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Carbon Capture and Storage

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Executive Summary

Emissions of carbon dioxide, the most important long-lived anthropogenic greenhouse gas, can be reduced by Carbon Capture and Storage (CCS). CCS involves the integration of four elements: CO_2 capture, compression of the CO_2 from a gas to a liquid or a denser gas, transportation of pressurized CO_2 from the point of capture to the storage location, and isolation from the atmosphere by storage in deep underground rock formations. Considering full life-cycle emissions, CCS technology can reduce 65–85% of CO_2 emissions from fossil fuel combustion from stationary sources, although greater reductions may be possible if low emission technologies are applied to activities beyond the plant boundary, such as fuel transportation.

CCS is applicable to many stationary CO_2 sources, including the power generation, refining, building materials, and the industrial sector. The recent emphasis on the use of CCS primarily to reduce emissions from coal-fired electricity production is too narrow a vision for CCS.

Interest in CCS is growing rapidly around the world. Over the past decade there has been a remarkable increase in interest and investment in CCS. Whereas a decade ago, there was only one operating CCS project and little industry or government investment in R&D, and no financial incentives to promote CCS. In 2010, numerous projects of various sizes are active, including at least five large-scale full CCS projects. In 2015, it is expected that 15 large-scale, full-chain CCS projects will be running. Governments and industry have committed over USD 26 billion for R&D, scale-up and deployment.

The technology for CCS is available today, but significant improvements are needed to support widespread deployment. Technology advances are needed primarily to reduce the cost of capture and increase confidence in storage security. Demonstration projects are needed to address issues of process integration between CO_2 capture and product generation, for instance in power, cement and steel production, obtain cost and performance data, and for industry where capture is more mature to gain needed operational experience. Large-scale storage projects in saline aquifers are needed to address issues of site characterization and site selection, capacity assessment, risk management and monitoring.

Successful experiences from five ongoing projects demonstrate that, at least on this limited scale, CCS can be safe and effective for reducing emissions. Five commercial-scale CCS projects are operational today with over 35 million tonnes of CO_2 captured and stored since 1996. Observations from commercial storage projects, commercial enhanced oil recovery projects, engineered and natural analogues as well as theoretical considerations, models, and laboratory experiments suggest that appropriately selected and managed geological storage reservoirs are very likely to retain nearly all the injected CO_2 for very long times, more than long enough to provide benefits for the intended purpose of CCS.

Significant scale-up compared to existing CCS activities will be needed to achieve large reductions in CO_2 emissions. A 5- to 10-fold scale-up in the size of individual projects is needed to capture and store emissions from a typical coal-fired power plant (500 to 1000 MW). A thousand fold scale-up in size of today's CCS enterprise would be needed to reduce emissions by billions of tonnes per year (Gt/yr).

The technical potential of CCS on a global level is promising, but on a regional level is differentiated. The primary technical limitation for CCS is storage capacity. Much more work needs to be done to realistically assess storage capacity on a worldwide, regional basis and sub-regional basis.

Worldwide storage capacity estimation is improving but more experience is needed. Estimates for oil and gas reservoirs are about 1000 $GtCO_2$, saline aquifers are estimated to have a capacity ranging from about 4000 to 23,000 $GtCO_2$. However, there is still considerable debate about how much storage capacity actually exists, particularly in saline aquifers. Research, geological assessments and, most importantly, commercial-scale demonstration projects will be needed to improve confidence in capacity estimates.

Costs and energy requirements for capture are high. Estimated costs for CCS vary widely, depending on the application (e.g. gas clean-up vs. electricity generation), the type of fuel, capture technology, and assumptions about the baseline technology. For example, with today's technology, CCS would increase cost of generating electricity by 50–100%. In this case, capital costs and parasitic energy requirements of 15–30% are the major cost drivers. Research is underway to lower costs and energy requirements. Early demonstration projects are likely to cost more.

The combination of high cost and low or absent incentives for large-scale deployment are a major factor limiting the widespread use of CCS. Due to high costs, CCS will not take place without strong incentives to limit CO_2 emissions. Certainty about the policy and regulatory regimes will be crucial for obtaining access to capital to build these multi-billion dollar projects.

Environmental risks of CCS appear manageable, but regulations are needed. Regulation needs to ensure due diligence over the lifecycle of the project, but should, most importantly, also govern site selection, operating guidelines, monitoring and closure of a storage facility.

Experience so far has shown that local resistance to CO_2 storage projects may appear and can lead to cancellation of planned CCS projects. Inhabitants of the areas around geological storage sites often have concerns about the safety and effectiveness of CCS. More CCS projects are needed to establish a convincing safety record. Early engagement of communities in project design and site selection as well as credible communication can help ease resistance. Environmental organisations sometimes see CCS as a distraction from a sustainable energy future.

Social, economic, policy and political factors may limit deployment of CCS if not adequately addressed. Critical issues include ownership of underground pore space (primarily an issue in the US); long-term liability and stewardship; GHG accounting approaches and verification; and regulatory oversight regimes. Governments and the private sector are making significant progress on all of these issues. Government support to lower barriers for early deployments is needed to encourage private sector adoption. Developing countries will need support for technology access, lowering the cost of CCS, developing workforce capacity and training regulators for permitting, monitoring and oversight.

CCS combined with biomass can lead to negative emissions. Such technologies are likely to be needed to achieve atmospheric stabilization of CO_2 and may provide an additional incentive for CCS adoption.

13.1 Introduction: The Need for Carbon Capture and Storage

13.1.1 Introduction to Carbon Capture and Storage (CCS)

In 2008 fossil fuels provided over 85% of our energy supply and emitted over 30 Gt (billion tonnes) of carbon dioxide (CO_2) into the atmosphere. Stabilizing greenhouse gas (GHG) concentrations in the atmosphere at levels that avoid dangerous interference with the climate system will require reducing emissions by an estimated 50–80% by 2050 (IPCC, 2007). Fossil fuel use continues to grow worldwide, especially in countries with rapidly developing economies. Heavy reliance on fossil fuels for all aspects of our energy system makes the transformation to a sustainable future with lower GHG emissions very challenging. The principal benefit of CCS is that it reduces emissions from fossil fuel use, especially from power generation and industrial processes, thus enabling reducing or slowing growth of emissions while other lower GHG emission energy technologies mature and deploy more widely. In addition, over the longer term, CCS could be used to reduce emissions from sources that are difficult to eliminate in any other way, such as energy-intensive industrial processes, natural gas cleanup, hydrogen production, fossil fuel refining, petrochemical industries, and steel and cement manufacturing. The availability of scalable CCS technology by 2020 to 2030 would be most beneficial to lessen the disruption of this transformation by providing low-emission energy services from fossil fuels while alternatives are still developed and scaled-up to meet current and growing energy demands.

For heavily coal-dependent and coal-rich counties such Australia, Canada, China, India, the United States, and Russia, it will be difficult to provide adequate energy supplies while rapidly reducing emissions if CCS is not possible. Figure 13.1 illustrates the current reliance on coal and rate of capacity growth for new coal-fired plants for several of the world's largest economies. Among these heavily coal-reliant economies, those with the most rapid economic growth continue to install new plants at a rapid rate. Large new coal plants will each emit over 100 $MtCO_2$ over their 30- to 40-year lifetime, unless they can be retrofit with capture in the future.

CCS involves the integration of four elements: CO_2 capture, compression of the CO_2 from a gas to a liquid or a denser gas, transportation of pressurized CO_2 from the point of capture to the storage location, and isolation from the atmosphere by storage (see Figure 13.2). Technologies are available to carry out each of these elements, but today, implementation of CCS is challenging because the cost for capture is high, integration of CCS with electricity production or industrial processes is not demonstrated at a large scale, and more confidence is needed that storage can be safe and effective over time periods of 1000 years or longer. While in principle CCS could be deployed on a much wider basis today, the challenge of doing so should not be underestimated. Integrating CCS into existing power generation

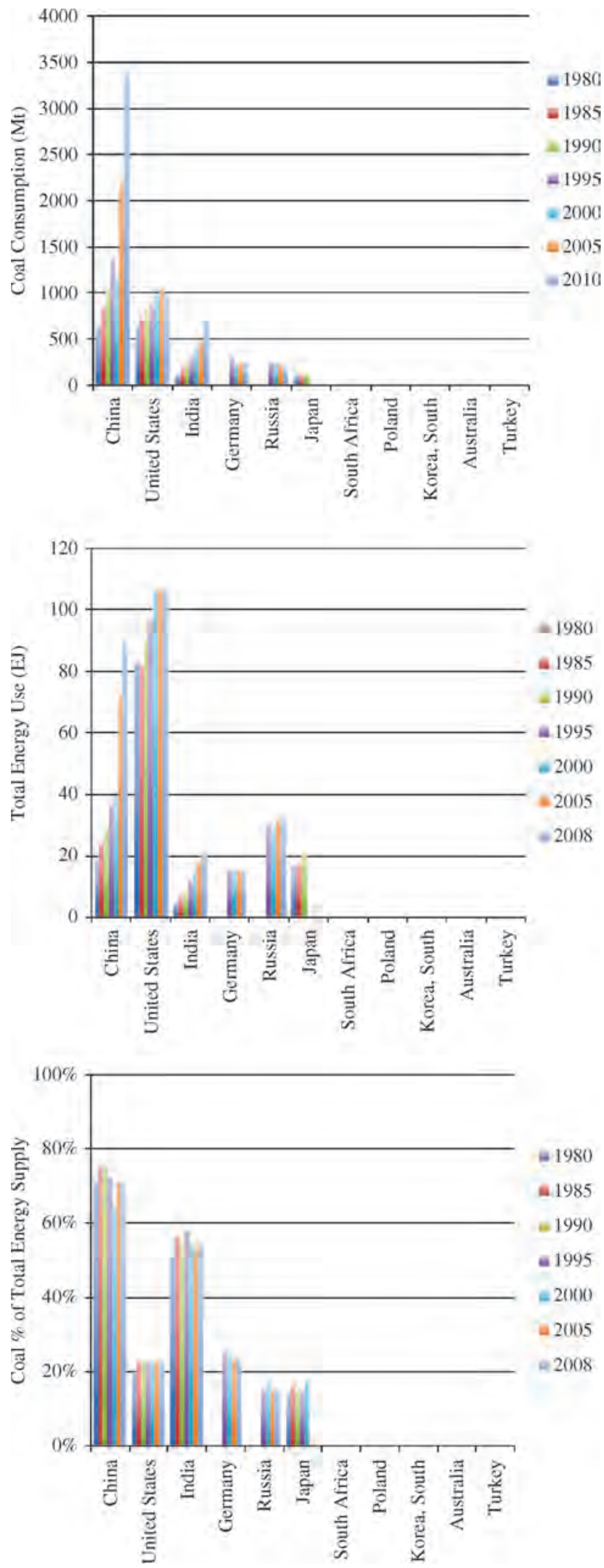

Figure 13.1 | Analysis of trends in the 11 largest coal consuming countries: (a) coal consumption from 1980 to 2010 (Mt), (b) total energy use (Exajoules), (c) percentage of total energy from coal.

