Policies to Advance the Business Case for Natural Gas Combined Cycle Power Plants with Carbon Capture and Storage

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Introduction

Carbon capture and storage (CCS) deployed on natural gas combined cycle (NGCC) plants is an important technological option to reduce greenhouse gas (GHG) emissions in the United States. The timeframe for deployment of the technology depends on the aggressiveness with which the U.S. addresses climate change and the cost effectiveness of NGCC with CCS relative to other GHG reduction strategies for the electric sector. The argument for CCS on natural gas-fired units echoes the argument for CCS on coal-fired units: there is a large domestic resource of natural gas, there are a large (and growing) number of natural gas-fired power plants supplying electricity in the U.S., and natural gas combustion results in greenhouse gas emissions. The challenges to CCS use on natural gas-fired units are similar to the challenges to CCS use on coal-fired units: integrated CCS has not been proven at scale on an electric generating unit and CCS is expensive relative to other forms of electricity – particularly relative to generation of electricity from combustion of fossil fuels in the absence of a price on carbon.

The goal of policies to support NG-CCS (and CCS technology develop in general) should be to accelerate the demonstration and deployment of the technology with the expectation that there will be a mandate to reduce GHG in the future and having the option to deploy CCS on natural gas in the future will reduce overall (societal) costs of compliance.

This focus is reflected in the Administration goal of five to ten commercial demonstration plants as outlined by President Obama in a Presidential Memorandum that created the Interagency Task Force on CCS:

> *The Task Force shall develop within 180 days of the date of this memorandum a proposed plan to overcome the barriers to the widespread, **cost-effective deployment of CCS within 10 years, with a goal of bringing 5 to 10 commercial demonstration projects online by 2016.** The plan should explore incentives for commercial CCS adoption and address any financial, economic, technological, legal, institutional, social, or other barriers to deployment.*[1]

Perspectives on CCS Deployment

The timeframe for CCS deployment is challenging to predict because its use is predicated on (1) the timing and aggressiveness of GHG reductions, (2) the demonstration of the technology at a commercial scale, and (3) the degree of financial support for early movers. At one end of the spectrum, modeling suggests reduction pathways in the range of 80 percent below 2005 levels by 2050 combined with significant demonstration and early mover incentives and a focus on domestic emission reductions could encourage CCS on natural gas-fired power plants before 2020. At the other end of the spectrum, modeling suggests reduction pathways in the range of 50 percent below 2005 emissions by 2050 might not require deployment of CCS on natural gas-fired power plants to the closing years of this half century.

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[1] The White House Office of the Press Secretary, "Presidential Memorandum: A Comprehensive Federal Strategy on Carbon Capture and Storage," February 3, 2010. http://www.whitehouse.gov/the-press-office/presidential-memorandum-a-comprehensive-federal-strategy-carbon-capture-and-storage

Modeling of the American Power Act of 2010 (APA), a comprehensive climate bill released by Senators Kerry, Graham, and Lieberman but never voted on by the Senate, provides an example of some of the more aggressive scenarios.[2] The bill, based on a bill that passed the House in June 2009, the American Clean Energy and Security Act of 2009 (H.R. 2454, sometimes call the Waxman-Markey Climate Bill), included a cap on GHG emissions and significant incentives for the development and deployment of CCS. The primary incentives took the form of bonus allowances based on tons of carbon dioxide (CO_2) sequestered. The Energy Information Administration's (EIA's) analysis of APA included a number of different economic and technology scenarios. Under the most aggressive domestic reduction scenario, which limited the use of international offsets, the first natural gas-fired power plants with CCS were projected to come online in 2019, three years behind the first coal-fired power plants with CCS. However, the baseline scenarios used natural gas assumptions that did not account for expanded natural gas supply. Under a scenario using high natural gas resource assumptions, reflecting shale gas potential, natural gas-fired power plants with CCS were not projected to start coming online until 2030. The 2030 estimate is consistent with the basic model run which included the EIA reference assumptions and implementation of the bill as designed. Figure 1 shows the coal with CCS deployment estimates (dotted lines) and the NGCC with CCS deployment estimates (solid lines) under four of the scenarios modeled by EIA.

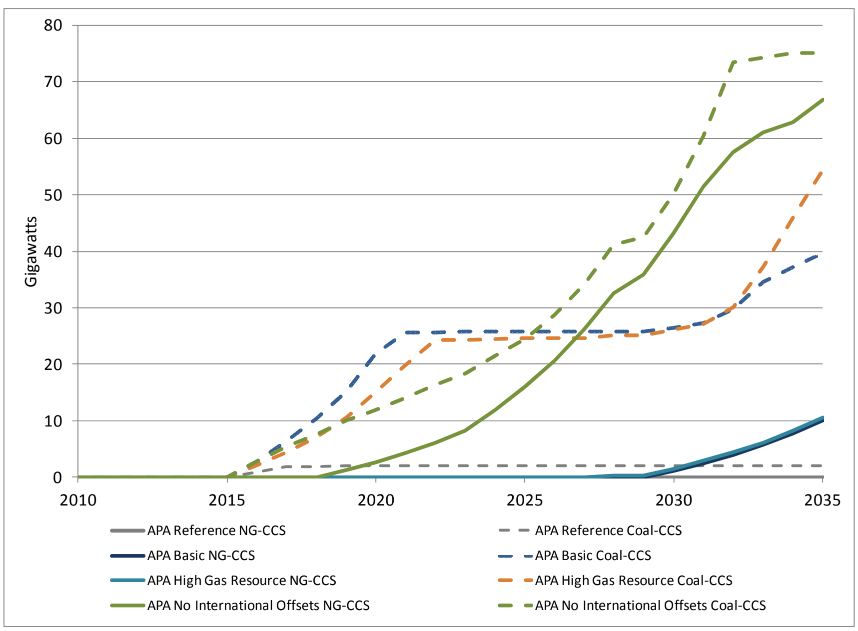

Figure 1. EIA Projections for Coal with CCS and Natural Gas with CCS Under the American Power Act (EIA 2010)

In 2011, MIT Energy Initiative released the latest of a series of reports on the future of energy in the U.S. In its *Future of Natural Gas* report, the researchers developed a "Price-Based Climate Policy" scenario that projected policies that gradually reduced U.S. GHG emissions to 50 percent below 2005 levels by 2050. Under the scenario, natural gas replaces other fossil fuels used for

[2] Energy Information Administration (EIA). *Energy Market and Economic Impacts of the American Power Act of 2010*. Report # SR-OIAF/2020-01. July 16, 2010. http://205.254.135.24/oiaf/servicerpt/kgl/index.html

electricity generation by 2035 and a small amount of CCS is required on natural gas units after 2045.[3] The MIT study authors have noted that all fossil-based electricity would have to be gradually decarbonized using CCS to meet more aggressive post-2050 targets (assuming continued use of fossil fuels). They note that this reality reinforces the need to remove barriers to CCS:

> *Barriers to the expansion of nuclear power or coal and/or gas generation with CCS must be resolved over the next few decades so that over time these energy sources will be able to replace natural gas in power generation. Without such capability, it would not be possible to sustain an emissions mitigation regime.*[4]

In 2010, the California Energy Commission, the California Public Utilities Commission, and the Air Resources Board formed a panel to review CCS policy and develop recommendations for legislation and regulations regarding CCS in California. While it did not establishing a specific deployment scenario, the California CCS Review Panel was particularly interested in CCS combined with natural gas combined cycle plants because of the need to reduce emissions from NGCC plants to meet California's goal of 80 percent reduction below 1990 levels by 2050. The panel cited a number of global studies, including the Intergovernmental Panel on Climate Change (IPCC), International Energy Agency (IEA) and the National Research Council (NRC), that emphasized the need for CCS to meet mid-century GHG reduction targets.[5]

The Electric Power Research Institute (EPRI) has developed a series of technology deployment scenarios for the electric sector over the past five years known as the EPRI Prism. The Prism was designed to provide an engineering judgment of the possible CO_2 emission reductions from the electric sector given current and developing technologies. The newest iteration of the model (Prism 2.0) includes economic modeling and expanded demand-side details by region and technology. EPRI makes coal with CCS and natural gas with CCS available in the model starting after 2020. In a "test drive" of the model with CO_2 prices starting at $30 per ton in 2015 and increasing five percent per year through 2050, natural gas with CCS and coal with CCS squeeze out uncontrolled coal by 2040 and uncontrolled gas by around 2050. An additional insight from the model is that technology selection varies significantly by region. As shown in Figure 2, with a carbon constraint, the EPRI Prism 2.0 projects gas with CCS in the west, east, and south but limited application in the Midwest.[6]

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[3] MIT Energy Initiative. *Future of Natural Gas: An Interdisciplinary MIT Study*. June 2011. http://web.mit.edu/mitei/research/studies/natural-gas-2011.shtml

[4] Ibid. At p 70.

[5] California Carbon Capture and Storage Review Panel. *Findings and Recommendations by the California Carbon Capture and Storage Review Panel*. December 2010. http://www.climatechange.ca.gov/carbon_capture_review_panel/documents/2011-01-14_CSS_Panel_Recommendations.pdf

[6] Hannegan, Bryan. *Prism 2.0: Preliminary Insights from EPRI's Regional Model*. EPRI Summer 2010 Seminar. August 2, 2010.

