructed in the next section.

2.3. Cost Model

The section establishes the existence of a "cost gap" for early investment in CCS and presents a cost model to quantify the innovation challenge resulting from this cost gap. This innovation challenge is the "above-market"[14] investment required to deploy CCS by 2050. First, the three major inputs to the model are described. Next the sample output and behavior of the cost model are explained. Finally, several scenarios and the output results of these scenarios are presented and discussed.

2.3.1. Model Inputs

2.3.1.1. Costs

The first major input is the CCS technology represented by a technology cost curve, modeled as CCS avoided cost (in $/tCO_2$avoided) as a function of built capacity (in MW). The technology cost curve represents the trajectory of CCS costs from the demonstration phase to the commercial deployment phase. The base case curve was derived from the regression model results for cost reduction through technological learning, as presented in Figure 2.8. Additionally, a high and a low cost case were developed by adjusting the NOAK costs to \$100/tCO_2 for the high case and \$50/tCO_2 for the low case; the cost curve was simply shifted upward by \$100-\$63=\$37 and downward by \$63-\$50=\$13, respectively. An example of the cost model input is shown as Table 2.6 and Figure 2.9.

Table 2.6. CCS cost cases.

Case	NOAK Cost (\$/tCO_2avoided)	FOAK Cost (\$/tCO_2avoided)
Base	63	126
High	100	163
Low	50	113

[14] An "above-market" cost is simply referred to as a cost above and beyond the carbon market price that must be paid for by someone if CCS is to be built.

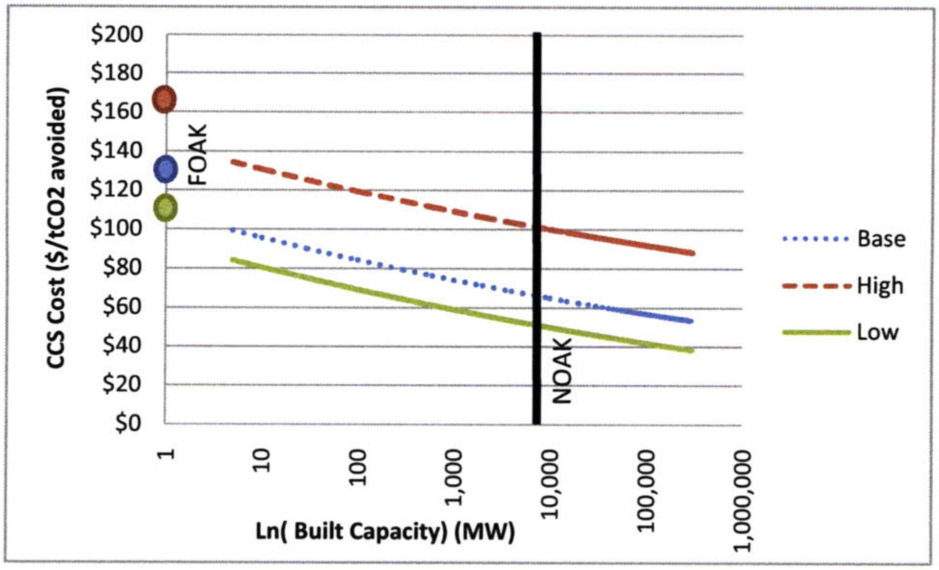


Figure 2.9. Cost model inputs showing FOAK and NOAK costs.

Note the gap in the curve at low values of built capacity; due to the asymptotic behavior of logarithmic functions, the learning curve cost model only approximates the starting FOAK value, which turns out not to be important because the function is only utilized at values of 10 MW built capacity and greater.

2.3.1.2. Adoption Rate

The second major input is an adoption path for an assumed rate of CCS deployment in the United States, which is primarily based on the deployment goal derived above. The path is modeled as built capacity (in GW) as a function of time (in years). A base case, a high case, and a low adoption case are created.

First, the model assumes that 10GW of demonstration and initial commercial projects will take X years from a 2010 start. The base case assumes X is 10 years, the high case assumes 8 years, and the low case assumes 20 years. This is represented in the model as a straight line increase from (zero years, zero GW) to (X years, 10 GW). This period is needed for technological learning to reduce the cost from the FOAK level to the NOAK level, which is consistent with discussions in the Harvard (Al-Juaied and Whitmore, 2009) and McKinsey (2008) cost studies explored earlier in Table 2.3.

Next the model establishes a goal for long-term deployment, such that the adoption path continues as a straight line between the (X years, 10 GW) point and the final 2050 deployment goal Y GW, defined as the point (40 years, Y GW). The basis for the 2050 deployment goal is the Socolow and Pacala "wedge" concept first explored in Section 1. One wedge is the equivalent of avoiding emissions of 1GtC/year or 3.67 $GtCO_2$/year by 2050. This paper assumes that for a base case, 1/3 of this goal could be achieved by CCS in the United States, which is 1.22 $GtCO_2$ avoided per year. Using the assumptions of CCS emissions rates presented in the MIT post-combustion cost estimate above, this implies the US must install 227 GW of electric generating capacity with 90% capture CCS by 2050. If the US embarked in 2010 on an ambitious 10-year program for 10 GW of demonstration and initial commercial projects to reduce technology risk, this would leave 217 GW capacity to be built from 2020-2050, or a rate of 6.2 GW per year for thirty years. Such a goal for CCS deployment may be difficult but it is certainly within the realm of possibility.[15]

The base case 2050 deployment goal is defined as 1.22 $GtCO_2$ avoided annually by 2050, which is 227 GW. A high case is defined as double this goal, 2.44 $GtCO_2$ avoided annually by 2050, which is 454 GW. A low case is defined as one-quarter of this goal, 305 $MtCO_2$ avoided annually by 2050, which is 57 GW. The adoption path inputs are shown as Figure 2.10.

[15] In comparison, the US nuclear construction push from 1960 to 1990 saw a maximum rate of increase of nuclear capacity of 9.75 GW in its peak year of 1985. Only six years out of the thirty-year period saw rates of increase higher than 6.2 GW per year (Source: EIA Annual Energy Review).

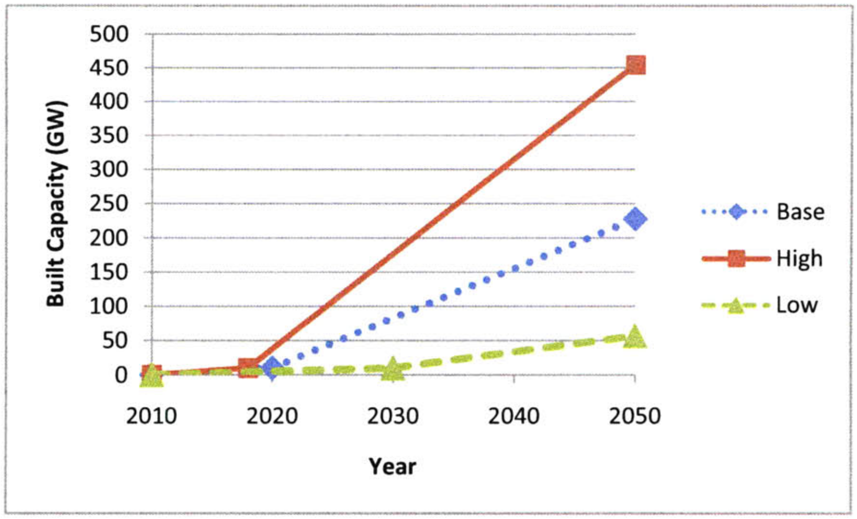


Figure 2.10. Adoption path input for case.

One can imagine a wide variety of scenarios for CCS deployment, justifying both the high and low inputs. In a high deployment scenario, there might be limited deployment of other low-carbon electricity options such as renewable or nuclear, leaving the US highly reliant on CCS as a means of reducing the electric sector's carbon emissions. Alternatively, the cost of CCS technology might decline significantly relative to other technology options, leading to high rates of deployment of CCS. In a low deployment case, there might be little support for CCS technology due to the political climate or some early technology failure or accident that turns the public against the technology.

2.3.1.3. Carbon Price

The final input to the cost model is the carbon price under a future cap-and-trade scheme (such as the current American Clean Energy and Security Act), and this has been estimated in the literature using economic modeling of which three such estimates are shown in Figure 2.11.

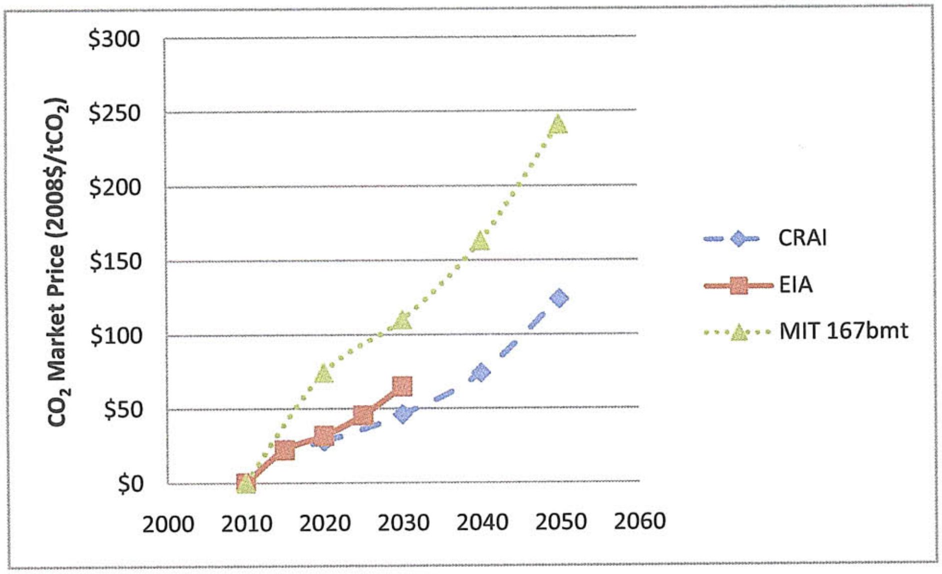


Figure 2.11. Projected carbon prices for recent US cap and trade policy analyses (Energy Information Administration, 2009, Montgomery et al., 2009, Paltsev et al., 2009).

The MIT 167bmt series[16] corresponds to a policy with a similar cap as the ACES Act assuming an 80% reduction of 2005 emission levels by 2050, but it does not include the offset and renewable electricity mandate provisions, which would both tend to lower the market prices for CO_2 (Paltsev *et al.*, 2009). The Charles River Associates International (CRAI) series performs a specific analysis of the ACES Act, and it includes numerous additional policy provisions, such as offsets and renewable electricity standards (Montgomery *et al.*, 2009). The EIA series also performs an analysis of the ACES Act, and includes these additional policy provisions, but comes to a slightly higher estimate in 2030. The MIT series is an example of an "economically optimal" carbon price that would result from a simple cap-and-trade scheme, whereas the CRAI and EIA series are examples of a "politically feasible" carbon price that is depressed through the inclusion of a package of interacting policies that tend to lower the carbon price from the economically optimal level.

The model input includes both a low case and a high case, the high case based on the carbon price CRAI analysis of the ACES Act, and the low case based upon a hypothetical weak carbon pricing scheme, similar to the approach used in the MIT Future of Coal study. The high case

[16] Inflated to 2008$ using a GDP deflator conversion of 5.2% increase from 2005

approximates the CRAI analysis with a price starting at \$20/tCO_2 in year 2010, increasing by 4.6% a year. The low case starts with a price of \$7/tCO_2 in 2010, increasing by 5% each year. The high and low inputs, along with a comparison to the CRAI series are shown in Figure 2.12.

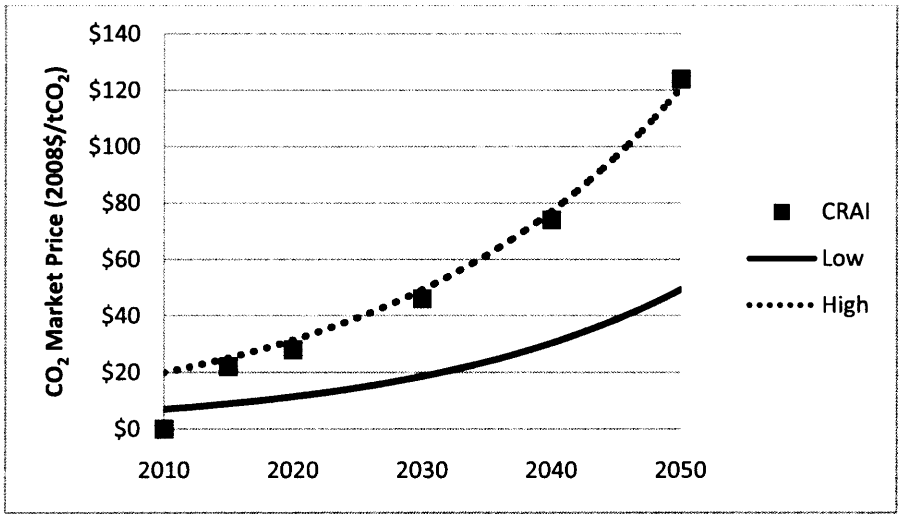


Figure 2.12. Carbon price inputs with comparison to ACES Act.

2.3.1.4. The Cost Gap

A "cost gap" exists for CCS technology, which is the difference between the CCS cost and the price of carbon from a carbon pricing scheme. A simplistic financing assumption is made such that a positive cost gap means that the decision to build CCS is uneconomic, and when this cost gap approaches zero, the decision to build CCS becomes economic. The cost of CCS and the price of carbon must be established to value this cost gap, and the level of investment required to bridge this cost gap between now and 2050 is the "innovation challenge" for CCS deployment. Note that price and cost volatilities further complicate the decision for large capital investments, but for simplicity, those considerations are ignored in our analysis.

All three inputs and the cost gap are as shown graphically in Figure 2.13, which includes the base adoption path and cost inputs and the low carbon price input.

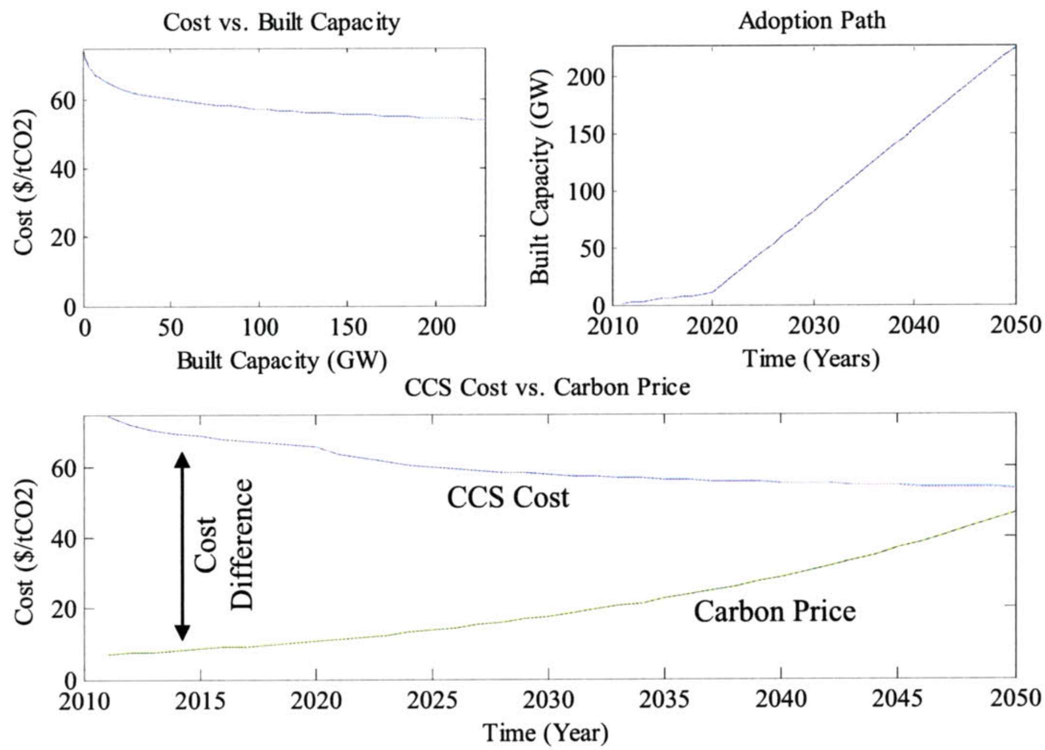


Figure 2.13. Sample cost model input showing the cost gap.

2.3.2. Model Output

2.3.2.1. Methodology

To determine the annual and cumulative cost gap, several additional steps are taken in the model.

For each year in the model, the quantity of CO_2 emissions avoided by CCS must be calculated; the reference assumption is that an uncontrolled SCPC power plant would have been built instead of post-combustion CCS on a SCPC plant. Next, the cost difference (in $/t$CO_2$ avoided) and the avoided emissions (in tCO_2 avoided) can be multiplied to calculate the annual cost gap, shown in Equation 3.7.

$$annual\ cost\ gap_i = cost\ difference_i * tCO_2\ avoided_i \tag{3.7}$$

Finally, the total cost gap can be calculated, discounting over time with a discount rate *r*, as shown in Equation 3.8.

$$\text{cumulative cost gap} = \sum_{i=2010}^{2050} \frac{\text{annual cost gap}_i}{(1+r)^{i-2010}} \tag{3.8}$$

This model assumes a zero discount rate, since this is how subsidies and spending measures are actually structured in congressional bills.

2.3.2.2. Cost Gap Outputs

Figure 2.14 shows an example of the cost gap output for a scenario with a base case CCS cost, a base case adoption path, and a low carbon price in both the annual and cumulative cost gap.

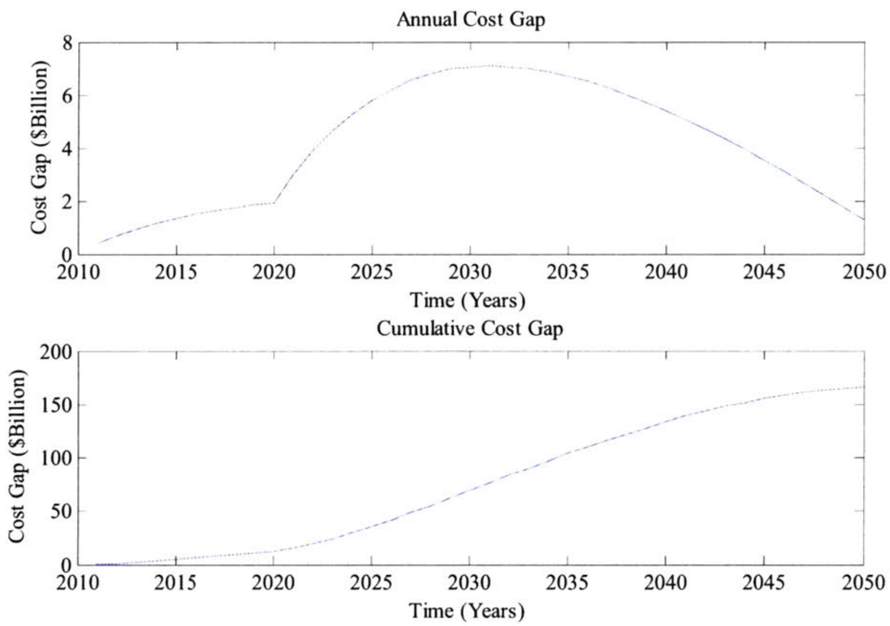


Figure 2.14. Annual and cumulative cost gap for Scenario #1.

Figure 2.15 shows the cost gap output for a scenario with a base case CCS cost, a base case adoption path, and a high carbon price in both the annual and cumulative cost gap.

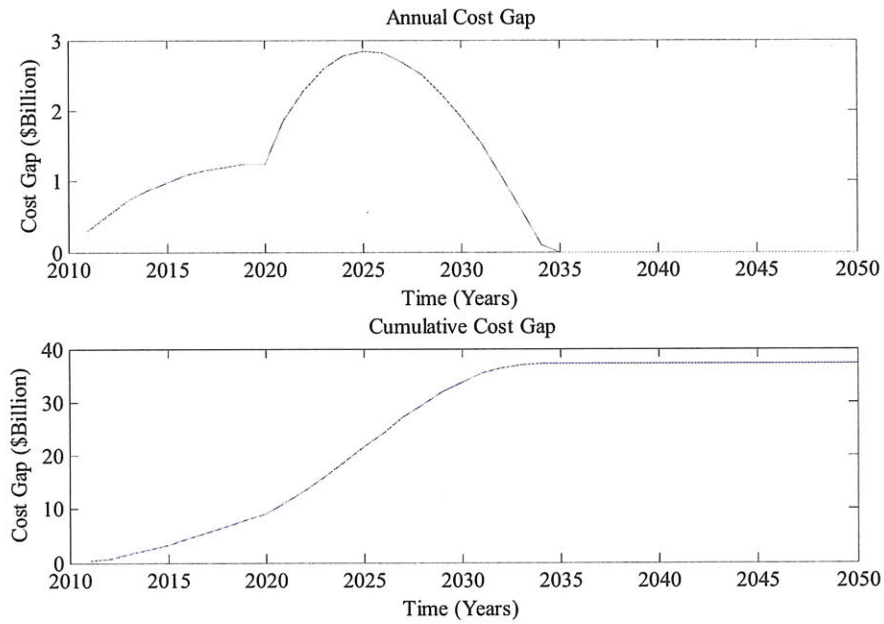


Figure 2.15. Annual and cumulative cost gap for Scenario #3.

A comparison of scenarios #1 and #3 shows the effect of carbon price on the annual and total costs. Note the drop off in annual costs in Figure 2.15. This is due to the fact that the cost gap is eliminated in the year 2034, eliminating the need for additional investment beyond what would be justified by a carbon price; this is in contrast to the low carbon price case in Figure 2.14 that would require additional investment continuing until 2050, implying that CCS technology does not become economic without additional policy support in this timeframe. Also note the maximum annual cost declines from over $7.0 billion in Figure 2.14 to $2.8 billion in Figure 2.15, which is a reduction of over $4 billion in maximum annual cost. Finally, note the difference in total costs for each scenario of approximately $160 billion - $40 billion = $120 billion; this is $120 billion that would be required beyond what would be justified by a carbon price, if a low carbon price was realized instead a high carbon price. A high carbon price makes investment in CCS (and all low-carbon energy technologies) much more likely, since a higher carbon price minimizes the cost gap.