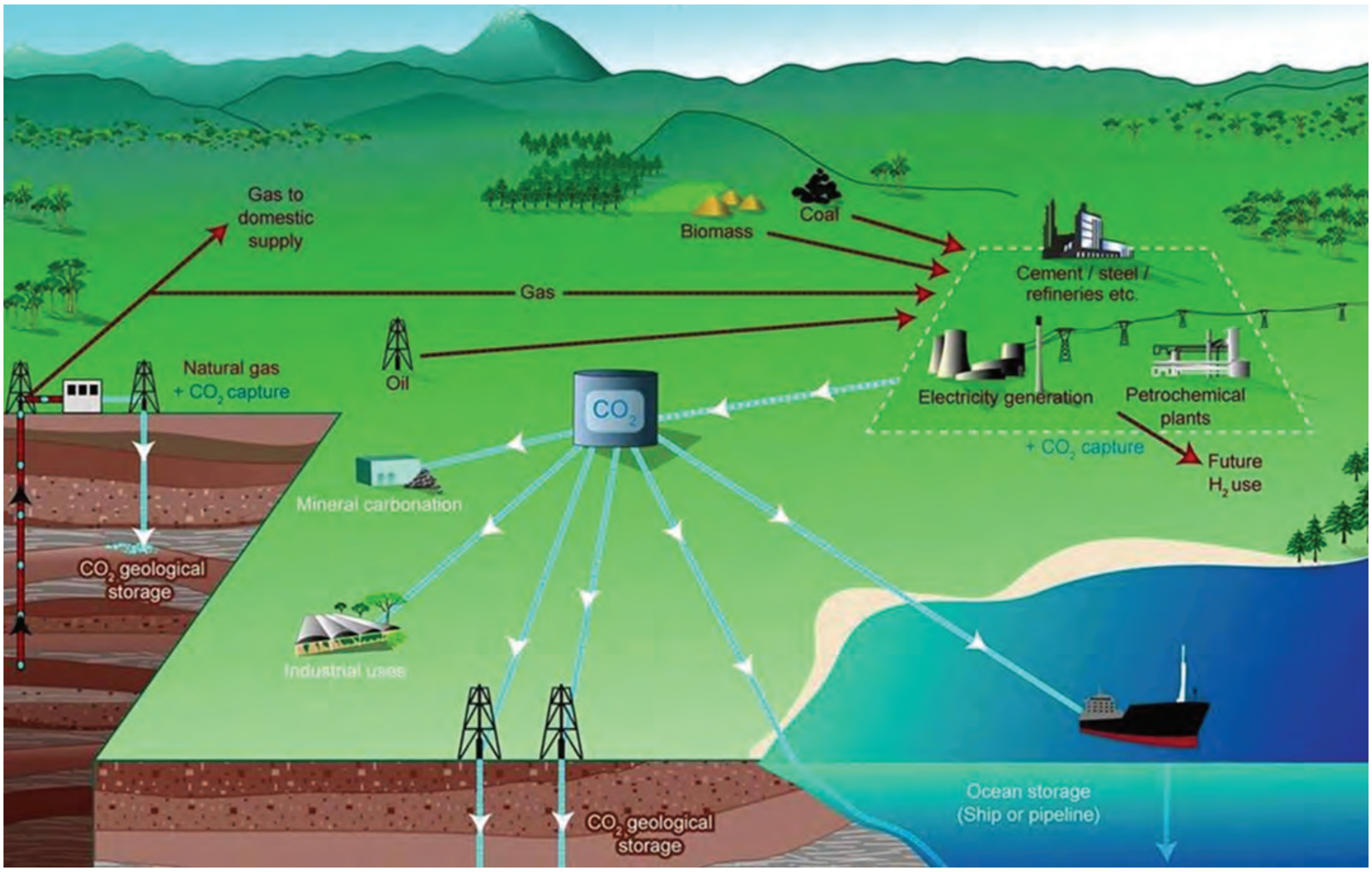

Figure 13.2 | Schematic of a fossil fuel-based energy system using carbon capture and storage to reduce CO_2 emissions. The red lines in the figure illustrate the extraction of oil, gas, and coal from natural resources and transport to facilities used for power generation, refining, and industrial applications. Carbon dioxide capture is integrated with the facilities for burning fossil fuels. After the CO_2 is captured, it is compressed to a dense gas, or more typically a liquid. From the compressor, CO_2 is put into pipelines for transport as shown by the blue lines. The CO_2 is transported to the storage sites, whereas shown, it could be injected into deep underground geological formations, converted to minerals, used to increase biological productivity in greenhouse and algae, or perhaps injected into the deep ocean. With today's technology, storage in deep geological formations is the most advanced of these storage options and could be applied on the scale needed to significantly reduce emissions. Source: IPCC, 2005.

facilities and other industrial operations that demand highly reliable performance is fraught with technological challenges, on top of the large capital investment and significant operating costs required for CO_2 capture. Moreover, with today's capture technology, from 10 to 30% of the output of the power plant may be consumed by the capture unit, depending on the capture technology, the vintage and type of power plant, and the degree of systems integration. Advances not only in capture technology, but ongoing improvements in the efficiency of power generation will be needed to offset the energy penalty for CO_2 capture.

An enormous effort is now devoted to advancing this technology with over 234 active or planned projects (GCCSI, 2011a). While many of these are small-scale pilot projects, 77 are large-scale integrated projects in various stages of the asset life cycle, nine large-scale projects are operating with two more under construction, and an additional 65 potential projects are at various stages of planning (GCCSI, 2011a). The vast majority of these projects have not yet made a final investment decision to go ahead with the construction and operation phases of these projects. Consequently, it is far too early to tell what will be the outcome of the large amount of activity in this area. As of April 2010, this represented US$26 billion of government investment.

Today, five CCS projects capture 0.5–2 $MtCO_2$/yr from industrial sources and store it in deep geological formations and have been operating for years to a decade or more, demonstrating that, at least on this limited scale, CCS can be safe and effective for reducing emissions. For four of these projects, CO_2 is captured from natural gas cleanup operations while in the fifth, CO_2 is captured from a coal to synthetic natural gas plant. Relevant experience from nearly 40 years of CO_2 enhanced oil recovery (EOR) also shows that CO_2 can safely be injected underground. While most of the CO_2 used for EOR is from natural CO_2 reservoirs, a small fraction is produced from industrial sources such as natural gas cleanup, hydrogen production, and ammonia production. A five- to ten-fold scale-up in the size of individual projects would be needed to capture and store emissions from a single large coal-fired power plant (e.g. current CCS projects store about 1 Mt/yr, while a 500–1000 MW power plant with capture would need to store from 5–10 $MtCO_2$/yr). Globally, a thousand-fold scale-up from current CCS operations would be needed to achieve a contribution to emissions reductions on the order of 20% of current fossil fuel derived emissions over the next century (IEA, 2008a).

13.1.2 The Potential Role of CCS in Climate Change Mitigation

The goal of CCS is to reduce CO_2 emissions from large stationary sources such as power generation, natural gas processing, hydrogen (H_2) production from coal or gas, cement manufacturing, or steel making. Considering full life cycle emissions, using CCS technology on an individual facility can reduce about 65–85% of CO_2 emissions from fossil fuel, although greater reductions may be possible if low emission technologies are applied to activities beyond the plant boundary, such as fuel transportation. In reality, the optimal degree of emission reduction will depend on the tradeoffs between the amount of emission reduction and the cost of capture and age of the facility on which it is deployed. Partial capture may in some cases be more advantageous than striving for the largest emissions reductions possible from a particular facility. For example, a low cost and widely deployed retrofit technology that captures 50% of the emissions from existing coal-fired power plants in China may be one of the most cost effective ways for near-term emission reductions. On the other hand, for a newly built power plant with integrated capture, emissions reductions of 90% may be preferable.

Worldwide assessments suggest that under a range of stabilization scenarios, the contribution of CCS is anticipated to be about 20% of needed emission reductions over the next century, on par with the contributions from renewable energy supplies and end-use efficiency gains (IPCC, 2005; 2007; IEA, 2008c). While the early focus of CCS has been on reducing emissions from coal and natural gas electricity generation, it is estimated that by 2050 about 2–3 $GtCO_2$/yr from industrial sources will need to be captured and stored (IEA, 2009). In the future, CCS may also contribute significantly to emission reductions from the transportation sector via hydrogen production and use for light- and heavy-duty vehicles, electrification of vehicles, production of synthetic fuels using captured CO_2, or the manufacturing of other products such as cement or polymers from captured CO_2 (see also Chapter 12). The importance of CCS will vary by region, depending on the mix of primary energy supply and storage options. Key determinants of the extent to which CCS is likely to be deployed include:

- capacity for storage in appropriate sites in suitable geological formations;
- policy frameworks to encourage emissions reductions, likely to include incentives for early deployments for capacity building;
- lack of lower cost opportunities for reducing emissions such as the increased use of renewable energy resources or nuclear power;
- pace of technological progress to lower the cost and increase confidence in the safety and permanence of geological storage;
- interest in widespread deployment of CO_2-EOR;
- public acceptance of CCS in the local communities where projects are deployed; and
- access to the large capital investment needed for CCS projects, on the order of several billion US$ for a 500 MW power generation plant, particularly for first-of-a-kind facilities (Al-Juaied and Whitmore, 2009; US DOE, 2010).

Today it is difficult to predict the extent to which CCS will be deployed, given the rapidly evolving energy technology and policy landscape.

In the long run, CCS combined with biomass gasification/combustion could be used to create net negative emissions. Net negative emissions are possible when CO_2 is captured from the atmosphere by plants and then used as an energy source with CCS. However, the extent to which this is possible will depend on a number of factors, which are described below (see Section 12.2.3.2 for additional discussion).

Co-location of Geological Storage Opportunities, Energy Services Demands, and Woody Biomass Resources: Rock formations suitable for geological storage are not distributed equally around the world. Additionally, pipeline transportation of CO_2 over distances longer than several hundred kilometers can become costly and impractical, especially in urbanized areas. A quantitative assessment of the co-location of biomass resources, sequestration capacity, and electricity/heat demand is needed to provide a realistic assessment of negative emissions potential.

Flue Gas Composition from Biomass Combustion: Technology options, energy requirements, and cost for capture depend on flue gas composition, which could range from about 15% CO_2 for fully combusted biomass to less than 5% for partially oxidized biomass. Alternatively, combustion in pure oxygen could be used to achieve very high concentrations of CO_2 that would need little post-combustion processing, but this would come at the cost of reduced efficiency caused by the energy needed to separate oxygen from air. A systematic study to evaluate technology options, energy requirements, and cost of capture of CO_2 from woody biomass is needed – with an overlay of the practicality of various technology options depending on the scale of the woody biomass resource, technology access in different parts of the world, and desired balance between CO_2 and biochar production.

Scalability of Negative Emissions from Capture and Storage of Woody Biomass: Today's paradigm for the capture and storage of CO_2 emissions is based on deployment at very large central station facilities (greater than 1 $MtCO_2$/yr emissions). CCS is a complex technological endeavor embedded in a policy framework regulated by numerous local, national, and potentially international laws. Depending on the size and continued availability of these biomass resources, this large-scale approach to deployment using stationary facilities may not be appropriate. The technological and socioeconomic requirements for scaling down this technology and operating storage facilities in a far more distributed manner must be assessed.

13.1.3 Consequences of Excluding CCS from the Mitigation Portfolio

The consequences of excluding CCS from the emission reduction options fall into three broad categories.

First, the cost of the overall emission reduction actions will be greater if CCS is excluded. Integrated assessment studies indicate that the overall cost of cutting emissions will be significantly higher if CCS technology is not included in the portfolio of emissions reductions opportunities (e.g., EPRI, 2008; IEA, 2008c).

Second, sufficiently large emissions reductions may not be possible without CCS. Maintaining a reliable supply of electricity that meets needs for both base-load and peak-load power may not be possible in the 2050 timeframe without CCS. Renewable energy sources are intermittent and of limited geographic distribution. Firming these supplies either by having large-scale energy storage or an extremely extensive electrical grid and needed storage may not be practical in the 2050 timeframe. Additionally, while rapid advances in demand-side energy management are promising, the extent to which these can be aggregated and used to balance supply and demand remain unproven. Nuclear power may provide more of the energy services currently provided by fossil fuels, but to displace them entirely may require an unrealistically rapid scale-up of the nuclear power industry. Additionally, nuclear power plants are not well suited to providing the variable, low-load factor generation currently provided by fossil fuel plants.

Third, political support for reducing emissions may not be sufficient if CCS is excluded from the portfolio of emission reduction options. In many parts of the world, including China, North America, and the Middle East, coal and natural gas provide the major source of electricity. Emission mitigation strategies that do not enable continued use of these domestic and plentiful resources are likely to meet with insurmountable political opposition. Furthermore, some geographic areas lack alternative options for providing reasonably priced electricity with lower emissions. Hence, CCS would be favored under these conditions. Excluding CCS as an option would hinder international negotiations seeking global solutions to the climate change problem.