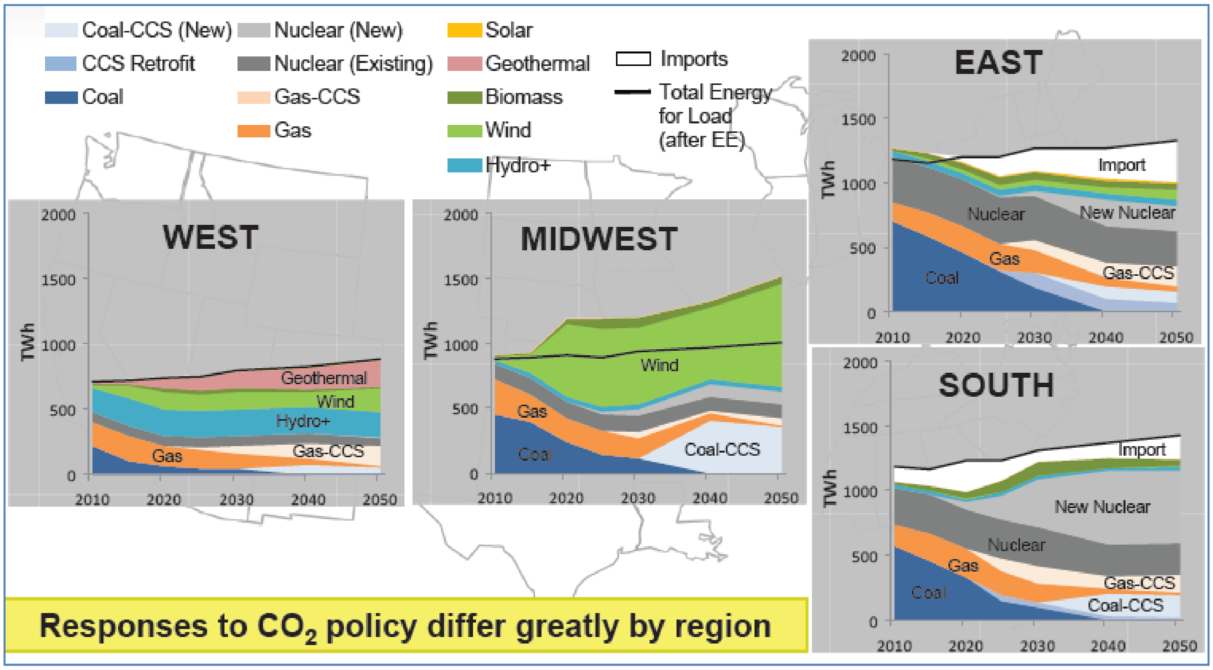

Figure 2. Preliminary EPRI Prism 2.0 Regional Analysis[7]

While each of these studies has different assumptions around technology availability, incentives, and required emission reductions, 2020 is likely the earliest deployment date for commercial-scale NGCC with CCS. Given the current lack of enthusiasm for GHG reduction requirements in the U.S., a case could be made that NGCC with CCS will not be significantly deployed until after 2030.

Barriers to NGCC-CCS Deployment

As with any long-lived asset, power plant construction involves making assumptions about future conditions and becoming comfortable with uncertainties. Before starting construction, planners have to map out expected fuel prices and electricity demand to justify the costs associated with construction. As they evaluate potential costs, investors have to consider the appropriate generation technology, regulatory approval, expected technology performance (efficiency and availability), the location of the power plant (including any local stakeholder concerns), potential construction cost and time overruns, and current (and potential future) environmental regulations. Existing electricity markets – both regulated and deregulated – have developed ways to handle these risks. However, even within mature markets, projects are often announced and cancelled before construction begins.

The addition of CCS to a power plant adds a number of risks that are not fully accounted for in today's electric power markets including uncertainties around: long-term GHG regulations, new technology performance, transportation and storage permitting and liability, and long-term stewardship.

[7] Hannegan, Bryan. *Prism 2.0: Preliminary Insights from EPRI's Regional Model*. EPRI Summer 2010 Seminar. August 2, 2010.

- Uncertainty about the long-term GHG regulatory pathway. Methods of pricing environmental externalities through command-and-control regulation, cap-and-trade systems, or a carbon tax could create a demand for CCS. Lack of certainty encourages waiting and increases the public cost of demonstration.
- New technology risk (first mover). Compounding the lack of a clear mandate to reduce GHGs, a new power plant with CCS is going to have to deal with risks associated with integrating technologies that have limited history of integration – particularly at scale. Shareholders and customers (i.e., public utility commissions) have little incentive to subsidize the development of a technology when the benefits will be diffuse and when there is significant uncertainty about when it will be needed.
- Transport and storage risks. The large volume of CO_2 and the need for pipeline transport off site makes it more challenging than other forms of air pollution that power plants have traditionally addressed. Power companies will have to establish relationships with oil and gas companies that have a comfort level with the transport of CO_2 and the injection and monitoring techniques associated with storage and new service companies will have to be formed. Natural gas-fired plant owners and operators do have significant experience dealing with large volumes of gas in pipelines.
- Long-term stewardship. Long-term risk associated with CO_2 leakage is difficult for companies to assess (particularly on top of the regulatory and technology uncertainties).

GHG Regulatory Uncertainty

The biggest impediment to CCS demonstration and deployment is the lack of a sufficiently stringent program to reduce GHG emissions (i.e., a price on carbon). A requirement to reduce GHG emissions, or a requirement to pay a fee per ton of GHG emissions, would create a market for lower carbon technologies. When the penalty for emitting the carbon is great enough, technologies that produce electricity without the associated carbon emissions will become more economically attractive. Without a requirement to control GHG emissions, fossil fuel-fired generation with CCS will always be more expensive than uncontrolled fossil generation. This makes CCS a non-starter in the absence of GHG control requirements.

Figure 3 summarizes a number of studies of the economics of NGCC with CCS completed between 2007 and 2011. On average, the studies suggest that CCS will add about $30 per megawatt hour (MWh) to the cost of electricity (COE) from a NGCC power plant, with a high estimate of an additional $43 per MWh and a low estimate of an additional $25 per MWh (all in 2007 dollars). The majority of these costs are associated with the capture technology and the energy penalty associated with capturing and compressing the CO_2, transportation and storage costs make up about 10 percent of the costs associated with CCS.

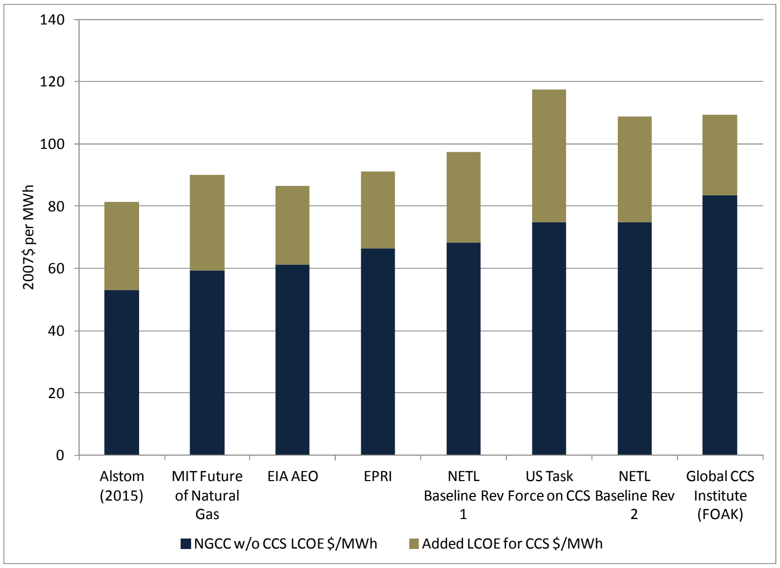

Figure 3. Levelized Cost of Electricity Estimates for NGCC Power Plants with and without CCS (All Estimates Converted to 2007 Dollars)[8]

Looking at the EIA projections for the American Power Act featured in Figure 1, Figure 4 reinforces the need for regulation of GHGs to drive demand for NGCC with CCS. Only with a carbon constraint do electric power prices approach the level needed. The EIA 2011 Annual Energy Outlook projects the cost of generation in the U.S. to average below $60 per MWh (in 2007 dollars) through 2035.[9]

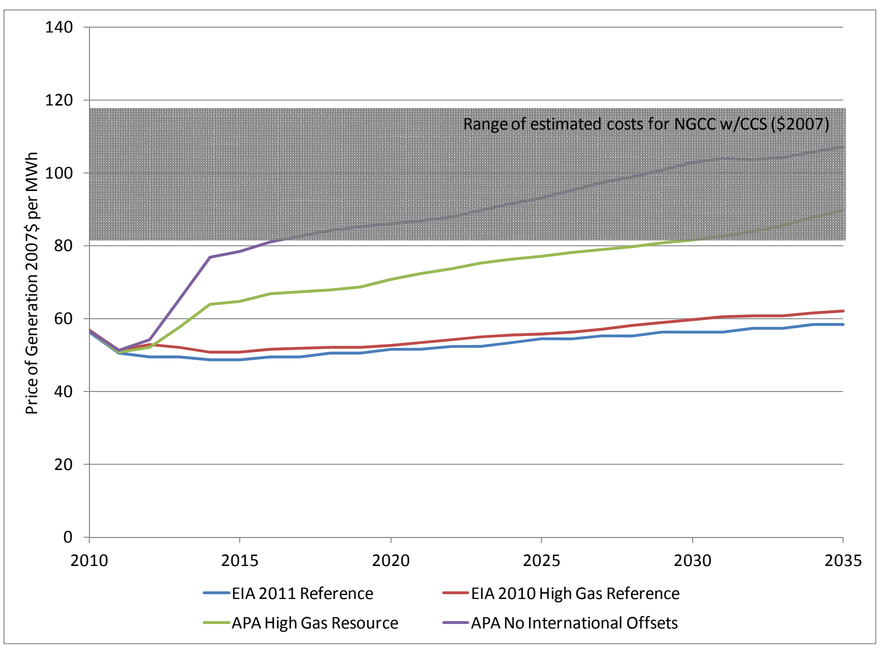

Figure 4. Comparing the Estimated Costs of NGCC with CCS to the Estimated Price of Generation Under Reference and GHG Controlled Cases

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[8] See Appendix A for references, additional information.
[9] U.S. Energy Information Agency (EIA), *Annual Energy Outlook 2011*. April 26, 2011. http://www.eia.gov/forecasts/aeo/

Without a clear pathway toward a significant price on GHG emissions in the U.S., either explicitly through a cap-and-trade system or a tax or implicitly through a regulatory requirement, there will not be a long-term market for CCS. In the absence of a clear market, it is challenging to develop a project without significant additional incentives.

In the U.S., there are currently four commercial-scale power plant projects with CCS that are at various stages of planning and development; five projects that have been put indefinitely on hold; and one project, FutureGen 2.0, that recently lost the support of the power plant owner.[10] Table 1 provides some information on the technologies and federal funding amounts associated with these projects. While there are multiple reasons any specific project is put on hold, the circumstances around the projects that were either officially or unofficially put on hold in the past year (American Electric Power's Mountaineer Project, Basin Electric's Antelope Valley Project, and Tenaska's Taylorville Project) reinforce the idea that the financing of first-of-a-kind projects becomes more difficult in the absence of a clear long-term market.

