Topic Paper #27

Carbon Capture & Storage (CCS)

On August 1, 2012, The National Petroleum Council (NPC) in approving its report, *Advancing Technology for America's Transportation Future*, also approved the making available of certain materials used in the study process, including detailed, specific subject matter papers prepared or used by the study's Task Groups and/or Subgroups. These Topic Papers were working documents that were part of the analyses that led to development of the summary results presented in the report's Executive Summary and Chapters.

These Topic Papers represent the views and conclusions of the authors. The National Petroleum Council has not endorsed or approved the statements and conclusions contained in these documents, but approved the publication of these materials as part of the study process.

The NPC believes that these papers will be of interest to the readers of the report and will help them better understand the results. These materials are being made available in the interest of transparency.

National Petroleum Council Future Transportation Fuels and North American Resource Development Studies

<u>Carbon Capture & Storage (CCS) White Paper</u>

Scope of the Paper

The purpose of this paper is to:

1) Inform the National Petroleum Council Future Transportation Fuels and North American Resources study teams.

    - Provide an assessment of the role that CCS could play as a technology to reduce GHG emissions over the next four decades.
    - Assess CCS application over various sectors including natural gas processing, coal power, gas power, refining, biofuels manufacturing, H_2 production, Oil Sands production, and natural gas production.
    - Summarize costs in various sectors for first-of-a-kind (FOAK) and nth-of-a-kind (NOAK) installations.
    - Summarize barriers that need to be overcome for broad CCS deployment.

2) Serve as a primer on CCS for NPC report audiences.

Summary Conclusions

1. **CCS is a promising technology to mitigate GHG emissions from stationary sources on a significant scale.**
2. **The component technologies of CCS are mature, but integrated installations are limited. Hence, CCS should not yet be considered a demonstrated technology for regulatory controls.**
3. **Clear climate policy direction is a pre-requisite to widespread CCS deployment.**
4. **High cost of capture is a barrier in most sectors near to medium term.**
5. **Flexible regulatory frameworks with clear authorities, including long-term CO_2 storage liability provisions, will be necessary.**
6. **Infrastructure and appropriately skilled technical personnel requirements for widespread CCS deployment are very significant.**
7. **Public acceptance of CCS at project level and across society is critical.**
8. **Enhanced Oil Recovery (EOR) can be an enabler for CCS demonstration, but potential EOR storage capacity is limited relative to total stationary source emissions.**
9. **CCS ≠ CCS ..... costs and component technologies vary widely between industry sectors.**
10. **The greatest long-term opportunity for CCS resides in the coal and gas-fired power sector.**

What is CCS

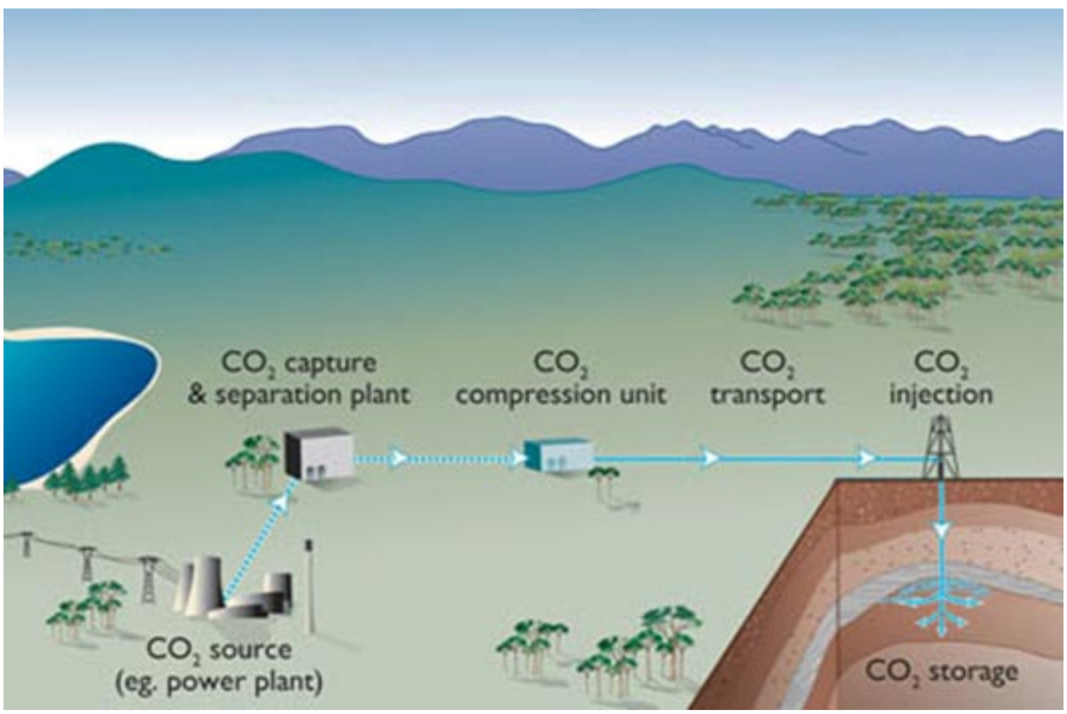
Carbon capture and storage (CCS) is a greenhouse gas emissions mitigation option that involves an integrated process of three distinct steps: 1) capture, 2) transportation and 3) long-term storage. Most of the technologies needed to implement CCS are currently available but have only been integrated at the commercial scale for natural gas processing and synfuels production.

CCS involves capturing the carbon dioxide in fossil fuel production or consumption and storing it for the long-term in deep geological formations. There are three generic process routes for capturing CO_2 from fossil fuel combustion plants:

- Post-combustion capture
- Pre-combustion capture
- Oxy-fuel combustion

Each of these processes involves the separation of CO_2 from a gas stream using either a solvent, physical adsorption, physical separation, or biological processes. Once separated, the CO_2 is compressed and transported to a suitable storage site. CO_2 is already transported at scale by pipeline, primarily for use in declining oil and gas fields to increase production. Road tankers and ships transport CO_2 in smaller amounts for industrial applications, with the latter having potential for larger scale transport. Capture from industrial processes (hydrogen production, natural gas processing, etc.) can involve similar technologies.

<u>Components of System for CCS</u>



Source: IPCC SR CCS, 2005

The final stage of CCS sees the CO_2 injected into, and contained within, suitable subterranean geological structures, usually at depths of one kilometer or more. Appropriate storage sites include depleted oil or gas fields, deep porous saline aquifers, or potentially deep unmineable coal beds, all of which have impermeable rock, known as a 'seal', above them. The seal prevents the CO_2 from returning to the surface while the CO_2 slowly dissolves in saline water and is trapped in small rock pores in the reservoir formation beneath the seal.

Barriers to CCS in the US

While there are no insurmountable technological, legal, institutional, regulatory or other barriers that prevent CCS from playing a role in reducing GHG emissions, early CCS projects face a number of challenges related to: 1) climate policy uncertainty, 2) incomplete regulatory frameworks, 3) high initial investment cost and extensive infrastructure, 4) first-of-a-kind technology risks, and 5) public acceptance.

1) Significant federal incentives for early deployment of CCS at the demonstration scale have been made available. However, many of these projects are being planned by the private sector solely in anticipation of requirements to reduce GHG emissions, and a key challenge to these projects proceeding is ongoing policy uncertainty regarding the value of GHG emissions reductions over time.

   Resolving climate policy will be a key to advancing the demonstration and deployment of CCS. Analysis of recently proposed climate change legislation suggests that CCS technologies will not be widely deployed in the next two decades absent financial incentives that supplement projected carbon prices under those proposals. Climate change policy that provides a predictable cost of GHG emissions over time that is sufficient to overcome CCS cost and risk will encourage investment earlier than an uncertain policy framework.

2) Challenges such as legal and regulatory uncertainty can hinder the development of CCS projects. Though early CCS projects can proceed under existing laws, there is limited experience at the federal and state levels in applying the regulatory framework to CCS. Issues that need clarity in order for projects to proceed include permitting, pore space ownership and access, and long term stewardship and liability.

3) Costs for separating CO_2 from low-pressure, low-concentration flue gas streams remain expensive. In addition, wide-spread deployment of CCS will require substantial infrastructure investments for gathering and injection. For illustration, if 40% of CO_2 emissions from the U.S. power sector were captured and sequestered, it would be ~20 million barrels per day of supercritical CO_2. That equates to the transportation and injection of more CO_2 than the total volume of oil the U.S. consumes today. Infrastructure of that magnitude takes many years, if not decades, to deploy. It also requires extensive human resources that will be in short supply, especially engineers and geologists that will also be in demand to provide world energy supplies and advance standards of living.

   It will be important to continually review the adequacy of capture technologies and classes of storage reservoirs to enable safe and cost-effective widespread CCS deployment. This ongoing assessment will assist researchers in targeting any remaining technology gaps and reducing CCS costs. More discussion of CCS costs is included later in this report.