2.3.3. Model Scenarios and Results

A matrix of scenarios was created by varying each of the three inputs with each other. Each of these scenarios was then processed in the model, and the output for selected scenarios is presented as Table 2.7. The scenarios selected were judged as reasonable by comparing each of the inputs to make sure there are no relationships between the three inputs that make the scenario unlikely or improbable. For example, high CCS adoption rates happen *because* of low costs or high carbon prices, so a scenario with low carbon prices, high CCS costs, and a high adoption rate would be excluded; such a scenario would be highly unlikely due to the extremely large cost gap.

Table 2.7. Cost model output.

Scenario #	CCS Adoption Target	Nth Plant Cost of CCS	Price of Carbon	Cumulative Cost Gap	Maximum Annual Cost Gap
				$ Billion	$ Billion
1	Base	Base	Low	$166	$7.08
2	Base	Low	Low	$89	$4.43
3	Base	Base	High	$37	$2.83
4	Base	High	High	$151	$8.10
5	Base	Low	High	$13	$1.17
6	High	Low	Low	$163	$8.57
7	High	Low	High	$20	$2.28
8	High	Base	High	$67	$5.72
9	High	High	High	$301	$16.6
10	Low	High	Low	$81	$2.95
11	Low	High	High	$37	$1.43
12	Low	Base	Low	$42	$1.49
13	Low	Low	Low	$25	$0.92

The total cost gap for the base case adoption scenarios (#1-5) range from $13 billion to $166 billion, and this range can be considered indicative of the magnitude of the innovation challenge to 2050. This cost model represents a simple approach to quantifying the cost above-and-beyond what is supported through a carbon price; a cost gap that must be bridged to create a market and deploy CCS significantly in the 2050 timeframe. If policy makers decide that significant commercial deployment of CCS technology is their policy goal, a combination of policies for CCS demonstration and commercial deployment must at minimum provide the support commensurate with these costs.

3. Barriers to CCS Deployment

3.1. Legal and Regulatory Framework

Despite the existence of a few large scale carbon sequestration projects around the world such as Sleipner in the North Sea, In Salah in Algeria, and the Weyburn Enhanced Oil Recovery project in Saskatchewan, there is a lack of a legal and regulatory framework in most countries that will be required for widespread adoption of carbon sequestration. As a recent report by the Harvard Law School states, a major impediment to CCS deployment is the "uncertainty surrounding responsibility for the risks of large scale geological sequestration projects, due to the absence of a liability and permitting regime" (Jacobs *et al.*, 2009). Unclear ownership of subsurface rights in some states and the lack of rules for long-term monitoring of sequestration sites provide additional impediments to commercial projects. Additionally, carbon sequestration projects could be subject to environmental regulations under existing US laws such as the Resource Conservation and Recovery Act (RCRA), the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), and the Clean Air Act (CAA) (Jacobs *et al.*, 2009). Some groups are also calling for the long-term ownership of injected CO_2 to be transferred to government.

This thesis will not focus on strategies to develop this legal and regulatory framework, but we do agree with the calls made in publications such as the MIT Future of Coal report that development of this framework is urgent if significant commercial deployment of CCS is to become a reality.

3.2. Demonstration Phase

Commercial-scale, integrated CCS system has still not been demonstrated, despite the many projects worldwide R&D that have demonstrated all components of this system individually on smaller scales. Given the major risks accompanying CCS technology, this demonstration phase is a necessity before the technology can be widely introduced in the traditionally risk-averse electric utility industry. A recent Harvard Law study on CCS describes the barriers to a demonstration phase succinctly: "high costs for early demonstration projects [...] and a lack of sufficient financial incentives to compensate early movers for costs and risks" (Jacobs *et al.*, 2009). The MIT Future of Coal report suggested a comprehensive program of several integrated

CCS projects in the United States, with "high priority given to a program that will demonstrate CO2 sequestration at a scale of 1 million metric tons CO_2 per year in several geologies" (Moniz and Deutch, 2007). Commercial deployment of CCS technology will not move forward without a demonstration phase, so this thesis will explore the options for designing such a program.

3.3. A Market for CCS

In addition to the lack of a clear legal and regulatory system for geological carbon sequestration and the lack of a targeted CCS demonstration program to lower technology risks, the most significant obstacle for commercial deployment of CCS is the lack of a market for the technology.

The major result of the cost model presented in Section 2.3 is that a cost gap for CCS technology will prevent the emergence of a market in the early decades of a US carbon pricing program. This cost gap must be bridged by public policy before significant commercial deployment of CCS can become possible. A CCS demonstration phase will have to bridge a large cost gap in the early years due to FOAK costs, as well as dealing with the major risks of early CCS projects. For commercial deployment of CCS, a decreasing cost gap must continue to be bridged by policy support, until such time that a high-enough carbon price ushers in a stable market for CCS technology. Therefore, a policy to develop the market for CCS and support commercial deployment should also seek to reduce this cost gap.

There are two major ways to minimize the cost gap over time: raise the carbon price or lower the technology cost. This thesis will focus on methods to help support innovation aimed at realizing long-term cost reduction in CCS technology. It does not address rationales and mechanisms for raising carbon prices. Reducing costs of CCS will increase the probability that significant deployment of CCS technology can be realized by raising the relative cost-effectiveness of CCS in comparison to traditional and low-carbon energy alternatives.

4. The Innovation System

This section provides background on the innovation system in which CCS technology exists, which will help identify some important questions about strategies to overcome barriers to large-scale deployment of CCS. This section will include both a brief study of the history of SO_2 emissions control technology in the US and a discussion of the theory of the innovation life-cycle as applied to CCS technology.

4.1. SO_2 Emissions Control: A Brief Case Study

The history of SO_2 emissions control technology shows that a dual strategy of "market pull", sometimes called "demand-pull", and "technology push" strongly affected the innovation system for flue gas desulfurization (FGD) and other SO_2 emissions control technology. This strategy evolved over four distinct policy eras, revealing policy makers' changing preferences for technology push and market pull policies. The study on this subject by Taylor, Rubin, and Hounshell from 2005 provides the major source of material for this section (Taylor *et al.*, 2005).

4.1.1. 1950s-1966 Era

The first policy era is the 1950-1966 timeframe. The Tennessee Valley Authority (TVA) was the first to start researching SO_2 emission control technology in the early 1950s by performing R&D on wet scrubber technology using private funds. Federal technology push for R&D in SO_2 emissions control technology began in 1955, when the Air Pollution Control Act "authorized federal funds for demonstration projects, grants to state and local air pollution control agencies, and research by the Department of Health, Education, and Welfare (HEW)" for SO_2 control technologies (Taylor *et al.*, 2005). In 1957, HEW and the Department of the Interior's Bureau of Mines began investigation of sorbents for dry scrubbing activity, continuing with bench scale and pilot work on multiple technologies throughout the 1960s.

The Federal government exhibited a very limited market pull effort during this period. The original Clean Air Act in 1963 expanded the government's technology push through expanded funding and support of local and state pollution control programs, but provided little market pull due to "limited enforcement power and a continued decentralized market" for FGD technology (Taylor *et al.*, 2005).

The 1950s-1966 era represented a public policy of only technology push efforts toward FGD and other SO_2 control technology. With the lack of a market pull market signal, little private RD&D occurred and there was no commercial deployment of the technology.

4.1.2. 1967-1976 Era

After over a decade of a weak regulation of SO_2 emissions and no centralized market support for FGD and SO_2 control technology, in 1967 the Air Quality Control Act signaled to private industry that state and regional limits on SO_2 were coming, and drafts of the bill proposed a set of stringent national limits on regional SO_2 emissions. However, slow enforcement of state implementation plans meant a continued weak and decentralized market for FGD technology. Still, despite the slow start to government regulations, Taylor *et al*'s 2005 analysis of patent filings for FGD technology show the year 1967 as the beginning of a major private R&D effort. This result indicates that the anticipation of stringent regulation can be effective in stimulating private R&D activity[17].

In 1970, Congress passed the first Clean Air Act Amendments bill, which was the beginning of a policy of continuous ratcheting-up of regulatory stringency, requiring power and industrial sources of SO_2 emissions to clean up their facilities. This resulted in a market for technology to achieve these emissions reductions, and is a prime example of a market pull strategy. In 1971, the Environmental Protection Agency (EPA) promulgated the New Source Performance Standards (NSPS), which established standards for "best available technology" emissions performance standards for new sources. The EPA would base these standards on technologies that were deemed adequately "demonstrated" for use by utilities. In 1972, the completed state implementation plans (SIPs) essentially required some form of SO_2 emissions control for all sources. Despite several important ongoing lawsuits that challenged these regulations, the combination of the NSPS and the SIPs was an emerging, technologically-flexible market pull

[17] Taylor, *et. al* note that this policy of "deliberate uncertainty" could potentially be created intentionally, although real implementation would be quite difficult "without having the government's bluff called".

requirement for SO_2 emissions control including the options of low-sulfur fuel switching, pre-combustion treatment, or FGD systems.

Simultaneously, the federal government's technology push efforts became more focused on commercial-scale demonstration, with increased funding to match. In 1967, the National Air Pollution Control Administration (NAPCA) became the lead body for this RD&D effort. In 1968, the federal funding levels were significantly increased, and in 1969, the TVA and NAPCA cooperated on a full-scale demonstration project for dry limestone injection FGD technology. Throughout the early 1970's, budgets for SO_2 RD&D increased and several significant commercial-scale (up to 10MWe) demonstration projects for wet- and dry- FGD, as well as pre-combustion coal treatment, were undertaken by the Environmental Protection Agency (which had taken over the federal RD&D program from NAPCA) and TVA.

Additionally, a novel technology push mechanism was introduced in 1973, through the founding of the SO_2 Control Symposium. This Symposium was a place for knowledge transfer between industry, academia, and government to take place, and it would play an important role in the innovation that occurred in SO_2 control technology over the coming decades. EPA funded this program until 1982, when the Electric Power Research Institute (EPRI) joined in; the Department of Energy joined funding this symposium in 1991. These symposiums would continue until the mid-1990s.

By the time the Supreme Court rejected the major lawsuits from the power sector in 1976, the Act's "strong enforcement power, national standards-based market signal, technological flexibility, and post-Supreme Court legal certainty were very conducive to creating an FGD market in the US" (Taylor *et al.*, 2005). The 1967-1976 era was characterized by an increasing and technologically-flexible market pull policy, allowing the market to decide the lowest-cost option for SO_2 emissions reduction. Commercial deployment of FGD increased, but was only one of several mitigation technologies used. This was combined with a significantly increased technology push policy for FGD and pre-combustion technology. Together these two approaches supported the establishment of a strong innovation system for FGD technology that laid the foundation for significant commercial deployment and cost reduction in the future.

4.1.3. 1977-1989 Era

The 1977 Clean Air Act Amendments provided further support for FGD technology by seeking to eliminate the lower-cost option of switching to low-sulfur western coals in existing plants. This law directed EPA to modify the NSPS so as to be based on a percentage reduction from uncontrolled emissions levels. EPA issued draft rules of the new NSPS in 1979, essentially guaranteeing a market for FGD technology, depending on the coal sulfur content. These rules removed the technological flexibility from the regulatory environment since, in effect, the government had "picked winners". Wet FGD for high-sulfur coal and dry FGD for low-sulfur coal would have to be installed on new and substantially-modified sources.

Throughout the 1980s, the US Congress threatened to increase the stringency of SO_2 emissions regulations, with 1987 being the most serious attempt. This bill increased expectations that moderate-removal FGD technologies would be required at all power plants. Additionally, this is the first time a serious subsidy program for FGD technology was discussed.

The technology push effort continued with EPA transferring much of the federal RD&D program to DOE's Office of Fossil Energy (FE) in 1979. In 1985, FE's demonstration effort was scaled up to become the DOE's Clean Coal Technology Demonstration Program, a $2.5 billion government-industry cost-sharing demonstration program for FGD and other "clean coal" technologies, including NO_x control technology. EPA continued work on the retrofit-oriented dry scrubbing and sorbent injection systems, in anticipation of new regulatory requirements for retrofit FGD.

The technological flexibility for SO_2 control was effectively removed through the adoption of a stringent NSPS policy, which effectively mandated FGD technology at new and existing sources. As a result of this, along with the anticipation of increasing regulatory stringency requiring FGD technology retrofits, the market pull for FGD reached its highest point during this era. It was coupled with a strong technology push of continued RD&D effort by EPA and DOE FE. Commercial deployment of FGD increased dramatically.

4.1.4. 1990-Current Era

A new policy era began in 1990, with a new set of Clean Air Act Amendments signaling a very different policy approach. The Act created a cap-and-trade system for SO_2 emissions, replacing the NSPS rules that had essentially mandated FGD technology. The cap would be reduced in two phases, and we are currently approaching the end of second phase in 2010. The program has been hailed as a resounding success by many, and it has provided the experience basis for a CO_2 cap and trade emissions trading scheme in Europe and potentially in the United States too. Emissions of SO_2 have been reduced significantly since this program started, at a cost much lower than the writers of the bill expected, often through the use of low-sulfur western coal (NPR All Things Considered, 2009).

All of the major technology push demonstration efforts by EPA, DOE, and TVA were concluded in the 1990s, and funding for RD&D programs was also reduced accordingly.

The major effect of this cap and trade system was to reintroduce the lower-cost option of low-sulfur coal fuel switching, which negatively affected the market for both wet- and dry-FGD technology. This was a more impartial, market-oriented approach, with limited specific support for FGD technology, as opposed to the previous era of intentional support for FGD. Additionally, this era saw a reduction in technology push, by the elimination of major demonstration programs for FGD, and a reduction in market pull for FGD, due to a new emissions cap and trade program under EPA that once again (similar to the 1967-1976 era) allowed technological flexibility and left it to the market to decide the lowest-cost option for SO_2 emissions reduction, which in many cases was fuel switching to low-sulfur coal (Taylor *et al.*, 2005). FGD technology again had to compete with the other options, and in many cases it was not the competitive option. New commercial deployment of FGD decreased as a result.

4.1.5. Enhancing Innovation through Technology Exclusion

The history of regulation in SO_2 emissions shows the potential value of enhancing innovation through the exclusion of other technology options, while also showing the risk of potential losses in economic efficiency associated with that exclusion. For FGD technology, this represented a trade-off between market pull and short term economic efficiency, but there remains the possibility that in the long-term, innovation can improve the economic outcome of this decision.

In the case study of FGD technology in Section 4.1, there was a history of changing government regulations with regard to technological flexibility, specifically through changes in the stringency of the NSPS SO_2 emissions performance standards. The lower cost options (on a per ton basis) of pre-combustion coal cleaning and importing of low-sulfur western coal were used to meet the initial NSPS requirements, but in 1977 Congress required EPA to exclude these options by raising the NSPS emission performance standards so as to effectively require either a wet or dry FGD system on all new sources.

This reduction in technological flexibility had two major effects. It supported the market for FGD technology, allowing significant innovation and cost reduction in the technology to occur, as shown by the result in Figure 4.1. The investments in SO_2 emissions mitigation that had previously been spread among several technology options were now limited to just a select few options, allowing cost reductions through learning by doing and using to be enhanced.

Despite this gain in innovation, it was also a more expensive approach, as evidenced by the lower cost SO_2 mitigation options that were widely implemented under the 1990 CAAA and the EPA Acid Rain cap and trade program.

Given that FGD technology was widely deployed worldwide after the U.S. led in developing the technology in the 1970s, there remains the possibility of a third effect --that improvements in long-term economic efficiency spilled over to international firms instead of being captured here in the US, due to the weaker market pull provided by the 1990 CAA. The policy makers in this case surely did not intend such a result, but this underscores the importance of a consistent long-term policy toward innovation for environmental control technologies like FGD and CCS.

4.1.6. Conclusions on Policy and Innovation in FGD technology

A dual strategy of "market pull" or demand-side policies, and "technology push" or supply-side policies strongly affected the innovation system for flue gas desulfurization (FGD) and other SO_2 emissions control technologies. The result was both significant commercial deployment of FGD technology worldwide and significant innovation in FGD technology, as revealed by reductions in cost and increases in performance over the decades. These cost reductions and performance improvements are the sum of innovations that came through both experience in construction and operation (learning by doing and learning by using) as well as improvements in design over time (incremental innovation and radical innovation); these mechanisms for innovation will be discussed further in Section 4.3. The data collected by Taylor *et al.* is shown in Figure 4.1. Given that the United States was the leader in technology push and market pull efforts for FGD technology, this revealed reduction in cost and increase in performance suggests that it was linked to these market pull and technology push efforts.

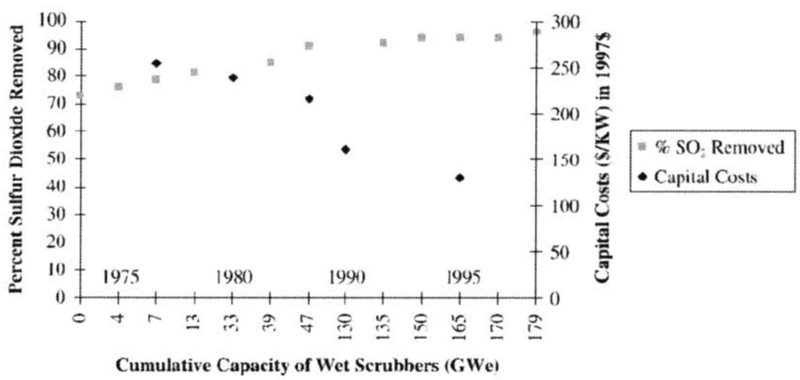


Figure 4.1. Decreases in FGD capital cost and increases in FGD efficiency as a function of world wet installed FGD capacity. (Taylor et al., 2005)

The FGD case suggests several important results that are directly applicable to CCS technology. The evidence presented by Taylor *et al.* suggests that market pull policies were most significant in spurring innovation by private firms, but that technology push policies can have an important complementary effect when pursued in tandem. The evidence also shows that regulatory exclusion of some technology options for SO_2 emissions reduction led to improved innovation in FGD, but likely came at the expense of short-term economic efficiency. This link between policy and innovation hints at the workings of some larger innovation system including public and private actors, public policy toward the technology, the existence of a market, and the processes that drive innovation, and this in turn justifies further exploration of this innovation system.

4.2. The Innovation Life-Cycle

As shown by the story of SO_2 emission control technology, innovation in technology has a mutually beneficial relationship to commercial deployment of that technology. There exists a rich body of literature on innovation processes and the systems to support innovation, and this section draws on a subset of concepts from this work describing the life cycle of innovation from its inception in basic research to commercial scale deployment over time. The research and development, demonstration, and deployment phases of the innovation process will be described and compared in the context of the changing risks faced by CCS technology as it matures.

This thesis supports the idea that innovation is an iterative and non-linear process, which differs significantly from the "linear" innovation model proposed in 1945 by Vannevar Bush. Instead of one basic research idea leading directly to large scale commercial deployment, it is more realistic to consider that technology is adapted and improved as new ideas and information are created over time as the technology is demonstrated and adopted. There is no single start or end point to the innovation process, but rather an interaction of parallel technology streams, some of which may be more commercially relevant than others. Figure 4.2 shows a model of this innovation life-cycle including the important addition of feedback between stages as innovation moves forward in time.

The fundamental research and discovery includes activity in the basic sciences such as chemistry, biology, and materials science; these activities are mostly performed by academic and government research bodies. Applied research and development (R&D), also resulting in new discoveries, include activities that apply the results of fundamental research to solving real-world problems. The private sector, academic institutions, and the public sector are all involved in these activities. Sometimes these applied R&D efforts inspire new fundamental research efforts. Demonstration projects are efforts to scale up the results of applied R&D into commercial technologies. Due to high technology risks or costs, a demonstration phase is often necessary before commercial deployment of new technologies can occur. These demonstration projects create knowledge that often inspires further applied R&D efforts, which in turn contribute to future demonstration projects. Early commercial adopters accept these high risks, but move forward with commercial application, perhaps to gain a first mover advantage.

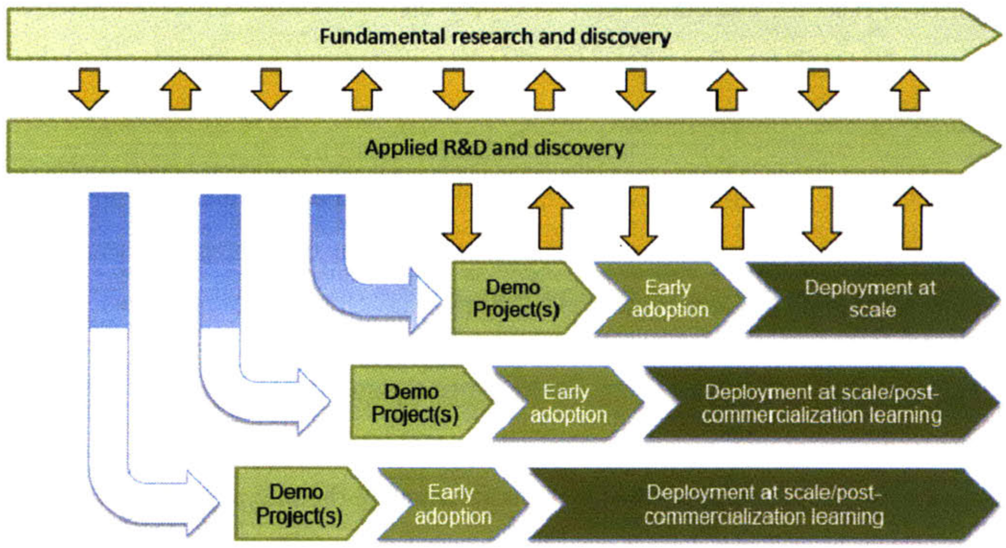


Figure 4.2. A model of the technology innovation process.[18]

Finally, the lessons of the demonstration phase and early adopter projects are applied to commercial projects when deployment occurs on a large scale. Each of these stages can provide information which can inspire cost reductions either directly or indirectly through new applied R&D and demonstration efforts (as shown by the FGD example).

The nature of this innovation process varies between industries and among technologies within the same industry. The next section attempts to characterize this innovation process in the context of CCS technology for the US electric utility industry. A discussion of the major risks associated with CCS technology is useful here, since the nature of these risks affects the type and pace of innovation, and can also provide insights about the institutions that might be required to support this innovation.