Table 1. Status of U.S. Commercial-Scale CCS Projects on Coal-Fired Power Plants

Project	Technology	Federal Funding	Status
AEP Mountaineer	Pulverized coal (PC) with post-combustion capture	$334 million (CCPI R3)	On hold
Basin Electric Power Coop	PC with post-combustion capture	$100 million (CCPI R3)	On hold
Conoco-Phillips Sweeny Gasification	Integrated gasification combined cycle (IGCC) with capture	$3 million for project development	On hold
Tenaska Trailblazer	PC with post-combustion capture		On hold
Tenaska Taylorville	IGCC with capture	$2.58 billion loan guarantee and $417 million ITC	On hold
Future Gen 2.0	Oxyfuel combustion with capture	$1 billion	Unclear
Hydrogen Energy California	IGCC with capture	$308 million (CCPI R3)	Restructured under new ownership
Mississippi Power Kemper County	IGCC with capture	$270 million (CCPI R2) + $133 million in ITC	Broke ground
NRG WA Parish	PC with post-combustion capture	$355 million (CCPI R3)	Moving forward
Summit Power Texas Clean Energy Project	IGCC with capture	$450 million ($350 million from CCPI R3 and a separate $100 million grant)	Working to secure financing and long-term off-take agreements

AEP Mountaineer. Working with a number of collaborators including Alstom, DOE's National Energy Technology Laboratory, and Battelle Memorial Institute, American Electric Power

[10] MIT Energy Initiative: Carbon Capture & Sequestration Technologies. "Power Plant Carbon Dioxide Capture and Storage Projects." Accessed October 2011.
http://sequestration.mit.edu/tools/projects/index.html
Associated Press. "FutureGen in talks over Ameren's role in project." November 12, 2011.
http://www.chicagotribune.com/news/chi-ap-il-futuregen-ameren,0,6957365.story

successfully completed a CCS pilot project on a slip-stream equivalent to 20 MW of generating capacity from its 1.3 GW Mountaineer Station in New Haven, West Virginia. The second phase of the project was to scale the pilot project up to 235 MW at the same power plant. DOE had awarded the project up to $334 million to cover half of the scale-up project.[11] However, after not being able to secure cost recovery for the project from state regulators in West Virginia and Virginia, AEP terminated its agreement with DOE and placed its CCS plans on hold.[12]

The decisions by the regulatory bodies in West Virginia and Virginia reflect one of the challenges associated with building a demonstration plant: while the benefits of a commercial-scale project will be widely realized, the costs will be borne by the company building the plant and, in turn, the customers of the power plant. As the Virginia State Corporation Commission concluded:

> *It is reasonable for AEP to evaluate and explore options regarding potential federal legislation or regulation regarding GHG emissions. We do not find, however, that it was reasonable for [Appalachian Power Company (APCo)] to incur the Mountaineer CCS project costs and then seek recovery from Virginia ratepayers. For example: (i) although AEP asserts that this demonstration project will benefit customers of all of AEP's operating companies and of all utilities in the United States, APCo's ratepayers (and not shareholders) are being asked to pay for all of the costs incurred by AEP for this project; and (ii) as stated by Consumer Counsel, "AEP is undertaking no other [CCS] initiatives at any of its other subsidiaries' plants," and "APCo and its customers are being asked to shoulder the entire financial burden and risk associated with AEP's [CCS] research and development." Accordingly, we deny the Company's request for cost recovery of the Mountaineer CCS demonstration project under the facts presented herein.*[13]

In a press release announcing the decision, Michael Morris, AEP chairman and chief executive officer said:

> *[A]s a regulated utility, it is impossible to gain regulatory approval to recover our share of the costs for validating and deploying the technology without federal requirements to reduce greenhouse gas emissions already in place. The uncertainty also makes it difficult to attract partners to help fund the industry's share.*[14]

Separately, project partner, Alstom, reinforced these points:

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[11] MIT Energy Initiative: Carbon Capture & Sequestration Technologies. "Power Plant Carbon Dioxide Capture and Storage Projects." Accessed October 2011. http://sequestration.mit.edu/tools/projects/index.html

[12] AEP. "AEP Places Carbon Capture Commercialization On Hold, Citing Uncertain Status of Climate Policy, Weak Economy," Press Release. July 14, 2011. http://www.aep.com/newsroom/newsreleases/?id=1704

[13] Commonwealth of Virginia State Corporation Commission. Application of Appalachian Power Company, Case No. PUE-2009-00030. July 15, 2010.

[14] AEP. "AEP Places Carbon Capture Commercialization On Hold, Citing Uncertain Status of Climate Policy, Weak Economy," Press Release. July 14, 2011. http://www.aep.com/newsroom/newsreleases/?id=1704

> *State and federal policy makers must recognize the long-term implications of failing to adopt policies that establish the economic certainty needed to drive development of low carbon energy technologies. In addition, policy makers should fund large scale demonstration projects and allow utilities to recover investments in such projects, which are essential if the industry is to move forward in de-carbonizing electricity in the most cost-effective manner possible.*[15]

Basin Electric. Basin Electric's Antelope Valley project was a proposed 120-MW slipstream from the 450-MW Antelope Valley Station in Beulah, ND. Basin Electric, working with HTC Purenergy, Burns and McDonnell, and Doosan Babcock proposed to demonstrate an ammonia-based post-combustion capture technology developed by HTC Purenergy. Despite a $100 million grant from DOE and a $300 million loan from the U.S. Department of Agriculture and projected revenue from the sale of CO_2 for enhanced oil recovery, the project was indefinitely put on hold in December 2010. Ron Harper, the chief executive officer and general manager of Basin Electric cited three factors in making the decision: the lack of a mature EOR market in North Dakota, uncertainty around environmental legislation, and the lack of a long-term U.S. energy strategy.[16]

Tenaska. As designed, Tenaska's Taylorville Energy Center project would be a 602-MW (net) integrated gasification combined cycle project. While not officially on hold, a bill that would have given Tenaska approval to recover costs from ratepayers was rejected by the Illinois Senate in January 2011.[17]

During a hearing held by the U.S. House of Representatives Natural Resources Subcommittee on Energy and Mineral Resources in June 2008, Tenaska's Gregory Kunkel, VP of Environmental Affairs, discussed the importance of long-term certainty in the context of another CCS project, the Trailblazer project in Sweetwater, TX:

> *Perhaps the most important thing Congress could do to facilitate the development of Trailblazer or similar carbon capture and storage projects, is to provide regulatory certainty, and in particular, a regulatory framework within which a market can develop that values greenhouse gas emission reductions. Without regulatory certainty and recognition of the value of emission reductions, developers are confronted with making multibillion dollar decisions in a policy vacuum. No developer can operate effectively while having to speculate on regulatory outcomes, especially outcomes so fundamental to the success of the enterprise.*
>
> *Accordingly, we have developed Trailblazer in anticipation of federal climate change legislation that would support, through placing a price on greenhouse gas emissions*

[15] Alstom. "Alstom Supports American Electric Power (AEP) Decision on Next Phase of Carbon Capture and Sequestration (CCS) Project," Press Release. July 14, 2011. http://www.alstom.com/us/news-and-events/press-releases/alstom-supports-aep-on-ccs-technology/

[16] Basin Electric. "Basin Electric Postpones CO2 Capture Project," Press Release. December 16, 2010. http://www.basinelectric.com/News_Center/Publications/News_Releases/Basin_Electric_postpones_CO2_capture_project.html

[17] Tenaska. "Illinois Senate Fails to Pass Taylorville Energy Center Legislation," Press Release. January 12, 2011. http://www.cleancoalillinois.com/press-110112.html

> *and other means, the significant capital and operating costs of carbon capture technology. Without climate legislation, it appears that revenues from enhanced oil recovery CO_2 sales will be insufficient to cover all carbon capture costs. With proposed climate legislation, projected compliance cost savings and other effects of climate change legislation, combined with EOR revenues, would provide the needed economic incentives to build and operate Trailblazer.* [18]

All of these projects had significant federal and state government support but that support was not enough to overcome the added costs of technology demonstration combined with long-term uncertainty.

New Technology (First Mover Risks)

The absence of a significant long-term market for baseload low-carbon electricity generation technologies increases the risks of investing in a demonstration plant and likely increases the costs of demonstration. Construction of any power plant requires the integration of complex technologies and carries with it the risk of project overruns and unexpected delays. Those risks are magnified when a project is demonstrating new technologies. Not only will designers and engineers have to deal with unexpected issues that arise during construction of large-scale systems but the entire supply chain will have to scale up technologies that may have only been proven at bench scale. Without timeline for construction beyond the current round of demonstration plants, developers and supply chain companies will be operating in an atmosphere where the project is likely to be one-of-a-kind. Such an environment increases the risk and cost of construction.

Despite the uncertainties, a number of commercial-scale demonstration projects continue to move forward. Two that have secured long-term revenue streams and have or are close to breaking ground are Southern Company's Kemper County IGCC Project in Kemper County Mississippi and Summit Power's Texas Clean Energy Project (TCEP) IGCC project in Ector County, Texas. Both of the projects have secured DOE grants and have announced long-term CO_2 purchase agreements for use in EOR.

The major difference between the two projects is that the Kemper County IGCC Project will be operated by Mississippi Power in a market regulated by the Mississippi Public Service Commission while the TCEP IGCC project will operate as a merchant generator. The Kemper County IGCC Project received approval from the Mississippi Public Service Commission to include cost recovery in the rate base starting in 2012 up to a total project cost of $2.88 billion.[19]

[18] Kunkel, Gregory P. *Testimony before the U.S. House of Representatives Natural Resources Subcommittee on Energy and Mineral Resources*. June 12, 2008. http://www.tenaskatrailblazer.com/pdfs/080612-Tenaska-Kunkel-Testimony.pdf

[19] Public Service Commission of the State of Mississippi. *In Re: Petition of Mississippi Power Company for a certificate of public convenience and necessity authorizing the acquisition, construction, and operation of an electric generating plant, associated transmission facilities, associated gas pipeline facilities, associated rights-of-way, and related facilities in Kemper, Lauderdale, Clarke, and Jasper Counties, Mississippi*, Docket No. 2009-UA-14. May 26, 2010.