4) The O&G industry has been separating CO_2 from gas streams for decades. Likewise, the industry has been transporting CO_2 by pipeline, ship, and road tanker and injecting it into depleted reservoirs for enhanced oil recovery or industrial uses for decades. Integrated facilities for CO_2 capture, transport, and storage, however, are limited. Full-scale demonstration projects at stationary sources such as power plants should be encouraged to understand and improve CCS technologies on a large scale. Public and private investment will be needed on these first-of-a-kind installations. CCS is not currently a demonstrated technology for regulatory controls irrespective of the economics and other barriers.

5) Public awareness and support are also critical to the development of new energy technologies. Notwithstanding experience with the existing EOR projects, public acceptance and support are widely viewed as vital for CCS projects (IPCC, 2005; CRS, 2008; IEA, 2009c). Whether the public will support or oppose commercial-scale CCS projects is largely unknown (Malone et al., 2010) and the public's reaction will be project-specific and vary by location. Unlike most countries of the world, U.S. laws on mineral rights and pore space private ownership can aid public acceptance through royalty payments. The notable public rejection of the Barendrecht project in the Netherlands contrasts with "competitions" for the U.S. DOE FutureGen project in Illinois and Texas.

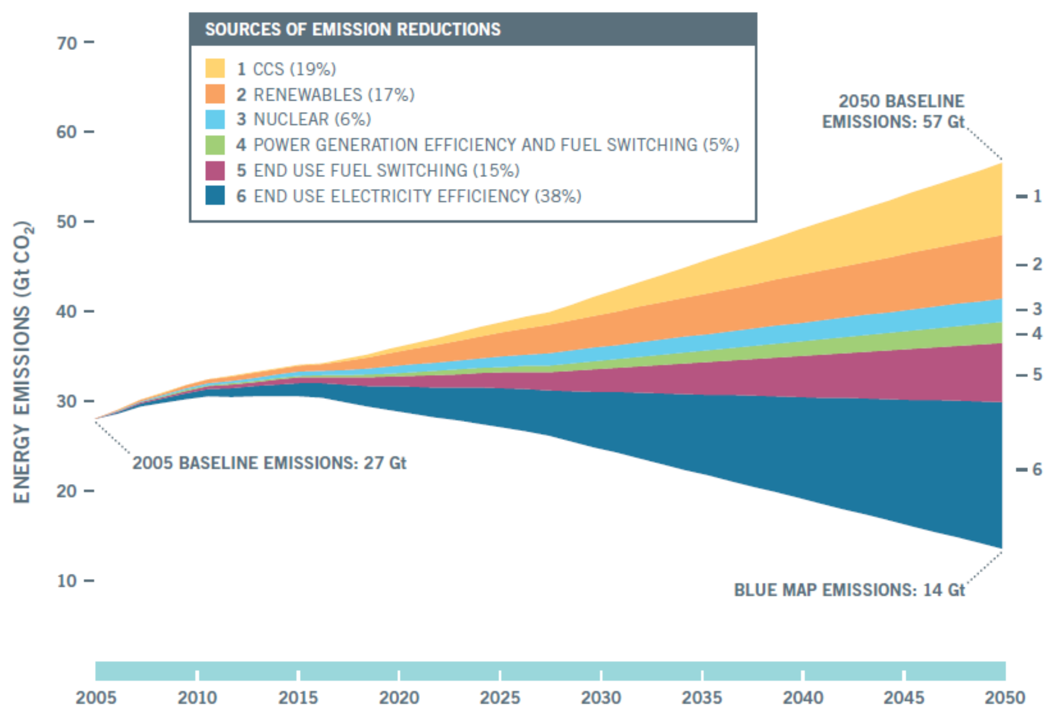
> Industry, government and NGOs need to develop a comprehensive outreach strategy to inform public debate about the role CCS can play, and address potential issues of public concern, whether at a project level or more broadly. Public outreach for CCS should leverage existing efforts among Federal agencies, States, industry, and NGOs.

Private, public and non-governmental entities should also continue to support international collaboration that complements domestic CCS efforts and facilitates the global deployment of CCS. Leveraging resources and sharing results across countries will improve the viability of CCS and potentially speed up global commercialization.

Status and Potential of CCS

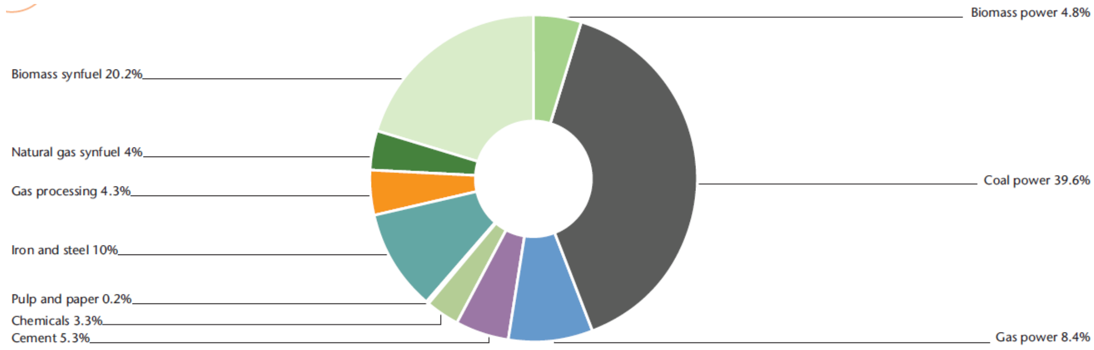
Most global GHG reduction scenarios require wide-spread deployment of CCS for meaningful reductions over this century as one component of an ambitious GHG reduction portfolio. In 2008, the Group of Eight leaders asked the International Energy Agency to project what would be required to reduce global greenhouse gas emissions by 50% by 2050. The total global CCS contribution required in the IEA projection (referred to as the BLUE Map scenario) is 8.2 $GtCO_2$ avoided, equivalent to 19% of the total mitigation effort needed to halve emissions by 2050. In scenarios without CCS, overall global costs to halve emissions by 2050 are at least 70% ($31 trillion) higher than scenarios that include CCS.

IEA Energy Technology Perspectives BLUE Map Scenario



Source: IEA Energy Technology Perspectives (2010) Scenarios and strategies to 2050.

2050 Sector CCS Contribution in IEA Blue Map Scenario



Source: IEA, CCS Roadmap (fold out) 2010

Global Projects

The Global CCS Institute (GCCSI) publishes an annual report on the status of CCS around the world. The report includes a summary of all CCS projects in the world at various stages of planning, construction, or operation. The report focuses on those projects that are commercial scale and integrate all parts of the CCS chain from capture to transport to sequestration. These projects are referred to as Large Scale Integrated Projects (LSIP).

The latest GCCSI report identifies 74 CCS LSIPs around the world with a total CO2 storage capacity of almost 160 million tonnes per year. Eight of those LSIPs are actually in operation and six LSIPs are in the execution stage worldwide. These 14 projects (see table below) have a total CO2 storage capacity of 33 million tonnes per year demonstrating the significant contribution that CCS can make to reduce GHGs. All eight operating LSIPs and five of the six in execution are linked to the oil and gas sector as they either capture CO_2 from natural gas processing, inject CO_2 for enhanced oil recovery (EOR), or both. Two projects involving power plants are in the execution stage. The other 60 projects are in various stages of development planning prior to a final investment decision.

Most of the 74 LSIPs are in developed countries (notably the United States, Europe, Canada and Australia), and a few projects are starting to surface in emerging markets such as China and Middle East. The inclusion of CCS into the UNFCCC Clean Development Mechanism should provide an enabler for future projects in Developing Countries.

Over ½ of the LSIPs are in the power generation sector and 15% are in the natural gas processing sector. The fertilizer production and syngas sectors have five and six projects respectively. Other industries such as cement, pulp and paper, oil refining, and iron/steel show little to no project activity.

These operating and planned LSIPs are providing ‘natural laboratories’ for understanding the movement and behavior of CO_2 in the subsurface, enabling testing of monitoring and verification techniques, and providing tools, models, and procedures.