13.1.4 Key Conditions for CCS to Contribute to Climate Change Mitigation

There are a number of conditions that must be met if CCS is to contribute to climate change mitigation at a significant scale. First, if CCS is implemented as a major part of this transformation, large volumes of CO_2 will need to be captured and stored, on the order of several Gt/yr, with cumulative totals over the next century on the order of hundreds to thousands of Gt. The pathways described in Chapter 17 indicate that a maximum of 400 Gt of CO_2 storage will be needed over the range of decarbonization pathways examined. In addition, these pathways indicate this will require large storage capacities broadly distributed over the globe within several hundred kilometers of large emission sources. Second, unless the technology reaches maturity sometime in the next several decades and wide-scale deployment begins shortly thereafter, other options for reducing emissions may emerge and displace CCS in the carbon mitigation portfolio. Technical maturity will require demonstrating that:

- CCS is a cost-competitive way to reduce emissions;
- storage sites can be selected effectively and managed during and after operations are complete;
- populations living near storage sites feel safe and that storage does not unreasonably compromise property values;
- policies are established to reduce emissions;
- regulations are developed and effectively implemented for managing a CCS project over its entire life cycle, including the post-injection period where long-term stewardship of stored CO_2 is required; and
- methods are available for integrating power generation with CCS in the evolving electricity generation, transmission, and distribution system.

All of these issues are addressed in the following sections.

13.2 Carbon Dioxide Capture and Compression Technology

The objective of this section is to present a brief status of CO_2 capture (separation) and compression technology, focusing on the updates since the *IPCC Special Report on Carbon Dioxide Capture and Storage* (IPCC, 2005). This includes CO_2 capture for energy-intensive industrial applications and electricity production with fossil fuel and biomass feedstocks. The focus is on the new developments in the three CO_2 capture technology process options (pre-combustion, post-combustion, and oxyfuel combustion), as well as CO_2 compression technology.

Costs of CCS are addressed by first developing CO_2 avoidance costs (see Section 13.5.2.1 for a precise definition of CO_2 avoidance cost) for both new and existing coal power plant baselines. The CO_2 avoidance costs are then applied as a CO_2 tax to determine the "triple-point" where product cost (i.e., electricity) is the same for coal with and without CCS and natural gas combined cycle (NGCC) without CCS based on varying the price of natural gas (NG). Learning curves and prospects for technology improvements to reduce CCS costs are also addressed.

In the seven years since the *IPCC Special Report on Carbon Dioxide Capture and Storage* there have been significant technology developments in CO_2 capture and transport. This brief section is an update of only the CO_2 capture technology and costs. A brief description of next-generation capture research and development is also provided in Section 13.3.2.9.

13.2.1 Applications and Feedstocks for CO_2 Capture

The greatest focus of CCS is on coal-based electric power generation. This focus is logical because close to 40% of total human-made fossil fuel CO_2 emissions are from this one application and feedstock. Coal-based power plants also dominate the lists as the biggest stationary CO_2 point sources. Nevertheless, there are other applications and feedstocks for CCS. For example, all of the large commercial-scale CCS projects currently in operation are for industrial applications such as natural gas clean-up, biofuels production, and production of synthetic natural gas from coal. Only one of the five commercial scale projects operating today uses coal.

13.2.1.1 Industrial CO_2 Capture

Examples of CCS projects of approximately 1 Mt/yr or greater of CO_2 storage that have been successfully operated for over five years (listed from the oldest) include:

- Statoil's Sliepner offshore gas platform in the North Sea between Scotland and Norway, with CO_2 from associated natural gas purification injected into an undersea deep saline formation;
- Dakota Gasification in North Dakota, United States, with brown coal (lignite) gasification via synthetic natural gas (SNG) purification into a CO_2 pipeline to Weyburn, Saskatchewan, Canada, for use in enhanced oil recovery (CO_2-EOR);
- ExxonMobil's LaBarge facility in Wyoming, United States, with CO_2 from natural gas purification into a CO_2 pipeline for CO_2-EOR in the Powder River Basin of Wyoming;
- BP's In Salah facility in Algeria, with CO_2 from natural gas purification with injection into the same formation, but at a distance from the production well; and
- Statoil's Snøhvit Project, which sequesters CO_2 from a liquefied natural gas facility in a saline formation underneath the Barents Sea.

Most of these successful commercial-scale CCS projects have the economic advantage of producing a large pure CO_2 vent from raw natural gas purification. Natural gas produced from these fields contains from about 2% to over 15% CO_2 or more. Carbon dioxide removal or capture is required to meet natural gas pipeline energy content specifications, regardless of the CO_2 mitigation issue. CO_2-EOR projects have the added economic advantage of a small market value credit for the CO_2 after its compression and CO_2 pipeline delivery expenses to nearby oil fields (EPRI, 1999). Thus, the overall costs of these CCS projects have significantly lower CCS costs than those discussed later in this section.

There has been some debate about whether CO_2 used for EOR should be considered as CO_2 storage. While the amount remaining underground varies from place to place and well to well, about 50% of the injected CO_2 never returns to the surface (Stevens et al., 2003). Moreover, in almost all cases, the CO_2 produced with the oil is separated and injected back into the reservoir, primarily because it is a valuable commodity and avoids the need to purchase more CO_2. Beyond this, some argue that the CO_2 emitted into the atmosphere when the oil is used negates the benefits of storage. However, at least on the margin, if this CO_2 was not geologically stored in EOR, the alternative replacement oil from other sources would not have reduced the CO_2 in the atmosphere at all. In the United States, where most of the CO_2-EOR is carried out, CO_2 utilization credits for EOR are only about US$10/t (or US$0.53 per thousand standard cubic foot (scf) in common EOR terms). That is significantly less than the total cost of CCS unless the CO_2 is being captured regardless of the CO_2 mitigation issue.

There are several important industrial applications that produce large, nearly pure CO_2 vents. These include raw natural gas and synthesis gas (H_2 and CO from gasification) purification, plus the production of high-value products like ammonia and sometimes other synthesis gas products such as hydrogen, synthetic natural gas (SNG), coal-to-liquids, or methanol. It should be noted that most hydrogen is made from natural gas via steam methane reforming (SMR), which normally does not produce a pure CO_2 stream (Shah et al., 2006). However, hydrogen made from heavy oil, petcoke, or coal via gasification does produce large, pure CO_2 streams.

Industries with moderately large point sources of CO_2 include cement kilns, iron/steel making, oil refining, and bulk chemicals. Large industrial CO_2 point sources have typically less than 1 $MtCO_2$/yr. These CO_2 sources for CCS are relatively small compared to the big coal power plants. Nevertheless, the pure industrial CO_2 vent sources for CCS should not be overlooked due to their lower CCS costs. Nations, such as China with over 65 coal gasification plants and 20 GWt of synthesis gas capacity for ammonia, methanol, and hydrogen, have these pure CO_2 vents for lower cost CCS (Simbeck, 2009a).

13.2.1.2 Electric Power Generation

As already discussed, electric power generation and large industrial operations are the focus of CCS efforts due to their large overall CO_2 emissions and large point sources. Typical central coal power plants (resulting in 40% of total worldwide fossil fuel CO_2 emissions) emit 0.8–1.0 tCO_2/TWh of net electricity generated. A 1000 MWe coal power plant at a 75% annual load factor emits about 6 $MtCO_2$/yr. An equivalent baseload 1000 MWe NGCC power plant emits about 3 $MtCO_2$/yr. There are very few industrial point sources that match the size of fossil fuel power plants.

Fossil fuel power plants in wealthy nations are the most susceptible to CO_2 reduction mandates and thus CCS may be strategic to their future CO_2 mitigation options. Furthermore, unlike other energy-intensive industries, with few exceptions, power plants cannot move to nations with fewer CO_2 restrictions. CO_2 taxes on energy-intensive industries are only effective if the imported products are taxed based on their manufacturing and shipping direct and indirect CO_2 emissions (Davis and Caldeira, 2010). Otherwise, the movement of industries to countries with fewer CO_2 restrictions would hurt the economies of countries with high CO_2 restrictions while failing to reduce total world CO_2 emissions.

13.2.1.3 CCS Feedstocks

Feedstocks for CCS reflect the industry, applications, and fuel availability. More importantly, CCS also requires large point sources located near good geologic CO_2 storage sites. This key issue favors large coal uses for CCS, which are dominated by central coal-fired power plants but also large coal-based integrated steel mills and cement kilns.

Most industries are natural gas-based, except for nations where it is not readily available, such as China, where coal is widely used by energy-intensive industries. Industrial natural gas applications tend to be relatively small CO_2 point sources, thus generally not attractive for potential CCS. Industrial exceptions are the large oil refineries, cement kilns, and iron/steel making and ethanol fermentation facilities.

Oil refinery CO_2 emissions are generally from processing raw crude oil into usable oil products. The heavier the crude oil feed and the lighter the products, the higher the CO_2 emissions. If available, oil refineries prefer using natural gas for hydrogen production and fuel gas, thus reducing the need for more expensive oil for their internal use. CO_2 emissions from the process of oil refining are only about 9% of the carbon in the raw crude oil feed. Also, the extensive use of residual oil coking for heavy oil conversion avoids a significant amount of CO_2 emissions by oil refiners. Most CO_2 emissions from crude oil are emitted by the end user of the oil refinery products, both premium distillate fuels and low-value petcoke. Emissions from the end user of petroleum products are widely distributed and are often from small and mobile sources such as cars, trucks, and airplanes, which are, of course, difficult to capture.

Cement kilns are large CO_2 producers due to both the fuel requirement and the conversion of limestone to lime. It should be noted that cement kilns have the highest CO_2 emissions per unit value (or per million dollars) of product. Cement kilns are also ideal for the utilization of waste fuels. If waste fuels are not available, coal or petcoke are commonly used.

Integrated steel mills are traditionally coal-based and make mostly virgin iron from iron ore via coke ovens and blast furnaces. This should not be confused with mini-mills recycling scrap steel via electric furnaces. Integrated steel mills have very high CO_2 emissions per unit value of product. Mini-mills have much lower overall energy use, and most of their CO_2 emissions are indirect, e.g., located at the electric generation facilities.

A potentially interesting and often overlooked CCS CO_2 source could be the high purity CO_2 vent of ethanol fermentation from biomass (US DOE, 2010). Ethanol plants are extensive and growing for gasoline replacement in the United States and Brazil due to government mandates and subsidies. Currently, US ethanol production is about 54.27 billion liters/yr (13.3 billion gallons/year) and almost all of it comes from corn fermentation. The high purity CO_2 vented from corn ethanol fermentation in the United States alone is about 30 Mt/yr. However, a challenge is the small size of the CO_2 ethanol fermentation vents. With about 150 ethanol plants operating in the United States, the average point source is about 0.2 $MtCO_2$/yr per plant. Nevertheless, many of these US corn ethanol facilities are concentrated in the corn belt of the upper Midwest, from Indiana to eastern South Dakota, with the major capacity located in Iowa, Illinois, and Nebraska.

Electric power generation is traditionally focused on coal feedstocks for "baseload" (60–80% annual load factor) power generation due to its low and stable fuel costs (US EIA, 2009). Natural gas is more commonly utilized for cycling and peaking power generation unless the local grid does not have enough coal or nuclear available for baseload. The demand for natural gas-based cycling and peaking generation increases with mandates for more intermittent wind and solar renewable power. Therefore, CCS for electric power generation logically focuses first on coal-based power. However, this could change in the future due to the heightened interest in natural gas-based power. If stable long-term supplies of lower natural gas prices are available, and gas is used in high-efficiency cogeneration (COGEN) or baseload power with high annual load factors, natural gas power generation may become the focus of CCS.

The focus on large coal power plants for CCS creates an interesting longer-term opportunity for biomass, as discussed in Section 13.1.2 and Chapter 12. The CCS infrastructure would likely begin with coal due to its low delivered fuel cost. However, as CO_2 avoidance values grow, the economics begin to favor blending waste biomass (whenever available) with coal to increase CO_2 reductions using biomass with CCS.

