Carbon Dioxide Capture and Storage: Perspectives on Cost and Economics

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Background

Technology will continue to play a key role in providing affordable energy for worldwide social and economic development. Improved technology will be needed if there are to be options for the deep reductions in greenhouse gas emissions that may be justified over the next half-century, a period over which strong demand for energy services is expected to continue. The capture of CO_2 from large point sources, its compression, transport via pipelines, and injection into deep aquifers, coal beds, or oil or gas reservoirs for long-term storage form one family of technological options. CO_2 capture and storage (CCS) has the potential to provide significant reductions in CO_2 emissions from large stationary sources, particularly in electricity generation. How and when CCS will compete with other GHG mitigation options depends on a clear understanding of CCS costs and drivers, as well as resolution of barriers to CCS deployment.

The cost of CCS is influenced by the size of the CO_2 source, CO_2 concentration, CO_2 pressure, the maturity of technology, and the proximity and quality of storage (CERA 2010). The capture step dominates CCS cost from electricity generation. CCS cost estimates are primarily derived from consideration of equipment requirements and operating costs. However, issues associated with impurities, permitting, and long-term responsibility for CO_2 storage are not fully resolved. Resolution of these issues may require changes in design and operation that could entail additional costs. Construction costs for the capture step are likely to be higher than common basis assumptions, especially for a first-of-a-kind plant.

The Special Report on Carbon Dioxide Capture and Storage by the Intergovernmental Panel on Climate Change (IPCC 2005, Table SPM.5) summarized a very wide range of cost estimates (2002 US$) for the major steps of the CCS process: 1) capture, 2) transport, and 3) storage, monitoring and verification. The capture cost for coal and gas-fired power plants was assessed to be 15-75 \$/t CO_2 captured. The capture from hydrogen and ammonia production or gas processing was 5-55 \$/tCO_2 captured. Capture costs from other industrial sources were 25-115 \$/tCO_2 captured. The cost for transportation via pipeline was assessed to be 1-8 \$/tCO_2 transported 250 km by pipeline for a scale of 5-40 million metric tons CO_2 per year (MtCO_2/yr). The cost of geological storage, monitoring and verification was assessed to be 0.6-8 \$/tCO_2 injected without including any cost offsets that might occur if CO_2 were used for enhanced oil recovery (EOR). For the situations assessed, these cost estimates indicate the cost of capture dominates the cost of CCS, and there is a wide range of capture cost estimates.

CCS benefits when there is economy of scale. In some situations, where relatively pure streams of CO_2 are generated (e.g. fermentation, Kheshgi and Prince 2005), capture costs can be lower than for combustion operations that result in CO_2 streams which are more dilute. However, the costs of capture, transport and storage generally all increase (per ton CO_2) as scale decreases.

Over the past seven years since the IPCC report was issued, there has been increased attention on CCS cost estimates. Reflecting the impact of increases in commodity prices, inflation had an effect on CCS cost estimates (Hamilton et al. 2009), raising them from those assessed by the IPCC (2005). With the recognition that existing coal power plants could result in a significant contribution to a future budget of CO_2 emissions, the retrofit of coal power plants with CCS has received further scrutiny; retrofit of power plants for CCS is expected to result in higher costs per ton CO_2 avoided than if a new plant were built (Simbeck 2009). With the increase in estimates of natural gas supplies, there has been increased attention on the potential application of CCS to power generated from natural gas to reduce greenhouse gas emissions relative to coal (Kheshgi et al. 2010, MIT 2011, Lytinski 2011, Simbeck 2011).

This paper provides perspectives on CCS cost estimates for applications to different CO_2 sources. In the next section we examine several interrelated cost basis assumptions including the maturity of CCS, construction costs and the cost of capital. In the following section we examine electricity cost from gas and coal generation with CCS. Most studies of CCS estimate the cost of CCS in terms of cost per ton CO_2 avoided assuming a base case facility (e.g. comparing a coal fired plant without CCS to one with CCS); Herzog et al. (2005) described the importance of the base case facility assumption on cost estimates. A focus on cost of electricity under assumed CO_2 emission costs allows the comparison of economic viability of a number of types of generation facilities. The last section focuses on the economics of CCS in oil and gas applications: specifically, refining, gas processing, and CO_2 EOR.

Cost Estimation: Perspectives on Cost Assumptions

An important factor for the cost of CCS, as well as a contributor to the magnitude of uncertainty in cost estimates for CCS, is the lack of maturity of CCS system technology. While all of the components of a post-combustion capture plant have been used commercially, there has not been commercial application of the entire technology system. The Government Accountability Office (GAO 2010) assessed the maturity of CCS (with post-combustion capture using amines) using NASA's Technology Readiness Level (a nine level classification of technology readiness ranging from level 1 with *basic principles observed* to level 9 with *commercial operation in relevant environment)* and found that the application of capture to coal power plants was at level 7 (*pilot plant at more than 5% of commercial scale)* or less. Experience tells us that cost estimates for technologies that are not mature are often highly uncertain and more often than not underestimate actual costs. Recent cost overruns for integrated gasification combined cycle coal (IGCC) plants provide examples (Power 2010, Power-Gen 2010). On the other hand, innovation sometimes results in different technology systems surpassing the cost performance of the initially envisioned technology, providing a lower cost for the same service but with a different technology system.

In addition to uncertainty in cost estimates, a first-of-a-kind plant is expected to cost more than a plant that is reproduced many times. Al-Juaied and Whitemore (2009) estimated that the cost (2008 US$ removing cost escalation particular to the 2007-2008 period) of capture from an IGCC plant appears to be 100-150 $/tCO_2$ avoided for a first-of-a-kind plant and plausibly 30-50 $/tCO_2$ avoided for an nth-of-a-kind plant (compared to a supercritical coal plant base case), whereas GCCSI (2009) estimates a much smaller difference between first-of-a-kind and nth-of-a-kind for capture from a supercritical pulverized coal plant (GCCSI 2011). Technical maturity is an important factor influencing cost. While the component technologies for capture from a supercritical pulverized coal plant are all commercially mature their integration is not (cf. GAO 2010, GCCSI 2009).