CCS LSIPs in the Operate and Execute stages

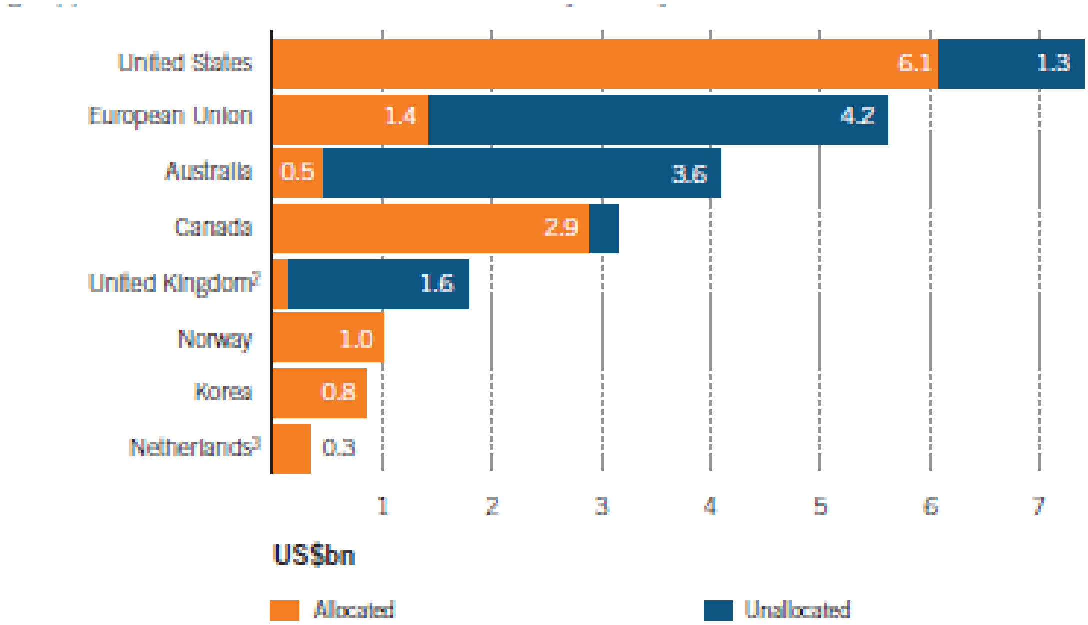
NAME	LOCATION	CAPTURE TYPE	VOLUME CO_2 (MTPA)	STORAGE TYPE	DATE OF OPERATION
Operate stage					
Shute Creek Gas Processing Facility	United States	Pre-combustion (gas processing)	7	EOR	1986
Sleipner CO_2 Injection	Norway	Pre-combustion (gas processing)	1	Deep saline formation	1996
Val Verde Natural Gas Plants	United States	Pre-combustion (gas processing)	1.3[1]	EOR	1972
Great Plains Synfuels Plant and Weyburn-Midale Project	United States/ Canada	Pre-combustion (synfuels)	3	EOR with MMV	2000
Enid Fertilizer Plant	United States	Pre-combustion (fertiliser)	0.7	EOR	1982
In Salah CO_2 Storage	Algeria	Pre-combustion (gas processing)	1	Deep saline formation	2004
Snøhvit CO_2 Injection	Norway	Pre-combustion (gas processing)	0.7	Deep saline formation	2008
Century Plant	United States	Pre-combustion (gas processing)	5 (and 3.5 in construction)[2]	EOR	2010
Execute stage					
Lost Cabin Gas Plant	United States	Pre-combustion (gas processing)	1	EOR	2012
Illinois Industrial Carbon Capture and Sequestration (ICCS) Project	United States	Industrial (ethanol production)	1	Deep saline formation	2013
Boundary Dam with CCS Demonstration	Canada	Post-combustion (power)	1	EOR	2014
Agrium CO_2 Capture with ACTL	Canada	Pre-combustion (fertiliser)	0.6	EOR	2014
Kemper County IGCC Project	United States	Pre-combustion (power)	3.5	EOR	2014
Gorgon Carbon Dioxide Injection Project	Australia	Pre-combustion (gas processing)	3.4-4[3]	Deep saline formation	2015

GCCSI, The Global Status of CCS: 2011

Government Support

Governments around the world have provided a range of financial support for the technology of CCS. In total over $23 billion has been made available to support large-scale CCS demonstration projects see table below). The United States is the largest provider of direct government funding to CCS projects, with over US$7 billion in both state and federal funding provided. However, several of the projects that funds were allocated to have been put on hold or cancelled due to uncertainty over energy and climate policies. It should also be noted that much of the U.S. funding came from 2009 stimulus spending.

Global Allocation of Funding



GCCSI, The Global Status of CCS: 2011

Several state governments have also enacted programs that include public financial support for clean energy technologies such as CCS, often on top of broader policies and legislation aimed at encouraging its development. For example, the government of Illinois has allocated US$30.5 million to three FEED studies, while Texas has made available tax credits.

In aggregate, 16 large-scale CCS demonstration projects have been granted significant federal funding (each more than US$100 million) to support their development, and a further eight projects have been granted smaller amounts (between US$0.5 million and US$3 million). In August 2010, the Report of the Interagency Task Force on Carbon Capture and Storage recommended that up to ten large-scale demonstration CCS projects be advanced by 2016, strongly supported by federal funding.

Federal financial support is evenly split between direct capital and operating grants, and tax credits for CCS projects. This relatively high weighting on tax credits differentiates the United States from all other countries, which tend to rely more on non-tax mechanisms.

DOE is also placing significant emphasis on the development of next generation CCS technologies such as advanced CO_2 capture, turbo machinery and large scale testing. Major funding is being made available through Advanced Research Projects Agency-Energy (ARPA-E) and National Energy Technology Laboratory (NETL). DOE has formed a nationwide network of regional partnerships to help determine the best approaches for capture and permanent storage. These Regional Carbon Sequestration Partnerships have undertaken characterization of sequestration opportunities and small scale validation tests. They are now working to implement nine large scale sequestration projects throughout the United States and Canada.

Storage potential and infrastructure

DOE has released the third edition of the *Carbon Sequestration Atlas of the United States and Canada (Atlas III)*, the result of collaboration among carbon storage experts from local, State, and Federal agencies, as well as industry and academia. *Atlas III* provides a coordinated update of CCS potential across most of the United States and portions of Canada and identifies extensive potential storage in proximity to large point sources. It's worth noting that potential storage estimates have increased dramatically through each iteration of the Atlas over four years as estimates are refined and more potential sites are identified although the methodology provides a course estimate.

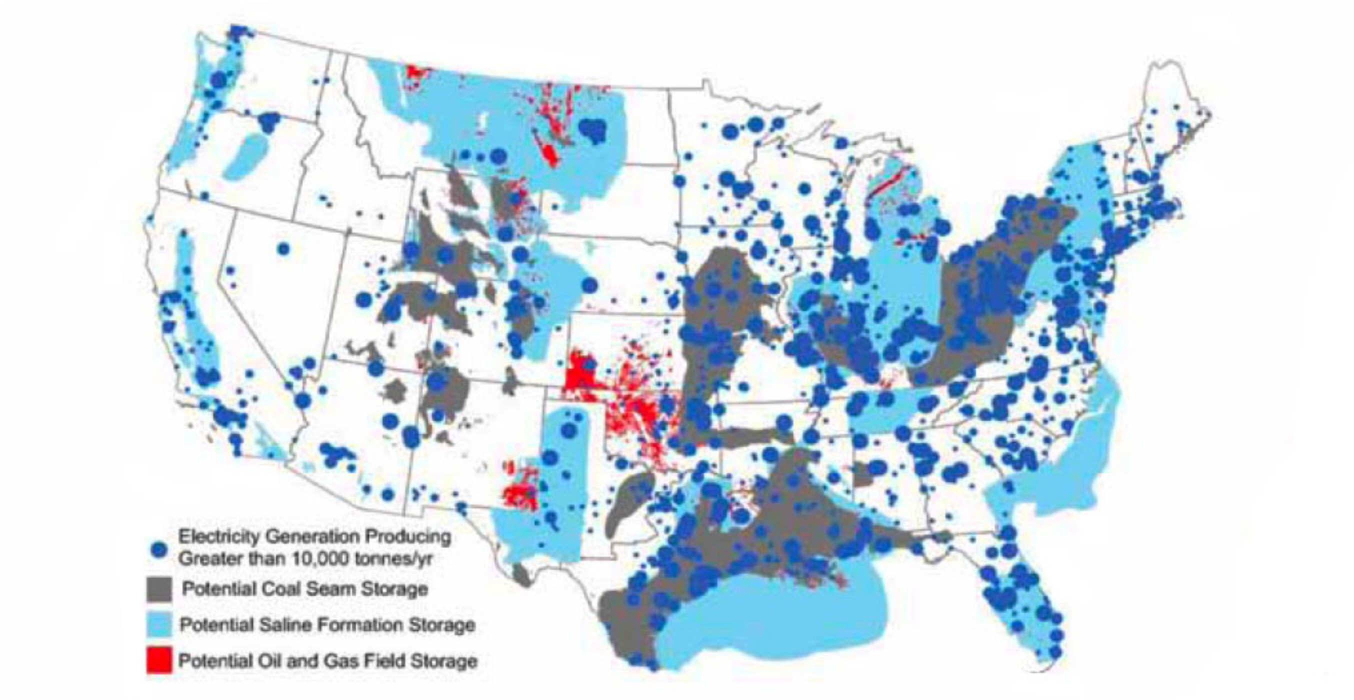


Figure 3-2. Current Power Plants and Potential CO_2 Storage Sites

DOE/NETL Carbon Dioxide Capture and Storage RD&D Roadmap, December 2010

Although there is large potential for storing CO_2, the process of identifying suitable sites with adequate storage is significant and involves methodical and careful analysis of the technical and non-technical features of promising areas. This process is largely analogous to one in the petroleum industry through which a project matures from an exploration project to a producing project (DOE/NETL November 2010).