The TCEP IGCC project announced a 25-year power purchase agreement for 200 MW of power (from an expected electric power capacity of 214 MW) with CPS Energy, the municipally-owned natural gas and electric utility in San Antonio, Texas.[20] As an additional source of revenue, TCEP has also announced a long-term contract to sell over 700,000 tons of urea fertilizer annually that will be produced during the gasification process. In public statements, Summit Power officials have indicated that the business plan for TCEP does not require a federal price on carbon.[21]

Transport and Storage

Beyond the power plant, there are significant uncertainties associated with the construction and availability of pipelines and storage locations for CO_2. While there is a mature network of CO_2 pipelines in the U.S. and the estimated costs of transportation and storage are a small part of the cost of CCS, developers considering CCS will have to identify storage locations, such as saline formations or EOR opportunities, and determine the extent of piping that might be required to move the CO_2 from the power plant to the storage location. Early integrated projects in the U.S. are primarily focused on EOR opportunities, in part because of the existence of CO2 pipelines and experience with the storage formations. A number of companies with pipeline and EOR experience, such as Denbury Resources and Kinder Morgan, have been engaged in CCS demonstration projects.

Given the extensive technical and regulatory experience associated with pipeline transport of CO_2, it is unlikely the construction of CO_2 pipelines will be a significant barrier to CCS deployment. However, pipeline siting and availability considerations could be challenging for early projects that are not located near a storage location. In advance of CCS development, there are areas where state level rules and regulations could be streamlined to ease the development of CO_2 pipelines. For example, in some states oversight of CO2 pipelines is divided between different agencies.

On the storage side, there are a number of significant CO_2 storage projects in the U.S. and globally that have been demonstrating the storage of CO_2 at scale in saline formations, depleted gas reservoirs, and as a part of EOR. As these projects advance and continue to collect data, the geologic storage of CO_2 will be better understood and confidence in long-term storage will increase.

To further reduce the uncertainty associated with storage, EPA has finalized rules through the Underground Injection Control program to protect drinking water sources during the injection of CO_2 for storage in geologic formations. EPA has also finalized rules for the reporting of emissions from CO_2 storage location through the GHG Reporting Program that provide a starting point for CO_2 monitoring and verification. These rules help to establish the framework

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[20] Summit Power. "Texas Clean Energy Project to Sell Power to CPS Energy in 25-year PPA," Press Release. June 20, 2011. http://www.summitpower.com/in-the-news/texas-clean-energy-project-to-sell-power-to-cps-energy-in-25-year-ppa/

[21] Goozner, Merrill. "Clean Coal: Lost Jobs, Wasted Money as Feds Dither," *The Fiscal Times*. September 29, 2011. http://www.thefiscaltimes.com/Articles/2011/09/29/Clean-Coal-Lost-Jobs-Wasted-Money-as-Feds-Dither.aspx?p=1

within which future projects will operate. In addition, the California Carbon Capture and Storage Review Panel identified the following regulatory gaps:

- Rules to protect non-groundwater environmental and mineral rights;
- Legal requirements regarding atmospheric emissions of CO_2;
- Appropriateness of the monitoring and verification requirements under the GHG Reporting Program for GHG reduction programs.[22]

A significant source of uncertainty in the development of CCS is ownership of pore space for CO_2 storage. The rules associated with the ownership of pore space vary from state to state. Some states having a history of mineral severance, with established rules and procedures for separating subsurface rights from surface rights, while other states have no such experience and ownership remains with the surface owner.

In anticipation of CCS development, Wyoming and North Dakota have passed legislation to clarify the issues of pore space ownership. Wyoming assigned ownership of all pore space (defined as the subsurface space which can be used as storage space for carbon dioxide or other substances) to the surface owner. Wyoming further clarifies that historic agreements conveying mineral rights do not convey ownership of pore space "unless the agreement explicitly covers that ownership interest." North Dakota similarly defines pore space and clarifies that surface owners retain pore space ownership. Unlike Wyoming, North Dakota does not provide for the severance of the pore space from surface ownership. In both statutes, the states create a system whereby consent of pore space owners is necessary to begin CO_2 sequestration. In Wyoming, 80 percent of owners must consent, in North Dakota, 60 percent of owners must consent.[23]

Long-term Stewardship Risks

Once CO_2 is injected into a formation for long-term sequestration, the intent of all parties will be for it to remain underground indefinitely. There are a number of concerns associated with long-term sequestration including who is responsible for potential risks to health, safety, and the environment and who is responsible for keeping CO_2 out of the atmosphere under a cap-and-trade or other regulatory regime. The challenge for legislators and regulators developing frameworks to address these types of liability is to sufficiently reduce any project risk to make the projects financially attractive while maintaining a level of responsibility that encourages owners and operators to operate in a way that promotes safe long-term sequestration.

Stakeholders at the state and federal level have started to develop frameworks to address the challenges associated with long-term stewardship and liability. For example, Louisiana, Montana, North Dakota, and Oklahoma have developed a model where the operator of a geologic sequestration site can transfer title and liability to the State after demonstrating that the site is stable. FutureGen Alliance, the industrial coalition formed to support the original DOE-sponsored FutureGen project to build an integrated CCS facility, included a request for

[22] California Carbon Capture and Storage Review Panel. *Findings and Recommendations*, December 2010.

[23] Vann, Adam, James E. Nichols, Paul W. Parfomak. *Legal Issues Associated with the Development of Carbon Dioxide Sequestration Technology*, Congressional Research Service, March 19, 2010.

states to indemnify the project in its request for proposal. The two states with sites in contention at the end of the process, Texas and Illinois, both passed legislation that would provide indemnification for the project. While the language in the legislation was specific to the FutureGen project and not applicable to other projects, this step suggests that states are willing to consider indemnifying certain projects.

At the federal level, a number of bills have been introduced into Congress in recent years that provide funding for large-scale CCS demonstration projects and also provide liability protection and federal indemnification for funded projects. The most recent draft of the legislation (S. 699) was introduced by Senator Bingaman in March 2011 and reported out of committee in July. While it is unlikely that Senator Bingaman's bill will be voted on by the Congress, the bill will likely be the framework for future attempts to address liability concerns through legislation. Appendix B includes a summary of S. 699.

Any approach to addressing long-term liability raises questions about the timeframes associated with monitoring and tracking CO_2. If a state or the federal government is going to indemnify a company that sequesters CO_2, when does that indemnification start? If a contract is structured so that the seller has to cover any potential leakage, how long into the future does the seller have to monitor the location? Is the owner or operator of a site responsible for leakage that could occur in 100 years, 1,000 years, or even 10,000 years?

While there are not clear answers to these questions, there is general agreement that the risk profile of a site declines significantly after injection ends. During injection, CO_2 is displacing fluids and creating a pressure front within a geologic formation. If there are unexpected leakage pathways or if there is unanticipated movement of the CO_2, it will likely happen during injection. Once injection ceases, geologists expect the risk of unexpected movement to decrease and the CO_2 to remain trapped by primary trapping mechanisms such as a cap rock. Over longer time frames, geologists expect the risk profile to decrease even further as the CO_2 becomes even more encumbered through secondary mechanisms such as dissolution into the fluid in the formation, capillary trapping in the formation pore space, and mineralization. If this model for risk is correct, the need for monitoring and verification should drop considerably during the post-injection period. A long-term stewardship framework will most likely be built on the testing and verification of this risk profile.

Developing a Business Case for NG-CCS

The business case for CCS on natural gas combined cycle plants is based on getting a reasonable return on the investment in a natural gas combined cycle unit with CCS. In a regulated market, this means the public utility commission allows the company to build these additional risks into the rate. In a deregulated market, this means the wholesale market is priced in a way to allow cost recovery for these additional risks.

To address the additional risks and encourage deployment of CCS on natural gas combined cycle units, policymakers can use mechanisms that either shift the supply curve or shift the demand curve. To reduce the cost of the technology and shift the supply curve, policymakers can fund research, development, and demonstration (RD&D) and facilitate knowledge transfer through sponsorship or organization of conferences and trade publications. To shift the demand curve, policymakers can develop regulations that create a market for the technology such as cap-and-trade systems, standard setting, or portfolio standards.

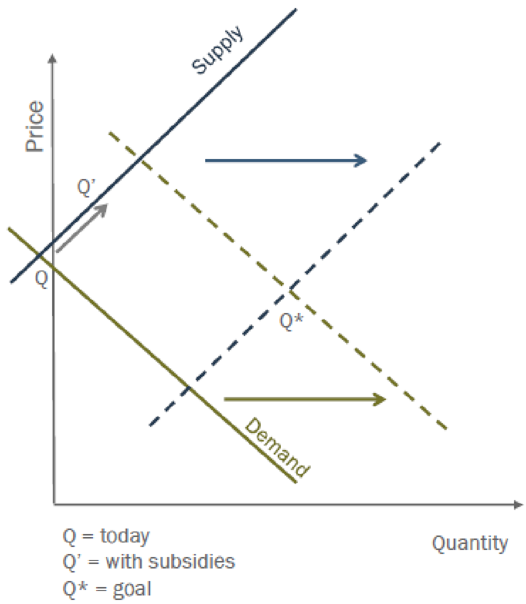

Figure 5. Idealized Supply and Demand Curve

Ideally, policymakers will use a continuum of policies that lower the cost of the technology while creating a long-term market. Figure 5 shows an idealized supply and demand curve. If the current state of the technology is at point Q (i.e. the equilibrium point is no demand), subsidies can make it economically attractive to demonstration the technology (moving along the supply curve to Q'). The goal of these subsidies should be to move the supply curve through learning-by-doing. Moving the supply curve means that a greater number of CCS power plants will be deployed at a given price. At the same time, policy makers should be creating a market for the technology to shift the demand curve and encourage a new equilibrium point (Q*) where more of the technology is deployed at a lower price.

Lowering Costs (Moving the Supply Curve)

Lowering the cost of CCS deployment could come in many forms: funding research in the hopes of technology breakthroughs, lowering the risks associated with the technology by subsidizing early demonstration projects, increasing regulatory certainty associated with CO_2 storage and long-term assurance, and encouraging stakeholder collaboration.

Considerable federal dollars have been committed to demonstration projects. The American Recovery and Reinvestment Act (ARRA) of 2009 included $3.4 billion to DOE for the Fossil Energy Research and Development program. The funding was directed to a number of different initiatives:

- $1 billion for fossil energy research and development programs, which was later committed to funding the revised FutureGen Project (FutureGen 2.0);
- $800 million for the Clean Coal Power Initiative Round III (CCPI R3) Funding Opportunity Announcement;
- $1.52 billion for a competitive solicitation for industrial carbon capture and energy efficiency improvement projects, including beneficial CO_2 reuse;
- $50 million for site characterization activities in geologic formations;
- $20 million for geologic sequestration training and research grants; and
- $10 million for program direction funding.