13.2.2 CO_2 Capture Status

CCS has several important decision steps and process choices. The following discussion simply and briefly explains these choices so the CO_2 capture and compression technology status can be discussed.

13.2.3 The Basics of CO_2 Capture

CCS requires large CO_2 stationary point sources within reasonable distances of good geologic storage locations. CO_2 can be from an existing source considering CO_2 capture retrofit or rebuild or from a potential new CO_2 source. It should be noted that a new CO_2 source adding CCS would only avoid increasing CO_2 emissions unless it were based on biomass or if it displaced an existing source without CCS. CO_2 emissions reductions based on fossil fuels require existing CO_2 sources to have retrofits, rebuilds, or new unit replacements, all with CCS.

Existing CO_2 sources adding CCS are subject to net capacity and efficiency losses (Simbeck and Roekpooritat, 2009a; 2009b). It may be useful to also consider rebuilding existing CO_2 sources for CCS to avoid efficiency losses, particularly in the case of older, inefficient coal plants. Rebuilding old power plants increases the total capital but can also avoid the net capacity and efficiency losses of adding CCS (relative to the older existing power plant). Existing CO_2 sources may also consider moving new replacement units with CCS to be co-located with CO_2 storage sites, thus avoiding CO_2 pipeline costs and permitting issues at the expense of permitting and the capital outlay of an entire new replacement plant.

The first step of CO_2 concentration, recovery, or capture to a high purity CO_2 stream is the most expensive and has the most options. This step is normally subdivided into three general process options (IPCC, 2005):

- pre-combustion,
- post-combustion, and
- oxyfuel combustion.

A schematic illustrating the major process steps and material flows for each of these options is provided in Figure 13.3. The choice of CO_2 capture process is complicated by the many different process technologies being developed as well as their state of their development.

13.2.3.1 CO_2 Capture and Storage Ready

The concept of making plants "CO_2 capture and storage ready" is to enable plants to be retrofitted with CCS when the necessary economic and policy drivers are in place, which in most countries currently are not. The term "CO_2 capture and storage ready" means different things to different people. The Global Carbon Capture and Storage Institute (GCCSI), in collaboration with the International Energy Agency (IEA) and Carbon Sequestration Leadership Forum (CSLF), has produced a definition of CCS ready (GCCSI, 2010), which states that in order for a facility to be considered capture and storage ready the project developer should:

- carry out a site-specific study in sufficient detail to ensure that the facility is technically capable of being fully retrofitted with CO_2 capture using one or more choices of technology that are proven or whose performance can be reliably estimated as being suitable;
- demonstrate that retrofitted capture equipment can be connected to the existing equipment effectively and without an excessive outage period and there will be sufficient space to construct and safely operate additional capture and compression facilities;
- identify realistic pipeline or other routes to storage of CO_2;
- identify one or more potential storage areas that have been appropriately assessed, and found suitable for safe geological storage of the projected full lifetime volumes and rates of captured CO_2;

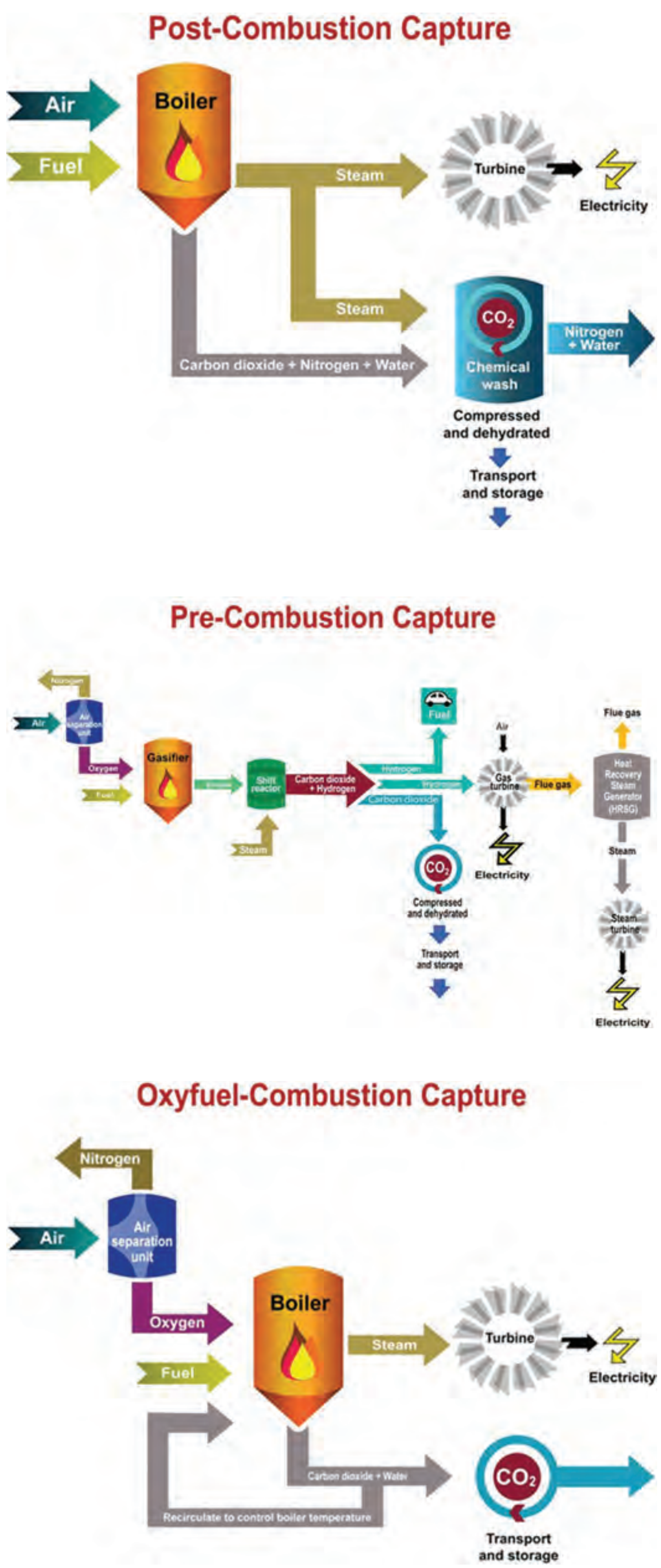

Figure 13.3a-c | Schematic showing the major steps and materials flows associated with the (a) post-combustion capture, (b) pre-combustion capture, and (c) oxy-combustion. Source: courtesy of ZEP, 2011.

- identify other known factors that could prevent the installation and operation of CCS and identify credible ways in which they could be overcome;
- estimate the likely costs of retrofitting CCS;
- engage in appropriate public engagement and consideration of health, safety, and environmental issues; and
- review CCS status and report on it periodically.

A much more dubious meaning of "CO_2 capture ready" is that processes or plants simply claim that space has been left for the addition of retrofitting CO_2 capture at a later date. This usually occurs for new natural gas or coal power plants. In these cases, there is no large pure CO_2 vent, just a normal natural gas or coal power plant with some extra space. However, once the investment is made, the economics of CCS greatly change. Sunk capital cost (paid-off or not) power plants that are considering adding CCS require much higher CO_2 avoidance costs in order to economically justify adding retrofit CCS than if the investment had been made before the original large power plant was built. This is shown in the later cost sections.

Additionally, the concept of "CCS ready" applies to processes or plants removing (capturing) CO_2 in their normal operation and venting it as a large, high-purity CO_2 stream. These sources provide good opportunities for low-cost CCS when compression and storage are added to the existing operations. Examples include most industrial synthesis gas gasification plants, some natural gas-based hydrogen plants, and some natural gas purification plants that remove high concentrations of CO_2.

13.2.4 Tracking Real and Proposed CCS Developments

There are numerous groups and organizations developing and promoting potential CCS technologies as well as bench scale research and development (R&D), pilot, demonstration, and commercial-scale projects. These include governments (at all levels), national laboratories, academics, and private organizations ranging for one-person government grant recipients to venture capital start-ups to major international corporations. A recent report by GCCSI lists hundreds of organizations working on CCS (GCCSI, 2009a).

Keeping up-to-date with the many developments and promotions of CCS projects is very time-consuming. Nevertheless, there are some excellent websites and organizations that are tracking the real and numerous proposed CCS projects. Some of these organizations are also attempting to document worldwide CO_2 point sources for potential CCS, as well as potential geologic CO_2 storage locations.

Some of the organizations tracking real and proposed CCS developments include:

- Bellona: www.bellona.org/ccs
- IEA GHG R&D: www.ieaghg.org
- MIT: sequestration.mit.edu/index.html
- NETL: www.netl.doe.gov/technologies/carbon_seq/global/database/index.html
- Scottish CCS: www.geos.ed.ac.uk/sccs/

In addition to the numerous government organizations funding CCS technologies and R&D, there are some important joint ventures and institutes actively involved in CCS:

- CO_2 Capture Project (CCP): www.co2captureproject.org
- Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC): www.co2crc.com.au
- Electric Power Research Institute: www.epri.com
- Global CCS Institute (GCCSI): www.globalccsinstitute.com
- Global Climate & Energy Project (GCEP): gcep.stanford.edu
- Zero Emissions Platform: www.zeroemissionsplatform.eu

13.2.4.1 Pre-combustion – Industrial

Pre-combustion CO_2 capture has the most commercial experience. However, all of this large-scale use has been in industrial applications, and not in electric power generation. All five of the large successful CCS projects discussed in the application subsection involve pre-combustion CO_2 capture in industrial oil and gas applications.

There are natural gas purification- and gasification-based synthesis gas (H_2 + CO) purification plants that remove (or capture) CO_2 at amounts greater than 1 Mt/yr. However, that high purity CO_2 is normally just vented. The CO_2 is simply removed to meet product gas (usually natural gas or H_2) specifications. The feed gas is at high pressure without any oxygen, making the CO_2 capture relatively easy. This CO_2 removal or capture is usually accomplished by scrubbing the high-pressure feed gas and then, with low-pressure steam use, stripping the CO_2 from highly loaded tertiary amine chemical solvents, or just high-pressure drop flashing the CO_2 from highly loaded physical solvents for even lower energy requirements.

Of the 50 GWt (synthesis gas) capacity of operating gasification plants around the world, most include large CO_2 capture. The exception is the 8 GWt of synthesis gas converted into 4 GWe of IGCC electric generation. This industrial CO_2 capture is due to the raw synthesis gas having a lower H_2/CO ratio, whereas the higher value uses are for a high H_2/CO ratio such as for hydrogen, ammonia, and methanol production. Therefore, H_2O is added to the CO-rich synthesis gas that reacts over catalysis into H_2 and CO_2 and the CO_2 is then removed. Examples of industrial gasification plants with pure CO_2 vents with CCS include the Dakota Gasification SNG plant in the United States, the Shell Oil Pernis refinery in the Netherlands, and the Shenhua Group coal liquefaction plant in China (CO_2 from the Shell coal gasifiers supplying the hydrogen). The Shenhua Group CCS plant is a smaller first stage demonstration of only 0.1 $MtCO_2$/yr, and it is still under construction. However, it will be the first CCS plant operating in China in 2011, and it may be expanded to a 3 Mt/yr CCS operation.

There has also been prior extensive experience with the combustion of H_2-rich fuel gas in oil refineries when there was excess hydrogen used as a fuel in refinery gas. However, this experience is for older and smaller gas turbines operating at relatively low firing temperatures, and it is only useful today for COGEN when the low gas turbine firing temperature does not hurt the overall efficiency.

Pre-combustion industrial CCS development tends to get much less publicity than electric generation. Nevertheless, industrial CCS costs can be much lower if the industrial process makes a large, pure CO_2 vent regardless of the CO_2 mitigation issue. This is commonly the case for the production of hydrogen (via gasification), ammonia, synthesis gas (for chemicals), and natural gas (when significant amounts of CO_2 are in the raw natural gas).