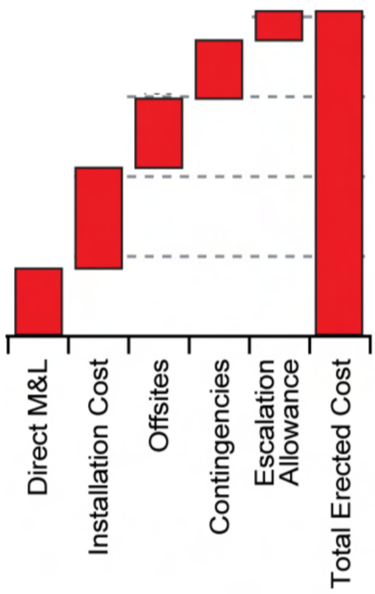

Figure 1. Illustrative build-up of total erected cost for a CO_2 capture plant.

About two thirds of the cost of capture from an amine post combustion plant is due to capital charges which are examined further below. A key factor which determines the estimated annualized cost of capture is the method used to calculate the total erected cost of the plant, specifically, how the total erected cost is built up from the bare equipment cost as illustrated in Figure 1. The details of how this is done vary among the types of industry and between specific companies within industry groups. Key components of this build-up include installation costs, offsites, contingencies, and escalation allowance. Differences in assumptions about these components (see, e.g., Thambimuthu et al. 2005, section 3.7.3), can lead to variation in cost estimates for hypothetical capture plants where assumptions often differ and may not be transparent. For example, Worley-Parsons produced cost estimates for a report by NETL (2007) for both coal and gas power plants including CCS, and for a report by the Global CCS Institute (GCCSI 2009) which includes further detail on the build-up of the total erected cost. Comparison of studies like these show that while the direct materials and labor (M&L) costs may be 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.

The cost of CCS is typically assumed to decrease over time, however, the rate of decrease and the driver for that potential decrease are a source of uncertainty, particularly if making estimates far into the future. Regulatory and permitting requirements add to cost, and how these change into the future is uncertain. The rate of cost reduction by "learning" has been an area of continued debate for energy technologies (see, e.g., Gruebler 2009, and Yeh and Rubin 2008), and cost reduction by learning has been applied to CCS cost estimates (see Rubin et al. 2006). The IEA (2004) concluded that for CCS "the potential for learning-by-doing is probably more limited than the potential for learning-by-innovation, but it is not negligible" suggesting a focus on the potential of innovation to bring down capture costs.

The cost of capital (financing) must be assumed in order to estimate the cost of CO_2 emissions avoided using CCS, or the cost of electricity of a power plant with or without CCS. Markandya et al. (2001) assess that the private rates of return to justify mitigation projects are potentially 10-25%. For power generation applications, the discount rate commonly used in CCS cost estimates is 7-10%. Financing at this rate typically is only available for low risk investments using mature technologies. Therefore, the availability of financing at low rates is an assumption in cost estimates which is contingent on factors such as technology maturity and investment risk profile.

Electricity Cost from Gas and Coal Generation with CCS

The Levelized Cost of Electricity (LCOE), defined as the unit cost of electricity sufficient to cover all generation costs over the life of the power plant including the cost of capital, is used to compare the cost of generating electricity with different technologies. Relative LCOE should be a key input in the choice of generation technology, but the least cost form of generation is highly dependent on fuel prices and CO_2 emission costs as well as on capital cost and other factors.

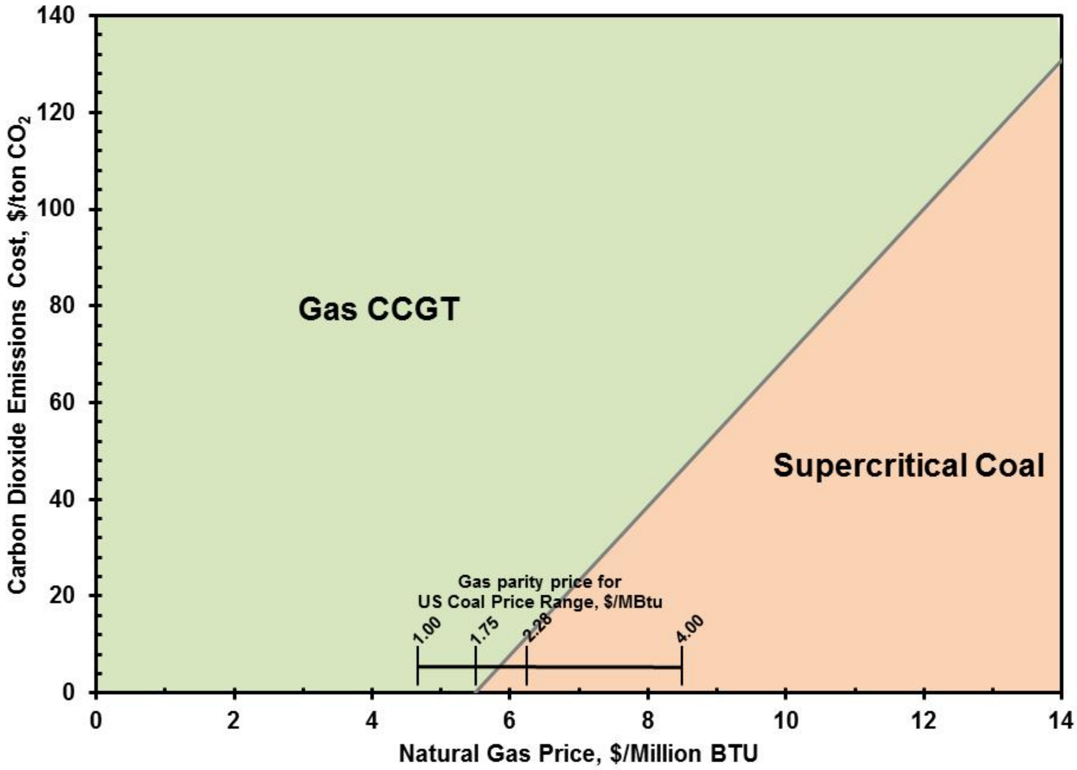

Figure 2. U.S. least cost generation technology zones comparing generation technologies for new plants: 1) gas CCGT, and 2) supercritical coal.