[18] Adapted with permission from Professor Richard Lester presentation at MIT Carbon Sequestration Forum 2009.

4.2.1. Major Risks for CCS Projects

Four categories of risks are associated with CCS projects: technology, financial, policy, and regulatory risks. These four major categories of risks will be used as a framework to discuss the innovation process for CCS technology.

Technology risks exist today because of the lack of real-world data and experience for situations that will arise in commercial operation of CCS systems. Some of this technology risk is from the carbon capture system on the power plant side. Some examples of these risks are:

- Capture system performance (e.g., is the capture plant actually able to capture at the 90% target rate as expected?)
- Dynamic plant operation performance (e.g., what are the interactions between the power block and the capture system during plant startup, shutdown, or at partial capacity?)

Another major set of technology risks come from the injection and sequestration activity, including operations, liability, and CO_2 ownership risks. Some potential risks are:

- CO_2 leakage (e.g., will the CO_2 stay in the geologic formation and not migrate to potable water reservoirs or escape to the air?)
- CO_2 plume migration (e.g., will the injected CO_2 migrate within the reservoir as expected?).

Financial risk includes cost risk and project default risk:

- Cost risk (e.g., especially for early projects such as demonstration and initial commercial projects, what is the uncertainty in final costs of construction, capital expenses, labor costs, and operations be, and how will this uncertainty affect the difficulty of financing CCS projects?)
- Project default risk (e.g., how could a long-term change in carbon market prices, electricity revenues, or CO_2 revenues from EOR projects affect long term success of the project in meeting its debt and equity return expectations?).

Policy risk includes the possibility of losing an essential financial support policy due to political or regulatory change. What would happen if a tax credit for sequestered CO_2 was eliminated? One example is the periodic sun-setting of the federal tax credits for wind power generation in the last decade, which has been detrimental to consistent investment in new wind power projects.

Regulatory risk is the risk of investment in CCS projects while the body of regulation relevant to CCS is at an early, unsettled stage without private risk-shielding mechanisms such as private insurance in place to spread such risks over the industry. Some of potential regulatory risks are as follows:

- Health and safety liability risks (e.g., who is responsible if CO_2 injection leads to groundwater acidification, seismic activity, or human suffocation in low-lying areas?)
- Long-term CO_2 ownership risk (e.g., who is responsible for leakage or contamination many hundreds of years into the future?)

4.2.2. Research and Development

The research and development (R&D) phase is where basic chemistry, thermodynamic, and materials concepts are applied to technology problems, hopefully leading to technology solutions that will be commercially viable someday. R&D is a key part of the "technology push" effort for CCS technology innovation.

4.2.2.1. Fundamental Research

In general, private actors do not invest heavily in basic research, since the work does not guarantee a return on investment on an acceptable timescale (Gallagher *et al.*, 2006). Stated differently, fundamental research creates sometimes insurmountable financial risks for private companies, since investments in this type of research rarely pay off soon enough. The goal of applied R&D is to appropriate the benefits of this basic research, through invention and development of intellectual property. As illustrated by the iterative and interconnected nature of the innovation process in Figure 4.2, not all ideas are born of basic science alone. In fact, the concept of using chemical absorption for CCS was an idea already used in slightly different applications in the chemicals industry. Applied R&D projects took this idea and optimized it for the specific CCS application.

Fundamental research programs for coal and CCS technology are commonly run by public sector bodies such as the U.S. Department of Energy (DOE) under both the Office of Fossil Energy, which includes funding for the National Energy Technology Laboratory and the Regional Sequestration Partnerships program, and the Office of Science, which performs more of the basic research tasks related to CCS. Table 4.1 shows the federal budget for the DOE's CCS R&D program.

Table 4.1. DOE budget (in Millions) for CCS R&D from FY1999 to FY2010 request (DOE FE, 2009)

DOE Office	FY 1999	FY 2000	FY 2001	FY 2002	FY 2003	FY 2004	FY 2005	FY 2006	FY 2007	FY 2008	FY 2009	FY 2010 Request
Science	6.8	19.5	19.2	22	25	27	35.3	25.1	22.8	29.5	29.7	29.7
Fossil Energy	5.9	9.2	18.8	32.2	37	44	45	64.7	97	150.6	200	223.9

4.2.2.2. *Applied Research and Development*

The greater the degree to which a private company can expect future profits through intellectual property or first-mover advantages (as is the case in the life-sciences industry), the higher the likelihood of significant investment in applied R&D activity. In industries where the funding company is unlikely to capture the full benefits of R&D spending, the incentives for investment are weak, and a market failure for R&D investment exists. Applied R&D activity brings with it a financial risk proportional to the extent that returns on these investments are uncertain.

To make up for this market failure for early stage R&D, industry cooperation and government programs provide R&D for electric power and environmental control technologies. Traditionally, individual electric utilities have provided little funding for internal applied R&D activity as compared to other industries, but together the industry supports the Electric Power Research Institute (EPRI) with an annual budget of around $300 million in 2008[19]. EPRI performs a variety of applied R&D, as well as pilot-scale and commercial-scale demonstration of technologies relevant to the power sector.

[19] 2008 EPRI Public Financial Statement.

The DOE performs more focused applied R&D for coal and CCS technologies as well. DOE's Office of Fossil Energy uses grant programs to fund projects, the costs of which are shared by private partners and government. These programs are generally funded through the annual budget and appropriations process, or through special funding such as the 2009 Stimulus Bill. Table 4.2 shows how the Stimulus Bill provided $3.4B for RD&D on clean fossil energy projects, and how this money is being spent by DOE. More details on cost and risk sharing programs will be explored in the context of a CCS demonstration phase in Section 5.4.3.

Table 4.2. Fossil RD&D Energy Spending under the 2009 Stimulus Bill.

Fossil Energy RD&D Program	**Amount**
FutureGen	$1,000,000,000
Clean Coal Power Initiative	$800,000,000
Industrial CCS	$1,520,000,000
Geologic Characterization	$50,000,000
Geologic Training	$20,000,000
Program Funding	$10,000,000
TOTAL	$3,400,000,000

A larger portion of the later-stage applied R&D is carried out by private firms; for CCS, power and chemical technology vendors such as Babcock and Wilcox and Fluor Daniel are doing applied R&D for carbon capture, and carbon services providers such as Schlumberger and Denbury Resources are doing applied R&D for geological carbon sequestration. These private firms hope to appropriate the benefits of their work through eventual commercialization of the technology.

This thesis will not focus on improvements to the R&D phase for CCS, since the most important policy obstacles to CCS are in the demonstration and commercial deployment phases. R&D activities are very important to the long-term innovation goals for CCS, however, so a continued strong program of publicly-funded R&D for CCS may be justified as part of a "technology push" strategy to support long-term innovation in CCS.

4.2.3. The Demonstration Phase

In Section 3.2, the lack of a comprehensive demonstration phase for CCS technology was identified as one of the major obstacles to commercialization of CCS. Since policymakers hope the traditionally risk-averse electric utility sector will heavily utilize this technology in the future, a major goal of these demonstration phase projects must be to better characterize and begin to reduce the technology, financial, and regulatory risks identified in Section 4.2.1.

A demonstration phase is necessary to develop information on and reduce technology risks for CCS technology. On the capture system and plant side, these projects will help to expose issues in the design, construction, systems integration, regulation, and operation of such systems. Differences in performance, reliability, and cost between the three major capture technology approaches will also hopefully be exposed by building these commercial scale demonstration projects. On the sequestration side of the system, these projects will also be significant for understanding and reducing technology risks. These projects will likely not reduce health and safety liability risks, but they will provide valuable experience in managing them and will help prove to future operators that such risks are tractable. Sequestration demonstrations will likely be chosen for several geographically-distributed geologic formations, and experience with the injection phase, as well as post-injection measurement, monitoring, and verification will be key to understanding and minimizing such risks.

These projects can also reduce financial risks. Cost risk will be reduced by providing real world data on the capital and operations costs of the technology. These projects will also likely exhibit the highest unit costs for CCS, so the demonstration phase will likely provide some upper bound on the future cost of CCS projects. This experience was supported by the discussion of cost reduction in CCS technology analogs in Section 2.2.2; the expectation is that costs will decrease through construction and operations experience, technological learning, and innovation. Project default risk will likely not be an issue for demonstration projects, since there is little likelihood that demonstrations will be operated as profitable commercial operations anyway, especially in the early years of operation, since operations costs are likely to be high and carbon prices are likely to be low, so there will be little financial incentive for private firms to invest in these projects.

Demonstration projects will also face policy and regulatory stability risks. Policy makers will play the larger role in mitigating these risks, through creating a stable policy environment and developing comprehensive legal and regulatory frameworks for carbon sequestration. Private investors can minimize exposure to policy risks through good planning and through seeking reliable funding sources, such as government grants or contracts, until such time that a predictable carbon price can be relied upon for partial financing of CCS projects.

Two examples of current CCS-related programs are the Clean Coal Power Initiative (CCPI) technology demonstration program and the FutureGen project, both of which received special funding through the 2009 Stimulus Bill, as shown in Table 4.2. The CCPI selects projects through competition, and the costs of the projects are shared by private partners and the funding party. Recently $1.3 billion in grants has been issued for several CCS projects using the Stimulus Bill funds, leveraged by nearly $3 billion in private capital investment:

- An ammonia-based post-combustion capture system on an120 MW flue gas stream the Basin Electric Antelope Valley Station coal plant capturing up to 1 million short tons of CO_2 per year.
- A pre-combustion capture system on a coal- and petcoke-fueled IGCC plant built by Hydrogen Energy International and providing up to 2 million tons of CO_2 per year for EOR.
- A chilled ammonia post-combustion capture system on a 235 MW flue gas stream at the American Electric Power Mountaineer Plant providing up to 1.5 million tons of CO_2 per year for saline aquifer sequestration.
- A retrofit amine-based post-combustion capture system on a 160 MW flue gas stream at the Southern Company Plant Barry providing up to 1 million tons of CO_2 per year for saline aquifer sequestration.
- A pre-combustion capture system on a 400 MW IGCC power plant in Texas providing up to 2.7 million tons of CO_2 per year for EOR in the Permian Basin.

Additionally, FutureGen is a major IGCC-based CCS demonstration project in Illinois that faced funding difficulties in recent years and has been delayed as a result. It was to be the first major large integrated CCS project in the world, but will likely no longer be since several other projects are being pursued around the world.

As early CCS projects are being proposed and built today, it seems more likely that a demonstration phase will consist of a wide variety of projects that vary in technology scope, size, and commercial orientation, but all of the projects will contribute to the universal goals of developing information on costs and risks for CCS.

This variety can be viewed as a continuum of projects in a demonstration phase. At one end of the continuum, there are demonstration projects which are more research-oriented, such as the FutureGen project or the Babcock and Wilcox/ Black Hills Corporation oxy-fired demonstration (see Appendix Section 8.7 for more detail). These projects are both receiving significant government support; commercial operation is not intended, and there is little or no expectation of cost-recovery through commercial operation. Both of these projects have the primary goal of collecting information on cost, performance and reliability, as well as some additional R&D goals. The Babcock and Wilcox demonstration surely has an additional goal of developing intellectual property that can lead to a commercially-available oxy-fired boiler technology that B&W would like to sell someday.

At the other end of the continuum, there are projects such as the Tenaska West Texas Trailblazer (see Appendix 8.7 for details) that are seeking to operate commercially and to generate (at least partial) cost-recovery for the investment. These projects are seeking as much government support as possible to make the project risks tractable and to operate the facility profitably.

4.2.4. Commercial Deployment

As the risks for CCS become more acceptable to private firms, more commercial projects will be undertaken. These projects will be intended to operate as commercial facilities selling electricity with a plant life of 30+ years with a high expectation of profitability.

The technology risks will have been reduced significantly by demonstration projects, and these risks will now be viewed as manageable. Technology vendors may offer performance guarantees on some parts of the CCS system at this stage. Sequestration risks will hopefully be managed under a well-developed legal and regulatory framework. Liability risk will have been significantly reduced at this stage. Health and safety risks will be well understood, and insurance coverage against these risks will be available. For long-term liability, a private insurance or government indemnification mechanism will have been developed and will now be widely accepted as credible.

For early commercial projects, the financial risks are still significant. Project default risk remains significant, and these projects will need to take advantage of every incentive available to ensure long-term operation, because the carbon price support for these projects may still be limited. Cost risks should be much lower than in the demonstration phase, due to the developing body of construction and operations experience with CCS technology. Given the lower-risk environment for CCS technology, a stable business model and value chain for CCS technology will emerge, making market penetration of CCS technology a more likely prospect.

Policy risks will also be significant for early commercial CCS projects. These projects will be financed in context of an uncertain carbon commodity price, and the additional support provided by other public funding mechanisms provides significant policy risk for these projects. Regulatory uncertainty risks will have hopefully been eliminated through a well-developed legal and regulatory framework for CCS.

As the market and the technology mature, these risks are minimized, and the investment structure for new CCS projects begins to look much like what exists today for conventional projects in this industry.

For regulated utilities, a public utilities commission (PUC), the state electricity utility regulatory body, traditionally allows cost recovery (including some profit margin for the utility) for a new power plant when justified as the lowest-cost option to meet electricity demand in the region or state. This is done through the setting of electricity rates. A power project with CCS would only be approved if it was the lowest-cost option as compared to other generation options, which could eventually occur in the future through regulatory requirement or high carbon price.

For unregulated independent power producers (IPPs), cost pass-through occurs via two methods: either through negotiating more expensive power purchase agreements (PPAs) with a local distribution company required to meet a portfolio standard or other regulatory requirement, or through cost recovery on the competitive wholesale power market (such as the Texas ERCOT market) by including the costs of CCS in the electricity dispatch bidding strategy. Given that the IPP would be bidding in competition with uncontrolled coal, gas, and wind generation, a CCS plant may have difficulty in achieving profitability under dispatch scenarios for wholesale generation assuming politically feasible carbon pricing, although under high carbon pricing CCS plants dispatch profitably.[20]

If CCS technology reaches this phase, it will have already become a significant contributor to carbon emissions mitigation and further commercial deployment of the technology in the US and internationally should be possible.

4.3. Policy and the Innovation System for CCS

Inspired by the FGD case study in Section 4.1, this section will show that both market pull and technology push policy strategies can support post-commercialization innovation and cost reduction in a technology, and this cost reduction further accelerates commercial deployment. The most important contributor to innovation is the creation of new knowledge and information which comes from commercial projects; this information drives innovation in several different ways, but the major result is always cost reduction. For CCS, this cost reduction can expand the market for the technology and improve the commercial viability of building CCS projects, both of which further accelerate commercial deployment.

4.3.1. Market pull policies can support innovation

The goal of a market pull policy strategy is to support a market for CCS technology; not only does this market lead directly to commercial deployment, but existence of a market for CCS technology will also provide the information and knowledge required for innovation, leading to cost reductions and further acceleration of commercial deployment. The innovation processes of "learning by doing" and "learning by using", as well as the concept of "information spillover', are explored here.

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[20] For more details on CCS in the electricity grid and the issues of wholesale market competition, dispatch strategy, and capacity factor, see the forthcoming MIT Master's Thesis of Gary Shu.

Market pull policies directly support commercial deployment:

- For example, a successful first generation of three commercial CCS projects was built using one company's carbon capture system; these projects were financed using support by federal loan guarantees and tax credits for sequestered CO_2, and were successful in profitable commercial operation.

These commercial projects produce useful information:

- An engineer working for this company discovered an uneven heat distribution when taking measurements on the solvent stripper unit of one of Firm A's projects; computer modeling leads to a determination that this heat distribution is promoting solvent degradation in the system, leading to a significant increase in solvent replacement costs.

Depending on how this information is utilized, it can lead to different kinds of innovation both directly and indirectly; each type of innovation results in cost reduction:

- The engineer develops a solution by designing a specific modification of the heat exchanger in the walls of stripper unit, significantly decreasing the solvent degradation rate; the modified heat exchanger is installed, the solvent degradation rate improves, and the maintenance costs for this company's capture system decrease; this application of useful information in an existing project, resulting in cost reduction, is an example of "learning by using" innovation.[21]
- Alternatively, the engineer develops the same solution, but instead he applies to the redesign of a second generation solvent system, so the modified heat exchanger is then designed into future installations, leading to cost reduction in these new systems; this is an example of "learning by doing" innovation. Learning-by-doing cost reductions can come from experience in design and construction of past project, realized through gains in efficiency or operations performance of future projects.

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[21] Another example of learning by doing is from the US nuclear power business over the period 1980-2000, an industry-wide effort to streamline the inspection process of the nuclear fleet contributed to a 22% increase in plant capacity factor, which had the effect of reducing levelized lifetime costs and vastly increasing the profitability of these plants.

- A third option is that the engineer presents his problem and its solution at a technical conference on solvent capture systems, not fully realizing the potential value of this innovation to other firms. This "information spillover" can inspire further public and private RD&D activity, perhaps allowing a different competing company to realize cost reductions, thus benefitting indirectly from the original company's innovation. More on the innovation mechanisms behind RD&D activity will be discussed in the next section.

In summary, market pull policies directly support commercial deployment, which supports innovation both directly through technological learning and indirectly through information spillover.

4.3.2. Technology push policy can support commercial deployment

Conversely, technology push policies support innovative activities such as RD&D or knowledge transfer opportunities, which support innovation and result in cost reduction for future commercial projects. This increases the competitiveness of the technology, thus improving its prospects for commercial deployment. This section explores the relationship between these activities, the different types and magnitudes of the resulting innovation, and how this innovation affects future commercial deployment.

Innovation originates from either external knowledge (knowledge "spillover") or internal knowledge. Sometimes knowledge spills over from one organization's project to the public domain, and is then used by a different organization to inspire innovation. Sometimes internal knowledge inspires innovation, which is created from original early stage fundamental research activities, independent of existing commercial technologies. Using either source, both private and public organizations use knowledge to inspire new or continuing RD&D efforts, which can be financially supported by technology push policies. The result of these RD&D efforts is innovation, which is the commercial application of new technologies with lower costs or higher performance than previous technologies to meet market demands.

There are two major dimensions on which innovations can be compared: the type and the magnitude of the innovation. An architectural innovation is a type of innovation defined by improvements in cost or performance through a new or improved combination of existing technologies. Alternatively, a process innovation is defined as improvements in cost or performance by a new or improved process.

The magnitude of innovation, that is the magnitude of improvement in cost or performance, is another important factor in discussing innovation. It is common in the literature to consider both incremental and radical innovation, the major difference in which is the magnitude of improvement as compared to incumbent or substitute technologies; this difference between radical and incremental innovation is difficult to define exhaustively, but an attempt to define this difference is made here.

Incremental innovation refers to small magnitude improvements in cost or performance, usually through modifications of existing technologies. Radical innovation can be described as a large magnitude improvement in cost, performance, or reliability. Over time though, a series of incremental innovations can lead to improvements comparable to those achieved by a radical innovation, depending on where one chooses a reference point for analysis. This problem in distinguishing incremental and radical innovation can be illustrated by the coal boiler technology example. The international RD&D program on advanced ultra-supercritical boiler technology could be considered an incremental innovation, because it provides moderate increases in efficiency through improvements in materials and modification of today's supercritical boiler design. The difficulty in definitively labeling this an incremental innovation is illustrated by a simple change in reference point: if one's reference point is the subcritical boiler technology common in many older, existing coal plants in the US, then the new ultra-supercritical designs could be considered a radical innovation since the magnitude of improvement in efficiency has been quite significant.

Incremental innovations can sometimes be readily introduced into commercial projects, but depending on the level of technology risk, may require a technology demonstration first. Radical innovations are, by definition, high-risk technologies in comparison to current technologies, thus often justifying further commercial-scale demonstration before introduction into commercial projects.

One example of radical innovation is the natural gas combined cycle (NGCC) power plant, which is an example of the novel combination of existing technologies known as an architectural innovation. Due to development of gas turbine technology in the aerospace field in the 1950s and 60s, high-efficiency gas turbines were in widespread commercial use in the aerospace field, but steam turbine technology still dominated the power generation market (Markard and Truffer, 2006). The idea of combining the gas and steam power cycles was commercialized in the 1970s, providing a new, highly-efficient, low capital and operations cost power generation option, but still the efficiency of these systems was roughly comparable to alternative coal generation facilities and commercial orders for NGCC systems remained low (Markard and Truffer, 2006).[22] Throughout the 1980s, further improvements in the efficiency of the NGCC system, combined with several important market and regulatory developments, resulted in the significant commercial deployment of NGCC technology throughout the 1980s and 1990s.[23] While many of the improvements in the NGCC system over the decades were small-magnitude, incremental innovations, the sum of these innovations in the context of market conditions in the 1980s leads to the consideration of the NGCC power plant as a radical innovation in comparison to incumbent single-cycle steam turbine systems.

A second example of radical innovation is the Union Carbide (now Dow Chemical) Unipol process for production of polyethylene (PE), the world's most common plastic. This radical innovation differs from the NGCC example since the cost and performance improvements of the Unipol process resulted from the invention of a new catalyst and a redesign of the PE production process (a process innovation), rather than a combination of two existing, independent technologies to produce the same product (an architectural innovation). The incumbent PE production processes were high-pressure and energy-intensive. Due to the invention of a new

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[22] Despite these advantages, these combined cycle systems were mostly limited to peak power applications, since gas supply infrastructure was geographically limited and US energy policy discouraged increasing use of natural gas at the time, as a response to foreign oil supply disruptions of the decade (Markard and Truffer, 2006).

[23] Due to a confluence of increasing domestic natural gas supply infrastructure, improvements in NGCC system efficiency, and the passing of the Public Utilities Regulatory Power Act of 1978 (PURPA), the NGCC power plant only became a viable option for middle load and base load power through the 1980s and 1990s (Markard and Truffer, 2006). Increasing gas supply and low gas prices, and increasing efficiency of large NGCC systems, increased the competitiveness of NGCC systems as an option for new power generation, compared to the alternatives of coal and nuclear generation. Additionally, PURPA allowed independent power producers to enter the electricity market and to develop cogeneration steam sales agreements, which in combination with the fast construction time of new NGCC plants, and the technology and fuel supply advantages noted above, led to a significantly increasing investment in NGCC technology over this period (Markard and Truffer, 2006). Since then, gas prices have risen and exhibited continued large price volatility leading to less base load deployment of these NGCC facilities and less construction of new facilities.

advanced catalyst material, the new low-pressure Unipol process provided between 25-50% reduction in capital costs compared to the incumbent process, and it reduced energy and cooling water requirements and improved plant flexibility in producing different types of PE product (Joyce, 1990). This new process was invented in 1968, and was developed and widely commercialized within a decade, primarily due to the invention of the new catalyst which made the process possible; the large magnitude of cost and energy reductions of the Unipol process as compared to the incumbent PE production processed can justifiably lead to the classification of this process as a radical innovation.