Before receiving money under ARRA, CCPI R3 had $600 million in existing funding. Bringing the total available under CCPI R3 to $1.4 billion. Five awards were made under CCPI R3:

- $100 million to Basin Electric Power Coop for post-combustion capture;
- $308 million to Hydrogen Energy International LLC for IGCC with CCS;
- $334 million to American Electric Power for post-combustion chilled ammonia capture;
- $350 million to Summit Texas Clean Energy for IGCC with pre-combustion capture; and
- $295 million to Southern Company for retrofit post-combustion capture. Southern Company declined the grant in February 2010. Recently, DOE announced that an NRG Energy-led project would receive $355 million for a 240 MW post-combustion demonstration project in Texas.

However, the lack of demand-focused policies decreases the effectiveness of the technology push policies. As discussed above, since late 2010, the Basin Electric and AEP projects have been put on hold. The Hydrogen Energy project has been significantly restructured and recently unveiled a new project plan under new leadership from SCS Energy.[24] In November 2011, the NRG Energy project was expanded from 60 MW to 240 MW with a goal of increasing EOR revenues to make up for the lack of a carbon price. As a part of the project, NRG Energy will construct a new 80-MW gas-fired combustion turbine to generate heat for the capture process. While the combustion turbine will be a significant capital expense, NRG Energy's goal is to reduce the parasitic losses to the coal plant.[25]

DOE has had significant success encouraging knowledge sharing and stakeholder interaction through the Regional Carbon Sequestration Partnerships and annual conferences. EPA has been working to address regulatory uncertainties through the UIC rule and the GHG Reporting Program requirements.

Increasing Demand for NG with CCS

Increasing the demand for CCS could come in the form of tax incentives and loan guarantees; a national, regional, or state program developed through legislation (cap-and-trade program, portfolio standard, carbon tax); or a national or state regulatory program (greenhouse gas standards).

Existing federal programs designed to encourage a market for CCS are in the form of tax incentives and loan guarantees. The Emergency Economic Stabilization Act of 2008 established tax incentives for CCS and EOR. The incentives provided a $20 credit per metric ton CO_2 captured, transported, and securely stored for geologic sequestration and $10 credit per metric ton CO_2 for EOR with secure geologic storage. Qualified facilities must capture at least 500,000 tons of CO_2 per year. The credit is capped after the first 75 million tons. Additionally, the Act established a 30% investment tax credit for advanced coal-based generation technology projects. Total awards are capped at $1.25 billion and qualified projects can be IGCC or pulverized coal with CCS and must sequester at least 65% of total CO_2 emissions.

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[24] SCS Energy. "SCS Energy Close Deal to Acquire HECA Project in Kern County," Press Release. September 28, 2011.
[25] Bandyk, Matthew. "NRG expanding carbon capture project in Texas," *SNL Energy*. November 30, 2011.

The Energy Policy Act of 2005 authorized loan guarantees for projects using innovative technologies to reduce GHG emissions from coal-based energy sources. DOE published a solicitation in Sept 2008 for up to $8 billion of loan guarantees in support of debt financing for integrated CCS systems and advanced coal gasification.

As discussed above, the biggest impediment to deployment of CCS on power plants is the lack of certainty around future greenhouse gas regulation. The projects in Table 1 were proposed in an environment where early-mover CCS projects had the potential to earn significant revenues through comprehensive climate legislation. In addition to putting a price on GHG emissions, the American Clean Energy and Security Act of 2009, as passed by the House, established a bonus allowance program to support the commercial deployment of CCS technologies. The program included a number of elements that balanced the need to provide near-term incentives while signaling that the support would phase out over time; however its focus was on coal-based power.

The bonus allowance program was limited to 72 GW of total cumulative generating capacity (including industrial applications). To be eligible a project had to implement CCS technology at an EGU with a nameplate capacity of 200 MW or more that derived 50 percent of its annual fuel input from coal, petroleum coke (a byproduct of the refining process), or any combination of the two fuels and captures and sequesters at least 50 percent of emitted CO_2 on an annual basis. The Act also included restrictions on bonus allowance eligibility for facilities initially permitted after January 1, 2009 and before January 1, 2020 if they do not capture 50 percent of CO_2 when they commence operation. The companion bill in the Senate, which never made it to the floor for a vote, would have refined these conditions to incentivize early deployment but limit the bonus pool after 2020.

Review of GHG Control Programs

Despite the absence of comprehensive Federal legislation to control GHG emissions, GHG emissions are regulated at the state level by the states participating in the Regional Greenhouse Gas Initiative (RGGI) and California. However, the stringency of these programs is not yet sufficient to drive development of CCS.

EPA has also started regulating GHG emissions from the electric sector as part of the facility permitting process (requiring the use of best available control technologies (BACT) for regulated pollutants) and is expected to release new source performance standards (NSPS) for GHG emissions from power plants in the coming months.

Regional Greenhouse Gas Initiative

The RGGI regional budget was established using a baseline of 2000 to 2004, which was then increased to account for the expected growth in emissions until the program launched in 2009. The budget was apportioned among the states. Since the cap was set, emissions in the RGGI region have declined significantly due to a variety of energy market dynamics. In 2010, emissions were approximately 27 percent below the regional cap. The discrepancy is the result of increased natural gas generation because of lower relative natural gas prices; increased generation by non-emitting resources, such as nuclear, renewable, and hydro plants, along with lower electricity demand due to the recession and energy efficiency efforts.[26]

With emissions projected to remain well below the regional cap for the foreseeable future, the cost of RGGI allowances is expected to remain at the auction reserve price of $1.86 per ton. The announcement in May 2011 by Governor Chris Christie of New Jersey that the state would leave RGGI at the end of 2011 and uncertainty regarding the continued participation of New Hampshire, Maine, and New York has further weakened demand for allowances. Given these dynamics, as it is currently designed, RGGI will not create a market demand for CCS on natural gas plants.

RGGI states are allowed significant leeway in how they allocate the value associated with their CO_2 emission allowances. Under the original RGGI Memorandum of Understanding, the states agreed that they would use at least 25 percent of the allowance value for a "consumer benefit or strategy energy purpose." Since the states elected to auction the vast majority of allowances, they have received substantial revenues, but most of the funds have been directed toward energy efficiency and renewable energy programs, rather than supporting the development of new low-carbon technologies.[27]

New York is the only state that allocated any RGGI auction revenues to support research, development, and deployment of CCS technologies. The state has allocated about $1 million for the TriCarb Consortium for Carbon Sequestration, which is working to identify potential geologic sequestration sites in Rockland County, New York.[28]

California

In 2006, California passed SB1368, which required the California Energy Commission (CEC) and Public Utilities Commission (CPUC) to establish an Emissions Performance Standard (EPS) for baseload generating resources. The EPS applies to distribution utilities and is designed to prevent these entities from making long-term investments in high-emitting baseload power plants. Long-term investments covered by the EPS include: construction of new units, expansion or purchase of equity share in existing units, and signing new long-term power purchase agreements.[29]

The EPS was set at 1,100 pounds of CO_2 per MWh. While this emission rate precludes long-term investments in coal-fired power plants without CCS, it is readily achievable by new natural gas

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[26] Environment Northeast. *RGGI Emissions Trends Report*. May 2011. http://www.env-ne.org/resources/open/p/id/1109/from/331

[27] Regional Greenhouse Gas Initiative. *Memorandum of Understanding*. December 2005. http://www.rggi.org/docs/mou_final_12_20_05.pdf

[28] New York State Energy Research and Development Authority. *Operating Plan for Investments in New York Under the CO_2 Budget Trading Program and CO_2 Allowance Auction Program*. June 2010. http://www.nyserda.org/RGGI/RGGI_Report_June.pdf

[29] California Energy Commission. Emissions Performance Standard. http://www.energy.ca.gov/emission_standards/index.html

combined cycle units. There are currently no plans to revise the EPS to a level that would drive investment in CCS for gas-fired power plants.[30]

California is scheduled to launch the first phase of its cap-and-trade program on January 1, 2013. At the outset, the program will cover the electric sector, including electricity imports, and large industrial sources. Unlike RGGI, the California cap is expected to be relatively stringent and could begin forcing reductions immediately.

In addition to the potential demand for reductions, the program starts with an allowance price floor of $10 per ton in 2013. The price floor then increases by 5 percent plus inflation each subsequent year. Assuming that the program exists as currently proposed, the minimum allowance price would reach nearly $18 per ton in real 2013 dollars by 2025.[31] The combination of the increasing price floor and potential demand for reductions could create an attractive environment for natural gas CCS in the medium-term.

California has a long-term target to reduce GHG emissions by 80 percent below 1990 levels by 2050. Achieving this goal will require contributions from all sectors of the economy, and the electric sector can be expected to provide some of the greatest reductions, given the relative abundance of low emission technologies, as compared with other sectors. The December 2010 study by the California Carbon Capture and Storage Review Panel acknowledges that in order to realize the state's long-term target emissions natural gas plants will eventually have to reduce their emissions or be phased out.

The review panel identified project financing as a key barrier to development and made the following recommendations[32]:

- *It should be State policy that the burdens and benefits of CCS be shared equally among all Californians. Toward this end, the permitting authority shall endeavor to reduce, as much as possible, any disparate impacts to residents of any particular geographic area or any particular socioeconomic class.*
- *The State legislature should establish that any cost allocation mechanisms for CCS projects should be spread as broadly as possible across all Californians.*
- *The State should evaluate a variety of different types of incentives for early CCS projects in California and consider implementing those that are most cost-effective.*

CCS as part of the Best Available Control Technology (BACT) selection process

Based on its interpretation of the Clean Air Act (CAA), as of January 2, 2011, EPA requires owners and operators of new or modified power plants to include control of GHG emissions in

[30] Van Atten, Chris. "Choices in Air Pollution Regulation: A Review of Alternative Air Emissions Policy Structures for the Electric Sector," *Report for the American Clean Skies Foundation*. February 23, 2011. http://www.cleanskies.org/wp-content/uploads/2011/05/AEPS_ACSF_22Feb2011.pdf

[31] California Air Resources Board, *California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms*, October 2011. http://www.arb.ca.gov/regact/2010/capandtrade10/ctfro.pdf

[32] California CCS Review Panel, *Findings and Recommendations by the California Carbon Capture and Storage Review Panel*, December 2010. http://www.climatechange.ca.gov/carbon_capture_review_panel/documents/2011-01-14_CSS_Panel_Recommendations.pdf

prevention of significant discharge (PSD) and Title V air quality permit applications. PSD permits require applicants to identify BACT for regulated pollutants. In November 2010, EPA released guidance on the process for identifying and selecting technologies as BACT (the guidance was updated in March 2011).[33]

In the guidance, EPA recommends, but does not require, the use of the Agency's five-step "top-down" BACT process that is currently used for other PSD pollutants. The top-down process involves determining all available control options, ranking them by effectiveness, and then examining them individually, beginning with the most effective. The resulting control option is chosen as BACT unless the permit applicant satisfactorily demonstrates that it should be disqualified from consideration based on technical considerations or its energy, environmental, or economic impacts. If the top-ranking option is disqualified, the next most effective control option is considered, and so on, until an option has been selected as BACT.