There is increasing interest in developing hydrogen units for oil refineries via steam-methane reforming (SMR) of natural gas that produce a pure CO_2 vent, as is already the case when making hydrogen via the gasification of heavy feedstocks. Most modern SMR units do not make a pure CO_2 vent because of the use of high-pressure swing absorbers (PSA). With the improvement of natural gas supplies and increase in hydrogen demand due to upcoming heavy fuel oil upgrading and desulfurization mandates for maritime fuel, an SMR unit with a pure CO_2 vent could be an excellent opportunity for low-cost CCS.

Research on vacuum pressure swing absorbers (VPSA), along with staged PSAs by the major industrial gas companies for integration into SMR to produce a pure CO_2 vent, is underway. Interestingly, this is already commercially applicable but not for SMR hydrogen units. A Linde VPSA system is used for synthesis gas recycle purification as part of a Corex/Midrex iron making unit in South Africa (Linde, 2009). However, VPSAs would have about half of the total SMR CO_2 emissions unless a portion of the product H_2 is used to fire the reforming furnace, which would greatly increase the overall cost. There are also commercially proven heat exchange reformers by several vendors that recover all of the CO_2 as a pure vent in making H_2 from natural gas. However, these designs require oxygen, whereas traditional SMR does not.

ExxonMobil is developing a cryogenic process for removing CO_2 from high pressure raw natural gas that is high in CO_2. It is called the Controlled Freeze Zone process and it is being demonstrated in a US$100 million unit at its LaBarge NG facility in Wyoming, United States (Mart, 2009). One of the advantages of this process is the production of liquid CO_2 at pressure, thus greatly reducing the CO_2 compression costs for CCS.

Due to high CO_2 emissions from iron/steel production, there is increased interest in advanced iron making processes that produce CO_2 in a pure stream for potential CCS. An option is to convert the air-blown blast furnaces to an oxygen-blown operation (plus adding CO_2/CO top gas for recycle). More advanced options are the utilization, integration, or advanced versions of synthesis gas-based direct reduced iron (DRI) processes, such as Corex or Midrex (ULCOS, 2008). The synthesis gas conversion pre-pass over the iron ore is low, and thus the top gas is recycled after removal of H_2O and CO_2 (products of iron oxide reduction to iron). As mentioned above, this is already commercially done with VPSA on a Corex/Midrex plant in South Africa. In addition, several coal-based DRI steel mills are under construction in India. The mills are based on separate coal gasification that will increase the H_2/CO ratio before feeding into the Midrex DRI units; thus, a second large pure CO_2 vent is produced (Jindal, 2009).

The ammonia solvent CCS process is usually associated with post-combustion CO_2 capture. However, it has some of the same benefits for use in pre-combustion CO_2 capture of stripping at pressure to reduce CO_2 compression costs. It has the added benefits of high solvent loading, fewer side reactions, no refrigeration, and fewer ammonia leakage issues when operated on high-pressure synthesis gas. Testing is currently being done at SRI International for application with SNG for coal with CCS.

13.2.4.2 Pre-combustion – Electric Generation (See also Chapter 12)

Pre-combustion CO_2 capture in electric generation is mostly focused on coal via integrated gasification combined cycle (IGCC) and not for NGCC. NGCC CO_2 capture is more focused on post-combustion CCS, as this avoids major modification to the standard NGCC design. Plus, the CO_2 capture can be by-passed when needed for additional peaking power.

Even before the CO_2 capture issue, the electric power industry had been slow to accept the IGCC option relative to conventional direct combustion pulverized coal (PC) boiler steam systems. This was due to the high capital cost, low availability plus complex chemical processing, and the integration requirements of IGCC. There is also an ongoing debate about the lack of expertise in the electric power industry because gasification is a very complex chemical process. There was a similar slow acceptance and learning curve by electric generators of wet limestone scrubber flue gas desulfurization and selective catalysis reduction nitrogen oxide (NO_x) controls, which are very simple chemical processes.

The addition of CO_2 capture to pre-combustion IGCC has some challenges. First, the hot raw synthesis gas cooling heat recovery is lost due to the large excess steam (H_2O) requirements of the CO conversion to H_2 and CO_2. More important are the special challenges of firing H_2-rich gas in high temperature gas turbines. This is generally due to the negative impact of the much higher heat transfer coefficient of H_2O vapor (after combustion of the H_2-rich fuel) on the critical hot gas path metal parts associated with the hottest initial stages of the gas turbine exhaust gas expansion. The options for addressing this issue include: reducing the firing temperature (lower capacity and efficiency) or shorter hot gas path metal parts life (i.e., higher maintenance), adding large amounts of high pressure nitrogen to the H_2 fuel (reducing net efficiency or most expensive air-blown gasification), or developing a special and challenging gas turbine pre-mix air and H_2 combustor. Reducing the firing temperature would be the worst choice, unless utilized in the industrial COGEN of combined heat and power (CHP).

Perhaps the biggest challenge facing pre-combustion CCS is the high capital cost of the few IGCC projects actually being built at this time. For example, the latest capital cost of Duke Energy's Edwardsport, Indiana IGCC project (currently under construction) has increased to US$3.3 billion for 618 MWe (net), or US$5593/kW, with no capture and storage. However, this very high capital cost does include "as spent" current and future dollars, some infrastructure for a potential second unit, allowance for funds during construction, and other owners' costs. While this high unit capital cost is reducing interest in IGCC, at the same time it is going unnoticed that the few conventional coal boiler power plants under construction in the United States have unit capital costs almost as high. A good example is Duke Energy's Cliffside project in North Carolina, at a cost of about US$3000/kW with no capture or storage. The few US nuclear plants currently under construction have also increased to significantly higher unit capital costs.

The positive activity in pre-combustion CO_2 capture for electricity is associated with increasing competition and innovative designs. This is likely a result of the many studies showing the incremental costs plus net power and efficiency losses of converting IGCC to CCS as being lower than for post- and oxyfuel combustion (US DOE, 2007; EPRI, 2008). However, the issue is higher power plant costs and the lower availability of IGCC compared to more commercially proven PC boilers before considering CCS.

There are more than 10 IGCC with CCS projects being promoted based on at least six different coal gasification technologies. Also, many pre-combustion power projects are being proposed by independent power producers (IPP), some having innovative designs based on "polygeneration" versus just stand-alone central power plant IGCC. The use of high H_2/CO ratio synthesis gas with CCS for various high-value products such as hydrogen, SNG, methanol, olefins, and plastics, as well as COGEN CHP, is involved. As previously explained, COGEN avoids the added challenges and costs of high-temperature gas turbine-fired H_2-rich fuel gas while also greatly increasing overall efficiency and reducing water demands (Simbeck, 2009a; 2009b). The combination of this added competition, especially from the more aggressive and innovative IPPs, will reduce overall costs and improve performance. In fact, the key potential advantage of pre-combustion CO_2 capture for electricity is that hydrogen has more uses and flexibility than just steam from boilers.

13.2.4.3 Post-combustion – Industrial

Globally, there are over 2500 industrial sources with CO_2 emissions over 0.1 Mt/yr. These emissions sources tend to be smaller than for coal-fired power generating stations, averaging about 1 Mt/yr (IPCC, 2005). Carbon dioxide concentrations in flue gas vary widely, from 7–10% for gas-fired boilers to 14–33% for cement kilns (IPCC, 2005). Post-combustion CCS for industry has been successfully demonstrated at a relatively small scale. The largest operating unit is only about 0.1 Mt/yr. There are few commercial post-combustion CO_2 capture (without special circumstances) units but MHI (Mitsubishi Heavy Industries) has for example built around 10 of the largest units, which handle flue gas from NG-SMR ammonia plant reforming furnaces to capture CO_2 to make urea from the ammonia.

The low pressure and low CO_2 concentration in flue gas after combustion requires large absorbers, high CO_2 removal solvent circulation rates, and high stripping steam use. The presence of oxygen in flue gas also eliminates many potential solvents and leads to a small amount of waste from the reaction with the solvents. However, for boiler systems it is possible to add flue gas catalysis combustion via the use of a small amount of NG to consume the few percent of oxygen in the flue gas and then use better solvents. This was commercially done in the early days of CO_2 EOR before large CO_2 pipeline sources of cheaper CO_2 became available.

Perhaps the greatest attribute of post-combustion CO_2 capture is the ability to retrofit any flue gas steam with little impact on the original process other than the added utility demands (which reduce net capacity and efficiency) and space requirements. The added utility demand, and consequently added energy demand, can be met by adding a small boiler with a steam turbine or gas turbine in a COGEN system for the CO_2 compressor power and low pressure CO_2 stripping steam. The CO_2 scrubber could be located in the base of a new wet stack, as has been done for a retrofit flue gas desulfurization (FGD) unit with space limitations. Back-end CO_2 capture also means the CO_2 capture process can be by-passed at any time, thus assuring higher availability than pre-combustion or oxyfuel combustion and the ability to meet any peak demands if CO_2 emissions are allowed.

Most of the effort on post-combustion CO_2 capture is focused on electric power generation applications. One exception is Statoil's current demonstration of chilled ammonia post-combustion CO_2 capture on flue gas from the fluid catalytic cracker (FCC) at its Mongstad refinery in Norway (Alstom, 2007).

13.2.4.4 Post-combustion – Electric Generation

Post-combustion CO_2 capture for electric generation has gained greater interest in the last five years. This increasing post-combustion CO_2 capture interest is due to many factors, including the following:

- a decreased interest in pre-combustion CO_2 capture, likely due to the high capital costs and slow commercial acceptance of IGCC (with or without CCS). Current reported capital costs for IGCC plants average about US$6400/kW normalized to a 460 MW plant with 90% capture (Al-Juaied and Whitmore, 2009);

- the number and scale of emissions from existing and planned PC power plants;
- improved designs for post-combustion CO_2 capture with more vendor competition and choices of chemical solvents;
- minimal impact to the traditional NGCC or PC power plant process other than the large need for low pressure steam for CO_2 stripping and for CO_2 compressor power;
- the ability to easily by-pass the back-end flue gas scrubber process when problems with the CO_2 system occur or when there is a need for additional peaking power; and
- lower total capital outlay (not to be confused with CO_2 avoidance costs) and ease of retrofit to the existing power plant, except for accounting for the moderately high net capacity and efficiency losses plus additional space requirement.

As already discussed, most interest in natural gas-based electric generation CCS is with post-combustion CO_2 capture for the CO_2 emission avoidance reasons. Lower natural gas prices and improved supplies are making NGCC more competitive with coal-based electric generation for baseload power. However, NGCC without CCS replacing coal is generally more economical than coal with CCS until there are very high CO_2 avoidance values or high NG prices. Also, with high natural gas prices, CCS economics can favor coal with CCS over natural gas with CCS.

There are at least five quality vendors offering improved amine CO_2 capture systems via advanced amines and/or innovative integration. There are also at least two quality vendors claiming even better performance based on less developed ammonia solvent in the place of amines (Black, 2006; McLarnon and Duncan, 2008).

The advantages of ammonia over amine CO_2 capture are higher solvent loading (units of CO_2 captured per unit of total solution recirculation), significantly lower stripping steam requirements, and sizable CO_2 compression power plus capital savings. However, ammonia to ammonium bicarbonate flue gas chemical scrubbing system is still in the early stages of demonstration. Nevertheless, ammonia for both pre-combustion and especially post-combustion CCS is likely the most significant development in CO_2 capture technology in the last five years.

The current small (0.1 $MtCO_2$/yr) "Chilled Ammonia" demonstration plants on coal boilers in North America and on NGCC and oil refinery FCC fuel gas in Europe are being followed closely (Alstom, 2009; Spitznogle, 2009). These demonstration plants should resolve concerns about potential ammonia leakage in the stack gas, solid ammonia bicarbonate buildups, the impact of higher quality steam to strip the CO_2 at pressure, expensive refrigeration, and extensive heat exchange requirements.

The Powerspan ammonia CO_2 capture process claims it can avoid the ammonia leakage concern and refrigeration requirements. However, they have only begun testing a very small CO_2 pilot plant. Powerspan also has the added challenge of integrating this process to its only demonstrated SO_2 and NO_x control process that utilizes high-cost ammonia for conversion into lower grade and less utilized ammonia sulfate fertilizer that may saturate local markets.