Figure 2 shows the zones of gas price and CO_2 emission cost over which gas Combined Cycle Gas Turbine (CCGT) plants and supercritical coal plants have lower LCOE in the U.S. The LCOE calculations assume baseload utilization (85%) and plant startup in the year 2025. Detailed assumptions for these LCOE calculations are provided by Kheshgi et al. (2010). LCOE for gas CCGTs and supercritical coal plants is equal along the border between the zones. The gas price where the border crosses the horizontal axis is the “parity” gas price with zero CO_2 emission cost. The “parity” gas price rises with CO_2 emission cost, since the coal plant produces 2.2 times as much CO_2 per kWh of electricity output as the gas plant. The chart is drawn based on the 10-year average U.S. real delivered coal cost of 1.75 $/MBtu, leading to a parity gas price of about 5.45 $/MBtu. The scale inset on the chart also shows the 2009 U.S. average coal price of 2.28 $/MBtu and the range of delivered coal cost to individual plants, 1 to 4 $/MBtu, depending on type of coal and transportation cost. The corresponding range of gas parity prices is about 4.50 to 8.50 $/MBtu with zero CO_2 emission cost.

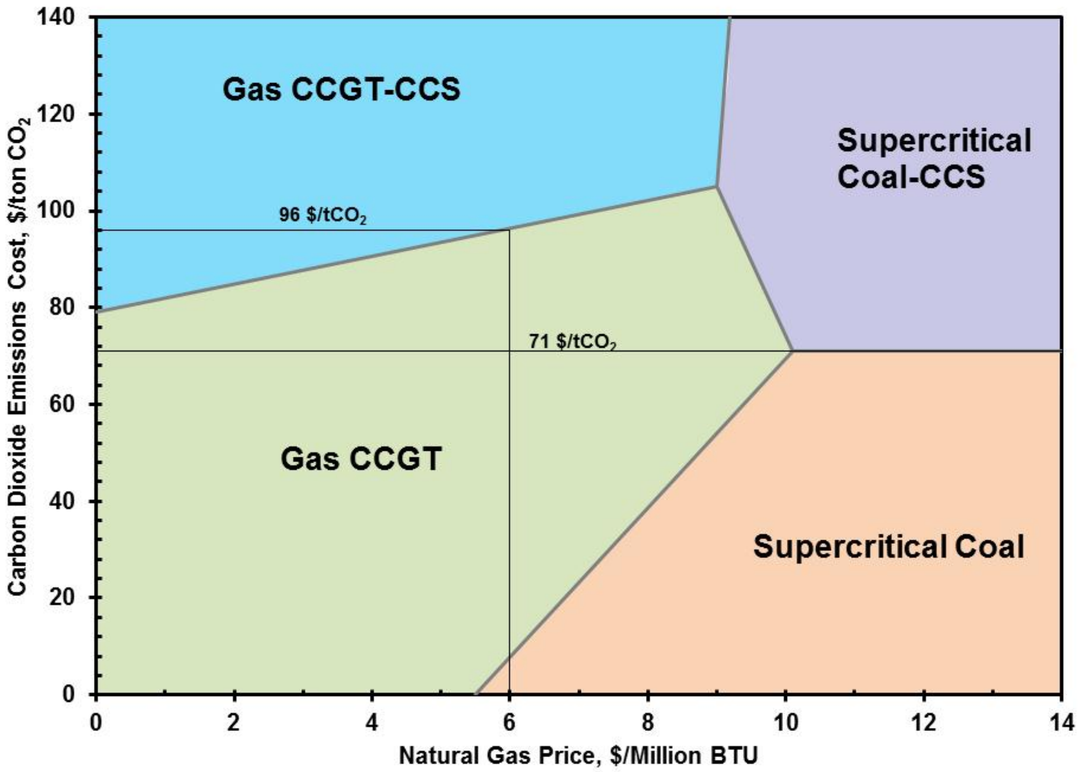

Figure 3. U.S. least cost generation technology zones comparing generation technologies for new plants: 1) gas CCGT, 2) supercritical coal, 3) gas CCGT with CCS, and 4) supercritical coal with CCS.

Figure 3 introduces gas-CCGT CCS and coal-CCS to the preceding chart, so that the zones indicate which of four generation technologies has the lowest LCOE as a function of the cost of CO_2 and the price of natural gas. The boundary between generation technologies with and without CCS can be interpreted as the cost of avoided CO_2 from building a plant with CCS relative to one without. For example, the avoided cost of coal-CCS relative to a supercritical coal plant here is 71 $/tCO_2$, and of course not dependent on the gas price (but dependent on coal price). The avoided cost of gas CCGT-CCS relative to gas CCGT is 96 $/tCO_2$ at a 6 $/MBtu gas price. This avoided cost is upward sloping – increasing with gas price – because CCS consumes energy and thus requires more gas per unit of net electricity output.

The increase in parity gas price from about 5.45 to 10 $/MBtu as CO_2 price rises from zero to 71 $/ton CO_2 (see Figure 3) and the recent improvements in unconventional gas and LNG supply (CERA 2010, MIT 2011) suggest that gas could play a significant role as a power generation fuel when there is a price on CO_2 emissions.