Identification of a storage site commences with screening of suitable locations within a reasonable distance of the source(s). Safe, underground geologic storage of CO_2 must be conducted through carefully planned site characterization and modeling, field development and operational design, and monitoring of the CO_2 before, during, and after CO_2 injection. Ensuring that CO_2 storage is safe and effective requires site-specific risk assessment, which combines performance assessment of a storage site, coupled with an assessment of potential environmental, health, or economic consequences. Table 1 summarizes key elements of a safe and effective CO_2 storage project.

Table 1. Key Elements of a Safe and Effective CO_2 Storage Project
(DOE/NETL December 2010)

Monitoring, Verification, and Accounting (MVA)	Simulation and Risk Assessment
• Mitigation options for identified risks • Robust, flexible accounting protocols • Best Practices • Effective public education and outreach	• Scale-up to commercial-size projects • Optimize well design, well management, and well integrity • Maximize CO_2 injectivity and storage capacity • Long-term storage security • Robust risk assessment process models

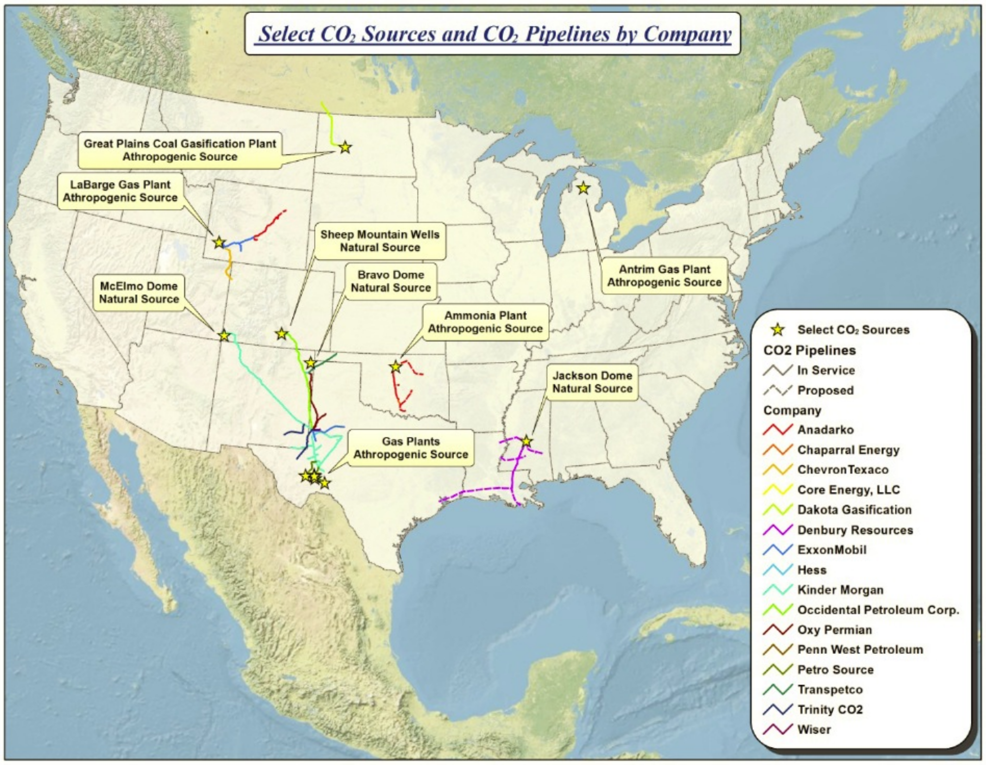
Monitoring, verification, and accounting (MVA) capabilities will be critical to ensuring the long-term viability of CCS—satisfying both technical and regulatory requirements. MVA encompass the ability to track the location of the underground CO_2 plume and detect and mitigate potential leaks of CO_2 or displaced brine. MVA data is also essential for optimizing operating conditions as well as updating simulations to predict the longer term CO_2 movement and its ultimate stabilization. A key challenge for CO_2 storage is the development of robust, equitable, and transparent accounting procedures with the flexibility to adjust to future regulatory and market situations. A successful MVA effort will enable storage project developers to obtain permits to operate and close the facility in a manner that ensures that human health and safety and the environment are protected.

EOR will likely continue to be a common form of de facto storage in the near to medium term. EOR can be a less costly and faster mechanism for the demonstration of LSIPs. Monitoring and verification of injected CO_2 above that required for typical EOR projects, however, will be needed to demonstrate long-term storage security. Storage in deep saline formations offers much greater storage potential in the longer term. The time and expense of proving up secure storage in these poorly characterized venues, particularly offshore, should not be underestimated.

Transportation

The transport of CO_2 in the U.S. today is dominated by pipelines. There are currently nearly 4,000 miles of existing EOR - related CO_2 transportation pipelines as shown on the map below. While significantly more pipeline infrastructure would be needed for widespread CCS deployment, existing pipelines provide decades of operating experience. An Interstate Natural Gas Association study estimates that, depending on the quantity of CO_2 and extent of EOR involvement, 15,000 - 60,000 miles of pipeline will be needed by 2030 to transport CO_2 to sequestration sites.

It is uncertain whether a national CO_2 pipeline network will emerge in the future or if dedicated source-to-sink pipelines will be more typical. Future pipelines will need to address permitting, right-of-way, and public acceptance issues similar to natural gas pipelines.



Source: NETL using data from Energy Velocity Database (2010).

Regulation

The US EPA issued final regulations for CO_2 storage within the Underground Injection Control (UIC) Program in 2010. The new Class VI well includes requirements for well construction, area of review, monitoring and closure. These regulations, which are aimed at accommodating the behavior of large volumes of CO_2 in the subsurface and the need for long term protection of groundwater, are quite rigorous. The default 50 year post-closure stewardship requirement (lesser period at the discretion of "the director", which could be an EPA regional or state regulator depending on primacy status), in particular may, discourage CO_2 storage by mnay operators. CO_2 EOR will continue to be regulated under UIC Class II (oil and gas production). CO_2 storage in EOR fields that have ceased significant oil production will likely be regulated under UIC Class VI.

Regulatory competence for CO_2 storage will be shared between the federal government and states that choose to qualify for primacy. A number of states have developed regulatory schemes in anticipation of or in parallel to federal regulations. Several states have passed legislation on pore space rights and at least two on liability (e.g. to attract FutureGen in Texas and Illinois). A large gap remains, however, in the broader financial responsibility / liability framework necessary to enable widespread deployment. While operators should be responsible during operations and for a period beyond closure, in the long term alternative frameworks must be found since business models are not capable of retaining "unlimited" liability over "infinite" time. Australia and Alberta, by comparison, have put regulations in place that transfer liability to the government once closure certification is complete.

Further detail on the regulatory picture at state level can be gleaned from: http://www.ccsreg.org/

Cost of CCS

As mentioned earlier, there are three generic process routes for capturing CO_2 from electricity generation: post-combustion capture; pre-combustion capture; and oxy-fuel combustion. Capture from industrial processes (hydrogen production, natural gas processing, etc.) can involve similar technologies. Each of these processes involves the separation of CO_2 from a gas stream using either a solvent, physical adsorption, or physical separation. Once separated, the CO_2 is compressed, and transported to a suitable storage site.

At a very fundamental level, the cost of CCS is comprised of the additional capital expenditures to build the hardware that is necessary to capture, transport, and store CO_2 and the operating and maintenance (O&M) expense required to run the facility. Included in these costs is the energy requirement for CCS, often referred to as parasitic energy load. This could be in the form of needing a larger power plant to compensate for the parasitic consumption or, less commonly, in the form of higher operating costs under the assumption that the extra energy needed will be purchased from outside the plant boundary at some assumed grid price and emissions. For example, GCCSI (2009) notes that a CCS retrofit of a coal-fired power plant (i.e., a subcritical unit with an efficiency of about 35%) would lead to an energy penalty of approximately 33 percent reduction in net power output. Therefore, for a unit that provides 600 megawatt-electrical (MWe) to the grid, an additional 200 MWe (33% of 600) of generation would be required with the addition of CCS equipment. However, if that new additional generation also has to capture its CO_2, a 267 MWe plant would be required to make up the power (200 MWe plus an additional 33% to make up for the parasitic energy loss). The implementation of CCS to a plant could potentially result in the need to generate an additional 44 percent of the original plant's power to the grid (267MWe/600MWe) to compensate for the 33% energy loss and achieve the same net power output.[1] For new coal plants, energy penalties are in the 20-35% range (IEA, 2011), implying an additional 25-33% of generation would be required. That said, the point here is not to specify what energy penalty is, but rather to illustrate the concept of an energy penalty and to caution the reader that replacement power costs and associated emissions are often not treated consistently between many economic evaluations.