There is increasing fundamental R&D interest in more advanced chemical a*b*sorption and a*d*sorption of CO_2, especially with solid sorbents and strong bases that could adsorb CO_2 more effectively (Rhudy, 2009). However, these ideas are at the very early stage of development and not close to the minimal small pilot plant stage or successful development. Solid sorbents range from non-volatile amine polymers to sodium carbonate to metal organics to lithium silicates. Adsorption and regeneration configurations, energy requirements, and sweep gas issues are yet to be resolved. Also under consideration is oxyfuel combustion for the regeneration to make the higher purity CO_2 stream. CO_2 flue gas capture into advanced cement and building materials are discussed separately in Section 13.2.4.7 due to their close association with reducing the large cement making CO_2 emissions.

13.2.4.5 Oxyfuel Combustion – Industrial

Oxyfuel combustion replaces air with oxygen, thus generating a CO_2-rich flue gas. Oxyfuel CO_2 capture is the least developed of the three CO_2 capture processes. However, it continues to gain interest and development. This is likely due to its potential advantage of greatly simplifying the overall CO_2 capture process plus avoiding most of the chemical processing associated with pre-combustion and post-combustion capture. Oxyfuel combustion also has the interesting potential to increase existing process efficiency in retrofit applications. This is due to its much lower gas volume of oxygen with recycle CO_2-rich flue gas replacing high N_2-content air with a much higher total gas volume per tonne of oxygen. However, the challenge here is the massive oxygen requirement at about 60% more oxygen needed than for pre-combustion CO_2 capture. The benefits of higher combustion efficiency with oxygen combustion is lost once the large energy demands of producing oxygen plus smaller energy demands of CO_2 recycle are considered. Also, oxygen from external sources or from air separation units using grid electricity will usually have large indirect or off-site CO_2 emissions.

The oxyfuel CO_2 capture is being seriously considered for CCS demonstrations by the CO_2 Capture Project (CCP) for oil refinery-fired heaters and FCCs as well as steam boilers. Petrobras is already testing oxyfuel in its FCC pilot plant in Brazil and Suncor is working with the provincial government of Alberta (Canada) on a potential oxyfuel retrofit of an existing NG-fired field steam boiler for steam generation in oil sands production via steam-assisted gravity drainage (de Mello et al., 2008).

Advanced oxygen production looping cycles are being developed at a small scale by numerous groups and companies. This involves the oxidation and reduction cycling of metals on ceramic particles at moderate temperatures. The high solid flow recycle rates per tonne of oxygen and contacting requirements of solids and gases generally favor the use of modified circulating fluid beds with long-term particle attrition being a key issue. Looping cycle oxyfuel CCS is being developed for both natural gas and coal as well as at atmospheric pressure and pressurized. Oxygen looping with natural gas is easier, as it avoids the added challenge of solids and coal ash. Oxygen looping cycles also apply to pre-combustion CCS while reducing the oxygen demands by about 60%.

13.2.4.6 Oxyfuel Combustion – Electric Generation

Despite being the least developed of the CO_2 capture options, oxyfuel combustion is perhaps the CO_2 capture option that the traditional electric power industry likes best. This is most likely due to the lack of chemical processing compared to the simple chemical processing of post-combustion and especially the complex chemical processing of pre-combustion CO_2 capture. There is hope that raw CO_2 from the oxygen combustion flue gas might be directly compressed for CO_2 storage, thus avoiding additional SO_2 and NO_x controls as well as 100% CO_2 capture and no stack or emissions. Oxyfuel combustion at moderate pressures could also noticeably reduce the CO_2 compression capital costs and power requirements relative to the added power/costs of making or compressing the oxygen at moderate pressure.

Oxyfuel combustion has several challenges, such as the large net capacity and efficiency losses associated with making the massive amounts of oxygen, which are 60% larger than required for pre-combustion. There are also challenging CO_2 compression, pipeline, and injection issues on purity relative to the raw CO_2 coming from oxyfuel combustion. Specifically, trace amounts of SO_2 and NO_x are likely to react and even a 1% residual amount of oxygen (from oxyfuel combustion) is generally not acceptable in a traditional CO_2 pipeline (White et al., 2008; Darde et al., 2008), so CO_2 purification using low temperature separation of other means will be required. Finally, N_2 that remains in the oxygen from the air separation requires higher pressure CO_2 to avoid a two-phase flow and can increase the injection well back-pressure.

Oxyfuel combustion for electric generation CCS has been under development by Vattenfall for its large Eastern European brown coal power plants for many years. There is now a small demonstration scale unit of 0.1 $MtCO_2$/yr at its large brown coal power plant at Schwarze Pumpe in Germany. FutureGen 2.0 in the United States will demonstrate retrofit of an old coal plant with oxyfuel combustion.

All of the major air separation vendors are working with most of the major boiler vendors on oxyfuel combustion. Larger oxyfuel combustion CO_2 capture demonstration projects are being promoted for several power plants. The projects are still smaller in size, and there are fewer proposed projects than for pre-combustion and significantly less than for post-combustion. A large oxyfuel demonstration proposed in Western Canada was abandoned due to its high capital costs. Most proposals are for PC boilers, both new and retrofits, where the mass of recycled CO_2-rich flue gas mixed with oxygen matches the mass flow and heat exchanges similar to conventional air and coal combustion boilers.

Praxair and Foster Wheeler have proposed a new circulating fluidized bed combustion boiler steam cycle oxyfuel CCS demonstration power plant in Western New York, United States. Circulating fluidized bed combustion boilers have the advantage over PC boilers of a much greater feed fuel flexibility to co-process larger amounts of waste biomass for double CO_2 reductions in CCS.

Oxyfuel combustion for CO_2 capture has revitalized renewed R&D in the magnetohydrodynamics (MHD) process for the advanced electric generation process from fossil fuels. The original MHD development suffered a big loss in performance because of the N_2 in its air combustion.

Most of the interest in oxyfuel for NG-based power generation CCS has been based on a modified steam turbine used like a gas turbine without the big air compressor. Large amounts of water injected with NG-oxygen combustion generate a high pressure of mostly hot steam working in the fluid for expansion as in the modified steam turbine. This produces a high steam temperature with direct NG-oxygen combustion plus high temperature double reheats with smaller oxyfuel combustors and then steam condensing. This is the basis for the Clean Energy System under development in both North America and Europe. It is also being proposed for integration with coal gasification.

For some, the potential of 100% CO_2 capture, avoiding separate SO_2 and NO_x capture, and totally avoiding a stack via oxyfuel CCS, is a great incentive to investigate sequestering "dirty CO_2." The only significant impurity in large commercial CO_2 operations is the H_2S from pre-combustion CCS. Specifically, Dakota Gasification's CCS project in Weyburn, Canada leaves all of the coal gasification H_2S in the CO_2. This is also common in EOR field CO_2 recycles as the oil production often has associated gas with H_2S. However, transporting H_2S-rich CO_2 gas through long pipelines carries greater risks and costs, thus negating some of the benefits of this approach.

Researchers are investigating innovative ways to integrate, convert, and/or process dirty CO_2. The trade-off of CO_2 compressors and pipelines versus varying the CO_2 purity has not been fully addressed. Traditional commercial EOR operations pipeline CO_2 purity specifications (except for the water content) have been developed based on the natural CO_2 dome sources, not CCS. Other options for dirty CO_2 include the reaction and recovery of SO_2 and NO_x before or during CO_2 compression and low temperature catalysis combustion with a small amount of natural gas to react all of the residual oxygen in the raw oxyfuel combustion flue gas.

13.2.4.7 CO_2 Capture via Advanced Building Materials

A growing area of interest is the development of advanced building materials that utilize CO_2, perhaps directly from fossil fuel stacks. This can be a "win-win" situation if CO_2 captured materials can be effectively utilized in place of traditional cement, thereby replacing limestone-based cement kilns, which are the second largest source of human-made stationary CO_2 emissions (after power plants).

Most of the focus appears to be based on the utilization of naturally occurring magnesium silicates to replace limestone in cement making. The magnesium silicate reacts to MgO by adding CO_2 to make cement that thereby reduces the CO_2 that is generated from current limestone cement kilns. The challenges are many, including traditional building material standards that have been based on chemical composition instead of performance required for the building material application. There are at least five developers of this general type of process. Somewhat related applications are the use of carbon-rich building materials to replace limestone-based cement and coal-based steel. Possibilities are a more carbon-rich asphalt replacing cement for road construction and a carbon fiber or CO-based hard plastic replacing steel.

All building material applications for CO_2 reduction have the challenge of the much larger mass of CO_2 emissions versus the order of magnitude smaller building material markets. In addition, large amounts of naturally occurring oxides of silica, alumina, and iron aggregate added to building materials are used because they are inexpensive and also because they have no impact on CO_2 emissions.

13.2.4.8 CO_2 Capture from the Air

A small group of mostly advanced research physicists have been promoting the idea of CO_2 capture from the air for some time (APS, 2011). If practical, this would be an elegant solution, as it would completely separate the CO_2 capture locations from the CO_2 emission sources and would indirectly solve the CO_2 reduction issue for mobile transportation fuels from mostly oil.

However, practical and economically competitive CO_2 capture from air is a major challenge due to its very low pressure and concentration in air of only about 390 ppmv of CO_2. The ultra-low CO_2 partial pressure in air (at just 0.0004 atmospheric pressure) would likely require strong bases to capture most of that CO_2 from the air as well as a very large adsorber or absorber contactor. This also could mean large energy requirements to regenerate the CO_2 from the strong basic sorbent into a high purity CO_2 stream for compression. Conversely, if a practical CO_2 capture system from the air is possible, it could be much cheaper with better performance if first used at higher pressure and much higher concentration CO_2 sources. CO_2 capture from the air is in the very early stages of development. A recently completed study suggests that direct air capture using chemicals will cost more than \$600/tCO_2 and will therefore not be competitive with capture from higher concentration sources (APS, 2011).

Basic R&D is also being done using biological processes for CO_2 capture from air. This could also be applied to higher concentration and pressure CO_2 sources (like fossil power plants). However, like microalgae for CCS, the annual load factors of CO_2 capture could be very low if it only works during warm, sunny daylight hours. The economics of CCS generally favor processes with high annual load factors due to the high capital costs.

13.2.4.9 Prospects for Advanced Capture Technology and Capture Research

Over the past five years or so, there has been a growing interest by governments, a new community of academic scientists, and industry in developing new materials and separations techniques that could dramatically improve the efficiency and lower the cost of CO_2 capture. While these new approaches are a long way from commercial implementation, in principle, they hold significant promise. Among these new methods are (e.g., US DOE, 2010):

- metal-organic frameworks, a new class of nano-structured hybrid materials with exceptionally high surface area that can improve the efficiency of absorption of traditional and novel organic solvents;
- ionic liquids with higher absorption rates and comparatively smaller energy penalties for regenerating the solvent;
- Si-based solvents requiring much less water for CO_2 capture;
- biologically motivated approaches that utilize nature-inspired catalysts such as carbonic anhydrase to capture and convert gaseous CO_2 to liquid or solid forms;
- membranes coated with CO_2 affinity materials to improve the selectivity and permeance to CO_2;
- hydrogen-conducting membranes for pre-combustion capture;
- catalytic membranes to simultaneously separate CO_2 and carry out the water-gas shift reaction;
- oxygen separation membranes to lower the cost of oxygen production; and
- solid adsorbents such as activated carbon, carbon nanotubes, or other nano-structured solids.

As these new approaches reach maturity, they will need to compete based on cost and performance with existing approaches for CO_2 capture as described above. These existing technologies are, of course, expected to improve as they become more widely deployed. For this reason, it is difficult to anticipate which of the existing and new technologies will emerge as market leaders.