In summary, the five-step BACT process is:

1. Identify all available control technologies.
2. Eliminate technically infeasible options.
3. Rank remaining technologies.
4. Evaluate most effective controls.
5. Select BACT.

EPA notes that while the guidance discusses some preliminary views on specific issues relating to determining BACT for GHGs, it does not give any final determinations of BACT for a particular source. The process requires a case-by-case analysis.

Within the guidance, EPA classifies CCS as an add-on pollution control technology that is "available" for large CO_2-emitting facilities, including fossil fuel-fired power plants. EPA says that CCS "merits initial consideration"[34] and should be included in Step 1 of the BACT determination, although it may be excluded in later steps as a result of considerations such as feasibility and cost.

EPA specifically discusses the technical feasibility of CCS, noting, "[w]hile CCS is a promising technology, EPA does not believe that at this time CCS will be a technically feasible BACT option in certain cases."[35] EPA recognizes that there are significant logistical hurdles and technical hurdles that may be involved in installing and operating a CCS system that may lead to its disqualification in Step 2. If other sources in the category have already applied CCS technology, or if the source is located in an area where transportation and sequestration opportunities already exist, a detailed analysis would probably be needed to exclude CCS in Step 2.

EPA also discusses CCS with respect to economic concerns, noting, "at present CCS is an expensive technology"[36] and based on its current costs, it will often be eliminated in Step 4 of the

[33] EPA, *PSD and Title V Permitting Guidance for Greenhouse Gases*, March 2011 (Update). http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf
[34] Ibid at p. 33.
[35] Ibid at p. 36.
[36] Ibid at p. 42.

analysis, if not before. However, EPA notes that there may be cases where the economics of CCS are more favorable, and research and development may render CCS more cost-effective.

In the initial permits for NGCC units that include GHG emissions, the focus has been on maximizing the efficiency of the unit through advance turbine technology. Consideration of CCS has followed EPA's guidance and the technology has not emerged as BACT. Given the slow pace of CCS development in the U.S., it is unlikely that the PSD or Title V permitting process, as currently structured, will drive use of CCS on natural gas units.

CCS as part of the New Source Performance Standard (NSPS) process

EPA is currently developing NSPS for GHG emissions from electric generating units under the CAA. Since GHG emissions are not regulated as toxic air emissions and EPA has not set a national ambient air quality standard for GHG emissions, the CAA requires EPA to set standards for existing as well as new and modified sources under the NSPS program. Once proposed, the new source standards will set a floor (i.e., the minimum standard new sources must meet) for GHG BACT.

EPA's schedule for proposing GHG NSPS is driven by a settlement agreement with a number of environmental litigants. Originally, EPA agreed to propose standards for new, modified, and existing sources by July 26, 2011 and finalize standards by May 26, 2012. That schedule has slipped a number of times. EPA and the litigants are expected to reach an agreement on a new schedule by the end of November 2011.

The standards for new and modified sources are intended to "reflect the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated."[37] This provides EPA with significant discretion in determining an appropriate standard. The standards are traditionally set at the unit level and states do not have the flexibility to approve less stringent standards.

The CAA provides EPA with considerable flexibility in establishing standards for existing sources. EPA is required to establish emission guidelines for states that provide a procedure for states to issue performance standards. States are required to develop implementation plans to regulate existing sources in a way that complies with the guidelines. A number of observers have speculated that states could propose the use of new or existing cap-and-trade programs as the basis for compliance with the emission guidelines.[38]

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[37] EPA. *Background on Establishing New Source Performance Standards (NSPS) Under the Clean Air Act*, 2010. http://www.epa.gov/airquality/pdfs/111background.pdf

[38] See for example the February 2011 Working Paper, *What's Ahead for Power Plants and Industry? Using the Clean Air Act to Reduce Greenhouse Gas Emissions, Building on Existing Regional Program* by Franz T. Litz and Nicholas M. Bianco of World Resources Institute and Michael B. Gerrard and Gregory E. Wannier of Columbia Law School, http://www.law.columbia.edu/null/download?&exclusive=filemgr.download&file_id=542077

It is unclear what standards EPA will propose under GHG NSPS. From the perspective of creating markets for CCS, EPA could determine that CCS is the best system of emission reduction for new fossil fuel-fired power plants. However, such a determination would be a departure from the focus on energy efficiency found in the GHG BACT guidance and would raise questions about how EPA considered costs in setting the standard. If EPA allows existing state or regional programs to be used to meet emission guidelines, those programs would have to be significantly more stringent than existing programs to drive the installation of CCS on existing power plants.

Impact of Incentives on Financing a Model NGCC Plant

Absent a GHG program that is sufficiently stringent to create a market for CCS technologies, the demonstration and deployment of CCS on NGCC power plants will depend on incentives such as grants and tax credits. As a way of reviewing the impact of subsidies on CCS deployment on NGCC power plants, MJB&A developed a financial model using technical and cost assumptions for NGCC with and without CCS. The data were based on analysis done by the Department of Energy's National Energy Technology Laboratory (NETL) for its series of reports *Cost and Performance Baseline for Fossil Energy Plants*.[39]

Table 2 summarizes NETL's assumptions. Note that the two units have different net power outputs (555 MW for the non-capture unit compared to 474 MW for the capture unit) but NETL designed them to consume natural gas at the same rate (167,333 pounds per hour). MJB&A assumed a three-year construction period followed by 32 years of operating life for each plant for a total project period of 35 years.

Table 2. DOE NETL Technical and Cost Assumptions for NGCC and NGCC with CCS

Parameter	Unit	NGCC (Advanced F Class)	
		No Capture	**With Capture**
Capture Rate	%	0%	90%
Capacity Factor	%	85%	85%
Gross Power Output	kWe	564,700	511,000
Auxiliary Power Requirement	kWe	9,620	37,430
Net Power Output	kWe	555,080	473,570
Natural Gas Flowrate	lb/hr	167,333	167,333
HHV Thermal Input	kW(th)	1,105,812	1,105,812
Net Plant HHV Efficiency	%	50.2%	42.8%
Net Plant HHV Heat Rate	Btu/kWh	6,798	7,968
Total Plant Cost	2007$/kW	584	1,226

The list of model inputs shown in Table 3 was developed using NETL's technology and cost assumptions and other assumptions based on MJB&A's own energy market analysis. As a way

[39] DOE NETL, *Cost and Performance Baseline for Fossil Energy Plants: Volume 1 – Bituminous Coal and Natural Gas to Electricity (Rev. 2)*, November 2010.

to understand how to make NGCC with CCS financially viable, MJB&A analyzed the levelized cost of electricity (LCOE) and then developed estimates of the revenue generation from electricity sales as well as potential subsidies. A key difference to the NETL work is their significantly higher base case fuel cost assumption – $6.55 per MMBtu compared to $5.00 per MMBtu in this analysis. Analysis of potential revenues was beyond the scope of the NETL analysis.

Table 3. Model Revenue and Expense Assumptions

Discounted cash flow components (2007$)	**Unit**	**No Capture** Year 0	**With Capture** Year 0
Revenues (revenue sufficiency)			
Inflation - electricity price	%	3.0%	3.0%
Wholesale electricity price	$/kWh	0.045	
Expenses			
Inflation rate - variable costs	%	3.0%	3.0%
Fuel cost	$/MMBtu	5.00	
Fixed O&M	$/kW-yr	26.3	49.9
Variable O&M	$/kWh	0.00130	0.00260
Capital cost	$	404,889,900	764,967,000
CO_2 TS&M	$/ton	0	8.09
Capex period	years	3.00	3.00
Distribution of capex	%/year	10, 60, 30	10, 60, 30
Escalation of capital costs	%	3.6%	3.6%
Equity cost[40]	%	12.0%	12.0%
Debt cost	%	4.5%	4.5%
Tax rate[41]	%	38.0%	38.0%
Debt %	% of total capital	50%	50%
WACC	%	8.3%	8.3%
Depreciation period	years	20	20

Table 4 summarizes the results of MJB&A's levelized costs and benefits analysis. The goal is to compare levelized costs and revenues, and determine how much subsidy revenue is needed to cover the costs.[42] In a scenario where wholesale electricity prices average 4.5 cents per kilowatt-hour (kWh) and increase at three percent annually over the life of the facility, the plants will

[40] Equity cost reflects the financial returns expected by equity investors in a CCS project. Equity cost is also referred to as a "hurdle rate" for investors. If an investor does not expect to earn his required rate of return, then he will not make his capital available to a project. Equity costs, therefore, must be reflected in the project economics, since they are needed in order to attract equity investors. Equity and debt costs together make up the weighted average cost of capital (WACC).

[41] Projected tax liabilities reflect estimated state and federal corporate marginal tax rates. A developer's unique tax situation may cause his actual tax rate to deviate from expected levels, but we assume that the project is taxed at the normal corporate rate.

[42] The levelized cost analysis includes capex and operating costs for the life of the project, as well as taxes and capital costs for both equity and debt, and therefore reflects developers' required rate of return.

earn levelized revenues of about $69 per megawatt-hour (MWh) or about 6.9 cents per kWh. This compares to an LCOE of about $68 per MWh for the no capture plant and about $95 per MWh for the plant with capture. In this scenario, the plant without capture would be economic while the plant without capture would not. Note that the LCOE difference between the capture and no capture plants ($27 per MWh) is in line with the estimates shown in Figure 3. At a fuel cost of $6.55 per MMBtu, as was used in the NETL analysis, the MJB&A no capture and capture estimates would be $84 and $115, respectively.