<u>Concepts Critical to Understanding Cost Estimates</u>

There is considerable variation in published estimates of the cost of CCS. Some of this variation is inherent uncertainty in an emerging technology that is largely undemonstrated. Some of it is variability between regions, fuel types, or specific projects, and some of it is bias in the estimate or selected measures. Some of the factors that cause variation in CCS cost estimates are briefly discussed below.

Measures of CCS Cost

There are several ways to measure the cost of CCS. These include the cost of CO_2 avoided, levelized cost of production, and cost of CO_2 captured.

The most widely used measure of cost is 'cost of CO_2 avoided'. This metric takes into account the fact that it takes additional energy (thus causing more CO_2 emissions) to capture, transport, and store CO_2. This value reflects the average cost of reducing CO_2 emissions by one unit while providing the same amount of useful product as a 'reference plant' without CCS. Results are very sensitive to the choice of reference or baseline facility (see for example Al-Juaied and Whitmore, 2009 page 12, figure 4). Typically, (but not always) the reference plant is assumed to employ the same technology as the plant being examined but without CCS, but sometimes results for various options are all presented relative to a predominant existing technology in a region.

---

[1] Under these circumstances, however, other studies indicate that a much more cost-effective solutions with much smaller energy penalty) would be to repower the existing unit with a high efficiency supercritical unit together with CCS (Simbec, 2008; Chen et al. 2003).

Levelized cost of production (LCOP), used in calculating the cost of CO_2 avoided, is an alternative metric that can inform business or policy decisions within a given sector as it reflects the cost to the consumer from CCS. It provides an indication of the cost of producing a product with and without CCS. GCCSI (2009) estimates that cost of avoidance for an N^{th}-of-a-Kind (NOAK) Supercritical Pulverized Coal (PC) plant (reference plant is same technology without capture) is $88/metric ton and for a NGCC plant (reference plant is same technology without capture) is $109/metric ton. However, the LCOP for the two plants is $136/MWh and $111/MWh respectively. On a LCOP basis, the NGCC-CCS plant thus produces lower-cost electricity than the PC-CCS plant – and with lower CO_2 emissions.[2] Kheshgi et al. (2010) note that "relative LCOE should be a key input in the choice of generation technology." This is particularly true if the regulation that is motivating the adoption of CCS is restricted to a particular sector, but is less true in a regulatory environment with an economy-wide carbon price.

The cost of CO_2 captured, another metric, simply compares the cost of producing a unit of production with and without CCS divided by the quantity of CO_2 captured per unit of production. This measure does not account for the extra energy and CO_2 emissions needed to support the capture process. Because of this, it will always yield a lower dollar value than a cost of CO_2 avoided calculation and is not generally an instructive measure for policy analysis but might be for commercial decisions such as whether to capture CO_2 for sale for EOR in the absence of a regulatory requirement.

Assumptions about Plant Construction

Many assumptions must be made when estimating the cost of applying CCS to a facility. These assumptions include plant size, fuel type, and level of abatement. Al-Juaied and Whitmore (2009, page 55) explain how plant efficiency -- and cost to operate -- is dramatically affected by the level of abatement. In general, there is a non-linear relationship between abatement level and per ton cost of CCS with the cost of the marginal ton rising as abatement level increases.

Unfortunately, differences in assumptions are often not transparent. Kheshgi et al. (2010) notes even when the direct materials and labor (M&L) costs are similar, estimates of installation cost, offsites, contingencies, and escalation allowance can result in large differences (e.g. a factor of two) in total erected cost.

Beyond direct materials and labor cost, cost of capital (financing) can also be a variable. Kheshgi et al. (2010) note that some studies find that the private rates of return to justify mitigation projects are potentially 10-25% while for power generation applications, the discount rate commonly used in CCS cost estimates is 7-10%. They contend that project financing at this rate typically is only available for low risk investments using mature technologies and so may not be appropriate for CCS, even in the power sector.

Lastly, the date when cost estimates were developed is also important. Many earlier studies have lower cost estimates compared to more recent studies. This is due in part to a dramatic escalation in construction costs across sectors roughly between 2005 and 2008. There are indications of costs falling from the peaks seen in 2008, but as economic conditions improve they may resume their upward trend. DNV (2010) has taken the approach of not including studies undertaken prior to 2008 "because they are considered less relevant than more recent references". This paper takes a similar approach and also does not include some studies done after 2009, but which are based on un-revised data from the early 2000's (e.g. Melien and Brown-Roijen, 2009).

Attempts to Derive Consistent Cost Estimates

Given the importance of being able to compare the cost of CCS using different technologies and in different applications, there have been attempts to derive comparable/standardized cost estimates. Al-Juaied and Whitmore (2009) adjust previous studies so that they are comparable. GCCSI (2009) creates bottom-up

[2] NGCC-CCS has higher avoided costs primarily because CO_2 is more dilute in gas-fired exhaust gas. NGCC-CCS has lower LCOP because it has about half the CO_2 per kWh produced compared to coal. Absolute LCOP for gas vs. coal CCS is highly dependent on the fuel prices.

estimates of technologies using consistent assumptions to arrive at comparable capture costs. McKinsey (2008, Exhibit 21, page 53) reconciles their cost estimates with MIT's 2007 results. The IPCC (2005), however, notes that many of the key parameters assumptions that go into CCS cost estimates (such as plant type, fuel properties, capacity factor and the cost of capital) vary from one situation to another for legitimate reasons, so that conclusions drawn for one set of consistent assumptions may not necessarily apply under a different set of (consistent) assumptions. Rubin (2011) points out that the greatest need for consistency across different studies is the list of items that are included in a cost analysis—many studies today exclude items that are included in others. Thus, more work is needed to provide consistency in CCS cost estimates moving forward.

Estimating Future Costs

There has been considerable debate over how much (and why) costs might decline over time as more plants with CCS are built. Two different approaches have been used to estimate future technology costs. The so-called "bottom-up" approach employs an engineering analysis of a new or improved technology or process design whose cost is then estimated based on available data and professional judgments (for example, about the future cost of a new sorbent material or the capital cost of a component that has never been built at the scale envisioned). Using this approach, for example, DOE has estimated the future cost of electricity (COE) of an advanced IGCC plant with CCS to be 31% below current cost, while an advanced PC plant with CCS would cost 27% less (DOE, 2010).

Cost projections based on a "top-down" approach often use "experience curves" (learning curves) derived from historical trends. For instance, Rubin et al (2007) developed a set of experience curves for existing energy technologies that provide cost histories versus experience, and then used these to predict potential future cost reductions as a function of the cumulative installed capacity of power plants with CCS. They estimated COE reductions ranging from 5% to 26% for different types of CCS plants once their worldwide capacity reaches about 100,000 MW (a level achieved after about 20 years for post-combustion sulfur capture at power plants). Their study also documented the significant cost *increases* that often occurred in the early stages of commericialization.

GCCSI (2009) estimate the cost decreases associated with experience gained with a specific process (i.e. FOAK vs. NOAK) at less than five percent. GCCSI state that "[t]he reason for this small decrease is that the majority of the capital costs are well proven technologies. Therefore, it does not provide the potential for future cost savings through increasing maturity." The report stress that the cost reductions represent decreased risk in the existing technologies and do not consider other improvements such as implementing new technologies for capture or economy of scale savings in transportation and storage.

Kheshgi et al. (2010) make the case that experience suggests that cost estimates for technologies that are not mature are often highly uncertain and more often than not underestimate actual costs. They cite recent cost overruns for IGCC plants (e.g. Power 2010, Power-Gen 2010). They also note that innovation sometimes results in different technology systems surpassing the cost or performance of the initially envisioned technology, providing a lower cost for the same service but with a different technology system.

<u>Energy-Sector Specific Discussion of Costs</u>

Applying similar technologies (e.g. post-combustion capture using MEA) to different industrial processes (e.g. flue stack at coal fired power plant vs. flue stack at refinery) can yield very different costs. This can be due to the specifics of the flue gas (e.g. composition, pressure, temperature, etc.) or can be due to facility specific details (e.g. space constraints, feasibility of ducting, etc.). Regardless of the reason, it is important to remember that costs for a technology in one sector are not directly applicable to another.

Electricity Generation

Electricity generation is responsible for 40.4% of the CO_2 emissions in the U.S. and 60.7% of the CO_2 emissions at stationary sources (EIA,2009). In some regards, capture from these facilities is fairly straight forward relative to industrial processes discussed below, as there are generally only one or two flue stacks to capture CO_2 from.