No matter the source of the information inspiring the innovation, the type of innovation, or the magnitude of the innovation, cost reduction in future commercial projects is the major result from technology push activities; this cost reduction improves the competitiveness of a technology and can accelerate commercial deployment.

Since technology push programs support innovative activities by public and private organizations, including such programs as part of an integrated policy for commercial deployment of a given technology, will be important to maximizing possibilities for long term cost reduction in a technology. These innovative activities directly support innovation, which leads to cost reduction, thus indirectly accelerating commercial deployment. This lesson is important for CCS technology: innovation will be key to achieving the cost reduction goal, so including technology push policies will improve the likelihood that a CCS can make a significant contribution to carbon emissions mitigation.

4.3.3. An Innovation System Model

In Section 4, the lesson from the SO_2 emission control technology case study is made clear: "the [market]-pull generated by legislation/regulation and the anticipation of regulation have a more direct effect on inventive activity [...] than governmental technology push activities" (Taylor *et al.*, 2005). This implies that market pull policies are more important than technology push policies in supporting innovation and long-term cost reduction, but that technology push policies can play an important complimentary role in supporting innovation. An innovation system model can connect this feedback between market pull and technology push policies, using the concepts of commercial deployment, knowledge transfer, innovation processes, and cost reduction, and this model is shown graphically as Figure 4.3.

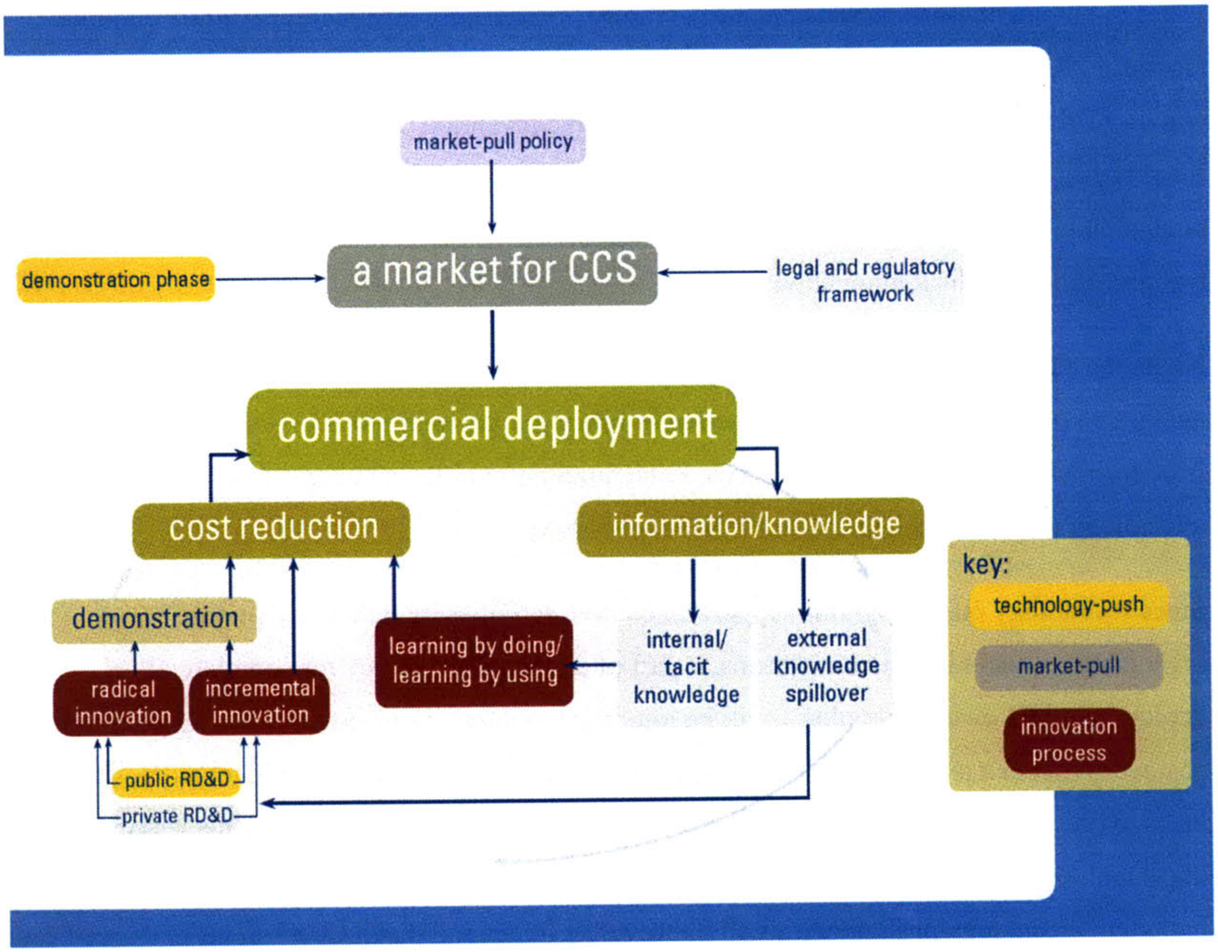

Figure 4.3. Innovation system model for CCS.[24]

Since CCS technology for coal power is quite similar to FGD technology in both its design and its market and regulatory context, it is plausible that the innovation system for CCS will operate in a similar manner; although there is no way for us to know if this is an accurate assumption, this innovation system model proposed reflects this assumption, and the policy analysis for commercial deployment in CCS will continue based upon this assumption.

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[24] Graphic Design courtesy of Natalie M. Couch.

Besides the requirement of overcoming the barriers of a lack of a demonstration phase and a legal and regulatory framework, strong market pull policies can lead to a market for CCS, the primary driver for commercial deployment; these market pull policies are also the primary driver for innovation. Technology push policies can play an important complementary role in supporting innovation, but without a market for the technology they seek to improve, their utility is minimized. Once the market is established, the cycle of innovation can begin to provide significant, long-term cost reductions for CCS technology. This cost reduction is not guaranteed, but we can be sure that without support of the market, innovation in CCS will be minimal, and the likelihood of significant cost reduction in CCS technology will be low.

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5. The Demonstration Phase

The CCS demonstration phase was identified in Section 3 as one of the three main barriers to commercialization of CCS technology. Its key role is to developing an understanding of and reducing technology risks so that private industry will invest in commercial CCS projects in the future.

5.1. What is a demonstration phase?

A demonstration project attempts to further develop new technologies by scaling-up the technology to relevant commercial scales. The primary goal of a demonstration project is to characterize the technology at scale and in so doing to reduce the risks of subsequent commercial application of the technology to acceptable levels.[25] The demonstration *phase* is comprised of a range of individual demonstration projects. For a given technology, this phase may consist of one or more such projects. Where more than one project is involved, the projects may be conducted in parallel or in series.

5.2. Why pursue a demonstration phase for CCS?

As presented in Section 3.2, a major obstacle to large-scale deployment of CCS technology is the need for immediate demonstration of CCS technology. All parts of the CCS technology system have been demonstrated around the world, often at commercial scale, but the lack of experience in construction and operation of integrated CCS systems and the likelihood of high costs and risks for these early projects are serious obstacles to the introduction of CCS to global energy markets. This in turn creates the need for a CCS demonstration phase.

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[25] Some companies may be willing to bear more of these risks, and may pursue early deployment projects that contribute to this same goal of reducing the risks of commercial application of the technology, while also seeking commercial success and profitable operation. There is no firm distinction between true demonstration projects and true early deployment projects; projects within a demonstration phase may be research oriented non-commercial ventures, or they may be truly commercial projects, or they may be some hybrid of the two. Examples of demonstration as compared to early deployment projects for CCS were presented in Section 4.2.3.

A CCS demonstration phase would have four major goals:

Information Generation and Communication

The primary objective of a demonstration phase is to develop credible information on cost, performance, reliability, and the risks of CCS technology, and to communicate this information effectively to future business participants, investors, and the public.

This information will also serve as the basis for a program to improve public perception of the technology. Given the significant risks associated with the geological sequestration part of the CCS system, the public must be in support of the concept of widespread carbon sequestration, or else the technology will never become a significant contributor to CO_2 emission mitigation. People living on top of sequestered CO_2 will need to become comfortable with geological sequestration, and this public perception challenge can be aided by providing credible information about real projects and effectively communicating the risks and benefits of the technology.

Urgency

A CCS demonstration program should be initiated quickly, so as to accelerate the commercial availability of CCS.

A demonstration program will take approximately ten years to achieve the goals of information collection on construction, operations, and reliability of the CCS system, and if this program is effective, commercial deployment of CCS should be able to begin shortly thereafter (Moniz and Deutch, 2007). This underscores the urgency of starting a demonstration program soon, since the sooner commercial deployment can begin, the sooner the long-term goal of making CCS a significant contributor to carbon emissions mitigation can be achieved.

Commercial Relevance

The CCS demonstration phase should focus on CCS technology options that are likely to be ready for full-scale commercial deployment when the demonstration phase is complete.

Especially for the first round of demonstrations, projects should seek to use carbon capture technologies that are ready for commercial-scale application, such as those approaches presented earlier in Section 2.1. These technologies would provide an easier transition to full commercial-scale deployment. Also, these projects should seek to emulate a commercial CCS business model where possible. As part of a continued technology push policy, later demonstration projects may seek to use more innovative technologies; this will be discussed further in Section 6 on commercial deployment of CCS.

A Technology Portfolio

The CCS demonstration phase should use a portfolio approach to provide at least one major CCS option ready for immediate commercial deployment.

Another important objective of the demonstration program is to provide one or more technology options ready for commercial deployment immediately after the demonstration phase. Calls from diverse groups such as the US Climate Action Partnership (US CAP) and the Carbon Sequestration Leadership Forum support this approach. To do this, a portfolio approach can be used. Any one project has technology risks that may lead to failure in achieving specific project goals. Each project should not be expected to successfully achieve all project goals; these failures can provide the motivation for further innovation, with success perhaps coming in future CCS projects. By pursuing several projects in parallel, a portfolio approach can spread these risks over several projects, to raise the chances of success of the entire demonstration phase.

Heterogeneity in capture technologies and sequestration geologies provides a motivation for diversity in CCS technology within the demonstration project portfolio. For the carbon capture side of CCS technology, there is no clear technology winner, especially given the complicating factors of differing regional fuel requirements and the requirements for new and retrofit application (as discussed in Section 2.1.4). For the sequestration side of CCS, given the diverse geologies potentially suitable for carbon sequestration in North America, a variety of geographically-distributed commercial-scale sequestration projects is justified as part of this portfolio.[26] Given these requirements for future commercial projects, diversity in CCS technology motivates a diverse *and* parallel demonstration phase, to achieve the dual goals of risk spreading and technology variety.

Additionally, integration of the entire CCS technology system should be sought within a few of these projects, but will not be required in every single project of the portfolio; much valuable information and experience can be gained from non-integrated CCS projects that may be less expensive than fully integrated projects.

At the completion of the demonstration phase, there will likely be some revealed successes and failures in specific projects, but a successful demonstration phase will hopefully provide at least one major CCS technology option ready for commercial deployment by using this portfolio approach.

5.3. Why can't private industry do a demonstration phase by itself?

Private industry cannot complete a CCS demonstration phase in the relevant timeframe due to the combination of high costs and risks faced by first movers considering CCS projects and the barriers to private investment in public goods.

Demonstration and early CCS projects will be very expensive, as described earlier in Section 2.2.1.4, and few of these projects are likely to operate as self-sustaining commercial projects. For example, the FutureGen IGCC demonstration project may cost \$6500/kWe+[27], as compared to a new uncontrolled coal-fired plant cost of ~\$2000/kW; this represents a 3x cost premium that electric utilities, regulated or unregulated, will not likely pay for.

Additionally, significant technical, financial, regulatory, and policy risks remain for early CCS projects that the traditionally risk-averse electric power industry will likely avoid until they are further characterized. These risks were described in detail in Section 4.2.1.

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[26] Demonstration and early deployment projects should consider saline formations as primary targets for geological sequestration, since these formations carry the largest potential for future sequestration capacity, but some projects using enhanced oil-recovery (EOR) or enhanced coal-bed methane will also be useful, especially since these projects can provide a revenue stream to offset the high costs of early CCS projects.

[27] Assuming \$1.8B total cost with 275MWe net size. See Section 5.7.2for details.

Investment in demonstration projects would carry a major financial risk, due to the lack of a clear carbon dioxide pricing scheme to price the externality of emitting CO_2. Even with pending legislation to establish a national carbon pricing scheme in the US, the expectation of a significant cost gap under the scheme for early CCS projects provides a significant financial risk to investment in demonstration projects, as established in Section 3.3.

Additionally, the information created by one firm's demonstration project is clearly a public good, and once created it can easily spill over to other firms at little or no cost, since keeping such information private can be very difficult (Jaffe *et al.*, 2005). Such public goods are generally underprovided by ordinary market activity, and a demonstration phase for CCS is a perfect example of this public goods problem.

Public support of demonstration projects can reduce the costs and risks faced by private industry and eliminate the problem of under-provision of public goods. This leads to the primary question for this analysis: How ought the US government and private industry participate in a CCS demonstration phase?

Every demonstration project involves three key roles: (1) bearing the financial costs and risks of the project; (2) project selection; and (3) project management. For CCS demonstration projects, an important question is how the responsibilities for these three roles should be allocated among government and private actors. To help answer this primary question, material will be drawn from both past US government energy technology demonstration programs and from expert feedback from the MIT Expert Workshop on CCS Innovation.

5.4. How should the costs and risks be allocated?

5.4.1. Private

This option would be appropriate if private industry deemed the costs and risks of CCS demonstration manageable and if most of the benefits of investing in the project could be captured by the investing firm. While this situation might characterize the commercial deployment phase, as discussed in Section 4.2.4, it does not describe the demonstration phase: CCS demonstration projects will face high costs and risks, with many of the latter the direct result of government action or inaction, and the benefits of early CCS projects are unlikely to be fully captured by private firms.

5.4.2. Public

This option would be appropriate for very high-risk projects with the expectation of only long-term benefits that cannot be directly appropriated by private firms. This well describes the circumstances in the basic research phase, discussed in Section 4.2.2.1. But the situation in the CCS demonstration phase is quite different: CCS technology demonstration projects would deliver some benefits to private firms in the near term, thus justifying a private role in sharing in the costs and risks of the projects.

5.4.3. Cost and Risk Sharing

This option is the middle ground of public and private sharing of the costs and risks of demonstration projects. By allowing costs and risks to be shared between public and private parties, the barriers to investment in demonstration projects can be overcome. Individual demonstration projects will face differing levels of costs and risks, and private parties will face differences in their potential to capture benefits from investment in these projects; as a result, the cost and risk sharing agreements should be negotiated on a project-specific basis.

The unpredictability associated with the congressional appropriation process creates a policy risk for private counterparties in cost and risk sharing arrangements. Therefore, the option of having dedicated funding from fees collected from electricity ratepayers into a dedicated trust fund is preferable to minimize this policy risk; this was proposed in the ACES Act Waxman-Markey CCS demonstration program, which is presented in detail in the Appendix Section 8.6.

5.4.3.1. Sequestration Risks

Sequestration risks are significant for demonstration projects. Issues of technical performance during injection and in post-injection measurement, monitoring, and verification, as well as the issue of liability for the health and safety risks posed by long-term carbon sequestration both remain unresolved issues. Given that these risks are not well understood, it is unlikely that private firms will participate in large-scale sequestration projects unless some mechanism can be provided to limit these private party risks.

One option is to have the government assume some or all of these risks. One proposal is a government indemnification program for long-term sequestration liability, which would require private parties to face risks for some post-injection period, after which the government could take over responsibility. This would be especially appropriate for demonstration projects, since there will likely not be a widely available insurance market for sequestration for early projects. One proposal is S.1462, the Bingaman Energy Bill, which would create a national indemnity program for the first 10 large CCS demonstration projects.[28] A different option is for state governments to directly assume liability for specific projects, which was recently done by Texas and Illinois in their competition to be selected for the FutureGen CCS demonstration project.

As more CCS projects are completed and information about real risks becomes available, the availability of private insurance for injection-phase and post-injection-phase will likely increase. Purchasing this insurance will likely become the major method of short-and medium-term liability limitation for private parties participating in CCS projects (Jacobs *et al.*, 2009).

5.4.3.2. *Revenue Benefits*

The distribution of revenues from electricity sales, CO_2 sales for enhanced oil recovery, gas or chemical sales, or CO_2 or industrial heat off-take agreements should be considered in agreements for demonstration projects. Valuing these revenues on a project-specific basis will be an important part of negotiating cost sharing agreements.

5.4.3.3. *IP Benefits*

Especially important to demonstration phase projects, intellectual property (IP) ownership must be discussed and agreed upon by all parties in each demonstration project. Private companies will want to keep as much IP as possible, but public support of such projects may justify making some or all of this IP public domain. Participants at the MIT Expert Workshop expressed

[28] According to the bill summary text, a clear framework for sequestration project closure and long-term stewardship will be set up, and after some specified period of time, the federal government would take over ownership of the site, and any liabilities occurring after this date.

concern that IP data for CCS demonstrations would serve an extremely valuable purpose if shared with the public, and that care should be taken to structure IP agreements accordingly.

5.4.3.4. *Project Ownership*

The ownership of project assets has already become an important issue in the public discussion over the FutureGen project, and will continue to be important to demonstration projects. Whether or not post-demonstration commercial operation is intended, an ownership agreement must be developed to guide the distribution of proceeds from equipment salvage or the transition to a different ownership structure after the demonstration period has ceased.

5.5. How should project selection be organized?

The selection of demonstration projects will strongly affect the achievement of the demonstration phase objectives of commercial relevance and a technology portfolio, due to the differences in incentives, capabilities, and coordination of public and private entities.

5.5.1. Single Private Company

Private companies such as electric utilities have incentives to choose technologies which give them the highest chance of commercial relevance in the long-term. These companies also have the capabilities to make effective project selection decisions since, as compared to public entities, they have a deeper and broader knowledge of the marketplace and skills in applying this knowledge to financial analysis and business strategy.

Despite this effectiveness in choosing commercially relevant projects, private companies have little incentive to support the technology portfolio objective, since this objective must be achieved through coordination of the project selection activities across the entire demonstration phase; individual companies making their own best decisions of project selection may not yield an ideal technology portfolio of demonstration projects in the long term.

Some examples of this project selection structure are early deployment projects such as Duke Energy's Edwardsport IGCC project, the Tenaska Power Taylorville and Trailblazer projects, and Southern Company's Kemper county IGCC project, which are discussed in the Appendix Section 8.7.

5.5.2. Private Coalition

A coalition of private companies, such as electric utilities, technology vendors, engineering, procurement, and construction contractors, and fuel suppliers, can join together to organize and select demonstration projects. It is common for such coalitions to develop naturally in the course of business in the US power sector, since these firms often have mutually beneficial goals and capabilities. To the extent that these coalitions form naturally as would be expected on a commercial project, they would have strong incentives to select commercially relevant projects, and they could potentially improve upon project selection capabilities as compared to a single private entity since technical expertise and proprietary knowledge from different firms could be combined to make a better-informed selection decision.

One example of this private coalition structure representing a natural business organization is the Babcock and Wilcox and Black Hills Corp. oxy-fired project, which is discussed in the Appendix Section 8.7.

The FutureGen Alliance, which is the backing private coalition managing the FutureGen project, is a good counter-example of how a coalition may not reflect a natural business organization, which could lead to different incentives for project selection than described here; this is discussed in more detail with respect to project management in Section 5.6.3.

5.5.3. Public

Public demonstration project selection, perhaps through the DOE or a government-appointed board, could well serve the technology portfolio objective, but while public entities may seek to make effective decisions about selecting commercially relevant projects, they face different incentives and inferior capabilities to select the most commercially relevant projects as compared to their private counterparts. The technology portfolio objective can be effectively achieved through central coordination of project decisions, which would be possible through a public decision making process. Despite this advantage, public decision makers face different incentives due to tight annual budget pressures, and human capabilities may be limited due to hiring requirements for civil servants and limits on compensation that exclude some well-qualified people from involvement in government (Ogden *et al.*, 2008). The history of US government demonstration project selection shows several additional problems with public project selection.

The FutureGen project is the major example of public project selection for CCS.

5.5.3.1. Narrow Consideration of Technology Options

In past public demonstration programs, government decision makers have exhibited a tendency towards narrow project considerations in project selection that should give caution to policy makers considering the public role in project selection for a CCS demonstration phase.

One approach exhibits a too-narrow consideration of the technology alternatives, due to high technological optimism about a specific high-risk approach. The synfuels program focused on technologies for conversion of eastern coal, due to political interest in supporting the economies of eastern coal states, even though the costs and technical challenges for converting western coal were much lower. The breeder reactor program considered only alternatives that achieved a very high fuel conversion target, even though research in other breeder technologies showed lower cost options (Cohen and Noll, 1991). In both cases, the decision makers were so optimistic about the pre-commercial performance or cost estimates for the chosen technologies that a narrow consideration of related technology alternatives was considered acceptable (Cohen and Noll, 1991). This caused the synfuels and breeder reactor programs to focus largely on technologies that were less commercially viable than other alternatives might have been, which was both detrimental to the commercial success of the programs and led to significant waste of taxpayer money.

The other approach exhibits an excessively conservative consideration of technology options that are already very close to commercial application, which risks spending public money on projects that would have already been pursued by private entities anyway. For example, the Clean Coal Technology Demonstration Program (CCTDP) program supported some technologies that might have been commercialized without any federal assistance, which may have not been the best use of taxpayer money. One such project combined two existing low-NO_x burner technologies that had been demonstrated overseas and in the US, with the DOE project essentially an effort to combine the two technologies (United States General Accounting Office, 1991). This problem is especially important for the case of CCS, since here the overarching goal of a demonstration program is commercialization of a technology, so political appointees making project selection decisions might be inclined to increase the probability of success by choosing projects that might have been funded by private entities with much less public support.