The higher avoided cost for gas CCGT-CCS than for coal-CCS may give the impression that CCS is more expensive for gas than for coal. This, however, need not be the case because one cost is relative to a gas CCGT, while the other cost is relative to a supercritical coal plant. In fact, on a per unit of electricity basis, adding CCS to gas is projected to be less costly than adding CCS to coal, because the coal plant produces 2.2 times as much CO_2 per unit of electricity generated. The added cost of dealing with much higher CO_2 production will outweigh the decrease in separation cost per unit of CO_2 captured from the higher concentration of CO_2 in a coal plant flue gas stream as shown in the cost estimates in Table

1. CCS increases the base LCOE for the gas CCGT by about 50%, but doubles it for the coal plant.

Table 1. Gas CCGT and supercritical coal LCOE estimates, assuming 1.75 $/MBtu coal and 6 $/MBtu gas.*

	$/MWh* Gas CCGT	Gas CCGT-CCS	Supercritical Coal	Supercritical Coal-CCS
Base LCOE	56	85	51	101
CO_2 Emission Cost**	21	2	48	5
Total LCOE	77	87	99	106

** Expressed in 2010$.*
*** Based on a CO_2 emission cost of 60 $/tCO_2$.*

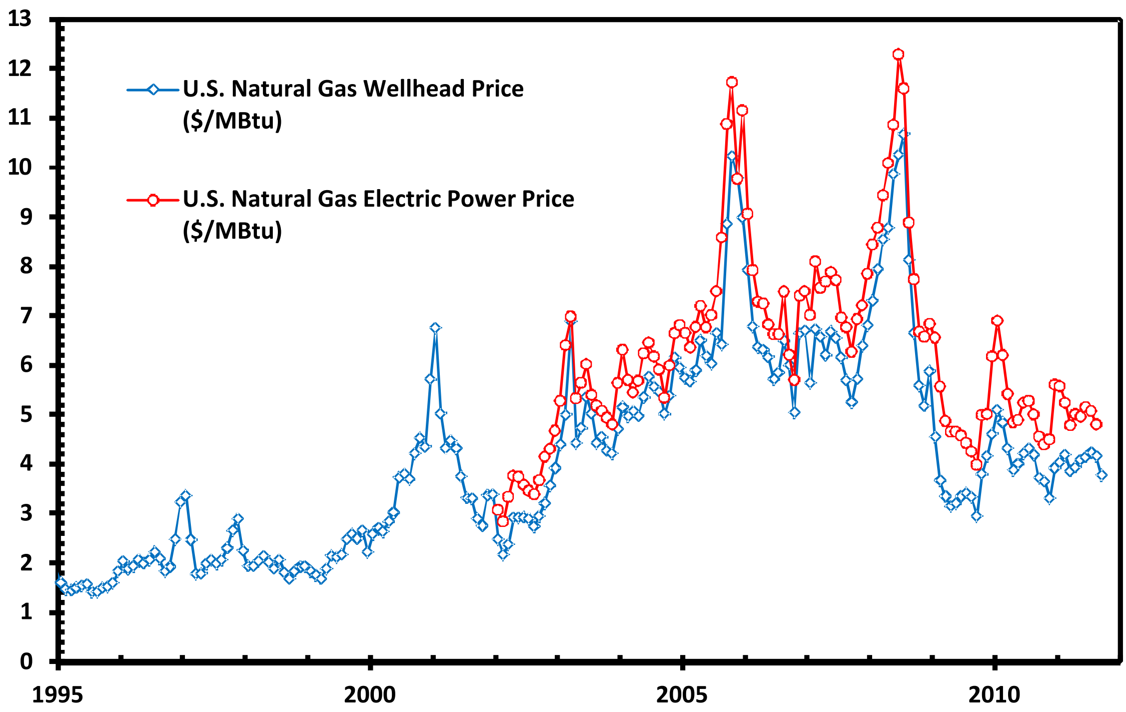

Figure 4. Monthly average U.S. natural gas price history (EIA 2011).

As the zones in Figure 3 show, at gas prices within the range of most U.S. experience (see Figure 4), a gas CCGT continues to provide a lower LCOE than coal-CCS at CO_2 emission costs reaching above 100 $/tCO_2$. At CO_2 emission costs above that level, gas CCGT-CCS LCOE would be lower than coal-CCS with gas prices below 9 $/MBtu, despite its higher cost of CO_2 avoided.