The table below lists the recent estimates of capture from power plants based on the technology choice, whether the plant is first-of-a-kind (FOAK) or nth-of-a-kind (NOAK) and the baseline or reference plant that the calculation is being made against.

The table does not examine the cost of retrofitting an existing electricity generating unit to capture CO_2. However, MIT (2007) has dated, but very detailed, cost information on new-builds and retrofits. The data from the study suggests there is about a 50% premium on the cost of avoidance for a retrofitted facility versus a new-build. Rebuilding the core of an existing unit by installing higher efficiency technology along with CO_2 capture may be more attractive than retrofits because the rebuilds have higher efficiency. The decision to retrofit will be extremely case specific based on unit age, design (including fuel type), and existing controls as well as site location.

Power Sector CCS Cost Estimates, $/T

Technology	Study	Cost of CO2 Avoided (FOAK)	Cost of CO2 Avoided	Cost of CO2 Avoided (NOAK)	Baseline
IGCC	GCCSI, 2011	56		54	same technology but w/o capture
IGCC	GCCSI, 2011	71		67	PC Supercritical w/o capture
IGCC	Al-Juaied & Whitmore, 2009	100-150		30-50	PC Supercritical w/o capture
IGCC - GEE	NETL, 2010		43		same technology but w/o capture
IGCC - GEE	NETL, 2010		66		PC Supercritical w/o capture
IGCC - CoP	NETL, 2010		54		same technology but w/o capture
IGCC - CoP	NETL, 2010		73		PC Supercritical w/o capture
IGCC - Shell	NETL, 2010		61		same technology but w/o capture
IGCC - Shell	NETL, 2010		86		PC Supercritical w/o capture
Oxy (Supercritical)	GCCSI, 2011	66		63	PC Supercritical w/o capture
Oxy (Ultra Supercritical)	GCCSI, 2011	54		51	PC Supercritical w/o capture
Oxy (ITM Supercritical)	GCCSI, 2011	69		66	PC Supercritical w/o capture
PC - Subcritical	NETL, 2010		68		same technology but w/o capture
PC - Subcritical	NETL, 2010		75		PC Supercritical w/o capture
PC - Supercritical	NETL, 2010		69		same technology but w/o capture
PC - Supercritical	GCCSI, 2011	82		79	same technology but w/o capture
PC - Ultra Supercritical	GCCSI, 2011	63		58	same technology but w/o capture
PC - Ultra Supercritical	McKinsey, 2008	80-120		47-67	same technology but w/o capture
Natural Gas Combined Cycle	GCCSI, 2011	107		103	same technology but w/o capture
Natural Gas Combined Cycle	NETL, 2010		84		same technology but w/o capture
Natural Gas Combined Cycle	NETL, 2010		36		PC Supercritical w/o capture

Note: Al-Juaied & Whitmore (2009), unlike the other studies, do not include transportation and storage costs (estimated by McKinsey to be $20/metric ton). For the McKinsey study, the ratio of Euros to dollars was assumed to be 0.75.

Refineries

The IPCC (2005, Table SPM1) assessed that refineries account for about 6% of CO_2 emissions from large stationary sources worldwide, with 638 refineries resulting in 798 million metric tons of CO_2 per year. EIA (2009, 2010) estimated that refineries in the U.S. emitted 260 million metric tons of CO_2 in 2008, which is 4.4% of US CO_2 emissions compared to electricity generation which constitutes 40.4% of US CO_2 emissions. Staelen et al. (2010) note that a refinery may use about 1.5% up to 8% of its feedstock as fuel, depending on the complexity of the refinery.

The total CO_2 emissions from a large, complex refinery are comparable to that of a power plant. However, there are numerous streams of CO_2 from a refinery with differing compositions and pressures scattered over a vast refinery complex (Staelen et al. (2010)). This makes capture technically complex and costly.

Space constraints and process safety risks have also been noted as barriers to broad application of CCS at refineries.

For purposes of discussion, various CO_2 sources at a refinery can be grouped together. Least costly for capture are the high pressure, high concentration sources. CO_2 streams from the hydrogen production plant (for refineries that have them[3]) may exhibit these characteristics, although they are typically much smaller than the CO_2 streams from coal-based power plants (Simbeck 2005). Staelen et al. (2010) point out that refineries using gasifiers to produce hydrogen in some cases have a high pressure and high concentration CO_2 stream. Staelen et al. (2010) estimate the cost of avoidance from gasifiers at $40/metric ton. IMC (2008) found the cost of avoidance in Alberta, Canada for hydrogen production (where the hydrogen was used primarily in non-combustive uses) via coal gasification ranging from $55-100/metric tons. However, most refinery hydrogen is produced from steam methane reforming (SMR), not via gasification. In the U.S., 95% of all hydrogen is produced via SMR (DOE, 2006). First generation SMR systems used chemical absorption which produced a high purity CO_2 stream. However, since the 1980s, most SMR systems have been changed to pressure swing adsorption (PSA) processes, which generally do not yield a high purity or high pressure CO_2 stream. IMC (2008) in a survey of Alberta, Canada facilities found costs of avoidance in a SMR system ranging from $75-190/metric ton depending on the specifics of the SMR process (see more detail under *Oil Sands*).

The fluid catalytic cracker (FCC) is another potential capture point, although not all refineries operate a fluid catalytic cracking unit. FCC unit emissions can constitute as much as 50% of refinery CO_2 emissions (Kuuskraa, 2009) and are the result of regenerating catalyst powder by oxidation with air. Two options exist for the capture of CO_2 from the FCC: one is post-combustion capture, the other is oxy-firing of the regeneration process. Al-Juaied and Whitmore (2009) estimate that the cost of avoidance from the FCC unit and CHP facility using chilled ammonia (a post-combustion technology) is $185-255/metric ton.

Another category of refinery CO_2 streams is made up of a number of flue gas sources at a refinery (e.g. stacks from furnaces and gas turbines, or the off gas from the refinery's utilities/cogeneration plant). Their cumulative large scale (although smaller than a full scale power plant) help lower the cost of CCS, but that is far more than offset by the ducting cost to gather them from dozens of stacks over a vast geography to a central location. They also are at low pressure and low concentration of CO_2.

The BACT permit application for the proposed Hyperion refinery in the U.S. is illustrative of the challenges of applying capture to these diverse CO_2 streams (RTP, 2010). Hyperion has CO_2 emissions from: IGCC unit (which provides hydrogen, power, and steam to the facility), process heaters, combined cycle gas turbines, and small combustion sources. The petroleum coke fed IGCC power plant produces a high purity CO_2 stream. Hyperion estimates the cost of avoidance at $47/metric ton. These costs are in-line with other estimates of capture from gasification when, as in this case, hydrogen is needed (as opposed to syngas). In an alternative power plant design, using combined cycle gas turbines and post-combustion capture, the cost of avoiding CO_2 emissions is estimated to be $136/metric ton. CO_2 from the thirty process heaters is more difficult to capture due to the sources /stacks being scattered throughout the facility and the CO_2 concentration of the flue gas being very low since the fuel source is natural gas. The cost of avoidance for this CO_2 stream is estimated to be $114/metric ton. The cost of avoiding the CO_2 emissions from other small combustion sources would be even higher.

Refineries are complex operations with limited space, and the cost of capital for refinery projects is typically higher than the cost of capital for power generation projects (Kheshgi et al., 2010). Refineries would be faced with the retrofit versus new build disadvantage since it is highly unlikely any new refineries will be built in the U.S. Each of these factors (retrofit, scale and complexity, varied stream compositions, distributed sources, and cost of capital) increases the cost of application of CCS to refineries, making it significantly higher than that for power plants. Finally, it is important to remember that only 13% of the life cycle emissions of a gallon of gasoline are attributed to the refining of the product (Jacobs, 2009).

[3] According to EIA (2008), 89 U.S. refiners (61%) have on-site hydrogen production capacity. This capacity amounts to 3,100 mmscfd. There is also an estimated 1,439 mmscfd of merchant-supplied capacity dedicated to refineries.