Table 4. Levelized Costs and Benefits for Model Plants

Component	No Capture ($/MWh)	Capture ($/MWh)
Net Levelized Costs	67.6	95.0
Capital costs	7.2	16.0
Fuel costs	52.9	65.7
F&VOM	7.5	10.1
Transport, Storage and Monitoring	0.0	3.1
Net Levelized Benefits From Electricity Sales	68.8	68.8

To review the impacts of grants and incentives based on CO2 stored on the financing of the capture project, MJB&A added a grant equal to 50 percent of the capital cost of the plant with carbon capture. For the model plant, this is equivalent to a $382.5 million grant, which is in line with the grants awarded to the two projects moving ahead ($403 million in the form of a grant and an investment tax credit to the Kemper County IGCC project and $450 million in grants to the Summit Power TCEP). Additionally, we looked at the impact of a credit equivalent to $20 per metric ton of CO2 (increasing with inflation at three percent annually) stored over the operating life of the project. Annually, MJB&A projected the model plant with CCS to capture and store 1.34 million metric tons of CO2, or about 44 million metric tons over the assumed 32-year operating life. The current geologic sequestration tax credit is capped at 75 million metric tons for *all* U.S. projects, which means that the modeled project on its own would use over half of the available tax credit. The actual benefit from that tax credit is therefore severely limited and it is unlikely that a single project would be able to absorb such a large share of the available tax credit. If current CCS projects continue to move forward and the use of CO2 for EOR expands, the tax credit pool will soon be depleted.

Figure 6 shows the results of MJB&A's analysis. With revenue from electricity sales starting at 4.5 cents per kWh, a grant equivalent to 50 percent of the capital requirement, and a tax incentive equal to $20 per metric ton of CO2 stored over the operating life of the plant, the CCS project is still not able to cover its costs.

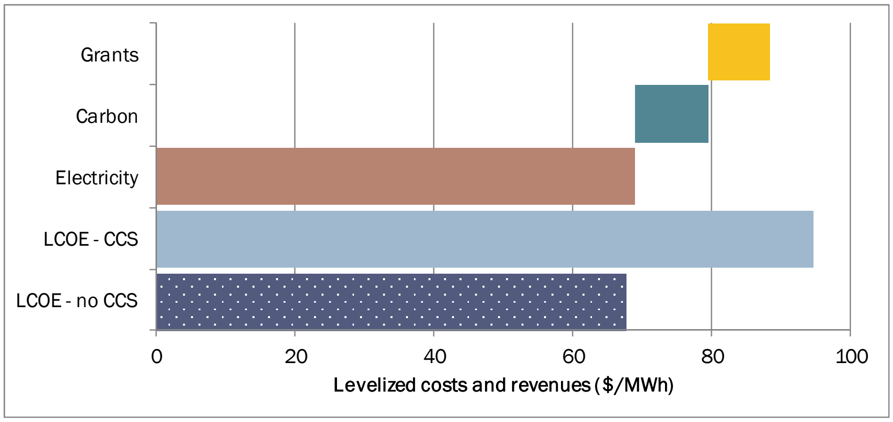

Figure 6. Cost and Revenue Comparison for Model NGCC Plants

As a way of exploring the sensitivity of LCOE to changes in CO2 credit value (carbon price); natural gas price; the weighted average cost of capital (WACC); operating and maintenance (O&M) costs; and transportation, monitoring and storage (TM&S) costs, MJB&A created high- and low-case scenarios for each variable. Figure 7 shows the results of this analysis. In Figure 7, the numbers in bold represent the base case assumptions described above; the values on either side of the bars represent low and high scenario assumptions. Carbon revenues, shown as negative, would offset the costs. The larger the rectangle, the more significant the values are to the LCOE. Within a reasonable range of assumptions, both the CO2 price and the fuel cost can significantly impact the LCOE of a project. As with any power plant, a CCS plant would benefit from entering into a long-term contract as a way of reducing fuel price risk. On the incentive side, with reasonable assumptions a significant long-term price on carbon has greater potential to help a project than loan guarantees or other mechanism that lower the cost of capital.

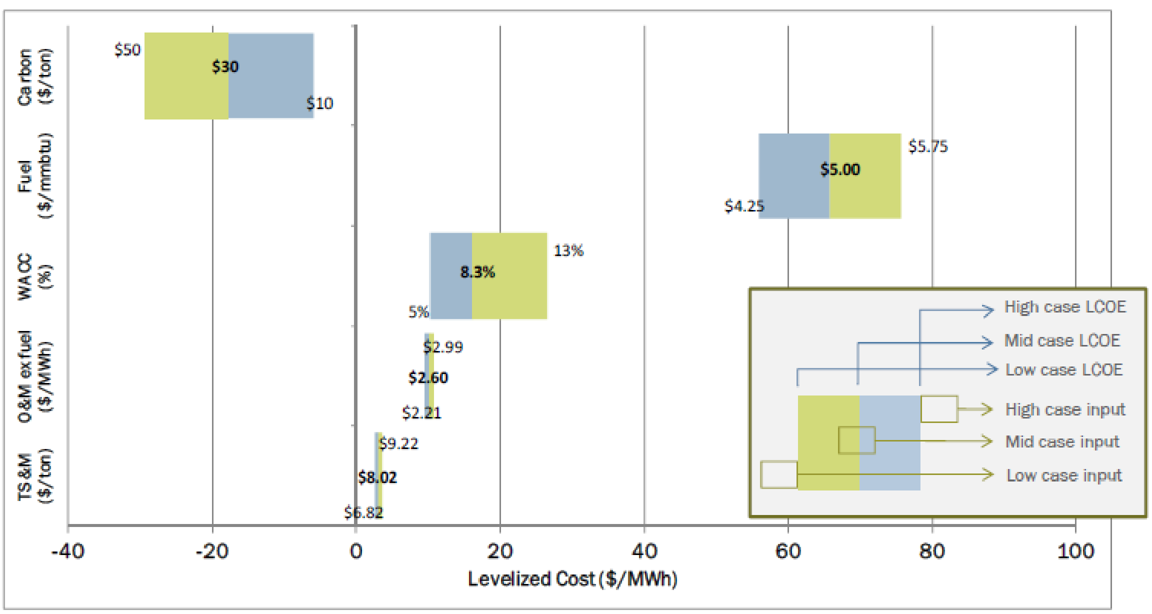

Figure 7. Sensitivity of LCOE to Changes in Key Variables

A volumetric, performance-based incentive like a long-term CO2 price would also be attractive because it rewards the desired action (i.e., storage of CO2) and not simply the construction of a plant.

For the model plant, a CO2 price of $50 per metric ton stored would be required to make the plant economically attractive. This price is lower than normally suggested in the literature but it represents payment for CO2 stored as opposed to CO2 avoided. Capture plants have to combust more fuel to generate the same amount of electricity. As a result, the baseline emissions, before capture, are higher on a per kWh basis, making the total captured greater than the total avoided. Under a comprehensive climate change policy, dollars per CO2 avoided would be the appropriate metric for compensation. The MJB&A model suggests a breakeven net CO2 production cost of $78 per metric ton. A probabilistic analysis completed by Professor Ed Rubin at Carnegie Mellon University suggests that a price in excess of $100 per metric ton would be required to induce CCS given the uncertainties around technology and policy.[43]

Conclusions

Deploying CCS at the scale required to impact climate change will require policy drivers as well as technological development. A key hurdle is the demonstration of CCS at a commercial scale power plant. Such a demonstration would increase confidence in the technologies and reduce costs through learning. While companies have successfully demonstrated the component technologies commercially (e.g., capture and separation to generate food-grade CO_2, transport of CO_2 from natural sources to oil wells in West Texas, and injection into geologic formations after stripping CO_2 from natural gas at the Sleipner Project in the North Sea), no one has constructed a full scale power plant with integrated CO_2 capture, transport, and geologic sequestration.

Over the past year, a number of integrated commercial-scale power plants with CCS have been put on hold. This trend was anticipated by the final report of the Interagency Task Force on Carbon Capture and Storage. The CCS Task Force concluded:

> *The lack of comprehensive climate change legislation is the key barrier to CCS deployment. Without a carbon price and appropriate financial incentives for new technologies, there is no stable framework for investment in low-carbon technologies such as CCS. Significant Federal incentives for early deployment of CCS are in place, including RD&D efforts to push CCS technology development, and market-pull mechanisms such as tax credits and loan guarantees. However, many of these projects are being planned by the private sector in anticipation of requirements to reduce GHG emissions, and the foremost economic challenge to these projects is ongoing policy uncertainty regarding the value of GHG emissions reductions.*[44]

[43] Rubin, Edward, *The Cost of CCS for Natural Gas-Fired Power Plants*, Presentation to the Natural Gas CCS Forum, Washington, DC. November 4, 2011. http://www.cleanskies.org/wp-content/uploads/2011/11/ERubin_CCSandGasForum_1142011.pdf

[44] Interagency Task Force on Carbon Capture and Storage, August 2010. http://www.epa.gov/climatechange/downloads/CCS-Task-Force-Report-2010.pdf

In a time of fiscal constraints and policy uncertainty, the greatest challenge to demonstrating CCS on a commercial scale may be finding the funding to overcome the significant financial obstacles. One approach that is currently gaining currency at DOE and elsewhere, is utilizing CO_2 for enhanced oil recovery.[45] However, at the reported contract prices for CO_2 for EOR (ranging from $20 to $40) additional sources of funding will be needed to make a commercial-scale power plant project viable.

In the absence of commercial-scale demonstration, policymakers should provide continued support for R&D to reduce the costs associated with CCS and should support initiatives to remove the legal and regulatory barriers to CCS, including work to reduce uncertainty around transport, storage, and liability.