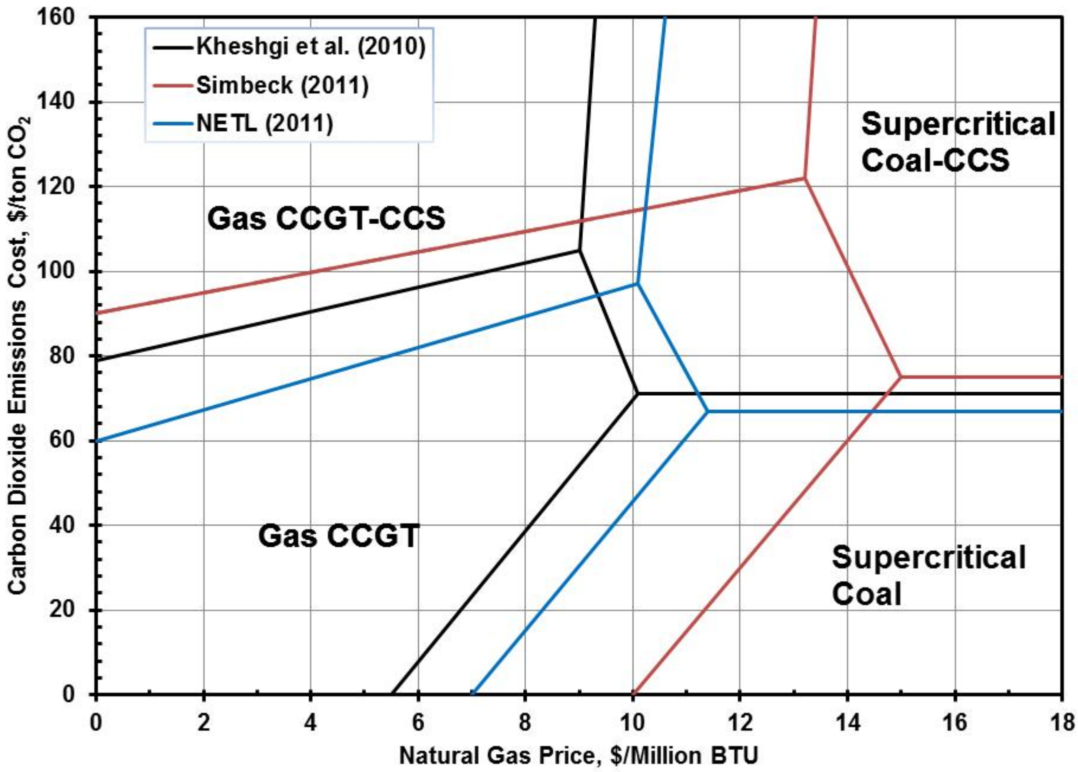

Figure 5. U.S. least cost generation technology zones comparing generation technologies: 1) gas CCGT (least cost in lower left zone), 2) supercritical coal (least cost in lower right zone), 3) gas CCGT with CCS (least cost in upper left zone), and 4) supercritical coal with CCS (least cost in upper right zone) from cost estimates from Kheshgi et al. (2010; same zone boundaries as shown in Figure 3), Litynski (2011), and Simbeck (2011).

Figure 5 compares the three studies that have now shown zones of lowest LCOE for new plants from the four technology choices as in Figure 3. All of the studies show zones of similar shape, however, the least cost zone for gas CCGTis shifted for the studies of Litynski (2011) and Simbeck (2011) than that shown in Figure 3 based on Kheshgi et al. (2010). Each study uses a different cost basis. The studies result in a LCOE for coal plant (excluding cost of CO_2) which is greater in Simbeck (2011) than in Litynski (2011), which is greater than in Kheshgi et al. (2010); this corresponds to a boundary between gas CCGT and coal that is at higher gas price (further to the right) for higher coal LCOE.

The avoided cost estimates shown in Figure 5 fit within the $60 to $95/ton CO_2 avoided range shown by the U.S. Presidential Taskforce on CCS (EPA 2010).

Nuclear is added to the technology set in Figure 6. Coal-CCS is higher cost than nuclear at all CO_2 costs and gas prices, so the coal-CCS zone is no longer visible. The cost of avoided CO_2 for nuclear relative to supercritical coal is about 28 $/tCO_2$. Nuclear has lower LCOE than a gas CCGT at gas prices above 7 $/MBtu and CO_2 emission costs above 28 $/tCO_2$. Gas CCGT-CCS comes into the picture only at gas prices below 4 $/MBtu.

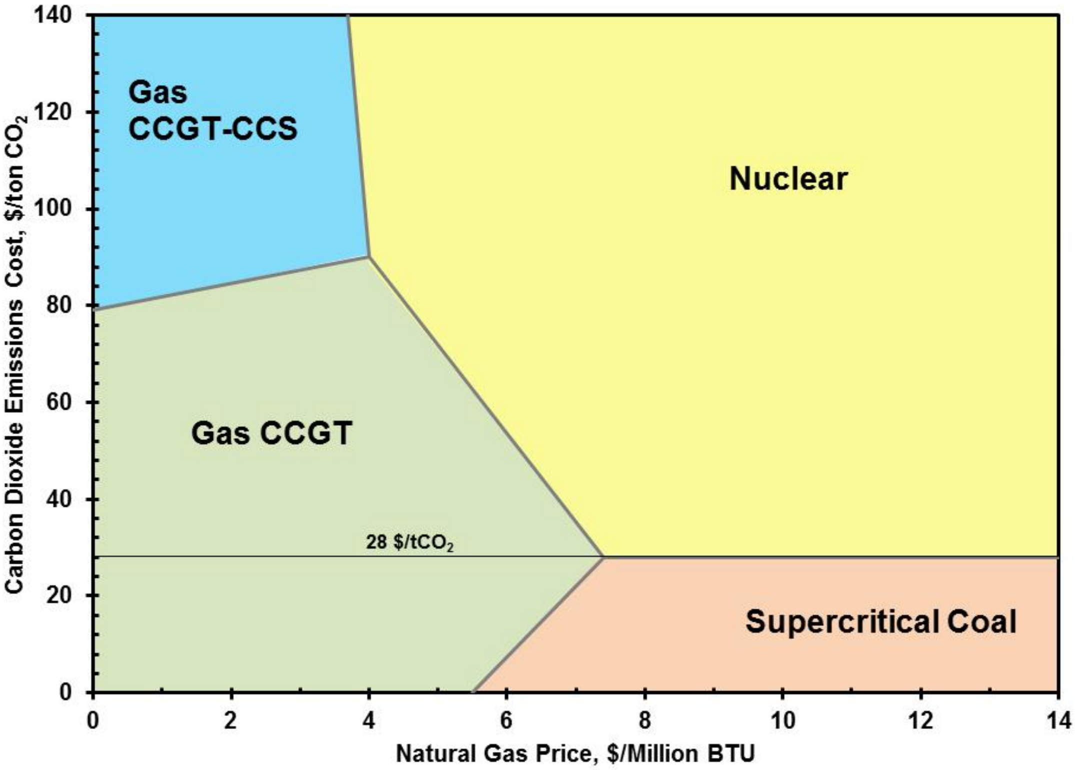

Figure 6. U.S. least cost generation technology zones comparing generation technologies for new plants: 1) gas CCGT, 2) supercritical coal, 3) gas CCGT with CCS, 4) supercritical coal with CCS, and 5) nuclear.

Comparing different sets of technologies, of course, changes the boundaries. For example, Simbeck (2011) estimates that electricity from a coal plant without including its capital cost has a lower LCOE than that of a new gas CCGT plant over the entire range of gas prices provided CO_2 cost is low; a comparison that may be relevant when considering if a new gas plant might displace and existing coal generation capacity. Alternatively, if we compare a gas plant without including its capital cost to a new coal plant, the LCOE from gas would be lower over a wider range of gas prices; a comparison that may be relevant when considering if a new coal plant might displace and existing gas power generation capacity.