5.5.3.2. *Inflexibility in Project Termination and Redirection*

Past project selection in government demonstration programs shows a lack of flexibility regarding project cancellation and redirection, stemming from political issues surrounding the budget appropriations process and geographical distribution of such projects. Despite new information about the commercial prospects for a technology, inflexibility in project reevaluation is common in government demonstration programs: "once commitments to build large-scale facilities had been made, projects did not respond to new information, or only did so after a long delay" (Cohen and Noll, 1991).[29] Both Congress and the executive branch have often put political considerations ahead of independent policy recommendations. Cohen and Noll partly attribute this behavior to the "technological optimism advocated by [technologists in] the executive branch", who continually hoped that the commercial prospects of the programs would shift in a favorable direction. Additionally, large projects such as the Clinch River Breeder Reactor satisfied the political demand for high visibility and tangible results combined with "distributive" political benefits gained through the spread of projects around the country to help gain political support. Congress controls the federal budget, so political considerations dominate decisions to cancel or repurpose these projects.

[29] For the breeder reactor program, an updated long-term forecast for electricity demand should have triggered, at minimum, a re-evaluation or re-purposing of the commercial focus of the program, since the entire program was justified on the basis of continuing high growth electricity demand. Despite this, the government did not change course or order a serious reevaluation of the program; rather they continued to increase funding. After a delayed revelation to the lack of commercial viability, the Clinch River Breeder Reactor (CRBR) project was officially cancelled, but the projects continued to be funded by congressional appropriation for several years after COHEN, L. R. & NOLL, R. G. (1991) *The Technology Pork Barrel,* Washington, D.C., Brookings Institution..

5.5.3.3. *Inflexibility in Technical Requirements*

"The perfect is the enemy of the good." - Voltaire[30]

As one of the primary objectives listed in Section 3, getting a demonstration program started quickly is one of the most important policy objectives of a CCS demonstration program. As part of the technology portfolio objective, some CCS "dream projects" should certainly be pursued, including full CCS system integration on plants with commercial-scale electricity capacity, saline aquifer sequestration, and 90%+ capture rate. But this does not mean that all demonstration projects should be "dream projects". Early projects could pursue only some of these technology objectives, and still could contribute significantly to the goals of urgency, information generation, and commercial relevance. Delaying demonstration projects because of a desire to achieve all of these requirements simultaneously risks letting the perfect be the enemy of the good.

The FutureGen project initially was one such "dream project" since it sought to achieve aggressive technical goals that were laudable from an engineering perspective, but it is plausible that inclusion of too many of these high-risk technology objectives in one project contributed to the delay and near-cancellation of what was the flagship US CCS demonstration project. The high and escalating costs attributable to inclusion of many first-of-a-kind technologies, when coupled with the fact that a significant share of costs and risks was borne by the FutureGen Alliance, led to delays and some loss of interest by the private coalition of companies managing the project. Now the future of this project is uncertain but it is moving forward slowly; more discussion of the FutureGen project is given in Section 5.7.2.

A more flexible approach is prudent and possible, as suggested by feedback from the MIT Expert Workshop on CCS Innovation as well as by evidence from real projects on the ground today. One participant at our workshop suggested that a better demonstration strategy would be to "start with less restrictions on early projects to get things started" then "push for more integration later". Additionally, several CCS projects in planning today show that industry sees value in less-than-perfectly integrated CCS projects. Demonstration projects targeting saline aquifer

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[30] A quote from Voltaire in *La Bégueule* (1772).

sequestration would no doubt be more relevant to future commercial CCS projects, but enhanced oil recovery (EOR) revenues can help lower costs and risks for private participants, which may be key to incentivizing private participation in demonstration projects. Duke Energy's Edwardsport IGCC project, Tenaska Energy's Trailblazer and Taylorville projects, and Southern Company's Kemper County, MS IGCC project are all seeking EOR opportunities to make financing of their CCS projects viable. Also, several projects are choosing partial capture CCS, also as a cost reduction measure: Duke's Edwardsport IGCC is planning 18% capture, rising to 53% in later years, and Southern Company's Kemper County IGCC project is planning 50% capture. More details on these projects can be found in Appendix Section 8.7.

In conclusion, perfect CCS projects should not be the enemy of a good CCS demonstration program; there is good reason for flexibility on the technical specifications and systems integration of CCS projects, especially for early projects, so that a demonstration program can get started soon.

5.5.4. Private Board

As shown previously, private entities have the right incentives and capabilities to support the goal of commercial relevance in project selection, but public decision making can more effectively provide the coordination needed to support the technology portfolio objective for a CCS demonstration phase. It follows that a public/private hybrid for project decision-making is a logical choice.

One such hybrid proposal is a private board for demonstration project selection, such as the Waxman-Markey ACES Act proposal, which would house it within the Electric Power Research Institute (EPRI), the major non-governmental R&D body for the US electric power sector. This board could theoretically combine the strengths of the public and private approaches above to produce a better set of incentives and capabilities for project selection. The board would be staffed by a variety of qualified representatives from the power industry to select commercially relevant projects. Assuming no conflicts of interest on specific projects, this board would have the right incentives and capabilities to select quality CCS projects, while achieving the balanced technology portfolio objective through coordination of projects across the entire CCS demonstration phase. The government's only role here would be to pass specific rules in forming this board to minimize conflicts of interest and define a narrow role for the board in selecting CCS demonstration projects.

Out of the four different options for organization of the project selection task, the private board project selection model seems clearly superior, since it can successfully combine the incentives and capabilities of private industry to select commercially relevant projects with the public benefit of a coordinated technology portfolio approach for a CCS demonstration phase.

5.6. How should project management be organized?

The project management of demonstration projects will affect the type and quality of information generated from design, construction, operations, and maintenance of these projects, as well as the business organization surrounding the projects. Ensuring that the most commercially relevant information is generated and communicated to the public and future business participants is a key objective of the demonstration phase. If the business organization of these projects can be as close as possible to what would be expected for future commercial CCS projects, this can help support the commercial relevance objective for the demonstration phase.

5.6.1. Single Private Company

If a private company has project management responsibility, the organization of the demonstration project would presumably look more similar to that of a commercial CCS project than it would if the project management task was government-run. Given that the commercial relevance of the CCS demonstration phase is a key policy objective, this is a definite advantage to the private management approach. One disadvantage to private management is that since information on design, cost, operations, and maintenance is valuable to the public information transparency mission, care must be taken to ensure that proper incentives are in place to give the private company reason to disseminate this information.

5.6.2. Public

Public management of CCS demonstration projects could be done through the DOE or by a government-appointed board. The major advantage of public management is the ability to ensure information transparency, since public project managers will be held accountable to collect and communicate information on cost and performance from demonstration projects. Despite this advantage, there are significant disadvantages in commercial relevance and the different incentives faced by government managers, as compared to their counterparts in private industry.

Publicly managed projects will arguably be less commercially relevant than privately managed projects, since the business organization surrounding a publicly managed demonstration project will bear only partial similarity to privately managed projects. Also, the incentives to collect the most commercially relevant information on construction, operations, and management are weak as compared to privately managed projects, which is detrimental to the information generation and communication objectives of the demonstration phase.

Also, past government management of large energy technology demonstration projects have had mixed results, with cost overruns, delays, and cancellations being common; while some of these problems can be expected for high-risk demonstration projects, there is evidence that mismanagement played a role in the breeder reactor and synfuels programs (Cohen and Noll, 1991).

Why have management problems been common in government demonstration projects in the past? It may be due to the different set of incentives that these managers face, as compared to project managers in private industry.

Managers in investor-owned utilities and other private companies face pressures to keep costs down, revenues up, and projects on time, hopefully leading to profits for shareholders. Good performance in these areas can lead to increases in pay and promotions within the company: a "pay for performance" incentive. Conversely, bad performance in these areas risks termination or demotion. Multi-million dollar cost overruns and project delays directly attributable to mismanagement would conceivably lead to someone getting fired and losing their career.

Conversely, DOE program managers may not face the same risks and incentives as their counterparts in private industry. The goal in publicly managed projects is to stay under budget and on time, mostly due to the annual congressional budget pressures. Multi-million dollar cost overruns and project delays have been common in public demonstration projects, perhaps due a lack of the "pay for performance" standard of private industry. While bad management within government is often recognized and dealt with, it is surely dealt with in a different manner than in private industry. These government program managers do not face the same incentives for good performance and high risks for bad performance as their counterparts in private industry, and more work should be done to consider ways to improve these incentives for government managers[31].

5.6.3. Private Coalition

A coalition of private companies could perform the management task for demonstration projects. Presumably such a group could manage the design, construction, operations, and maintenance tasks in a commercially relevant manner, but given that true commercial projects will usually be constructed and managed by one or at most a few companies, a large coalition of diverse companies may lead to a less commercially relevant business model than could be expected from a single private company management organization. The coalition behind the FutureGen Alliance is one example of how the number and scope of supporting private entities does not reflect a real-world business organization; international coal mining companies and Chinese and British electric utilities are now leading this coalition after US electric utilities Southern Company and American Electric Power left the coalition earlier in 2009.

5.7. Policy Proposals for Cost and Risk Sharing

Theoretically, any combination of the above options could be the basis for the organization of a CCS demonstration phase; this thesis will look at a few of these different combinations in the context of recent policy proposals and evaluate the proposals based on the above analysis.

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[31] Accordingly, one way to improve the DOE demonstration capability would be to precisely identify how these incentives are different, and modify the management structures and incentives accordingly; perhaps an engagement with a management consulting firm could expose these differences and help develop a strategy. There is a developing body of literature on improving the effectiveness of existing government organizations. One original thinker working on this approach, David Osborne in his paper "Reinventing Government" in 1993 suggests that "results-oriented government" is one potential reorganization strategy that could improve performance through elimination of focus on line-items and budgets to a new focus on holding managers accountable for results and performance, which implies a strong need for identifying the criteria for success in the first place, which is often not clear for past DOE demonstrations. Such approaches could potentially be applied to DOE to help improve their capacity to manage demonstrations.

5.7.1. DOE Traditional

Over the last several decades the US government has been involved in energy RD&D in a very significant way, including several efforts to commercialize new energy technologies through demonstration programs. The US Department of Energy (DOE) currently has a program called the Clean Coal Power Initiative (CCPI) as its major cost-sharing program for demonstration of advanced coal generation energy technologies, such as carbon capture and storage. The CCPI allows up to 50% government cost-sharing on commercial-scale demonstration projects; the CCPI has five active projects and one completed project since its inception in 2001[32]. The CCPI selects projects through competition, and the costs of the projects are shared by the private partners and the funding party. In July 2009, $408 million in grants were issued for Round III projects, which have focused on CCS projects, using 2009 Stimulus Bill funds. One project uses an ammonia-based post-combustion capture system on an existing Basin Electric coal power plant to capture up to 1 million short tons of CO_2 per year; the second project uses pre-combustion capture on a coal- and petroleum coke- fueled IGCC plant built by Hydrogen Energy International and providing up to 2 million tons of CO_2 per year for EOR. As this thesis was going to press in December 2009, an additional $979 million was awarded for three additional projects through the CCPI Round III funding[33].

There are proposals to expand the DOE approach to future CCS demonstration phase projects, such as the 2008 bill S.2323 proposed by Sen. John Kerry of Massachusetts. This bill would provide $1.6 billion to support 3-5 sequestration demonstration projects, as well as $2.4b to support 3-5 capture demonstration projects. Up to 50% of the cost of these projects could be supported by government funds.

Even with the drawbacks of government project selection, the initial CCPI Phase III projects seem like reasonable project selections, and the CCPI could be a valuable part of a larger CCS demonstration phase, assuming funding for this program does not dilute efforts for a comprehensive demonstration phase effort.

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[32] DOE NETL Website on 9/20/2009: http://www.netl.doe.gov/technologies/coalpower/cctc/ccpi/index.html
[33] DOE NETL Website on 12/10/2009: http://www.netl.doe.gov/publications/press/2009/09081-Secretary_Chu_Announces_CCS_Invest.html

5.7.2. FutureGen Structure

The FutureGen project is a public-private partnership between DOE and the industry-sponsored FutureGen Alliance that is working to demonstrate full-scale integrated CCS for electricity generation. As originally conceived, the project would have been the first integrated CCS project in the world with full 90% capture on a commercial scale IGCC plant with saline aquifer storage, but due to delays and funding difficulties, the project is now unlikely to carry that distinction. The industry group, the FutureGen Alliance, was initially supportive of these aggressive technical specifications, but the Alliance was a fragile consortium of private parties with little incentive to contribute capital and bear risk in the first place.

In late 2007, internal DOE calculations showed major cost escalation in the project, increasing from $950 million to $1.8 billion in only three years. This cost escalation led to a public fight between the White House, the DOE, and the FutureGen Alliance over who would cover the tremendous cost increases. Using the cost escalation as the primary excuse, the DOE cancelled FutureGen, and introduced an alternative CCS demonstration program called the Restructured FutureGen program. This Restructured program was a flop, due to hasty preparation of the project solicitation resulting in only two applications, both of which were deemed ineligible; independent government analysts also noted that it was very similar to the existing CCPI program and was therefore redundant (US Government Accountability Office, 2009).

In the two years since then, the FutureGen Alliance continued design and initial procurement work on the original project. During this period, the situation was exacerbated by the exit of two major funding members of the FutureGen Alliance, Southern Company and American Electric Power (Columbus Business First, 2009).

In 2009, the Obama administration decided to revive Federal support for the original FutureGen project, which is now estimated to cost $2.4 billion. In an effort to reduce costs, negotiations between DOE and FutureGen Alliance eventually led to elimination of some of the research aims of the project, such as the hydrogen transportation fuels effort, and to a downgrade of the capture percentage to 60% from 90%, which helped reduce capital costs[34]. Also, the FutureGen Alliance will now own the project capital assets, and cost escalation above the original agreed amount will be shared 50/50%.[35] Currently, the FutureGen Alliance has been given time to put forward a revised plan to ensure financial support for the private share of these costs, a decision to move forward on the project will be made depending on the results of this new plan.

The current status is a delay surrounding private funding. Out of the estimated $2.4 billion cost, the government has pledged $1.073 billion from the 2009 stimulus bill and the FutureGen alliance has pledged up to $600 million so far, but a significant budget gap remains[36]. The FutureGen Alliance has until Summer 2010 to raise the additional private contributions, or else the project might not move forward.

Given the slow progress, unexpected difficulties, and continued uncertain fate of the FutureGen project, it seems unwise to pursue this as a model for future demonstration projects.

5.7.3. "Boucher Bill" Trust Fund and Private Demonstration Board

Another proposal for cost- and risk- sharing for demonstration projects is a program that would be funded by a special CCS demonstration trust fund, with projects selected by a non-governmental board. The idea would be to charge a small fee on each kilowatt-hour of fossil electricity that would be paid by U.S. electricity consumers. The revenues from the fee would be put into a trust fund designated for funding CCS demonstration projects for the power industry. The basic idea for the user-fee and industry managed board was introduced by Paul Romer in 1993[37], although his original proposal was quite general and not envisioned in the context of the

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[34] For an excellent treatment of the concept of partial carbon capture and sequestration, see the MIT Master's Thesis of Ashleigh Hildebrand. http://sequestration.mit.edu/pdf/AshleighHildebrand_Thesis_May09.pdf

[35] DOE Office of Fossil Energy Press Release July 14th, 2009

[36] DOE Press Release July 14, 2009: http://www.netl.doe.gov/publications/press/2009/7637.html

[37] Romer proposed the idea of "self-organizing industry investment boards" to solve the collective action problem of investment in non-rival goods such as research and development (R&D). The idea is that an industry would lobby for permission to impose a fee on itself, the revenues from which would be allocated by one or more industry "boards" investing in these non-rival goods. The fee would have to be approved by a majority vote of the members of that industry. Each firm within the industry would be able to decide which board to give their share of the fee revenues to. This arrangement adds an important element of competition to the boards, who must organize work that satisfies a good portion of the membership or else the board will not be funded. Investments would take place only in common property that benefited the entire industry, such as basic technology R&D work. The R&D work of the Electric Power Research Institute (EPRI) is a good example of the type of non-rival goods that would be funded

application to electric utilities or CCS technology. The user-fee funded trust fund aspect of Romer's concept was recently adapted for CCS demonstration by Professor Edward Rubin of Carnegie Mellon University, though notably the creation of a competitive structure for the allocation of the fee revenues has been left out of this proposal.

The first legislative embodiment of this idea was recently proposed by Rep. Boucher of Virginia as H.R.6258, and is included in the American Clean Energy and Security (ACES) Act recently passed by the House. Details on the CCS provisions in the ACES Act Version of the bill are given in the Appendix Section 8.6.

This bill would impose a small fee on all fossil power sales for 10 years. The fee, based on the relative CO_2 emission of each generation source, would be 0.43 mill/kWh for coal-fired generation, 0.22mill/kWh for gas, and 0.32mill/kWh for oil. The fee would have a small impact per household, but when these fees are accumulated in a trust fund for CCS demonstrations, about $10B would be raised over ten years. This trust fund mechanism has been used in the past by the US Highway Trust Fund, the Propane Education and Research Council, and an oil and gas industry program for "Ultra-Deepwater and Unconventional Natural Gas and Other Petroleum Resources" (Greenwald, 2008).

This fund would be managed by the non-governmental Carbon Storage Research Corporation (CSRC), which would be organized as a division of the Electric Power Research Institute (EPRI) and managed by a board comprised of power industry representatives, with a non-voting membership of DOE to provide some federal oversight. This board would have ultimate decision-making control over the demonstration projects supported by CSRC, but would likely farm out project management to private firms.

With the mission of supporting large-scale demonstrations of CCS, half the funds would be dedicated to existing early deployment projects, and half the funds would be dedicated to new or retrofit CCS demonstration projects. After the fees were collected in the trust fund, the CSRC board would likely formulate an open solicitation for CCS demonstrations, laying out the desired

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by a board, although EPRI is not funded by the mandatory user fee concept, but rather a voluntary user fee. Source: ROMER, P. (1993) Implementing a National Technology Strategy with Self-Organizing Industry Investment Boards. *Brookings Papers on Economic Activity*, 345-399.

characteristics of the projects they would prefer. According to an analysis of this approach by the Pew Center for Global Climate Change, the board would be directed to fund the incremental costs of CCS, including installation, operations and management costs for 5 years, and reimbursement of revenue lost due to reduced generation. Assuming an average cost of $730-$950 million for each plant, the bill could fund as many as 10 demonstration and early deployment CCS projects (Greenwald, 2008).

This proposal provides an effective structure for a demonstration phase for several reasons. It sets up a feasible allocation scheme for cost and risk sharing that has political support from public and private actors. Projects would be selected by an industry-managed private board by qualified individuals who have the incentive and capability to choose commercially relevant projects in the context of a coordinated technology portfolio approach. This board could then allow specific private companies to manage projects so that the most commercially-relevant business organization and information can be generated, and the board could then help ensure this information is communicated to the public, regulators, and future business participants. In summary, the Boucher Bill proposal provides an integrated policy solution for the demonstration phase and it is politically viable, so should be passed as part of the ACES Act.

5.7.4. Energy Technology Corporation

Another proposal for a new body to fund and manage CCS demonstration projects is the Energy Technology Corporation (ETC). Recently proposed by John Deutch, John Podesta, and Peter Ogden, this would be a semi-private corporation funded by a large single appropriation to fund energy technology demonstrations for capital-intensive technologies like CCS and cellulosic ethanol production (Ogden *et al.*, 2008). The ETC would be managed by a board appointed by the President. The levels of funding required for such an approach have not been detailed, but one could assume tens of billions of dollars would be required.

This proposal is interesting and raises a potential solution to the disadvantages of government project selection and management while allowing the central coordination of projects in a demonstration phase. But due to the lack of development of this proposal, this cannot be recommended as a model for a demonstration phase. More work in developing this proposal could help bring this concept to fruition, since it proposes a very interesting structure important to more than just a CCS demonstration phase, but to the larger energy technology effort.

5.7.5. Subsidies

There is potential for supporting demonstration projects through a simple subsidy program, especially in the case of a project where the high costs and risks are deemed acceptable by the private backers. One such mechanism is a production tax credit, which has been used extensively for financing wind power projects in the US (further discussion of the subsidy mechanism is presented in Section 6.2.1.3). Generally, subsidy policy proposals are intended to share costs, but not risks, as distinguished from the cost- and risk-sharing proposals in the preceding paragraphs; with the project risks fully borne by private actors, subsidies can be a good policy tool for the more-commercial demonstration projects but would generally be an inferior policy tool for supporting more-high-risk demonstration projects. Since subsidies are viewed as net positive cash flow into a project's income statement, they could help offset the high capital and operations costs of early CCS projects, but would not offset some of the high risks of early CCS projects.

5.7.6. Cost Pass-through

"Cost pass-through" is a potential, but unlikely, method of financing more-commercial CCS demonstration projects, and will in the long term be the preferred method of supporting CCS projects since it is the standard mechanism for financing projects for regulated electric utilities. Cost pass-through is when the incremental costs for CCS are passed through to electricity ratepayers, either through rate regulation for regulated utilities or through long-term power purchase agreements, for merchant generators. Firms will unlikely be able to utilize this method of financing for demonstration projects since strong market and guaranteed return on investment must exist for this method of financing.

5.8. Conclusions

How ought the US government and private industry be involved in a CCS demonstration phase?

The contribution of this analysis is the development of an analytical framework that explores different options for the roles public and private actors can take in a demonstration phase. This section provides a framework for consideration of the objectives of (1) allocating cost and risk among public and private actors, (2) project selection, and (3) project management, and explores the policy options to achieve each of these objectives.

The Boucher Bill ACES Act proposal provides the most complete policy proposal for achieving all three of these major objectives, and it should be the cornerstone of a demonstration phase for CCS. The creation of a trust fund and ratepayer fee structure is a superior funding mechanism compared to using the budget appropriations process since it provides a definite and secure source of funding. This funding source ensures that the users of the technology are the ones paying for the technology demonstration; while taxpayer money could fund a demonstration phase, the political process has shown limits to willingness to fully fund a demonstration program through the federal budget. The private board project selection structure seems superior to the government or private technology selection options alone, since it combines the strengths of the private incentives for commercial relevance with the public incentives to support a technology portfolio approach. The private board management structure seems clearly superior to the government management approach, since it would provide commercially relevant project management organization.