Refining Sector CCS Cost Estimates, $/T

Application	Study	Cost per metric ton of CO2 Avoided	Costs included
Post-combustion capture from flue gas			
Power plant NGCC turbines using MEA	RTP, 2010	136	capture thru injection
CHP (nat gas fueled) & FCC unit using chilled ammonia	Al-Juaied & Whitmore, 2009	185-255	capture
Process heaters (post-combustion, MEA)	RTP, 2010	114	capture thru injection
Heaters, boilers, furnaces (post-combution, amine)	ERM, 2009	153	capture thru injection
H2 via SMR & PSA (CO_2 capture from flue gas stream)	IMC, 2008	140-190	dehydration, compression
Pre-combustion capture via gasification			
IGCC unit (nat gas fueled) used to produce power and hydrogen	RTP, 2010	47	capture thru injection
H2 via Gasification (feedstock not specified)	Straelen et al., 2010	40	unclear
H2 via Coal Gasification	IMC, 2008	55-100	dehydration, compression
Pre-combustion capture via SMR			
H2 via SMR & Benfield process (CO_2 capture from process stream)	IMC, 2008	75-110	dehydration, compression
H2 via SMR & PSA (CO_2 capture from process stream)	IMC, 2008	105-155	dehydration, compression

Notes on IMC, 2008: - Prepared by Ian Murray & Company for the Alberta Development Council, 2008
-Based on over 20 different facilities from over 10 company interviews, plus information from other recent studies.
- Cost ranges represent geographic, technological suitability as well as Greenfield versus retrofit considerations.
- $ are 2008 Cdn, based on levelizing real 2008 Capital and real 2008 Annual Operating costs discounted at 10% from year(s) incurred; in 2008, the Canadian dollar was in rough parity to the US dollar and the two are assumed equal in this study.
- $ /metric ton abated includes cost penalties for make-up production and incremental CO2 emissions resulting from CO2 capture.
- Gasification excludes cost penalty, if any, associated with production technology choice relative to alternative(s).
- Benfield excludes cost penalty, if any, associated with production technology choice relative to alternative(s).

Oil Sands

Some oil sands operations involve the "upgrading" of bitumen to synthetic crude oil at refinery-like facilities. Capturing CO_2 from these upgraders presents many of the same challenges as capturing CO_2 from refineries. In particular, the hydrogen production units represent the largest sources of CO_2, be they SMR units or gasifiers. Again, similar to refineries there are other sources of CO_2 that could be captured using post-combustion technology but capture of these low pressure and low concentration streams is considerably more expensive (both capital and operating costs are higher). Significant energy and equipment are required to separate and compress the CO_2, which makes the process costly and, depending on the power generation source used for capture, reduces the net GHG emissions benefit of the abatement.

CERA (2010) has estimated that capturing CO_2 at the upgrader hydrogen plant reduces GHG emissions per barrel by between 11 to 14 percent on a well-to-retail pump basis. CERA assumes that parasitic load from the CCS equipment increases energy use by about 30 percent and that after parasitic losses are considered, 40 percent of the emissions associated with the upgrading portion of the value chain are captured with CCS.

IMC (2008) conducted a survey of Alberta, Canada power, chemical, and petroleum sector companies on estimates of capital and operating costs to capture CO_2 from existing or planned facilities and received 20 facility specific estimates from 10 survey participants. IMC supplemented this data with some additional data from public reports and standardized some cost elements such as the cost of natural gas.

IMC estimated the cost of CO_2 avoidance from the hydrogen production unit under four different scenarios. The first was in a coal (or other solid such as coke or asphaltenes) gasification process where the hydrogen was used primarily for purposes other than combustion and costs of avoidance ranged from $55 to $100/metric ton avoided. The next three scenarios involved SMR systems. The first of these considered capture via a Benfield process with a fairly pure but low pressure CO_2 stream and found the cost to range from $75-$110/metric ton avoided. The second considered a PSA process where the PSA system was configured to capture the CO_2 from the process stream and estimated costs between $105 and $155/metric ton avoided. The last considered capturing the CO_2 from the flue gas of the PSA system and found the cost would range between $140 and $190/metric ton avoided.

The study is unique in that it also estimates the cost of CO_2 avoided from the natural gas-fueled boilers used to produce steam for SAGD production. Capture from this source is the most costly at between $175 and $230 per metric ton.

Natural Gas Processing

Natural gas reservoirs often contain H_2S and CO_2 along with natural gas. These gases generally are removed until the content is reduced to below 2% by volume for transportation, in order to comply with pipeline specifications (UNIDO, 2010). Because of this, the natural gas industry has significant experience with separating CO_2. In the U.S., natural gas processing plants account for 21 million metric tons of CO_2 emissions, about 1% of CO_2 emissions from electricity generation (EPA, 2010; EIA, 2010).

Despite the long experience with separating CO_2 from natural gas streams, cost estimates are few. Kheshgi et al. (2010) note that once separated, the costs of CO_2 compression, transport and injection are a fraction (e.g. 20%) of the cost of an equivalently sized post combustion CCS project from a coal fired power plant, with costs varying depending on the project specific design parameters and logistics – dominated by the distance of transport. GCCSI (2011) estimated the cost for drying and CO_2 compression at $19/metric ton of CO_2 avoided. ERM (2009) estimate the cost of compression, transport, and storage of CO_2 from a natural gas production site at $43/metric ton for an offshore facility and $18/metric ton for an onshore facility.

Hydrogen Production

Hydrogen production has been discussed in the context of refining and oil sands previously. Hydrogen production can also be a stand-alone process for selling to industry customers via pipeline, achieving economy of scale. There are several facilities like this, especially along the Gulf Coast where they service the local refineries and petrochemical plants. Increasing scale will generally reduce the cost of CO_2 avoided. ERM (2009) estimated the cost of avoidance at a large stand-alone hydrogen facility using SMR and post-combustion capture at $43/metric ton. Costs include transportation and storage ($15/ton), fuel costs (1.45 GJ/ton captured at $6/GJ), O&M cost at $6.23/ton, and $57 million in additional capital expenditures, The size of the facility examined by ERM (2009) was 270 mmscfd (facilities between 60 and 200 mmscfd are classified as large) and would likely become more common if hydrogen were to become a larger part of the transportation fuel mix.

Coal/Biomass-to-Liquids

Coal-to-liquids (CTL) and biomass-to-liquids (BTL) produce liquid fuel from coal and biomass, which can be used to replace oil-based fuels. In the most commonly used CTL/BTL technology, coal is first gasified to produce synthesis gas which, in turn, is catalytically treated in a Fischer-Tropsch (FT) process to produce different liquid fuels like gasoline and diesel. Gasification, as discussed elsewhere in this section, produces a highly concentrated CO_2 stream. The costs of avoidance for gasification referenced in the earlier sections (e.g. oil sands) are also applicable here. The National Academy of Sciences (NAS 2009) highlights the relatively low cost of CCS in Coal and Biomass to Liquids applications due to the availability of a high-concentration, high-pressure CO_2 stream.

Ethanol Production

Ethanol plants are seen as potential early adopters of CCS systems as the cost of capturing CO_2 from these facilities is believed to be quite low. The fermentation process involved in producing ethanol results in a very pure stream of CO_2 that is typically vented to the atmosphere. The CO_2 stream from these ethanol plants would only need to be dehydrated (to prevent corrosion in CO_2 pipelines) and compressed to typical pipeline pressures. However, the scale of an individual plant is small and several plants would have to be aggregated to adequately spread the costs for transport and storage.

Conclusions on Costs of Capture

The laws of thermodynamics imply that CCS will always have a cost, regardless of technological progress (Page et al., 2009). How much that actual cost will be is currently subject to considerable uncertainty and variability. GCCSI (2011) states that there is a margin of error of +/- 40% in their estimates. Nevertheless, the data reviewed here suggest the following conclusions.

First, CCS from electricity generation presents a unique opportunity because of the very large quantity of CO_2 that could be captured and the relatively moderate cost of avoiding CO_2 emissions. Specifically, projected cost of avoidance for new coal-fired power plants tend to cluster around the $60 to $80 per metric ton range and $80-100 per metric ton for gas-fired power plants, based on a comparison to the same type of plant without CCS. Currently, coal and gas-fired power plants account for approximately 40% of all U.S. CO_2 emissions and 60% of stationary source CO_2 emissions in the U.S. (EIA, 2009).[4] On a levelized cost of electricity basis, CCS can be more economical for gas than coal depending on relative fuel costs.

Second, it is unlikely that any meaningful amount of CCS can be applied in refineries at costs below $150 per metric ton. Even though there are some estimates that suggest that limited capture at refineries could be done at low costs, these estimates are based on processes that are not present at the vast majority of refineries. Cost of avoidance for the bulk of CO_2 emissions at a refinery (i.e. flue gases) are universally estimated at well over $100 per metric ton with some estimates well over $200 per metric ton. Moreover, although refineries are the second largest source of stationary source CO_2 emissions, their emissions are about one tenth of the emissions from electricity generation.

Third, CCS at some types of facilities is likely to be characterized by relatively low cost but limited quantity. For example, natural gas processing often has low incremental costs associated with CCS but its CO_2 emissions are small (1% of those from electricity generation). Likewise CCS from ethanol production, hydrogen production, and coal or biomass-to-liquids is likely to be relatively low cost but of limited quantity. The exception to this could be oil sands operations with large scale hydrogen production and significant future growth projected.

As can be seen from this discussion, cost currently is a significant impediment to large-scale deployment of CCS. Successful implementation of CCS will need carefully crafted policy that does not stifle technology innovation nor favor certain technologies or fuels over others. If successful, CCS offers the prospect of mitigating CO_2 emissions from fossil fuel resources, which nearly all credible forecasts indicate will be needed for decades to come to meet the world's growing energy needs.