Changes in technology would also shift the zone boundaries. For example, a reduction in the cost of coal-CCS would lower the boundary between coal and coal-CCS to a lower CO_2 cost number and shift the coal-gas boundaries to the left (lower gas prices). If the plant utilization assumption is lowered from 85% (baseload) toward midrange or peaking use, the gas CCGT zone will shift to the right in all dimensions, since it is by far the lowest capital cost technology.

CCS Cost and Economics in Oil and Gas Applications

The cost and economics of CCS applied to different oil and gas operations spans a broad range and includes some applications where CCS can provide economic benefits (e.g. CO_2 EOR), and other applications where the cost of operations with CCS exceeds the cost of CCS applied to power generation. In this section three general types of applications are considered: refining, gas processing, and CO_2 EOR.

Refining

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 $MtCO_2$/yr. While there is limited literature on the capture of CO_2 from refineries, refinery CO_2 capture costs are often estimated by simply comparing the sources of refinery CO_2 to other sources such as those from power plants (recognizing there is still significant uncertainty in cost estimates for power plants for which there is considerably more literature).

The net CO_2 emissions from a large refinery are of comparable magnitude as that of a power plant. However, as Staelen et al. (2010) point out, there are numerous streams of CO_2 from a refinery with differing compositions over a vast geography. Streams include the exhaust from numerous burners and process units, with larger streams from cogeneration plants and hydrogen plants, although these larger streams alone are of smaller scale than that of a full scale power plant. Collecting these streams to achieve improved economy of scale is logistically problematic. Furthermore refineries are complex operations with limited space. Each of these factors (retrofit, scale and complexity, varied stream compositions, and distributed sources) increases the cost of application of CCS to refineries, making it significantly higher than that for power plants as was found by CONCAWE (2011).

Unlike the dilute streams of CO_2 from other refinery sources, hydrogen plant CO_2 emission streams in some instances have higher concentrations of CO_2, although they are typically smaller than coal-based power plants (Simbeck 2005). For example, Staelen et al. (2010) point out that refinery gasifiers to produce hydrogen in some cases result in a high pressure and high concentration CO_2 stream. However, most refinery hydrogen is produced from natural gas reforming (not via gasification), and increasingly a pressure swing adsorption process is used to produce high purity hydrogen. Pressure swing absorption results in CO_2 streams that are rich in hydrogen and are typically recycled through burners which result in dilute CO_2 streams at low pressure. For those refinery CO_2streams where the capture of CO_2 is possible at low cost, a shared transport infrastructure with other large nearby captured CO_2 sources would be important to achieve economy-of-scale common in analyses of CCS for power generation (see CONCAWE 2011). Therefore, while there may be some very selective opportunities to capture and transport some refinery CO_2 at low cost, the vast majority of refinery CO_2 would involve capture that is far more costly than capture at power plants.

Gas Processing

Commercial scale CCS experience has primarily been in CO_2 capture in natural gas processing as is shown in Table 2 which lists the current operating large-scale integrated CCS projects worldwide. In these situations, the CO_2 capture cost is typically necessary to enable natural gas sales. The remaining CCS 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 (IPCC 2005, MIT 2007), with these costs varying depending on the project specific design parameters and logistics – dominated by the distance of transport. CO_2 streams are captured in gas processing plants at Sleipner, In Salah, and Shute Creek where CO_2 is injected into a saline formation, a gas formation, and oil fields for CO_2 EOR, respectively. The Gorgon project under development in Western Australia will capture CO_2 and inject it into a saline formation. These applications of commercial capture of CO_2 in natural gas processing provide early experience with commercial application of CCS, at scales (≥1 $MtCO_2$/yr) comparable to the scale of CCS for a power plant.

Table 2. Operating Large Scale CCS Projects.

Location	Anthropogenic CO_2 Source	Pipeline Transport	Storage
Algeria	In Salah gas processing plant	14 km onshore	saline formation (2004-, 1 $MtCO_2$/yr)
Norway	Sleipner gas processing platform	minimal	offshore saline formation (1996-, 1 $MtCO_2$/yr)
Norway	Snohvit LNG plant	154 km offshore	offshore saline formation (2007-, 0.7 $MtCO_2$/yr)
United States (ND)/ Canada	Great Plains Coal Gasification plant	330 km onshore	Weyburn-Midale EOR (2000-, 3 $MtCO_2$/yr)
United States (OK)	Enid fertilizer plant (0.7 $MtCO_2$/yr)	onshore network	EOR network
United States (TX)	Century gas processing plant plus several others (~7 $MtCO_2$/yr and >35 $MtCO_2$/yr from natural sources)	Permian basin onshore network	EOR network (including Sharon Ridge: 1999-, and many others)
United States (WY)	LaBarge gas processing plant (6 $MtCO_2$/yr)	onshore network	EOR network (including Rangely, CO 1986-; Salt Creek, WY: 2004-, and others)

Sources: GCCSI (2010), Murrell (2011), and Melzer (2007)