Despite evidence that public project selection may lead to less commercially-relevant projects, the DOE Clean Coal Power Initiative Phase III is currently supporting five valuable CCS demonstration projects, and this CCPI can be continued in tandem with the Boucher Bill ACES Act proposal. Pursuing this dual strategy of the Boucher Bill approach and the CCPI could introduce an interesting competitive element between these two public and private demonstration institutions. Since the development of the Boucher Bill is likely a direct response to past failures in government demonstration programs, this competition should increase pressure on DOE to improve the performance and commercial relevance of their demonstration activities.

If urgency in moving forward on CCS demonstration is the most important consideration, then moving forward on these proposals immediately will provide an effective structure to achieve the objectives of a CCS demonstration phase.

As part of future work on the design of a demonstration phase for CCS, further analysis of the trade-offs between these proposals would be useful. Continued analytical work could explore the questions that have been raised in this framing in a more grounded manner by quantitative analysis or in-depth case studies. These studies should also seek to include interviews with those with the most experience in past energy demonstration projects such as government program managers and representatives from the power sector and academia.

6. Commercial Deployment

CCS has the potential to be a significant technology for carbon emissions mitigation worldwide, but significant commercial deployment of CCS is unlikely unless the three major barriers identified in Section 3 are addressed soon. Correcting for the absence of a viable demonstration phase and the uncertain legal and regulatory framework could help achieve "technology readiness" for CCS technology. But while these actions will be necessary, they will be insufficient to achieve significant commercial deployment for CCS, due to the persistent lack of an adequate market for CCS.

6.1. What are the policy objectives for commercial deployment policy?

To make CCS technology a significant contributor to CO_2 emissions mitigation, commercial deployment will be necessary. Here there are two broad objectives for policy:

- *Market penetration:* The goal here would be to achieve a guaranteed level of market penetration of CCS technology by some specified date.
- *Cost reduction:* The goal here would be to reduce the costs of CCS technology so as to make it more competitive in the long-term.

These goals are not mutually exclusive: achieving the goal of cost reduction will require market penetration, while the goal of market penetration will be furthered by cost reduction. On the other hand, the two goals will each require somewhat different policy interventions to achieve them. Policymakers' priorities regarding these goals can be expected to be influenced by (1) expectations as to the future availability of other low-cost, low-carbon energy technologies; (2) expectations as to the severity of the climate change threat; (3) beliefs as to the appropriate role of government in the economy.

This section will describe how policies could promote the achievement of each goal, both in the short and long term. The answers provided set up a straw-man policy proposition for each goal, which is useful for understanding potential reasoning behind each goal.

6.1.1. Market Penetration Goal

A market penetration policy goal would be to ensure the adoption of a specified amount or achieve a specified market share of CCS technology by some future date. One potential rationale for this goal is that the long-term public benefit of carbon emissions mitigation (e.g., avoiding the worst harms of global climate change) is too great to leave deployment of CCS to the vagaries of the marketplace, so some contribution from CCS should be mandated. Other rationales could be based on national energy security or the economic value of the domestic coal industry. In the case of solar photovoltaics, an interesting rationale for supporting market penetration has been to buy down the cost of the technology, but a recent case study of installed US solar photovoltaics shows that this rationale may be problematic[38].

Achieving the goal of market penetration may require deploying CCS even if it is more expensive than competing technologies. Thus the cost of achieving this goal will be highly dependent on both future cost reductions in CCS technology, which are the result of innovation from information produced from commercial projects, as well as the structure of the specific policies used to create the market for CCS. Conceptually, the simplest way to achieve this goal of guaranteed market penetration would be a regulatory mandate, perhaps akin to the high percentage (20-30%) renewable portfolio standards adopted by US states over the past decade. Subsidies would also support market penetration, but they cannot easily guarantee a specified penetration level. One risk of pursuing this goal is that if the long term costs of CCS technology remain high as compared to alternatives, the costs of the policy could become very high, and achievement of this goal would become less politically tenable.

6.1.2. Cost Reduction Goal

The goal here is to reduce the costs of the technology through innovation, so that CCS can be a competitive option with little or no additional policy support in the long term. Cost reduction goals have actually been an explicit part of US DOE policy toward CCS. The current objective is to "make progress toward a capture and sequestration goal of less than 10% increase in the

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[38] See the 2009 MIT Master's Thesis of Phech Colatat.

cost of electricity for gasification systems and less than 35% for combustion and oxy-combustion systems"[39]. This particular DOE goal may or may not be feasible, but an alternative quantitative goal could obviously also be chosen.

In contrast to the market penetration goal, the cost reduction goal implies conditional support for the deployment of CCS technology. Significant deployment would occur only if the after-policy cost of CCS was fully or nearly competitive with other low carbon electricity options.

The pursuit of this goal in the short and medium term might entail similar policies to those proposed for the market penetration goal, but in the long term, the focus on cost reduction would require less policy support.

6.2. What are the policy options available to achieve these objectives?

There are two categories of policies to support these two goals. Some policies would provide incentives for investment in commercial projects and support for market creation, thus driving demand for the technology. These are referred to as "market pull" policies. Other policies would provide support for technology development and innovation, thus improving the options for supply of a technology. These policies are referred to as "technology push" policies. In achieving either of the goals above, one can consider market pull or technology push policies, or a combination of the two. The innovation system model proposed in Section 4.3.3 described the relationship of these various policies to innovation and long-term cost reduction. The major conclusion of that section relevant for commercial deployment policy is that market pull policy is of primary importance in establishing a market, but also in supporting cost-reducing innovation, and that technology push policy can play an important complementary role in supporting cost-reducing innovation.

6.2.1. Market pull

Market pull policies provide incentives for private actors to invest in commercial deployment of a technology. There are a variety of support mechanisms that in principle can be used to create

[39] DOE Press Release from December 4, 2009 titled "Secretary Chu Announces $3 Billion Investment for Carbon Capture and Sequestration".

market pull for CCS technology, and these can be combined to achieve the desired effect. As the cost gap for CCS described in Section 2.3 suggests, US political reality is likely to prevent any single market-based policy mechanism from properly correcting for the environmental externalities of CO_2 emissions. Using multiple policies to achieve a specific policy goal may be a good approach in a "second-best" policy world (Bennear and Stavins, 2006).

These market pull mechanisms can be broadly separated into three major sub-categories: carbon pricing, mandates, and subsidies. A table showing some policy categories along with several specific mechanisms is shown as Table 6.1.

Table 6.1. Summary of policy categories and specific mechanisms for market pull.

Policy Sub-Category	**Specific Mechanism**
Carbon Pricing	Cap and Trade
Carbon Pricing	Emissions Tax
Mandates	Portfolio Standards
Mandates	Emissions Performance Standards
Mandates	Design Standards
Subsidies	Tax Credits
Subsidies	Bonus Allowances
Subsidies	Feed-in-Tariffs
Subsidies	Government Financing

6.2.1.1. Carbon Pricing

Carbon dioxide emissions pricing, or carbon pricing, is the first and most fundamental policy option to support a market for CCS technology. The concept is to internalize the unpriced externality of the long-term negative effects of climate change in the price of goods and services that emit greenhouse gases. This carbon price will then change the mix of economic choices away from carbon-intensive goods and services toward those with lower net carbon emissions. In the power industry, the effect would be to impose higher costs on companies using fossil fuel generation, thus giving low-carbon technologies like renewables, nuclear, and coal with CCS a relative advantage. The higher the price of carbon, the more likely an electric utility will decide to invest in CCS.

One can either directly price carbon emissions through a tax, or let the emissions price be established as a market price under a cap-and-trade scheme. The current US policy momentum has shifted strongly toward a cap-and-trade program, and this paper will not discuss the carbon tax option further.

A cap-and-trade scheme is the most widely discussed approach for a potential US carbon pricing system. The European Union (EU) Emissions Trading Scheme (ETS) is a good example of a functioning cap-and-trade approach, and it has been in effect since 2005. The EU member countries specify a cap on greenhouse gas emissions from major point sources, and this cap is progressively lowered each year. Allowances are issued in the amount of the cap, such that regulated entities emitting greenhouse gases must surrender an allowance for each unit of greenhouse gas they emit. If an entity was not issued enough permits initially, or did not purchase enough permits through a government auction, the entity can purchase additional permits on the open market, or conversely, the entity can sell excess permits if it has found ways to reduce its own emissions. Currently the market price of a CO_2 permit under the ETS is €13.06/tCO_2e, which is equivalent to \$19.40 USD[40].

The major current US policy proposal for a cap and trade system is the ACES Act, which was passed by the US House in summer 2009. The details of this proposal are in the Appendix Section 8.5.1, and an analysis of the impact of carbon market prices from this bill was performed in the cost model analysis in Section 2.3.

6.2.1.2. Mandates

Three major mandate mechanisms will be discussed here: portfolio standards, emissions performance standards, and design standards.

Portfolio Standard

A portfolio standard is one type of mandate for a specified amount of energy technology deployment, specified as either generation (MWh) or capacity (MW). Portfolio standards have been used in many US states for renewable generation and energy efficiency. Twenty-five US

[40] Carbon market price from 11/21/2009, using price indices listed publicly by Point Carbon, Inc.; price adjusted to USD using exchange rate from Citibank on 11/21/2009.

states have passed rules requiring as much as 33% of electricity generation by 2030 (California) to come from renewable sources[41]. The same concept has been applied in the form of a "clean coal" portfolio standard in Illinois, where the state is requiring 5% of electricity to come from plants using CCS by 2015.

The ACES Act of 2009 includes a national renewable portfolio standard, called the "renewable electricity and efficiency standard (RES)", that requires approximately 20% renewable power nationally by 2020. Details can be found in the Appendix Section 8.5.2.1.

A "total" portfolio standard for CCS would require generators to generate a certain percentage of their total generation or capacity portfolio using CCS technology. Such a mandate would effectively guarantee a market for CCS technology, but this is the least economically-efficient policy option, since it eliminates all choice by private firms in their investment decisions. This policy specifies the amount of generation or installed capacity at some date in the future, which would have to be reached irrespective of the cost, so this policy would effectively achieve the market penetration goal; conversely, pursuing this policy for the cost reduction goal in the long-term would be inadvisable since there is zero consideration of the relative competitiveness of CCS technology costs.

A total portfolio standard would lower economic efficiency since it eliminates all choice by private firms in their investment decisions. Despite this downside, this guaranteed market for the technology, combined with the continuing technology push RD&D efforts, could lead to significant innovation in CCS technology, improving economic efficiency over the long term. This cost reduction is not guaranteed though, so if the costs of CCS did not come down significantly, making CCS cost effective on its own terms, this could be a very expensive mandate for ratepayers.

A "coal-only" portfolio standard would require generators to generate a certain percentage of their coal-based generation using CCS technology. This policy would provide more market pull for companies choosing to build or continue coal generation, but it would not compel them to

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[41] US DOE Office of Energy Efficiency and Renewable Energy website - http://apps1.eere.energy.gov/states/maps/renewable_portfolio_states.cfm

build CCS if they chose not to, as would be the effect with a total portfolio standard. Alternatively, it would require a certain percentage of their coal-fired capacity to use CCS technology. To my knowledge, this policy option has not been proposed, but it is worth considering as an intermediate option with respect to the curtailment of private decision making between an emission performance standard and a total portfolio standard. Since coal with CCS would still have to be competitive with non-coal alternatives for a coal-only portfolio mandate to work, this mechanism would not be effective in providing a guaranteed level of technology deployment, unless combined with additional market pull policies providing further incentives.

This option could be useful in mitigating regional equity issues, which are increasingly visible as a political barrier to passing comprehensive climate and energy legislation on the federal level. Since CCS must still be somewhat competitive with alternatives for a coal-only portfolio mandate to work, this mechanism is not effective in guaranteeing a specified level of technology deployment, unless combined with additional market pull policies providing further incentives. This policy would also significantly restrict the choices of private firms at the portfolio level, which reduces short term economic efficiency more than restricting choices for individual projects as the emission performance standard policy does. In the long term, the level of market pull is greater than for the emission performance standard policy, and therefore long-term economic efficiency is improved due to the results of innovation and cost reduction.

Emissions performance standard

The second major mandate considered for CCS is an emissions performance standard, which specifies a maximum emissions level for CO_2. It would require new coal plants to capture a minimum percentage of their CO_2 emissions using CCS technology. This standard provides market pull indirectly, by eliminating the option of building uncontrolled coal power plants. It implies that CCS technology must still be competitive with other clean energy technologies to achieve market penetration. Depending on the level of the standard, this mechanism could exclude uncontrolled coal power plants only, or it could also exclude "partial capture" CCS, which is a popular option for early CCS projects, as shown in Section 5.5.3.3.

Used alone, an emissions performance standard only excludes uncontrolled coal fired power plants, but this does not ameliorate the economic difficulties faced by new CCS projects. This policy cannot provide enough market pull to guarantee any significant level of market penetration; therefore, this policy could be best used in conjunction with other mandates or subsidy policies to provide additional market pull. Since this policy only minimally constrains private decision making, it has a correspondingly low impact on short-term economic efficiency, and a low potential for supporting long-term innovation inspired through commercial deployment.

Mechanisms of this type have been used to regulate power plants and industrial sources since passage of the Clean Air Act in 1970, and similar CO_2 emissions performance standards are being proposed to support adoption of CCS technology. The EPA regulations under the Clean Air Act specify new source performance standards (NSPS), which set an emissions rate limit for new or substantially modified sources emitting the controlled pollutant. The stringency of this standard relative to what is technologically achievable is an important factor in the effectiveness of this tool in driving innovation (Ashford and Caldart, 2008).

California passed SB 1368 in 2007, which set an emissions performance standard of 1100 lbsCO_2/MWh for new plants or for any electricity imported into the state, effectively eliminating uncontrolled coal generation as an option. However, it would still allow partial-capture CCS, full capture CCS, and natural gas-fired generation. For CCS, only an emissions capture standard of approximately 90% or less is currently feasible, since a more stringent standard would drastically increase the marginal costs of avoided emissions based on current carbon capture technology.

Since most new and existing coal plants emit somewhere between 1800 and 2100 lbsCO_2/MWh, a relevant standard will obviously be less than this. It might be set somewhere between the level of equivalent natural gas emissions of 800-1200 lbs/MWh, which would correspond to a 45-60% capture rate or 'partial capture', and 200-350 lbs/MWh, which would correspond to 85-95% capture rate or 'full capture'.[42] California has chosen a standard of 1100 lbs/MWh, thus allowing the option of partial capture CCS as well as natural gas plants with no capture.

[42] Emissions performance standards above approximately 90% capture for new sources will only serve as a disincentive for investment in CCS technology, due to limitations in existing carbon capture technologies; as

The ACES Act of 2009 includes an emissions performance standard for CO_2 that tightens over time in accord with the expected commercial availability of CCS technology for coal power plants. Details can be found in the Appendix Section 8.5.2.2.

Design Standards

A third regulatory mandate approach would involve more specific technology design standards, as was common with early "command and control" regulatory approaches to environmental pollution. This thesis strongly recommends against such an approach since there is no clear technology winner for carbon capture technology, as shown in Section 2.1.4. The case study for FGD technology showed that such an approach is feasible in some circumstances. The EPA passed regulations requiring industry to apply the best available control technology (BACT) to meet new source performance standard (NSPS) requirements for SO_2 emissions, as described in Section 4.1. In that case, EPA's restriction of technology options led to significant innovation in FGD technology. In December 2009, the EPA released an endangerment finding for CO_2 emissions that is a legal precursor to further regulation of CO_2 emissions under the Clean Air Act authority, including the potential for regulation of coal-fired power plant emissions. However, applying this approach to CCS is not recommended due to the lack of clear technology winners and the diverse technology options for carbon capture technology that are near to commercial application.

6.2.1.3. Subsidies

The third broad category of market pull policies is subsidies. This includes specific mechanisms such as tax credits, bonus allowances, feed-in-tariffs, and government financing programs.

Tax credits have been used for the past decade in supporting wind and solar energy in the US. Wind power technology has received a per-kWh production tax credit (PTC) support. Solar

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introduced in Section 2.1, the post- and pre-combustion approaches to carbon capture use a chemical absorption approach, which exhibits diminishing economic returns to increasing percentage capture, especially as capture percentage increases above 90% (Hildebrand, 2009). Even though progressively more stringent emissions performance standards have been advocated by others in support of innovation in environmental control technologies (Ashford and Caldart, 2008, Taylor et al., 2005), until radical innovation provides further technology options for carbon capture without this constraint (which is another reason for the simultaneous technology push of continued RD&D), this emission performance standards approach should not be further increased beyond the 90% capture level.

power has received a per-kW capacity investment tax credit (ITC) support. Carbon sequestration received its first per-ton CO_2-avoided sequestration tax credit (STC) program in the Federal stimulus legislation in late 2008.

Bonus allowances are a subsidy program funded through allowances set aside from a cap and trade allowance allocation program to support commercial deployment of CCS technology. This concept was introduced first in the Lieberman-Warner climate bill of 2007, and a slightly different version of this policy is included in the current ACES Act of 2009, which is described in detail in Appendix Section 8.6.

A third mechanism for subsidy is the feed-in-tariff, which has been successfully used in several European countries. The feed-in tariff provides a guaranteed price for electricity generation from a specific source, such as solar photovoltaics, wind, or perhaps CCS. This mechanism is not very popular in the US, especially in application to CCS, so this thesis will not consider this mechanism further.

The final subsidy mechanism is via government financing programs that access to lower-cost debt financing for commercial projects. One example is the current DOE Loan Guarantee program, initiated under the Energy Policy Act of 2005, which issues loan guarantees for large nuclear power projects and coal gasification projects. These loan guarantees help high-risk projects to access lower-interest private debt financing. One serious proposal to expand this government financing approach is the Clean Energy Deployment Administration concept presented in the 2009 Bingaman Energy Bill; more details on this are given in Appendix Section 8.5.3.3.

Funding stability of a subsidy program is important, given the recent history of uncertainty for renewable energy tax credits. The CCS cost model in Section 2 estimated the total above-market cost to be on the order of $100+ billion dollars over the next several decades. Meeting this entire cost gap through a subsidy policy may be politically difficult to sustain through the normal federal budget process. Moreover, the attempt to do so could introduce a major risk of funding instability into CCS project investment decisions. The prospects for greater funding stability could be enhanced through three different options: 1) Minimize exposure to the federal appropriations process through the use of large, infrequent appropriations; 2) Increase the length of a subsidy award for any program using the appropriations process, which the ACES Act deals with through providing a 10-year subsidy contract; 3) Eliminate the need for funding through the appropriations process altogether by funding a subsidy program through a source of funding outside the federal budget, which the ACES Act deals with by funding through the cap and trade allowance emissions allocation program, such as the "Bonus Allowance" Phase I and II subsidy programs in the ACES Act.

The economic efficiency of a subsidy program is also important. While a very high subsidy value could effectively guarantee a specified level of long-term market penetration, this risks becoming a very expensive and inefficient policy. Windfall profits are likely for low cost producers in this case, and the cost-effectiveness of CCS with respect to technology alternatives would be ignored.

A more efficient and politically reasonable subsidy program would be a subsidy policy more sensitive to technology costs and the availability of alternatives in the long term, and would therefore be in support of the cost reduction goal. This subsidy program would provide support in the short and medium term up to the point where the net after-subsidy cost of CCS is equivalent to alternative generation technologies, but an efficient subsidy would be no higher than this[43]. Over the long term, the subsidy program could then be scaled down to reflect either one of two situations: CCS has become cost-competitive and requires no subsidy to compete with alternatives, or that CCS remains expensive and these alternative options should be pursued by the market. Additionally, this policy would introduce uncertainty in the actual level of market penetration achieved, and would thus be a sub-optimal policy for achieving a market penetration goal.

One example of this structure is the ACES Act Bonus Allowance Phase II program as described in detail in Appendix Section 8.6.3. The program provides a subsidy program up to 72 GW of installed capacity, or when the funds for the program run out, whichever is earlier. Assuming the reverse auction valuation structure keeps costs down, and 72GW is reached, the presumption is

[43] It is important to note that there is little evidence that policy makers are adept at choosing proper subsidy values initially or altering subsidy values retroactively to reflect private costs and current market realities; despite this a best effort should be made

after this point that CCS has reached the point where it must compete, or else other alternatives will be chosen.

A consideration of the cost gap concept can help define an appropriate upper bound for this subsidy, assuming one has confidence in private CCS costs and future carbon market conditions; in reality policy makers may have high uncertainty in these parameters. The cost model presented in Section 2.3 explored the value of cost gap, and a similar analysis could be useful in putting numbers on the subsidy value and total subsidy program cost. Also, there is potential for windfall profits for low-cost firms if a fixed-value subsidy is chosen to be significantly higher than actual private costs. One solution to reduce the likelihood of windfall profits is a reverse auction valuation structure which adds a competitive element to the valuation of subsidy contracts, which is proposed in the ACES Act Phase II subsidy program for CCS.[44]

Each of these subsidies works in a different manner, but in the final analysis each subsidy shows up as net revenue on the income statement, helping to defray costs for companies building CCS projects, and so providing market pull and driving commercial deployment.

6.2.2. Technology push

Technology push policies seek to promote commercial deployment by directly lowering technology cost through support of innovative activities. Lowering technology costs makes CCS more competitive and furthers the goal of market penetration. Technology push policies can be an important compliment to market pull policies, but used alone are insufficient for achieving the goals of market penetration and cost reduction. Besides the required technology push provided by demonstration phase for CCS, a broad set of continuing technology push policies can be an effective complementary strategy to the market pull policy needed to achieve the market penetration or cost reduction goals.