13.2.5 CO_2 Compression

CO_2 compressors are commercially well proven from their use in EOR over the last 30 years. In 2010, 50 MtCO_2 were compressed and transported through over 4800 km of CO_2 pipelines. Nevertheless, there are some development opportunities in this area. The impact on overall CCS cost and performance improvements, however, is likely much smaller than in the development of better CO_2 capture processes.

Current CO_2 compressors have high capital costs of over US$1000/kW, and the power requirements are significant at 100–150 kWe per t/hr of CO_2 (McCollum and Ogden, 2006). The best and easiest improvement is doing the CO_2 capture at high pressure. An operating pressure of 3–5 atmospheres will begin to significantly reduce CO_2 compression costs.

Development is occurring on an advanced CO_2 compressor via shock wave compression. This might reduce the total installed unit capital cost ($/kWe) by a large amount, as this type of compressor may require only two stages of compression compared to current CO_2 compressors that require 8–12 stages plus more intercoolers. The developer, Ramgen Power Systems, is working with Dresser-Rand on commercialization (see Ramgen, 2011).

As discussed in the oxyfuel CO_2 capture subsection, there is ongoing development for advanced compressors and pipeline standards for handling dirty CO_2. The raw flue gas from oxygen combustion emits mostly CO_2, but also significant amounts of H_2O, N_2, and O_2, as well as lesser amounts of SO_2 and NO_x. H_2O and O_2 may require removal or conversion, respectively. Current CO_2 compressors may unintentionally convert the SO_2 and NO_x into ammonia sulfate and plug the compressor.

13.2.6 CO_2 Capture Costs (See also Chapter 12)

There are numerous reports documenting current and future estimates for the cost of capture for power generation and industrial emission sources (e.g., IPCC, 2005; MIT, 2007; Al-Juaried and Whitmore, 2009; US DOE, 2010). Costs of capture for the n^{th}-of-a-kind plant range from about US$30–100/t$CO_2$ avoided. First-of-a-kind plants are expected to cost significantly more with estimates in the range of US$100–150/t$CO_2$ avoided. Costs of capture for first generation CCS power plants available in the early 2020s are estimated to be about $45/t$CO_2$ avoided for coal and $115/t$CO_2$ avoided for natural gas (ZEP, 2011). Estimates vary widely, in part because they use a variety of different assumptions about baseline technology, capture technology, discount rates, material and labor inflation, regional indices, first-of-a-kind plants versus n^{th}-of-a-kind plants, etc. We do not repeat these here, but provide an overview that describes not only the complexity of these estimates, but the underlying drivers as well. Examples providing costs are provided for a variety of illustrative scenarios. CO_2 capture cost estimating for CCS is extremely challenging for several reasons, including:

- Costs are application specific. Therefore, while it is necessary to analyze the CCS costs for coal-based power plants, the use of natural gas or biomass with CCS for a double CO_2 reduction needs to be considered, as well as other applications especially those for industrial applications with existing large, pure CO_2 vents, regardless of the CO_2 mitigation issue.
- Costs will also be site specific, depending on labor rates, material costs, construction codes, safety codes, local construction constraints, etc.
- Comparison of costs with and without capture needs to also consider baseline costs in a broad context. Fuel type, fuel switching, and future fuel price impacts – especially as a carbon-constrained world develops – will have a significant effect on costs. Coal energy prices are currently low and stable and may even go down slightly as a carbon-constrained world develops and coal use declines. However, natural gas energy prices are significantly higher than coal and are highly volatile with few, if any, long-term fixed price contracts, except for take-or-pay Liquefied Natural Gas (LNG) contracts. Furthermore, natural gas prices will almost certainly go up as a carbon-constrained world develops. Natural gas supplies will be stressed as natural gas begins replacing some of the large coal use applications long before economics warrant serious consideration of coal or natural gas with CCS. Also at high natural gas prices, the cost of NGCC with CCS quickly becomes higher than coal with CCS.
- Costs can be assessed based on a variety of metrics, such as the increase in product cost (i.e., $/MWh for electricity) with CCS versus without CCS or the CO_2 costs of CCS as CO_2 capture costs or CO_2 avoidance costs.
- Existing CO_2 sources considering retrofit CCS have much different costs than those for a proposed new CO_2 source considering CCS. There are also issues that a new CO_2 source with CCS would only minimize CO_2 emissions growth unless it replaces an old existing CO_2 source that is shut down. Also to be considered is the large impact of CO_2 avoidance costs based on the baseline fuel with coal having about twice the baseline CO_2 emissions as natural gas.
- Basic capital cost estimates have changed due to the large run-up in construction costs (materials, labor shortages, and equipment) from 2005–2008, but since then there has been moderate construction cost decline. There is also the issue of site-specific cost factors such as contingencies, capitalization of allocation of funds during construction (common for regulated US electric utilities), and cost of capital or project capital return rates due to mainly the debt/equity ratio, but also due to local taxes, depreciation rates, and the design basis (e.g., extreme weather conditions or earthquake rating). For example, recent all-in capital costs estimates by SaskPower for the commercial-scale oxyfuel and post-combustion capture demonstrations for coal boiler power plants are over CAN$12,000/kW (US$12,453/kW).
- CCS costs are traditionally estimated based on the assumption of proven commercial operating experience, sometimes called the "n^{th}" plant design, which signifies that the cost estimate is not for the 1^{st}, 2^{nd}, or 3^{rd} commercial unit. In other words, there are much lower cost estimates than for the first large-scale demonstration or first commercial plant using a specific CCS technology because it has already progressed down the learning curve.

- Estimating cost for developmental technology without any large-scale operating demonstration plant experience is difficult. In this case, it is common to excessively overestimate performance and underestimate costs.

This section attempts to reduce these complexities to simple economics. More importantly, the economics are presented in a logical and transparent way with an emphasis on the key variables and relative consistency. Learning curves and impact of the state of development are also addressed, as the less developed CCS systems are more likely to have their performance overestimated and costs grossly underestimated.

13.2.6.1 What Does CO_2 Avoidance Cost Mean?

Most economics of CCS are stated in terms of CO_2 avoidance cost. Therefore, it is essential to fully understand what the CO_2 avoidance cost matrix means as well as what the key inputs, sensitivities, and other options are to CCS.

It is also essential to understand the key difference between CO_2 capture and CO_2 avoidance costs, especially with CCS. This is because CCS usually reduces net capacity and efficiency. CO_2 capture cost is calculated based on the CO_2 captured per unit net product. Thus, larger the efficiency losses can erroneously appear to lower CO_2 capture costs. However, CO_2 avoidance is calculated based on the CO_2 reduction or avoidance to the atmosphere per unit net product. Thus, the larger the efficiency losses, the higher the CO_2 avoidance costs, especially when the fuel costs are high. The goal of CCS is reducing CO_2 emissions into the atmosphere; thus, it is almost always best to work with and estimate just CO_2 avoidance costs.

It is typically assumed that CO_2 avoidance cost is the likely minimal CO_2 tax required for a major human-made CO_2 emissions source to start seriously considering CCS. Using a coal-fired power plant as a simple example, the CO_2 avoidance cost is the $/t$CO_2$ emissions tax at which the $/MWh electric "loaded" (capital charges, fuel, and operations and maintenance) price is the same as paying the CO_2 tax or adding CCS to avoid paying most of the CO_2 tax. In reality, the CO_2 tax (or CO_2 avoidance costs) must be even higher to justify the added capital and much higher risks of adding CCS versus simply paying the CO_2 tax.

The formula for CO_2 avoidance cost is relatively simple. As shown below, the formula estimates the product costs (in $/MWh) and CO_2 emissions per unit of product (tCO_2/MWh) for a traditional plant (called "b" for baseline case) and then estimates the higher product costs but with lower CO_2 emissions (called "c" for carbon reduction cases). The lower CO_2 emissions case can simply be a higher efficiency or lower carbon fuel with or without CCS. The CCS added option is the most common comparison option due to the larger potential CO_2 reduction. Nevertheless, conversion without CCS to higher efficiency or lower carbon fuel switching cannot be overlooked or ignored, due to its higher efficiency and much lower capital and avoiding CO_2 storage liability risks.

The formula is as follows:

$$\$/tCO_2 \text{ avoidance cost} = (\$/MWh_c - \$/MWh_b) \div (tCO_2/MWh_b - tCO_2/MWh_c) \quad (1)$$

This simple formula makes it easy to understand the conditions where the CO_2 avoidance cost estimates can be high or low. Low CO_2 avoidance costs occur when small increases in power costs give large CO_2 reductions. High CO_2 avoidance costs occur when there are large increases in power costs and small reductions in CO_2 emissions. The following three simple examples show the fluctuation of CO_2 avoidance costs depending on the baseline and choice of CO_2 reduction option. All three examples are for a coal power plant baseline and assume baseload (high annual load factor) power prices at the plant gate, without added transmission or distribution costs.

- First, consider the CO_2 avoidance cost of an old, dirty, and inefficient, but paid-off coal power plant that is replaced with a new, clean, state-of-the-art coal plant without CCS. The electricity price increase would be about US$40/$MWh_c$, assuming US$80/MWh_c for the new, efficient coal power (with all of the capital charges) up from only US$40/$MWh_b$ for the old paid-off baseline plant (with no capital charges and just operating costs). The CO_2 reduction would be only about 0.2 t/MWh, assuming 1.0 t/MWh_b for the old subcritical coal plant baseline, and reduced to 0.8 t/MWh_c for the new efficiency supercritical plant. Thus, the CO_2 avoidance cost would be very high at US$200/t$CO_2$ based on a US$40/MWh power increase divided by 0.2 t/MWh of CO_2 reduction.

- Second, consider the CO_2 avoidance cost for a proposed new coal power plant contemplating the addition of CCS. The electricity price would increase about US$40/$MWh_c$, assuming US$120/MWh_c for the new coal power with CCS, up from only about US$80/$MWh_b$ for the normal new state-of-the-art coal unit. The CO_2 reduction would be large at about 0.7 t/MWh, assuming 0.8 t/MWh_b for the new state-of-the-art coal plant baseline reduced to only 0.1 t/MWh for the similar new coal unit but now having CCS. Thus, the CO_2 avoidance cost would be US$57/t$CO_2$ based on a US$40/MWh power increase divided by 0.7 t/MWh of CO_2 reduction.

- Third, consider the CO_2 avoidance for replacing the old coal power plant in the first example with the new coal plant with CCS in the second example. The CO_2 avoidance would now be US$89/t$CO_2$ based on a US$80/MWh power increase divided by 0.9 t/MWh of CO_2 reduction.

In general, CO_2 avoidance costs are usually high if the baseline is a paid-off existing facility with low cost fuel or if the CO_2 reduction is relatively low. Conversely, CO_2 avoidance costs are the lowest when the baseline is for a new proposed CO_2 source and the CO_2 reduction are high.

A CO_2 avoidance cost involving natural gas can be more complex due to the large potential variation of prices and the relatively low CO_2 emissions of natural gas. Over the long term, as a carbon-constrained world develops, natural gas prices will likely increase and supplies may be stressed as coal is replaced with natural gas long before it becomes economical to consider CCS.

13.2.7 Triple CCS Point Economics

Due to the above complexity of CCS CO_2 avoidance costs with coal versus a similar scenario with natural gas, it is useful to develop "triple point economics" from a coal baseline that also includes natural gas. This would avoid the suggestion that a CO_2 tax or CO_2 avoidance cost where coal with CCS could become competitive while ignoring the simple use of natural gas without CCS to replace coal. Three simple steps define the CO_2 tax triple point economics where the power price is the same for natural gas without CCS versus coal with or without CCS.[1]

The following examples of triple point economics are estimated for two recent projects. As discussed, the baseline choice of existing versus proposed new CO_2 sources greatly impact the economics of coal-based CCS and natural gas price where it would be less expensive to simply replace coal with natural gas and avoid CCS.