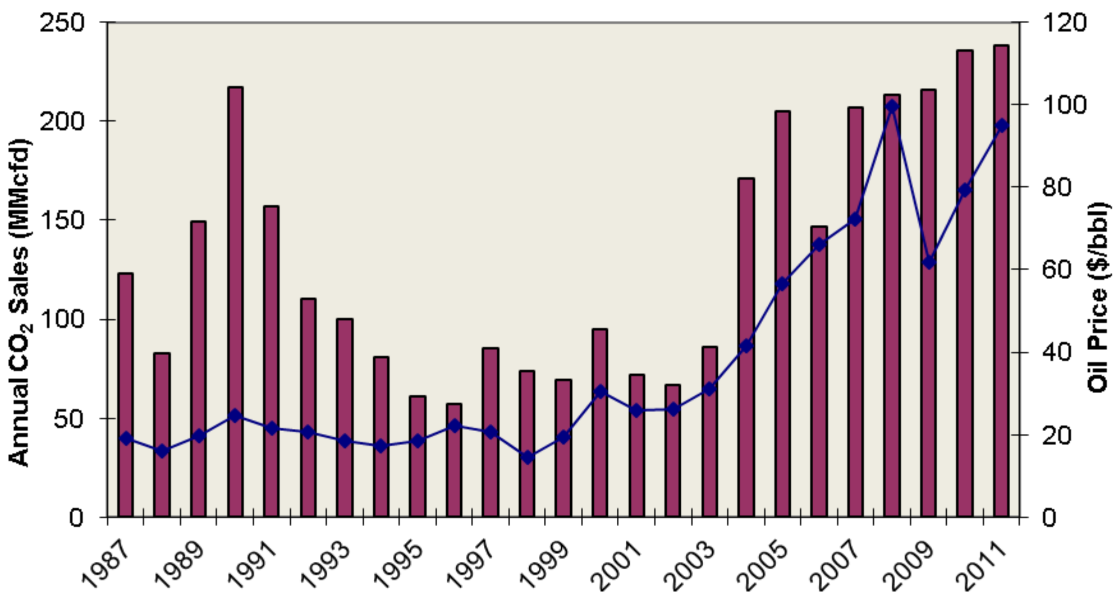

Figure 7. Annual CO_2 sales volumes from the Shute Creek Treating Facility (bars) compared with annual average oil prices (line) (Bailes et al. 2011).

The capture of CO_2 from the processing ("sweetening") of sour natural gas resources, which can contain a large fraction of CO_2, could provide additional experience if economic and other challenges associated with sour gas projects can be overcome. Sour natural gas constitutes a significant fraction of global gas resources (see Burgers et al. 2010) and represents a large portion of new resource opportunities. One way to improve the economics of sour gas treating is through the development of more efficient and less costly technologies (see, e.g., Kelley et al. 2010) to separate sour gas streams.

In situations where capture and transport costs are low and value is added through use of the CO_2 for EOR or by not incurring CO_2 emission costs, CCS can be economic. At the Shute Creek Treating Facility at LaBarge, Wyoming, USA over 4 $MtCO_2$ were provided in 2009 for CO_2 EOR at oil fields including the Rangely and Salt Creek fields (Parker et al. 2009, Sweatman et al. 2009, GCCSI 2011). ExxonMobil's Shute Creek facility is the largest gas sweetening industrial facility today where the CO_2 is used for subsurface injection. Figure 6 shows the history of CO_2 sales from the Shute Creek Treating Facility through 2009. In recent years, higher oil prices have led to new EOR projects and increased demand for CO_2 in the Wyoming region (Parker et al. 2009). In 2010, the Shute Creek Treating Facility has expanded its CO_2 sales capacity to 7 $MtCO_2$/yr (EPA 2010 p. 143, Parker et al. 2009), increasing its sales volumes by about 50% (Murrell 2011).

CO_2 EOR can tolerate some limited impurities in the injected gas for specific situations (see Wilkinson et al. 2010). As transport costs are an important factor influencing the economics in such situations, the proximity of sour gas resources and CO_2 EOR opportunities is important (see Burgers et al. 2010).

<u>CO_2 EOR</u>

The oil and gas industry has been successfully using CO_2 for EOR for over 35 years. The technologies and operational practices for treating, transporting, and injecting CO_2 for EOR are well developed and are very similar to those technologies anticipated to be used generally for CCS.

CO_2 EOR provides the opportunity to store CO_2 while offering the benefit of providing incremental production of oil and gas. The revenue provided by the incremental oil and gas production can provide an economic advantage for a system that captures CO_2 and utilizes (and stores) that CO_2 for EOR as opposed to a CCS system that does not utilize the CO_2 (IPCC 2005). However, the economics of CO_2 EOR are site specific, primarily because the response of incremental oil production induced by CO_2 injection varies by reservoir. Experience to date, based primarily on mature projects in the U.S. Permian Basin, indicates an average CO_2 EOR recovery uplift of between 5 to 15% of original oil in place at an average net CO_2 utilization (retention in reservoir) of about 0.3 tCO_2 per incremental barrel of oil recovered with a range of 0.15-0.5 tCO_2/bbl (Brock et al., 1990, Stell, 2005, and Hargrove et al., 2008).

A field's proximity to attractive CO_2 sources is also an important factor determining economic viability. The vast majority of CO_2 EOR projects to date have been in the U.S. Permian Basin and injected CO_2 produced from natural subsurface accumulations. Several projects have also been implemented in Mississippi and Wyoming. Over 90% of the CO_2 currently used for EOR comes from nearby subsurface sources, including CO_2 captured via gas processing, and over 80% comes from gas reservoirs containing nearly pure CO_2 (Hargrove et al., 2008). The only projects to date based on CO_2 captured from coal are in the Midale-Weyburn area in Saskatchewan, Canada, and the Williston Basin in the U.S, which inject CO_2 piped from the Dakota Gasification Plant in North Dakota. Along the US Gulf Coast, new CO_2 resources are being developed that will create new EOR opportunities for this region. As part of this effort and over the longer term, developers are also pursuing access to anthropogenic CO_2 resources from power generation and other industrial processes.

Table 3. Indicative CO_2-EOR threshold oil prices (US$/bbl) as a function of CO_2 supply cost and representative capital and operating expenditures.*

CO_2 Supply Cost (US$/t$CO_2$)	Capex: $3/bbl Opex: $6/bbl	Capex: $6/bbl Opex: $10/bbl	Capex: $9 bbl Opex: $15/bbl	Capex: $12 bbl Opex: $20/bbl	Capex: $15 bbl Opex: $25/bbl
20	**$32**	**$54**	**$77**	**$103**	**$127**
40	**$39**	**$62**	**$85**	**$110**	**$134**
60	**$48**	**$70**	**$92**	**$117**	**$141**
80	**$56**	**$78**	**$100**	**$124**	**$148**
100	**$64**	**$85**	**$108**	**$132**	**$156**

* Based on NPV 12% with net CO_2 utilization of 0.38 tCO_2/incremental barrel of oil and 55% government take (taxes, royalties, and/or government participation).