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[44] The only market pull mechanism that directly supports market competition is the reverse-auction subsidy valuation mechanism; this market competition leads price competition, providing an incentive for cost-reduction among competing firms. The reverse-auction valuation process for the subsidy contracts leads to competition among projects such that the lowest-bidding project wins the contract, which provides an incentive for competition between companies building CCS to lower costs so the profitability can be maintained under the awarded contract. See the Clean Air Task Force/Northbridge Group paper for more details: http://www.coaltransition.org/pages/reverse_auction/51.php

In general the amounts of funding required for technology push policies will be significantly less than what is required for market pull, due to the fact that such policies support mostly early stage technology activities that are at lab, pilot, or demonstration scales. The major increases in capital requirements come during large-scale deployment. There are several different technology push policies that can support innovation in CCS:

- Direct RD&D Spending - This is the fundamental technology push policy, and it is especially useful for supporting high-risk fundamental and applied research projects, as well as demonstration projects, which were analyzed in detail in Section 5. Direct government spending on RD&D activities is common for CCS technology, mostly through the DOE Office of Fossil Energy as described in Section 4.2.2. This program has been largely successful, and this thesis advocates a continuing public R&D effort as part of a technology push policy for CCS, but further options for improvements to these programs will not be considered here.
- Indirect Incentives for Private RD&D – There are a number of potential ways to support private activity in applied RD&D. One major current policy is the federal R&D tax credit, which provides an economic incentive to undertake risky applied R&D activities. This policy has had cycles of lapse and renewal since it was established in 1981, and some are calling for establishment of a permanent R&D tax credit[45].
- Support of knowledge transfer opportunities – One example is the public support of industry/academic/government technology conferences associated with specific technology areas (Taylor *et al.*, 2005). By providing a forum for exchange of knowledge between innovators in a technology space, these knowledge transfer opportunities are an integral part of the innovation process and can be a relatively inexpensive technology push policy, as compared to the sums required for direct RD&D support.

6.2.3. Analysis

Mandate policies can be useful in achieving the market penetration goal, which indirectly can support the cost reduction goal through innovation. In the long-term, the lack of sensitivity to

[45] For example, see http://www.investinamericasfuture.org/.

technology costs makes these mandates policies insufficient to achieve the cost reduction goal; accordingly, a strong mandate policy has the potential to be a very expensive and politically-unpopular long-term policy if cost reductions through innovation are not realized.

Alternatively, pursuing the goal of market penetration alone can be done through subsidies alone, but only a very expensive and inefficient subsidy program could achieve a guaranteed level of market penetration. Supporting the cost reduction goal through significant subsidy market pull in the short and medium term, with a significant reduction of the subsidy program in the long term, would be a more efficient subsidy program while still supporting the goals of market penetration and cost reduction.

Finally, a combination of mandates and subsidies can be used to achieve either goal. In support of the market penetration goal, a subsidy program can successfully offset the political difficulties of meeting a strong mandate through a shifting of the cost burden from utilities and ratepayers to taxpayers (in the case of a subsidy program funded by general tax receipts) or to a different geographical distribution of ratepayers (in the case of a subsidy program funded by carbon allowances, such as the bonus allowance programs). This shifted cost burden could help mitigate the political difficulty of regulatory risks surrounding cost allocation in meeting a strong mandate.

In support of the cost reduction goal, a mix of mandates and subsidies, complemented by technology push policies, can be used to provide the desired level of market support in the short and medium term. For instance, in the ACES Act, both a strong subsidy program and an emissions performance standard mandate are provided for CCS, to provide the level of market pull necessary to get market penetration in the short and medium term, hopefully leading to innovation and reduced technology costs.

6.3. What is the right goal for commercial deployment of CCS?

The goal of technology readiness and its requirement for a significant demonstration phase is a necessary and important goal, but this goal is not sufficient for significant commercial deployment of CCS. Technology readiness is just the first step along the path to making CCS a significant contributor to carbon emissions mitigation.

Beyond technology readiness, creating a market for CCS is fundamental for reaching any level of commercial deployment. Especially in the short and medium term, a carbon price alone will be insufficient to create this market. Other market pull policies will be required to bridge the cost gap for CCS. How this market pull ought to be provided depends on a policy maker's preference between the goals of market penetration and cost reduction for CCS technology.

Market penetration can be ensured through strong market pull policies, both in the short and long term, but this may be a very expensive policy approach since the relative cost of CCS technology compared to low-carbon alternatives would not be considered. The commercial projects supported through this policy could help to lower technology cost through innovation. But the lack of an explicit focus on cost reduction to make CCS competitive with alternatives is problematic.

A more prudent goal for commercial deployment of CCS is long-term cost reduction, which places priority on the economic feasibility of CCS compared to other options. Meeting this goal will require strong market pull policies for the short and medium term, with an added focus on continued technology push policies over the entire period. In the short and medium term, a combination of significant market pull support and aggressive technology push policy is justified to encourage commercial deployment for two reasons: 1) To accelerate the development of the innovation system to provide cost reductions for CCS technology in the long term; 2) To put the US on the right path to achieve significant deployment of CCS in the long term. In the long term the major difference between the cost reduction and market penetration goals becomes apparent: cost-reducing policies can be significantly scaled-down or eliminated since the cost of CCS will have become economically competitive with alternative generating technologies, or else the necessary cost reduction is not achieved, and CCS will not be supported for long term commercial deployment.

Unlike the market penetration goal, pursuing a cost reduction goal will not guarantee that CCS will become a major contributor to carbon emissions mitigation in the future. But it does provide a more cost-effective path since the long-term priority here is the economic feasibility of CCS. If CCS costs don't come down significantly, CCS will not reach significant commercial deployment in the long term, leaving two possible futures: either alternative generation technologies will provide sufficient carbon emissions mitigation, or the US will simply fail to achieve this, leaving us to rely on adaptation to global climate change.

Pursuing the goal of market penetration alone is short-sighted and could lead to a very expensive and politically difficult long-term policy toward CCS. While achieving this goal would provide significant carbon emissions mitigation through CCS, the lack of sensitivity to CCS cost and alternative technologies make this an inefficient policy goal.

The right goal for commercial deployment of CCS is the cost reduction goal, achieved through a policy of strong market pull in the short and medium term, a continued technology push policy over this period, and in the long term, a significantly reduced or eliminated market pull policy for CCS. Pursuing this goal is preferable from an economic perspective, since it focuses on the economic viability of CCS in the face of alternatives, instead of the potentially unlimited support provided by pursuing the market penetration goal alone. If the cost reduction goal is pursued but is not achieved, CCS will not and should not be commercially deployed.

This analysis strongly recommends that both a publicly funded CCS demonstration phase and a strong market pull policy for CCS should be pursued immediately as the short term policy for CCS. The ACES Act climate and energy bill passed the US House of Representatives in summer 2009, as discussed in detail in Appendix Section 8.6. This legislation includes a combination of market pull and technology push policies that effectively achieve significant market pull for CCS in the short and medium term. This proposal provides support for a technology push demonstration phase followed by a strong market pull policy for CCS in the short and medium term, through the combination of a carbon pricing scheme, a significant subsidy program for CCS, and progressively more stringent emissions performance standards. The carbon price provided by this Act would be politically constrained, and therefore the Act provides a subsidy program to bridge the remaining cost gap for CCS. The Act would support up to 72 GW of CCS deployment, after which CCS will have to make economic sense with only a carbon price and an emissions performance standard. The ACES Act represents a conditional and cost-effective approach to long term support for CCS, and therefore is consistent with meeting the cost reduction goal.

7. Conclusions

The United States has a dual interest in CCS technology. It has the potential for significant mitigation of CO_2 emissions to prevent global climate change. It also has the potential to contribute to energy security because it would enable the use of the vast North American coal reserves. Several good technologies for CCS exist today, but they come with high costs and risks that stand as a barrier to private investment. On the capture side of the system, regional market requirements, differences between new and retrofit applications, and the lack of a clear technology winner mean that several very different capture technologies will likely be used in early CCS projects.

Early estimates of actual CCS costs and the likely results of a politically feasible US carbon pricing scheme were combined in a cost model showing the existence of a significant cost gap for CCS on the scale of $100 billion dollars, a major barrier to commercial deployment of CCS. In addition, two other major barriers persist for CCS: the uncertain legal and regulatory framework and the lack of a demonstration phase. This thesis has provided a framework for assessing alternative policies for implementing a demonstration phase and for creating a market for CCS, both of which will contribute to significant commercial deployment of CCS technology in the long term.

An exploration of the innovation system for FGD revealed several important insights relevant to CCS innovation policy. Market pull policies are likely to be the primary driver for commercial deployment, and these market pull policies are also the primary driver for innovation. Technology push policies can play an important complementary role in supporting innovation, but without a market for the technology they seek to improve, their utility is minimized. Once a market is established, the cycle of innovation can begin to provide significant, long-term cost reductions for CCS technology. These cost reductions are not guaranteed, but we can be sure that without market supports, innovation in CCS will be minimal, and the likelihood of significant cost reduction in CCS technology will be low.

A CCS demonstration phase should have four major objectives: information generation and communication, urgency, commercial relevance, and a technology portfolio. The analysis here provides a framework for considering how the demonstration phase can be designed so as to improve the likelihood of achieving these goals. Given the performance problems of past large government energy technology demonstration programs, a public/private cost and risk sharing model, with projects selected by a dedicated private board and projects managed by private industry, would provide a better structure for the demonstration phase. The Boucher Bill proposal included in the ACES Act provides such a structure, and should be pursued alongside the current DOE Clean Coal Power Initiative Round III, which has already secured funding for several early CCS projects. Additionally, this combined approach could provide a real-world laboratory of competition between public and private programs that could expose more clearly some of the risks and benefits of the two approaches.

For commercial deployment of CCS, creating a legal and regulatory framework and implementing a demonstration phase can provide technology readiness, but these actions will not be sufficient to reach significant commercial deployment of CCS. If the CCS cost gap persists, additional policy support will be required to achieve commercial deployment of CCS. The required mix of short and long term market pull and technology push policies will depend on how the objectives of market penetration and cost reduction are prioritized. Pursuing the goal of market penetration alone would be short-sighted and would likely be very expensive. Cost reduction is a better goal for commercial deployment. This could be achieved through a policy of strong market pull in the short and medium term, coupled with continued technology push policies over this period and, in the long term, significant scaling back or elimination of the market pull policies. If costs are not reduced such that CCS can become competitive with alternatives, CCS will not and should not be deployed on a large scale. In this case, either other technologies will provide the emissions mitigation, or the US will fail to reduce its CO_2 emissions.

The analysis here leads to the conclusion that the policies in the ACES Act package for both commercial deployment and demonstration should be supported, since they provide a combination of market pull and technology push that is capable of achieving the goals of technology readiness and cost reduction in CCS, while also providing good prospects for achieving significant long term market penetration of CCS technology.

8. Appendix

8.1. Abbreviations and Acronyms

ACES - American Climate and Security Act – H.R. 2454
BACT – best available control technology
CAA – Clean Air Act
CCPI – Clean Coal Power Initiative
CCTDP - Clean Coal Technology Demonstration Program
CCS – carbon capture and sequestration
CEDA – Clean Energy Deployment Administration
CERA – Cambridge Energy Research Associates
COE – cost of electricity
CRAI - Charles River Associates International
CRBR - Clinch River Breeder Reactor
CSRC – Carbon Storage Research Corporation
CPI - consumer price index
DOE – US Department of Energy
EIA – US DOE Energy Information Administration
ETC – Energy Technology Corporation
EOR – enhanced oil recovery
EPA - US Environmental Protection Agency
EPRI - Electric Power Research Institute
ERDA – Energy Research and Development Agency
ESP – electro-static precipitator, a particulate matter removal technology
ETS – European Union Emissions Trading Scheme
FE – DOE Office of Fossil Energy
FERC – Federal Electric Regulatory Commission
FGD – flue gas desulfurization, an SO_2 removal technology
FOAK – first-of-a-kind
HEW – US Department of Health, Education, and Welfare
HHV – higher heating value efficiency
IEA GHG – International Energy Agency Greenhouse Gas Programme
IGCC - integrated gasification combined cycle
IPCC – UN Intergovernmental Panel on Climate Change
ITC – investment tax credit
LNG – liquefied natural gas
MIT – Massachusetts Institute of Technology
NAPCA - National Air Pollution Control Administration
NETL – US National Energy Technology Laboratory
NGCC – natural gas combined cycle
NOAK - Nth-of-a-kind
NSPS – new source performance standards
O&M – operations and maintenance
PC – pulverized coal

PTC – production tax credit
PUC – public utilities commission
R&D – research and development
RD&D – research, development, and demonstration
REC – renewable energy certificate
RES – renewable electricity standard
S&P – Standard and Poor's
SCPC - supercritical pulverized coal
SCR – selective catalytic reduction, a NO_x removal technology
SMR – steam methane reforming
TVA – Tennessee Valley Authority

8.2. The MIT Expert Workshop on CCS Innovation

Within each innovation phase, a variety of different actors participate, including businesses, government agencies, industry partnerships, lawmakers, public interveners, and non-governmental organizations. Our research group decided it would be useful to try and bring together a small group of experts representing many of these sectors to discuss innovation and public policy for CCS technology. The Industrial Performance Center (IPC) organized a workshop on CCS Innovation in Washington, D.C. on April 23, 2009. It was hosted by Professor Richard Lester, Director of the IPC, MIT Energy Initiative Principal Research Engineer Howard Herzog, Rohit Sakhuja, Executive Director of the IPC Energy Innovation Project, and Michael Hamilton. Attendees included:

- American Petroleum Institute
- Clean Air Task Force
- Coal Utilization Research Council
- Edison Electric Institute
- House Science and Technology Committee Staff
- Senate Energy and Natural Resources Committee Staff
- George Mason University researchers
- MIT researchers from the Joint Program for the Science and Policy of Global Change, the MIT Energy Initiative, and the MIT Industrial Performance Center

The event was a no-attribution discussion, so no details of the specific attendees or their comments will be provided, but the feedback will be used to support arguments in the policy analysis portions of the thesis.

This workshop was formulated by splitting the discussion into three major innovation phases, R&D, demonstration and early commercial projects, and commercial deployment. For each phase, the following questions were asked to guide the discussion on the institutions and policies relevant to innovation in CCS technology:

- Who will be responsible for making project and technology selection decisions?
- Who will carry out the work?
- Who will pay?
- How will the work be financed?
- How will the risks and benefits be allocated between different parties on the projects?

8.3. Cost Model Details

Table 8.1 shows the details of cost input for the model, corresponding to the Figure 2.9 shown earlier.

Table 8.1. Cost input details.

	Base Case	High Case	Low Case
Nth Plant Cost	\$65/t CO_2 avoided	\$105/tCO_2 avoided	\$53/tCO_2 avoided
First-of-a-Kind Cost Premium	190%	190%	190%
Demo/Early Deployment Phase Length	10 GW	10 GW	10 GW
Regression Equation	Cost = -3.537ln(Capacity) + 86.547	Cost = -5.408ln(Capacity) + 155.39	Cost = -3.164ln(Capacity) + 72.812
Regression R^2	0.9749	0.9596	0.9803

First, an avoided CO_2emissions rate must be calculated as shown in Equation 8.1.

$$avoided\ CO_2\ emissions\ rate\ = CO_2\ emissions\ rate_{reference} - CO_2 emissions\ rate_{capture} \quad (8.1)$$

Assuming the same capacity factor assumptions as in Section 2.2, the net annual generation is calculated for year *i* in Equation 8.2.

$$generation_i = capacity_i * capacity\ factor * hours\ in\ a\ year \tag{8.2}$$

The quantity of annual avoided CO_2emissions for year *i* is calculated as Equation8.3.

$$avoided\ emissions_i = avoided\ emissions\ rate * generation_i \tag{8.3}$$

With the three inputs established, the basic function of the model can be described. The three inputs can be written mathematically as Equations 8.4 through 8.6:

$$\text{Adoption: } capacity = f(time) \tag{8.4}$$

$$\text{Cost: } cost = f(capacity) \tag{8.5}$$

$$\text{Carbon Price: } price = f(time) \tag{8.6}$$

The cost can then be transformed into a function of time by inserting the adoption model into the cost model, shown as Equation 8.7:

$$\text{Cost: } cost = f\big(f(time)\big) \tag{8.7}$$

Then the CCS cost and carbon price can be plotted as a function of time, and the cost gap between the CCS cost and carbon price can be calculated, shown as Equation 8.8.

$$costgap = cost - price \tag{8.8}$$

8.4. Past Government Demonstration Programs Comparison

The US government organized several major demonstration programs for energy technologies, starting with the mid-1960s breeder reactor program to the recent FutureGen experience.

With management covering such public entities as the Energy Research and Development Agency (ERDA), EPA, the Synfuels Corporation, and DOE, three major energy commercialization case studies are included: the breeder reactor program, the synfuels program, and the photovoltaics program. *The Technology Pork Barrel* (1991) by Cohen and Noll describes the history of these programs, none of which ever achieved its goal of wide commercial deployment of its focus technology.[46] DOE's multi-decade Clean Coal Technology Demonstration Program (CCTDP) was a considered a technical and commercial success, but it was not without its problems. Finally, the rocky start of the current DOE FutureGen CCS demonstration project provides additional material.

There were two major criteria for success in these past programs, both the achievement of technical goals and commercialization of the technology. Every program had a set of technology objectives it was trying to reach, and a further goal of commercial adoption of the technology. These two criteria are used here to compare the programs.

The breeder reactor commercialization program was a wide ranging RD&D effort to support the use of breeder reactors as a high fuel efficiency alternative to common commercial nuclear reactor designs. The program had some promising technical results, the sources of which were the smaller projects that were later eclipsed by an excessive focus on the large commercial demonstration project, the Clinch River breeder reactor (CRBR) project, which was both a technical and commercial failure. The CRBR project never reached commercial operation, and the entire breeder reactor program in general was considered a commercial failure, since the economic rationale for seeking breeder reactors in the first place had vanished (Cohen and Noll, 1991).

The synfuels commercialization program was a wide-ranging RD&D effort to support the use of domestic coal in creating synthetic fuels such as synthetic crude oil and synthetic natural gas. This program had many expensive technical failures, with none of the major liquefaction pilot and demonstration projects ever reaching their performance targets. There was one clear technical success, the cool-water combined cycle gasification project, which led to further work

[46] Linda Cohen and Roger Noll's book *The Technology Pork Barrel* (1991) provides the source material for this discussion on these three cases.

in IGCC technology under the Clean Coal Technology Demonstration Program (CCT) in the late 1980s, but IGCC has only reached very limited commercialization due to the availability of less expensive and more reliable alternatives, such as supercritical coal-fired power plants (Cohen and Noll, 1991).

The photovoltaics commercialization program was fast growing RD&D effort beginning in the early 1970s. The program used an "original management strategy" using competitions based on a "single, simple cost-reduction parameter" as the goal. While the program was a technical success due to its gains in technology development and cost reduction, the program was scaled back before final goals of commercialization could be reached. The major demonstration project of this program, the Flat-Plate Solar Array, was considered a technical success, but photovoltaics technology has still today only reached limited commercialization (Cohen and Noll, 1991).

The Clean Coal Technology Demonstration Program was initiated by DOE in 1984 to support commercial demonstration of a wide variety of coal-related energy technologies. The program demonstrated such technologies as IGCC, low NO_x burners, pressurized and atmospheric fluidized bed combustion, FGD technologies for SO_2 reduction, selective catalytic reduction (SCR) technology for NO_X reduction, and coal upgrading technologies. DOE has claimed both technical and commercial successes in the program, with the subsequent commercialization of several technologies, such as FGD and SCR technology, low NO_x burners, and atmospheric fluidized bed combustion (McKee, 2000).

The FutureGen project is a first-of-its-kind IGCC plant integrated with 90% carbon capture and deep saline formation sequestration; the original project's aims were quite aggressive and nearly led to the project's undoing. In addition to these stringent technical specifications, the project had an additional research aim of creating hydrogen transportation fuels, as part of the Bush Administration's push for a "hydrogen" economy. After a rocky start to the project, whether this project will be a technical and commercial success remains to be seen.

8.5. Details of Policy Proposals for Commercial Deployment

8.5.1. Carbon Pricing

The major current US cap-and-trade bill under consideration by the U.S. House of Representatives is H.R. 2454, The American Clean Energy and Security (ACES) Act of 2009, nicknamed Waxman-Markey for the two main congressmen behind the bill. Full details of this program are given in the ACES Act summary in Appendix Section 8.6. For large sources of CO_2, the cap on carbon emissions will be 17% below 2005 levels by 2020 and 83% below 2005 levels by 2050. The cap covers the emissions from the electricity, transportation, and industrial sectors, all of which have potential to apply CCS technology. The bill allows a number of cost-containment mechanisms such as unlimited banking of allowances, and a strategic reserve of allowances allowing additional allowances to be auctioned if the market price of carbon increases beyond 160% of its previous three-year average. The bill plans to allocate allowances to electricity consumers, trade-vulnerable industries, merchant coal generators, and CCS projects, all of which may help offset the costs of deploying CCS for electricity and industry carbon emissions reduction. Electricity consumers will receive 43.75% of allowances in 2012, reducing to zero by 2030; CCS project deployment support programs will receive 1.75% in 2014, increasing to 5% for the 2020-2050 period. The expected effect is to decrease the compliance costs for the entities receiving the allowances by permitting them to sell these allowances on the carbon market to the entities that actually have to surrender allowances for CO_2 emissions. Two examples of carbon price estimates for the ACES Act were presented earlier in Figure 2.11.

8.5.2. Mandates

8.5.2.1. Portfolio Mandate

Many US states have adopted renewable or energy efficiency "portfolio standards" over the last decade, which are, in effect, mandates for given amount of clean power or efficiency. The current ACES Act is proposing a nationwide renewable electricity and efficiency standard (RES) requiring 20% nationally by 2020. The bill requires utilities to meet 15% of this requirement through renewable generation and the other 5% through energy efficiency. State governors may lower the renewable requirement to 12 percent for their state, but the efficiency mandate would then rise to 8 percent to keep the overall 20 percent level (E&E News, 2009). Qualified sources are "wind, solar, geothermal, biomass, biogas, biofuels, increased hydropower capacity since 1988, waste-to-energy, landfill gas, wastewater treatment gas, coal mine methane used to create power at or near the mine mouth, marine renewables such as wave and tidal power" (E&E News, 2009). New nuclear generation, existing hydropower, and fossil generation with carbon capture and storage are excluded. An analysis by NREL shows that the effective level of renewable generation required depends highly on the level of energy efficiency that each state decides to adopt. The bill establishes a national trading system for renewable energy certificates (RECs) and an alternative compliance payment option in lieu of an REC of $25 per MWh.