One significant takeaway from ongoing efforts is a relative lack of focus on CCS for natural gas. Globally, the most advanced project is the Mongstad Project in Norway.[46] Domestically, the California Energy Commission in collaboration with WESTCARB, Pacific Gas & Electric, and Lawrence Livermore National Laboratory has initiated a study of the potential for NGCC with CCS in California.[47] That study is funded by DOE and is expected to get underway by the end of 2011, with results in 2012.[48]

When compared to coal-fired power plants, NGCC power plants have significantly lower GHG emissions per unit of electricity generation relative to coal-fired power plants.[49] However, to meet stringent mid-century GHG reduction targets, emissions from NGCC power plants will have to be dramatically reduced. As the National Petroleum Council concluded in its recent *Prudent Development* report:

> *However, under a more aggressive 80% GHG reduction target, natural gas, even with its relatively lower carbon intensity, cannot meet the carbon constraints alone without low to zero-emitting technologies such as CCS. Hence, it is imperative that research, development, and demonstration (RD&D) efforts related to lower-carbon technologies, including CCS, continue if a steep, long-term target is established and substantial natural gas use is to be maintained over the longer term.*[50]

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[45] See, for example, the National Enhanced Oil Recovery Initiative (http://www.pewclimate.org/initiatives/eor) and DOE NETL's recent report on "Next Generation" CO2-EOR opportunities (http://www.netl.doe.gov/energy-analyses/pubs/NextGen_CO2_EOR_06142011.pdf)
[46] MIT Carbon Capture & Sequestration Technologies. *Statoil Mongstad Fact Sheet: Carbon Dioxide Capture and Storage Project*. Updated November 16, 2011. http://sequestration.mit.edu/tools/projects/statoil_mongstad.html
[47] Gravely, Mike. *Assessment of Natural Gas Combined Cycle (NGCC) Plants with CO2 Capture and Storage*, Presentation to California Energy Commission. January 14, 2010. http://www.energy.ca.gov/contracts/2010-01-14_westcarb/presentations/01_Mike_Gravely_CEC.pdf
[48] MJB&A conversation with participants from Pacific Gas & Electric. October 2011.
[49] Staple, Gregory C. and Joel N. Swisher. *The Climate Impact of Natural Gas and Coal-fired Electricity: A Review of Fuel Chain Emissions Based on Updated EPA National Inventory Data.* April 19, 2011. http://www.cleanskies.org/wp-content/uploads/2011/06/staple_swisher.pdf
[50] National Petroleum Council. *Prudent Development – Realizing the Potential of North America's Abundant Natural Gas and Oil Resources.* Final Report Approved September 15, 2011. http://downloadcenter.connectlive.com/events/npc091511/Carbon-091511.pdf

One of the additional challenges associated with CCS on natural gas is reflected in many of the economic assumptions that go into modeling CCS on NGCC. While most of the economic scenarios use baseload capacity factors (those in Figure 3 assume capacity factors associated with baseload operation (>75 percent). In 2009, the average capacity factor of NGCC plants in the U.S. was only 42.2 percent.[51] While an important research topic is looking at the potential to optimize capture technologies for load-following or cycling natural gas power plants, opportunities for early, cost effective deployment will be on NGCC units that have high capacity factors.

Using EIA data, MJB&A estimates that only six natural gas fired power plants in the U.S. had capacity factors of more than 70 percent in 2010 (those six power plants had a total of 19 combined cycle units on site). Only one of those power plants had a capacity factor greater than 75 percent. Only 15 power plants and 55 units had a capacity factor of at least 65 percent (see Appendix C for a list). The 15 natural gas-fired power plants with capacity factors of more than 65 percent were located in seven states: California, Connecticut, Florida, Louisiana, New York, Oklahoma, Oregon, and Texas. California and Texas combined for almost half the total, four in California (with 14 units) and three in Texas (with 13 units). Figure 8 shows the number of plants with more than 250 MW of installed NGCC capacity associated with various ranges of estimated utilization in 2010.

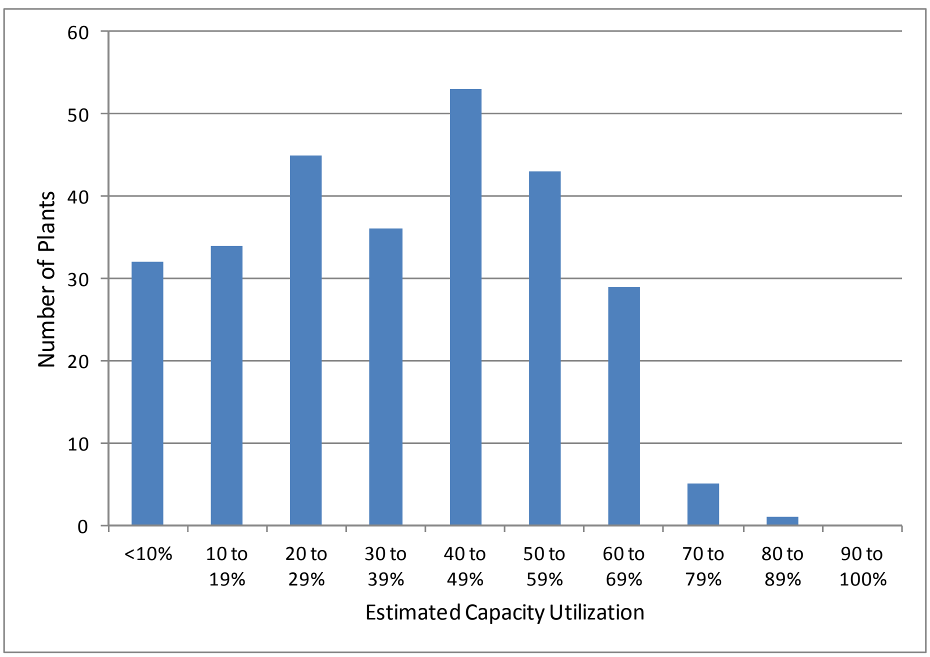

Figure 8. Estimated Utilization of Natural Gas Combined Cycle Capacity at Plants with Greater than 250 MW of Combined Cycle Capacity (MJB&A using EIA Form 860 and 923 data)

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[51] U.S. Energy Information Agency (EIA). "Average Capacity Factors by Energy Source", *Electric Power Annual with data for 2009*. November 23, 2010 (April 2011 Update). http://www.eia.gov/cneaf/electricity/epa/epat5p2.html

Moving forward, an important research area for CCS on NGCC will be finding ways to optimize capture for conditions where the power plant has a low utilization and cycles on and off based on demand.

Appendix A: Summary of Recent Studies of NGCC-CCS Economics

Parameter	**Units**	**Alstom (2015)**	**MIT Future of Natural Gas**	**EIA AEO**	**EPRI**	**NETL Baseline Rev 1**	**US Task Force on CCS**	**NETL Baseline Rev 2**	**Global CCS Institute (FOAK)**
Study year	Year	2011	2010	2011	2009	2007	2010	2010	2011
Cost year	Year	2011	2005	2009	2007	2007	2009	2007	2010
Natural gas price	$/MMBtu				7.00	6.75		6.55	
Capacity factor	%			87%	80%	85%		85%	
Net plant efficiency w/o capture, HHV	%			53.1%	46.7%	50.8%		50.2%	
Net plant efficiency w/capture, HHV	%			45.4%	39.7%	43.7%		42.8%	
Natural Gas Price	$/Mbtu				7	6.75		6.55	
NGCC w/o CCS COE	$/MWh	58	56	63	66	68	77	75	88
NGCC w/CCS COE	$/MWh	88	85	89	91	97	121	109	115
Added COE for CCS	$/MWh	31	29	26	25	29	44	34	27
Cost of CO2 Avoided	$/tonne CO2	111			74	92	115	106	107

Sources

Alstom: MacNaughton, Joan. “CCS – Commercially Viable but a Political Priority?” *Presentation to the United States Energy Association*. August 4, 2011.

MIT Future of Natural Gas: MIT Energy Initiative. Future of Natural Gas: An Interdisciplinary MIT Study. June 2011. http://web.mit.edu/mitei/research/studies/natural-gas-2011.shtml

EIA AEO: U.S. Energy Information Agency (EIA), *Annual Energy Outlook 2011*. April 26, 2011. http://www.eia.gov/forecasts/aeo/

EPRI: As reported by Rubin, Edward, *The Cost of CCS for Natural Gas-Fired Power Plants*, Presentation to the Natural Gas CCS Forum, Washington, DC. November 4, 2011. http://www.cleanskies.org/wp-content/uploads/2011/11/ERubin_CCSandGasForum_1142011.pdf

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Global CCS Institute: Schlumberger and WorleyParsons. *Economic Assessment of Carbon Capture and Storage Technologies: 2011 Update*, Global CCS Institute. March 8, 2011. http://cdn.globalccsinstitute.com/sites/default/files/publications/12786/economic-assessment-carbon-capture-and-storage-technologies-2011-update.pdf

Appendix B: Summary of S. 699

On March 31, 2011, Senator Jeff Bingaman (D-NM) introduced S. 699, the Department of Energy Carbon Capture and Sequestration Program Amendments Act of 2011. The bill has six cosponsors: Senators John Barrasso (R-WY), John Hoeven (R-ND), Lisa Murkowski (R-AK), John Rockefeller (D-WV), Jon Tester (D-MT), and Mark Udall (D-CO). S. 699 was reported out of the Senate Committee on Energy and Natural Resources in July 2011 but is not currently scheduled to be considered by the full Senate.

S. 699 would amend the Energy Policy Act of 2005 to create a large-scale carbon storage program. As a part of the program, the Secretary of Energy would be authorized to provide financial and technical assistance to up to ten large-scale demonstration projects, where large-scale is defined as a project that results in the injection of over 1 million tons of CO_2 annually into geologic formations. However, the bill does not provide funding for the program.

To encourage the development of projects, the bill authorizes the Department of Energy to provide projects with liability projection and federal indemnification up to $10 billion. The bill includes post-injection closure and monitoring requirements that extend to ten year after the CO2 plume has stabilized following the end of injection activities. After fulfilling the requirements, the bill would allow participating owners to transfer long-term monitoring and responsibility to the Department of Energy.

Appendix C. Natural Gas-Fired Power Plants with Capacity Factors Greater than 65 % in 2010, By State

Plant Name	State	Combined Cycle Capacity (MW)	No. of Units	Estimated Utilization of Total CC Capacity At Location	Classification
Cosumnes	CA	530	3	74%	Regulated Utility
Pastoria Energy Facility LLC	CA	779	5	73%	IPP
Sunrise Power LLC	CA	605	3	68%	IPP
Palomar Energy	CA	559	3	67%	Regulated Utility
Milford Power Project	CT	578	2	71%	IPP
Lansing Smith	FL	620	3	69%	Regulated Utility
Manatee	FL	1,225	5	68%	Regulated Utility
Louisiana 1	LA	406	5	67%	IPP
Astoria Energy	NY	520	3	72%	IPP
Brooklyn Navy Yard Cogeneration	NY	322	4	68%	IPP
McClain Energy Facility	OK	469	3	85%	Regulated Utility
Klamath Cogeneration Plant	OR	502	3	68%	IPP
Gregory Power Facility	TX	432	3	72%	IPP
Deer Park Energy Center	TX	996	5	66%	IPP
Channelview Cogeneration Plant	TX	918	5	65%	IPP