Historically, the market price of CO_2 in US$/t$CO_2$ in the Permian Basin has been between 60 and 80% of West Texas Intermediate oil price in US$/bbl. Many of the long-term Permian Basin contracts were negotiated at less than 15 US$/t$CO_2$; but with volatile crude prices and tight supplies of CO_2 from subsurface sources (which are tied to existing infrastructure), CO_2 prices in some cases have climbed to more than 30 US$/t$CO_2$. The relative economics of each project are affected by target oil volumes, injectant supply costs, operating costs, capital costs for injection and recycling equipment, and tax/royalty rates. For typical Permian Basin conditions (ARI, 2010), Table 3 illustrates the minimum oil prices required to justify CO_2-EOR at net present value (NPV) 12% in relation to CO_2 supply costs at varying capital and operating expenditures for an EOR project.

Summary of Key Findings

This paper provides a comparison of the cost of electricity of five power generation options – coal and gas Combined Cycle Gas Turbine (CCGT) with and without CCS and nuclear – and shows regions of carbon price and fuel prices where each can be economically viable.

Current avoided cost estimates for coal CCS -- Kheshgi et al. (2010), Litynski (2011), Simbeck (2011), U.S. Presidential Taskforce on CCS (EPA 2010) -- are in the $60-$95/ton CO_2 avoided range – higher than some of the earlier CCS estimates, and higher than the generally accepted range of expected carbon prices in the next two decades. The high cost of coal CCS suggests that:

- Gas based power generation is more economical than coal CCS at CO_2 prices below the 60-95 $/ton CO_2 range.
- Even after carbon prices reach the 60-95 $/ton CO_2 range, gas CCS produces lower cost electricity than coal CCS as long as natural gas prices remain below 9 $/MBTU.
- Nuclear has a lower cost of electricity than coal CCS.

Although Coal or Gas CCS is unlikely to be economical in power generation over the next two decades, subsidized demonstrations of CCS are likely to occur. In addition, components of CCS technologies will continue to be economically practiced in early use segments such as natural gas processing and Enhanced Oil Recovery (EOR) operations. Currently, all operating large scale integrated CCS projects (see Table 2) include capture of CO_2 from gas processing and/or storage of CO_2 as a result of using CO_2 for EOR, where none as of yet captures CO_2 from power generation on a commercial scale. In the natural gas processing industry, CO_2 separation cost is a fraction of the cost of CO_2 capture in power generation due to its higher gas pressure, and the CO_2 separation is typically necessary to monetize the natural gas resource.

In contrast, CCS for most refinery and industrial emissions is expected to be significantly more costly than for power generation because the CO_2 streams are typically smaller scale and more distributed than those from large power plants.

Realistic estimates of cost for CCS, as well as for other greenhouse gas (GHG) mitigation options, are an important input for focusing research, development and demonstration (RD&D) addressing barriers to applications that show the greatest promise, and development of sound policy.

Conclusions and Discussion

Focus on Carbon Capture and Storage (CCS) has grown over the past decade with recognition of CCS's potential to make deep CO_2 emission reductions and that fossil fuels will continue to be needed to supply much of the world's energy demands for decades to come. How CCS will compare to other options in the future depends critically on the cost of CCS (the focus of this paper) and resolution of barriers to CCS deployment, as well as costs and barriers for other emission reduction options.

The cost of CCS remains highly uncertain given the very limited commercial application of the integrated CCS technology system. The discovery of the cost of commercial-scale CCS is progressing slowly. Cost uncertainty is a deterrent to private investment in the power industry. Nevertheless, cost estimates provide important guidance for efforts to improve CCS as an option to reduce CO_2 emissions from large stationary sources.

The cost of CO_2 capture, which is generally the largest contributor to CCS cost, continues to present a significant economic challenge to the application of CCS to combustion sources such as those from electric power generation.

For power generation, CCS viability depends on: long-term fuel prices, the cost of generation technologies without capture as well as the cost of capture technologies themselves, and technology improvement. Furthermore, CCS cost depends on transport costs, which in turn are driven by the distance, scale and path to storage, as well as CO_2 injection and storage costs. Additional factors such as long-term responsibility and permitting may create additional costs as well as project delays that in turn raise costs.

Drawing on recent cost estimates, the comparison of the levelized cost of electricity is instructive. In the current and emerging U.S. natural gas environment (abundant, competitively priced resources), gas-fired generation is emerging as the lowest cost option. As CO_2 prices increase, gas fired generation with CCS is lower cost than coal-CCS (as well as gas or coal without CCS). And in cases where nuclear power is viable as an option, it is favored over coal with CCS.

Given that power generation makes up the largest fraction of stationary CO_2 sources, it is a research priority to develop lower-cost capture technologies for power generation from both coal and gas. As described by Figueroa et al. (2008), there is a portfolio of technologies for capture ranging from commercial or near-commercial technologies to those that still require significant development and/or breakthroughs and may require a decade or more until their potential commercialization. If the expectation is that CO_2 prices will not be sufficient in the near term to exceed the cost of near-term capture technologies, it may make sense to focus capture research on breakthrough options that have the potential for large cost reductions as opposed to incremental improvement of existing non-commercial technologies (c.f. Flannery and Kheshgi 2004).

A second priority is to address barriers to CCS that raise costs or risks to CCS investments. In particular, it is important to create a sound regulatory framework for CCS and clear and equitable rules on CCS long-term responsibility. Unlimited exposure to liability risk on long-term storage would seriously deter private investors.

Finally, it is important to learn from the demonstrations and the limited commercial experience that already exist in order to better understand the costs before committing to large-scale CCS implementation. For demonstrations that are not otherwise economic, it is important to have a clear recognition of the costs and an understanding of what knowledge will be gained for those costs. Under some circumstances (e.g. using CO_2 streams separated during gas processing for use in CO_2 EOR) the capture and storage of CO_2 is economic today, and in those circumstances where it has become commercial, experience gained (e.g. Sweatman et al. 2009) is valuable.

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