Some states, such as Illinois, have actually passed a portfolio standard specific to CCS, and the bill, SB 1987, was signed into law in early 2009 to require 5% of electric generation in 2015 to come from electricity sources using CCS, with a non-binding goal of 25% by 2025.

8.5.2.2. Emissions Performance Standards

Emissions standards for CCS would likely put a maximum on emissions of CO_2 per MWh of electricity generated. California passed SB 1368 in 2007, which set an emissions performance standard of 1100 lbsCO_2/MWh for new plants or any electricity imported into the state. Additionally, EPA has precedent in regulating using emissions performance standards for NO_x and SO_2 under the New Source Performance Standards (NSPS) provision of the Clean Air Act (CAA) regulations (Rubin, 2009). This approach is being considered nationally for CO_2 from large point sources such as coal fired power plants.

The ACES Act also specifies a performance standard intended to support CCS deployment. Full details of this program are given in the ACES Act summary in Appendix Section 8.6. For new coal-fired power plants permitted between the beginning of 2009 and the end of 2019, a 50% capture rate will be required four years after CCS technology is "in commercial operation"; the bill defines "in commercial operation" as the year that either 4GW of CCS has been installed or at least 12 MtCO_2 is being sequestered annually. For plants permitted after the beginning of 2020, a 65% capture rate is required. Thereafter, every 5 years the standards are to be reviewed and updated pursuant to the "best system of emission reduction" available at that time. Environmental law precedent under CAA regulations have established a similar standard of best available control technology (BACT), which is established considering a combination of economics and performance of "adequately demonstrated" technology (Taylor *et al.*, 2005), which is another interesting consideration for a publicly-supported demonstration phase for CCS; for example, the DOE Clean Coal Technology Program was a success in demonstrating SCR NOx reduction technology before the regulations were in place[47].

8.5.3. Subsidies

A large coalition of groups such as the US Climate Action Partnership (USCAP) strongly support a subsidy program for commercial CCS projects (source USCAP), and this influence has been shown in the commercial deployment subsidy program included in the recent ACES Act legislation. Subsidies can be effective in deploying CCS technology, since it directly reduces costs for firms that choose to build CCS projects. The subsidy lowers costs for generators choosing to build CCS helping to make CCS cost-competitive with other low-carbon technologies.

Subsidies can also provide a market pull for CCS technology by reducing costs for firms seeking investment in CCS technology. Tax credits and bonus allowances can provide a guaranteed stream of income for CCS projects. Government financing supports CCS projects through access to lower cost debt than would be available from the market. Each mechanism can be useful in establishing project financing agreements with private investors or in negotiations with the PUC for cost recovery through rate adjustments.

The degree of market support depends on the net after-subsidy cost of CCS relative to other clean electricity technologies. A too-small subsidy will not bridge the cost gap for CCS technology, and will result in a lack of market support for CCS. A too-large subsidy risks windfall profits by private firms investing in CCS, decreasing the economic efficiency of the subsidy program. This again shows a potential tradeoff between the market support for CCS and the economic efficiency of the program, so policy makers understand that the level of effective subsidy is the most important consideration in developing an effective subsidy approach to support CCS. Only by looking at the specific magnitude of the subsidies in each subsidy

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[47] Source from pre-publication discussions with Professor David Hart of George Mason University.

proposal for CCS can one evaluate whether the program is more or less effective in supporting a market for the technology and more or less economically-efficient.

8.5.3.1. Tax Credits

There have been numerous tax credit programs used for CCS in the past, and more are being considered for significant CCS commercialization support in current legislation such as the ACES Act. There are three major subcategories of tax credits: investment, production, and sequestration tax credits. Investment tax credits provide support for capital expenditures for CCS-related projects, production tax credits provide support for electricity sales from plants with CCS, and sequestration tax credits provide support for CO_2 sequestration, usually in saline aquifers or for enhanced oil and gas recovery purposes.

In 2008 congress included three tax credits relevant to CCS in the "bailout" bill H.R. 1424 entitled the Emergency Economic Stabilization Act of 2008. Besides providing authorization for up to $700 billion to help ease the effect of the credit crisis on the US financial industry, the bill also included three major tax credits for CCS: the Advanced Coal Project Investment Credit, the Coal Gasification Investment Credit, and a carbon sequestration tax credit.

Originally, these first two investment tax credits were introduced as part of the Energy Policy Act of 2005. This program was then authorized to provide up to $800 million for IGCC projects and $500 million for advanced coal-based generation technologies over three years. The tax credits have the potential to support CCS since often CCS can be relatively easily applied to new IGCC plants, and the Advanced Coal Project credit would include efficiency upgrades on older plants expecting to retrofit for CCS someday. The bill also contains a CCS-related modification to both the Advanced Coal Project Investment Credit and the Coal Gasification Investment Credit. The updated Advanced Coal Project Investment Credit program extends the period of application by three years, and provides an additional $1.25 billion for advanced coal projects capturing and sequestering at least 65% of their CO_2 emissions. Up to 30% of the project cost can be awarded the tax credit. The updated Coal Gasification Investment Credit program provides an additional $250 million for gasification demonstration projects that capture and sequester at least 75% of their CO_2 emissions. The new program also allows credit for gasification projects producing liquid fuels for transportation.

The bill also provides a new sequestration tax credit for secure geological CO_2 storage or for enhanced oil and gas recovery projects. For facilities capturing more than 500 $ktCO_2$ annually, a $20/$tCO_2$ tax credit can be applied to sequestration in secure geological storage which includes deep saline formations and un-mineable coal seams and a $10/$tCO_2$ tax credit can be applied to sequestration for purposes of enhanced oil and gas recovery. This credit will apply for the first 75Mt of CO_2 sequestered. This credit will likely help support some early private-sector CCS demonstration projects, and in fact it was referenced as an important support for the Tenaska Taylorville, IL CCS project discussed in Appendix 8.7.

The production tax credit is a third method that has not been often discussed in context of CCS, but rather mostly for renewable electricity sources such as wind, solar, and geothermal power. The 2009 stimulus bill, the American Recovery and Reinvestment Act of 2009, reinstated the 2.1¢/kWh tax credit for renewable electricity sources. The credit can then be used for the first 10 years of operation.

8.5.3.2. Bonus Allowances

The concept of bonus allowances as a subsidy program is only possible under an existing cap-and-trade carbon pricing scheme. Some percentage of the allowances are reserved for deployment of CCS technology, and these allowances would then be given to CCS projects as a subsidy to offset the higher costs of reducing emissions using CCS.

In the current ACES Act bill, a "bonus allowance" deployment support program has been defined to support the commercial deployment of CCS projects. The allowances come from the quantity of allowances set aside for a CCS deployment subsidy program, as described in the carbon pricing section earlier. These bonus allowances are intended as incentives for early deployment of CCS projects to help offset the "cost gap" for CCS. The bonus allowances are issued based on amount of sequestered CO_2 each project achieves, and the value of the allowance is specified depending on the capture rate and the timing of the project.

This program exists in two phases. Phase I of the Bonus Allowance program is available for the first 6GW of cumulative CCS generation. Equation 8.9 shows how the number of bonus allowances issued will be calculated.

$$BonusAllowances = \frac{Metric\ Tons\ CO_2\ Avoided \times Bonus\ Allowance\ Value}{CO_2\ Market\ Value\ from\ Preceding\ Year} \quad (8.9)$$

For units achieving 85% capture, bonus allowances equivalent to $90/t$CO_2$ avoided are awarded. An allowance schedule will be defined for capture rates in between 85% and 50% with 50% capture corresponding to a minimum of $50/t$CO_2$. Early-mover projects can increase the value of the allowances by $10/t$CO_2$ if in operation by 2017.

Phase II of the Bonus Allowance program is available following the first 6GW of cumulative CCS generation, continuing until either 72GW of CCS is deployed or the program runs out of money. This Phase II does not give a fixed-value subsidy to CCS projects based on capture percentage; rather this program establishes a reverse auction system to award 10-year contracts for commercial CCS projects. The reverse auction system would define five different auction types, to be defined by coal type, capture technology, sequestration geology, new, retrofit, etc.; the different auction categories ensures that not only the lowest cost CCS approach is awarded a subsidy, but rather some more expensive approaches such as retrofit project.

8.5.3.3. Government Financing

Several mechanisms of government financing exist such as loan guarantees and clean energy bonds. Presumably these mechanisms would fill a role not provided by the private financial sector, such as supporting high-risk projects, which would make early commercial CCS projects a prime candidate. The value of the financing mechanism would likely come in the form of lower interest financing, effectively amounting to a subsidy since it is a valuable discount from what the market would normally offer.

DOE Loan Guarantee Program

Currently the DOE has a loan guarantee program authorized by the Energy Policy Act of 2005, which gives the DOE authority to assume private debt obligations if the borrower defaults, thus giving borrowers access to lower cost debt capital. This is different from a loan because the federal government is not actually paying anything up front, except in the case of default, where the government would take control and liquidate the project assets, then pay back the debt obligations. The DOE has authority to issue loan guarantees of up to $6 billion for CCS projects and $2 billion for coal gasification. A subsidy cost covering the expected value of default for each project must be either covered by an additional government appropriation or by the borrower; the value of this subsidy cost is currently a contentious issue for new nuclear loan guarantees.

Government Investment Bank

A government investment bank approach is considered a subsidy approach because it can lower the cost of capital or provide direct capital investment for high-risk energy projects like early CCS projects. Sen. Bingaman's 2009 energy bill, currently being considered by the Senate Energy and Natural Resources Committee, would create a new entity within DOE called the Clean Energy Deployment Administration (CEDA), which would effectively subsume the loan guarantee program currently under DOE. The goal of CEDA is to help finance the deployment of high-risk technologies with high potential to address climate and energy security needs. Essentially a government-sponsored investment bank, CEDA could potentially fund CCS demonstration projects.

CEDA would be an independent administration within DOE, like the Federal Energy Regulatory Commission (FERC). It would be governed by a board of directors and an administrator, all of whom would be appointed by the Senate. CEDA would also have a permanent Technology Advisory Council to advise on the technical aspects of potential projects. The administration would be funded by congressional appropriation, and these funds and any collected fees would be stored in the "Clean Energy Investment Fund". The agency would essentially be acting as a bank by providing various types of credit including loans and loan guarantees, but would also seek to establish clean energy-backed bonds that would facilitate lending for private sector investment in clean energy technologies. The agency would also seek to accommodate riskier debt and thus provide a mechanism for deployment of the most innovative technologies. As described in the bill summary, "the agency is to use a portfolio investment approach in order to mitigate risk and is to try and become self-sustaining over the long term by balancing riskier investments with revenues from other services and less risky investments."

Additional advantages of this proposal have been noted by the Center for American Progress (Podesta and Kornbluh, May 2009). CEDA would have stable funding since it avoids the annual appropriations process. It could modify the availability and types of financing instruments to respond to changing market condition. It avoids domination by capital-intensive investments in one technology through limits on investment in any single technology. Operating costs would be covered through fees charged for its services, and partial risk-sharing would be required on every transaction. The proposal seeks a 10-to-1 leverage ratio, so the total private investment in clean energy technology would be ten times the amount capitalized by congress. CEDA would be subject to the Federal Credit Reform Act and Budget Enforcement Act to ensure accountability to Congress and to minimize the taking-on of excessive credit risk.

8.6. Summary of CCS Provisions in ACES Act of 2009

5 Major CCS Provisions:

- Cap and Trade Allowance Allocation– Sec. 321
- Demonstration and Early Mover Support
- Carbon Storage Research Corporation - Sec. 114
- Bonus allowance deployment support – Sec. 115
- Emissions performance standards – Sec. 116
- Storage regulations guidance – Sec. 111-113

8.6.1. Cap and Trade Allowance Allocation– Sec. 321

- 1.75% from 2014 to 2017
- 4.75% from 2018 to 2019
- 5% from 2020 to 2050
- EPA has 2 years to determine allocation scheme
- For electricity and industrial CCS, except solids-to-liquids processing
- Allowances not allocated roll over to next year

8.6.2. Carbon Storage Research Corporation (CSRC) - Sec. 114

- Creates a board called the CSRC under EPRI to award grants for commercial-scale CCS demonstration projects
- Intended to support CCS for electricity, not industrial purposes
- Funded through fossil electricity user fee, collecting ~$1B per year for 10 years
- Half of funds granted to existing early-mover CCS projects
- Half of funds to new CCS demonstrations, new or retrofit for a variety of coal types, geologies

8.6.3. Bonus Allowance Deployment Support - Sec 115

- Supports first 10 years of CCS operation,
- New sources must be at least 200 MW nameplate, 50% of fuel is coal or petcoke, and at least 50% CO_2 emissions reduction
- Retrofit sources must apply capture to 200MW equivalent flue gas, with at least 50% CO_2 emissions reduction on treated flue gas
- Industrial sources must emit at least 50 ktCO_2 / year
- Supports up to 72 GW of combined electricity and industrial CCS
- Electricity CCS :Phase I – Fixed Value Subsidy
    - First 6GW of CCS projects get bonus emissions allowances dependent on capture %
    - 85% capture gets allowances equivalent to a fixed \$90/tCO_2 subsidy
    - 50% capture gets allowances equivalent to a fixed \$50/tCO_2 subsidy
    - Subsidy increases linearly with capture %
    - Early movers before 2017 get \$10/tCO_2 more
- Electricity CCS : Phase II – Reverse Auction Subsidy
    - After 6GW of CCS, value of subsidy is set through reverse auction bidding
    - Bids define level of subsidy desired and quantity of carbon sequestered over 10 year support period
    - 5 different auction types to be defined by coal type, capture tech., geology, new vs. retrofit, etc.
    - Alternative Method (if reverse auction method is deemed a failure)
    - Sliding scale of subsidy dependent on capture rate
    - Tranches of 6GW or less, with the sliding scale of subsidy decreasing in each tranche
- Limit on Eligibility for Early Movers
- 2009-2014: CCS must be in operation at the start of operation, or else the eligible subsidy is reduced by 20% each year until CCS is in operation
- 2015-2020: Only units achieving at least 50% emissions reduction in emissions are eligible for support
- Industrial Sources: A maximum of 15% of allowances can be given to industrial CCS projects
- Projects can receive support up to incremental costs of CCS

8.6.4. Emissions performance standards - Sec. 116

- For new coal-fired power plants
- 65% reduction in CO_2 emissions, for permits issued after Jan. 1, 2020
- Provisional 50% reduction in CO2 emissions, for permits issued from 2009 – 2020
- Standard is triggered when 4 GW of commercial CCS is in operation, or on Jan. 1 2025
    - At least 3GW must be CCS for electricity
    - Up to 1GW may be industrial CCS (3 MtCO_2/year = 1GWe)
    - At least two 250MW electric CCS projects with saline aquifer storage
    - At least 12 MtCO2/year is being captured and stored

- If standard not triggered by 2025, petition for non-compliance available
- By 2025 or before, a review of the standards applies, and lower emissions rates may be required if lower-emitting CCS technology is demonstrated

8.6.5. Storage Regulation Guidance - Sec. 111-113

- EPA has 2 Years to promulgate regulations for CO_2 storage governing health, safety, environmental, leakage, and liability issues
- Integration and redundancy with the Safe Drinking Water Ace (SDWA), the Clean Air Act (CAA), and existing EPA regulations will be addressed

8.7. Current CCS Projects Study

8.7.1. Duke Energy's Edwardsport Project[48]

This plant is being built on the same site as an existing coal-fired generation unit in Edwardsport, Indiana. The project is a 632 MWe integrated coal-gasification combined-cycle (IGCC) plant starting construction last year in 2008 and hoping to start operation in 2012. Indiana is a fully regulated electricity market, and the Indiana Utility Regulatory Commission has given a green light for the project, allowing the estimated $2.35 billion[49] project to be paid for by Indiana ratepayers. The project is currently a cooperation between Duke Energy, the owner, General Electric, who will supply the gasification and power plant technology, and Bechtel, who will perform the engineering and construction of the plant.

The CCS component of the project has not been finalized, and Duke is currently performing a front-end engineering and design (FEED) study to determine the different options for integrating CCS into the project. Future plans include a $121 million investment in a three year testing of the feasibility of CCS technology for the Edwardsport facility; the company is seeking 50% of this from a federal government program and the rest from ratepayers[50]. A New York Times source speculated the plant would start with a low 18% capture by 2013, rising to a 53% capture a few years later. This could be possible using a pre-combustion capture system, with a shift reactor added later to convert more of the CO into CO_2 for capture. Duke is likely leaving

[48] The material for this section is based upon a formal interview with Darlene Radcliffe, Project Manager for Duke Energy's Edwardsport IGCC Project on XX.
[49] Current as of 7/21/2009.
[50] http://www.bizjournals.com/charlotte/stories/2009/07/06/daily12.html

options for capture open since the destination of CO_2 for sequestration is highly uncertain. They are looking at both EOR and saline aquifer options. EOR options may exist either in the Illinois basin area, or in the Southern US, both of which would involve transporting CO_2 via pipeline. Duke is working with Denbury Resources to analyze options for EOR. These EOR options could provide a revenue stream potentially, which would help offset some of the costs of CCS. For saline aquifer storage, Duke is working with Schlumberger, the Illinois State Geological Survey, and the Midwest Regional Carbon Sequestration Partnership to look at Illinois Basin sequestration options.

The financing of this project is unique because they were able to get the cost of the plant worked into the rate structure by the state utility commission. Most public utility commissions (PUCs) have expressed limited interest in funding early commercial CCS projects due to the technology risks and high costs compared to other options. Relevant to their decision was that the state of Indiana has had experience with IGCC before with the Wabash River IGCC demonstration by Dow Chemical in the 1990s. CCS on the Edwardsport project is not guaranteed, and will likely only be financed if some form of public support for CCS or revenue from EOR can be made available.

8.7.2. Tenaska Energy's Trailblazer Project[51]

Tenaska Energy is a large independent power producer and electricity marketer, with generation assets spread across the US. Tenaska Energy has two projects considering CCS currently. The first project is the West Texas Trailblazer project, which is 600 MWe PC plant using post-combustion capture. The plant is targeting an 85-90% capture rate, and is planning to use the CO_2 for EOR operations nearby in the Permian Basin through their partner Kinder-Morgan. The all-in capital cost for the plant is $3.5 billion, with about $1 billion of that plant dedicated to the CO_2 capture and compression system. Tenaska is considering at least two different capture technologies, and both of are post-combustion chemical solvent absorption.

[51] The material for this section is based upon a formal interview with Jeff James, Project Manager for Tenaska Energy's West Texas Trailblazer Project on XX.

The financing of the Trailblazer project is unique since Tenaska is an independent power producer selling electricity into the fully-deregulated ERCOT market. They expect to finance the plant by combining several methods. They will seek to make power purchase agreements (PPAs) with electricity distributors, with the remainder of the revenue coming from EOR CO_2 sales, first-mover federal sequestration tax credits issued under the 2008 financial "bailout" bill, and eventually from increased value from a CO_2 cap-and-trade system. Additionally, the company views investment in generation with CCS to be a hedge against future CO_2 regulation risk, since the company's generation holdings currently consist of 7GW of gas generation.

8.7.3. Tenaska Energy's Taylorville Project[52]

Tenaska's Taylorville, Illinois project is going to be an IGCC plant producing synthetic natural gas (SNG) then using this SNG to produce 525MWe of electricity in a combined cycle power block. The plant would capture about 55% of its CO_2 emissions during the SNG processing stage, similar to how CO_2 is captured at the Dakota Gasification facility in North Dakota. The all-in capital cost is estimated to be \$3.5 billion for the facility. Tenaska is considering both EOR and saline aquifer options for sequestration. The EOR option may prove expensive since there are no existing pipelines to transport CO_2 from central Illinois. Saline aquifer storage may be possible since Taylorville is located on top of the Illinois Basin, which is also being considered for saline aquifer storage by the FutureGen project planned for Mattoon, Illinois.

The linchpin to financing on the Taylorville project appears to be the Illinois state law passed in 2007 establishing a "clean coal" portfolio standard which requires 5% electricity generation in Illinois to come from clean coal power by 2014. Illinois is a semi-regulated market, so as an IPP selling into this market, Tenaska will expect to receive a premium for their electricity sales, since they may be the only company providing clean coal electricity in the state.

[52] The material for this section is based upon a formal interview with Bart Ford, Project Manager for Tenaska Energy's Taylorville Project on March 15,2009.

8.7.4. Babcock & Wilcox's Oxy-Fuel Demonstration Project[53]

Babcock and Wilcox is one of the oldest steam power technology companies in the world, and they plan to offer an oxy-fuel power system. The first commercial scale demonstration of this technology is now planned as a mine-mouth 100MWe generation plant in the Powder River Basin of Wyoming in cooperation with Black Hills Corporation, a regional electric utility and merchant generator. The facility will be a true demonstration facility, with the intention being to run the power plant and capture 1 Mt/year of CO_2 for only three years, but the details of sequestration have not been decided yet. The estimated capital cost of the project is about $1 billion.

The financing of this demonstration is dependent upon funding from the DOE's Restructured FutureGen program intended to fund the incremental cost of several CCS demonstrations around the US. The project technology partners Air Liquide and Batelle will share in the IP and experience benefits that will come from constructing and operating such a demonstration facility; this helps to offset some of the private costs that will have to be paid for this facility.

8.7.5. Southern Company's Kemper County Project

Southern Company is a major shareholder-owned utility in the southeast US with a large share of coal-fired generation. The company plans to build a 582MW IGCC facility in Kemper County, Mississippi. The plant will be lignite-fired, and will use KBR's transport gasifier technology, which was developed in conjunction with Southern Company's technology R&D facility at Wilsonville, AL. The facility will achieve 50% capture using MHI's advanced amine absorption technology, and the CO_2 will be used for EOR in the Mississippi Valley. The capital cost is approximately $2.2 billion.

Since Mississippi has a fully regulated power market, the state regulatory commission has given Southern Company the permission to pass the costs for the plant through to the ratepayers. This approval is contingent upon additional support from the DOE's clean coal power initiative

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[53] The material for this section is based upon a formal interview with Kevin McCauley, Project Manager for Tenaska Energy's Taylorville Project on March 21, 2009.

(CCPI) Round II funding of about \$300 million, gasification tax credits from the Energy Policy Act of 2005 worth \$135 million, federal tax credits for using Mississippi lignite as the fuel source, and revenue from EOR CO_2 sales.

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