[4] According to EIA, Electric Power Annual, 2009 coal-fired generation accounts for 80% of electricity generation emissions.

Glossary

ARPA-E Advanced Research Projects Agency - Energy

BTL biomass-to-liquids

CCS carbon capture and storage

CERA Cambridge Energy Research Associates

CHP **c**ombined heat and power

CO carbon monoxide

CO_2 carbon dioxide

CTL coal-to-liquids

DNV Det Norske Veritas

DOE Department of Energy

EIA Energy Information Agency

EOR enhanced oil recovery

ERM Environmental Resources Management

FCC fluidized-bed catalytic cracker

FEED front-end engineering and design

FOAK first-of-a-kind

FT Fischer-Tropsch

FTF Future Transportation Fuels

GCCSI Global Carbon Capture and Storage Institute

GHG greenhouse gas

H_2 hydrogen

H_2S hydrogen sulfide

IEA International Energy Agency

IGCC integrated gasification combined cycle

IMC Ian Murray and Company

IPCC International Panel on Climate Change

LCOE levelized cost of electricity

LCOP levelized cost of production

LSIP large scale integrated project

MEA monoethanolamine

MIT Massachusetts Institute of Technology

MMV measurement, monitoring, and verification

MVA monitoring, verification, and accounting

MW megawatt

MWh megawatt hour

NARD North American Resource Development

NAS National Academy of Sciences

NETL National Energy Technology Laboratory

NGCC natural gas combined cycle

NOAK nth-of-a-kind

NO_x nitrogen oxides

NPC National Petroleum Council

O&G oil and gas

O&M operating and maintenance

PC pulverized coal

PM-2.5 particulate matter greater than 2.5 microns

PSA pressure swing absorption

R&D research and development

SMR steam methane reforming

SO_2 sulfur dioxide

VOC volatile organic compounds

References

Al-Juaied, M.A. and Whitmore, A. 2009. *Realistic Costs of Carbon Capture*, Discussion Paper 2009-08, 73. Cambridge, Massachusetts: Belfer Center for Science and International Affairs, Harvard University.

CERA 2011. *Oil Sands Technology: Past, Present, and Future,* Cambridge, Massachusetts: IHS CERA.

Chen C, Rao AB, Rubin ES (2003) *Comparative assessment of CO2 capture options for existing coal-fired power plants*. Proceedings of 2nd Annual Carbon Sequestration Conference, US Department of Energy, National Energy Technology Laboratory, Pittsburgh, PA. May.

Dahowski, R., and Dooley, J. 2008. *Source/Sink Matching for U.S. Ethanol Plants and Candidate Deep Geologic Carbon Dioxide Storage Formations*. PNNL-17831.

DNV 2010 (draft). *Global Technology Roadmap for CCS in Industry: Sectoral Assessment, Refineries*. Prepared for UNIDO.

DOE, 2010. "Carbon Dioxide Capture and Storage (CCS)," CCS Briefing to Senate Energy and Natural Resources Committee, by S.M. Klara, National Energy Technology Center and Office of Fossil Energy, Washington, DC, March 5, 2010.

DOE 2006. Hydrogen Production Fact Sheet. http://www.hydrogen.energy.gov/pdfs/doe_h2_production.pdf Department of Energy, Hydrogen Program. October, 2006.

DOE/NETL November 2010. *Site Screening, Selection, and Initial Characterization for Storage of CO_2 in Deep Geologic Formations*

DOE/NETL December 2010. *Carbon Dioxide Capture and Storage RD&D Roadmap*

EIA 2009. *Emissions of Greenhouse Gases in the United States 2008*. Washington, D.C.: Energy Information Agency. December, 2009

EIA 2010. *Annual Energy Outlook 2011*. Washington D.C.: Energy Information Agency. December, 2010.

EIA 2008. *The Impact of Increased Use of Hydrogen on Petroleum Consumption and Carbon Dioxide Emissions*. Washington D.C.: Energy Information Agency. August, 2008.

EPA 2010. *Inventory of U.S. GHG Emissions and Sinks: 1990-2008*. Washington, D.C.: Environmental Protection Agency.

ERM 2009. *Financial Support Mechanisms for CO_2 Capture and Storage*, December, 2009.

GCCSI 2009. *Strategic Analysis of the Global Status of Carbon and Storage, Report 2: Economic assessment of carbon capture and storage technologies*. Global CCS Institute.

GCCSI 2011. Economic Assessment of Carbon Capture and Storage Technologies: 2011 Update. Global CCS Institute.

IEA 2011. *Cost and Performance of Carbon Dioxide Capture from Power Generation*. Paris, France: International Energy Agency.

IEA 2004. *Prospects for CO_2 Capture and Storage*, 252. Paris, France: International Energy Agency.

IMC 2008. *Alberta CO_2 Capture Cost Survey and supply Curve* Prepared by Ian Murray & Company for the Alberta Development Council, December, 2008.

IPCC 2005. *IPCC Special Report on Carbon Dioxide Capture and Storage*, 442. Prepared by Working Group III of the Intergovernmental Panel on Climate Change. New York, New York: Cambridge University Press.

Jacobs 2009. *Life Cycle Assessment Comparison of North American and Imported Crudes.* Prepared for Alberta Energy Research Institute.

Kheshgi, H., Bhore, N., Hirsch, R., Parker, M., Teletzke, G., and Thomann, H., 2010. *Perspectives on CCS Costs and Economics*. Presented at the SPE International Conference on CO_2 Capture, Storage, and Utilization, New Orleans, LA., 10-12 November 2010.

Kuuskraa, V., (2009). *Carbon Dioxide Capture for Storage in Deep Geological Formations*, Volume 3, pages 9-14.

Mantripragada, H. and Rubin, S., (2010) "CO_2 reduction potential of coal-to-liquids (CTL) process: Effect of gasification technology". *Energy Procedia* 2010.

McKinsey & Company (2008). *Carbon Capture and Storage: Assessing the Economics*.

Melien, T. and Brown-Roijen, S., (2009) Chapter 17: *Economics* in Carbon Dioxide Capture for Storage in Deep Geological Formations, Volume 3, p. 237-264.

MIT 2007. *The Future of Coal: an Interdisciplinary MIT Study*, Cambridge, Massachusetts: Massachusetts Institute of Technology.

NAS 2009 *Liquid Transportation Fuels from Coal and Biomass: Technological Status, Costs, and Environmental Impacts*, Washington, D.C., National Academy Press.

NETL, 2010. *Cost and Performance Baseline for Fossil Energy Plants, Vol. 1*, Revision 2. DOE/NETL-2010/1397, 600. Pittsburg, Pennsylvania: National Energy Technology Laboratory.

NETL, 2007. *Cost and Performance Baseline for Fossil Energy Plants, Vol. 1*, DOE/NETL-2007/1281, 516. Pittsburg, Pennsylvania: National Energy Technology Laboratory.

Page, S.C., Williamson, A.G., and Mason, I.G. (2009) Carbon capture and storage: Fundamental thermodynamics and current technology. *Energy Policy* 37 3314-3324.

Power, 2010. Duke Energy: Edwardsport IGCC plant to cost 23% more. *Power Magazine*, April 21, 2010.

Power-Gen, 2010. IGCC power plant cost top $5,500/kW. *Power-Gen Worldwide*, March 19, 2010.

RTP, 2010. *Hyperion Energy Center: Best Available Control Technology Review for Greenhouse Gas Emissions*. Prepared for Hyperion Refining LLC. October.

Rubin, E.S., "Audiences, Measures and Methods for CCS Costs," Proc. of 10th Annual Conference on Carbon Capture and Storage, US Dept of Energy, Pittsburgh, PA, May 2011

Rubin, E.S., Yeh, S., Antes, M., Berkenpas, M. and Davison, J. 2007. 'Use of Experience Curves to Estimate the Future Costs of Power Plants with CO_2 Capture', in *International Journal of Greenhouse Gas Control*. Vol. 1, pp 188-197.

Simbeck (2008) *The carbon capture technology landscape*. Energy Frontiers International Emerging Energy Technology Forum, SFA Pacific, Inc., Mountain View, CA. February.

Simbeck, D. 2005. Hydrogen costs with CO_2 capture, in *Greenhouse Gas Control Technologies, Volume II*, 1059-1066. Amsterdam, The Netherlands: Elsevier.

Sraelen, J. van., Geuzebroek, F., Goodchild, N., Protopapas, G., and Mahony L. 2010. CO_2 capture for refineries, a practical approach. *International Journal of Greenhouse Gas Control* 4: 316-320.

UNIDO, 2010. *Carbon Capture and Storage in Industrial Applications: Technology Synthesis Report* Und National Industrial Development Organization, Vienna, 2010.