13.2.7.1 Triple Point CCS Economics for an Old Existing Coal Power Plant Baseline

Existing coal-fired power plants represent most of the current large CO_2 point sources that are good prospects for CCS. For example, in the United States there are over 300 GW of existing coal power plants with a MWe-weighted average age of almost 40 years old. Recent estimates for this option have been made assuming US$2.00/MMBtu of coal and all costs in constant US_{2008}\$ (Simbeck and Roekpooritat, 2009a; 2009b). The lowest CO_2 avoided cost for continued coal use was a simple add-on retrofit post-combustion CCS to the old existing boiler at a CO_2 avoided cost of US$74/$MtCO_2$. This reduced the old existing power plant net capacity by about 27% and dropped the net efficiency (HHV) from 34% to only 25%. A rebuilt new supercritical steam coal plant with CCS would avoid the net capacity loss and decrease most of the net efficiency loss of CCS relative to the old subcritical steam coal power plant without CCS (US DOE, 2010). The new rebuilt coal units with CCS had higher CO_2 avoidance costs, however, due to the significantly higher total capital investment associated with the new power plant.

Existing paid-off power plant baselines generally force higher CO_2 avoidance costs due to the inexpensive baseline power costs. In this case, the existing steam coal power cost was estimated at only US$37/MWh (plant gate). At this relatively high US$74/$tCO_2$ avoided, the triple point electricity price was US$108/MWh. At this price for power generation, by converting to natural gas via repowering with a new NGCC unit without CCS, the same cost per tonne of CO_2 avoided could be obtained at US$8.31/MMBtu for natural gas. Consequently, repowering an aging steam coal power plant with new NGCC without CCS could be an attractive option if the natural gas industry and electric power generators become willing to agree to amenable long-term supply/price contracts.

13.2.7.2 Triple Point CCS Economics for a New Proposed Coal Power Plant Baseline

The more traditional CCS economics are based on proposed new coal and NG power plants. However, this would only minimize CO_2 emissions growth from the new power plant capacity addition unless an equivalent-size old fossil fuel power plant is shut down and replaced by the new power plant with CCS.

This scenario was evaluated in 2009. The lowest CO_2 avoided cost for a new coal power plant with CCS was the pre-combustion option at a CO_2 avoided cost of US$48/$MtCO_2$. However, the post-combustion and oxyfuel combustion CCS option costs and performance were relatively close. In comparison to the new supercritical steam coal plant baseline, the addition of CCS reduced the power plant net capacity by about 20% and dropped its net efficiency (HHV) from 39% to 32%.

As previously explained, setting a proposed new fossil power plant as the baseline reduces the CO_2 avoidance costs, as the new power plant baseline will have relative power costs even before the additional cost of CCS. At a moderate US$48/$tCO_2$ tax, the triple point electricity price would be US$113/MWh for the new coal unit with or without CCS or, if converting to a new NGCC without CCS, it would be US$11.15/MMBtu for natural gas.

Both the new and old coal power plant baseline estimates required about the same US$110/MWh power price for CCS. However, the electric costs increased by about 300% for the CCS addition to the old paid-off power plants, whereas the electric costs only increased by about 50% for CCS added to a new proposed power plant. The CO_2 avoidance cost and natural gas alternative prices (without CCS at the given CO_2 tax) were also much different for the two coal power plant baselines. Existing coal power plants would find it cheaper and a much lower risk to simply pay the CO_2 tax than to significantly reduce CO_2 emissions until the CO_2 tax is very high. Another option is to mandate

1 Start with estimating CO_2 avoidance costs for a coal plant baseline without CCS versus adding CCS. This is the most logical baseline due to the high CO_2 emissions per unit of coal energy, which is the dominant use in large central power plants having large point sources and a likely stable coal price even as a carbon-constrained world develops. The only major issue would be if the baseline is an existing PC power plant or a new state-of-the-art PC power plant. The CCS case can be retrofitted, rebuilt, or a new plant, and can include any or all of the CCS process options (pre-, post-, or oxyfuel combustion). Next, enter the CO_2 avoidance cost estimated in Step 1 for the same coal baseline estimate and CCS option with the lowest cost. The power cost should now be the same for the coal baseline without CCS (paying the CO_2 tax) and the best coal CCS option (avoiding most of the CO_2 tax). Finally, the third key alternative of natural gas without CCS is simply replacing coal. The natural gas replacement option is estimated by varying the natural gas price until this option (without CCS) has the same electricity price as the Step 2 coal cases (with and without CCS).

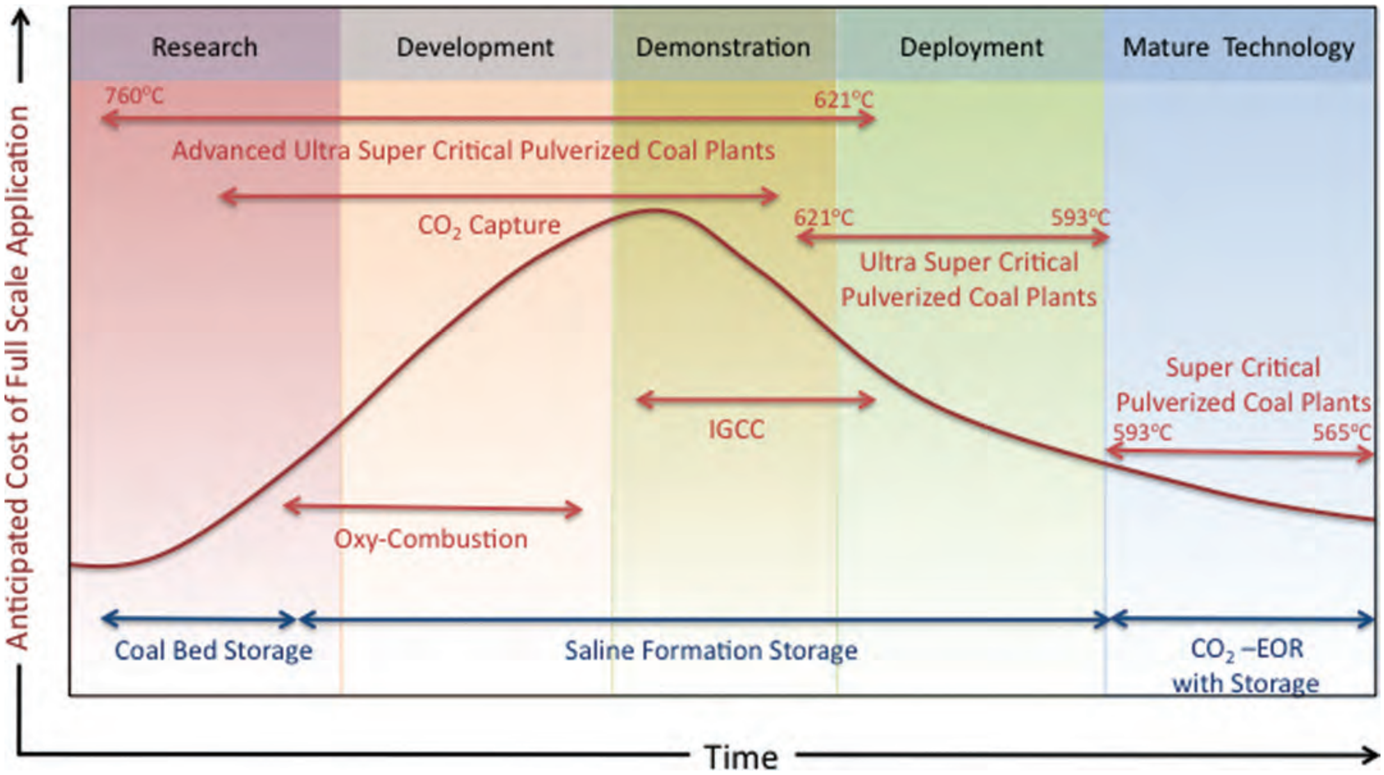

Figure 13.4 | Utility and petroleum industry perspective on CCS and advanced power generation technology for coal. Source: modified from Booras, 2009.

that old coal power plants shut down after 45 years of service, as is currently being proposed in Canada. In the meantime, ongoing talk about CO_2 mitigation encourages the life extension of existing old coal power plants with high emissions. However, life-extending old coal units maximize CO_2 emissions before potential CO_2 reduction mandates take place and increase the quantity of inexpensive CO_2 cap and trade allocations that existing coal unit owners will likely receive. This also keeps electric power prices relatively low in nations such as the United States, which have large fleets of aging coal power plants.

13.2.7.3 CCS Cost Estimating Learning Curves

There are very real learning curves associated with the increasing use of specific technologies in industries where the unit costs go down as the total installed capacity increases. This is sometimes referred to as "learning by doing." In the electric generation industry, these cost improvement "learning curves" are well documented for the growth in the use of flue gas desulfurization (FGD) SO_2 controls and selective catalytic reduction (SCR) NO_x controls (Yeh and Rubin, 2007). However, this is not always the case, as exemplified by the large cost increases for nuclear power plants (Grubler, 2010).

Learning curves are sometimes applied to CCS technologies. Only time will tell the accuracy of the estimates. Nevertheless, it is essential to realize that learning curves almost always start to reduce unit costs after the respective technology is established in commercial service and the total commercial capacity is growing at a high rate with time. From pilot to demonstration to the first commercial unit, the unit costs almost always increase before decreasing via the learning curve. This is illustrated in Figure 13.4, which shows cost versus stated development for coal technologies and CCS options (Booras, 2009). In the early stages of development, advanced technologies often overestimate performance and underestimate costs. The less developed the CCS technology, the more uncertain the estimates.

All CO_2 mitigation options performance and cost estimates are highly questionable until successfully demonstrated in large commercial-scale operations. The time and cost to progress from research to development is long and expensive for advanced energy and environmental technologies. It is even longer and more expensive for the electric power industry. This is because highly regulated industries do not reward risks, and traditional electric power generation, especially for CCS, is more economical in very large and expensive power plants. Innovative policies and incentives will be required to change this.

13.2.8 Air Pollution from Power Plants with CCS

Contrary to CO_2, where emission levels are mainly dependent on the fuel type, non-CO_2 emissions are mainly influenced by parameters related to specific conditions such as fuel composition, type of technology, combustion, operating and maintenance conditions, size and age,

Table 13.1 | Average minimum and maximum emission factors for energy conversion concepts with and without CO_2 capture as reported in the literature. The ranges, in brackets, report the minimum and maximum values found in 171 studies.

Capture Technology	Conversion Technology	CO_2 g/kWh	NO_x	SO_2	NH3	VOC	PM
			mg/kWh				
No-capture	IGCC	766 (694–833)	229 (90–580)	64 (40–141)	n.a.	n.a.	28 (27–29)
	NGCC	370 (344–379)	168 (90–262)	n.a.	n.a.	n.a.	n.a.
	PC	826 (706–1004)	374 (159–620)	414 (100–1280)	7 (3–10)	10 (9–11)	39 (7–51)
Oxyfuel combustion	GC	10 (0–60)	n.a.	n.a.	n.a.	n.a.	n.a.
	NGCC	8 (0–12)	0	n.a.	n.a.	n.a.	n.a.
	PC	47 (0–147)	172 (0–390)	25 (0–98)	n.a	n.a.	3 (0–10)
Post-combustion	NGCC	55 (40–66)	188 (110–275)	n.a.	6 (2–19)	n.a.	n.a.
	PC	143 (59–369)	537 (205–770)	9 (1–13)	209 (187–230)	n.a.	52 (9–74)
Pre-combustion	GC	21 (0–42)	n.a.	n.a.	n.a.	n.a.	n.a.
	IGCC	97 (71–152)	209 (100–550)	28 (10–51)	n.a.	n.a.	34 (34–35)

n.a.: no data available. The emissions factors are based on various fuels and power plant configuration and performance. Post-combustion capture includes capture with amine-based solvents and chilled ammonia.

Source: Koornneef et al., 2010.

and emission control policy (EMEP, 2009). Table 13.1 shows an overview of emission factors reported in the literature for power plants with and without CO_2 capture. General trends can be summarized as follows.

13.2.8.1 Sulfur Dioxide – SO_2

SO_2 emissions are expected to be very low for power plants with CO_2 capture. This will mainly be due to plants using fossil fuels with very low sulfur content (e.g., NGCC or GCs), a limitation in SO_2 content in the flue gas to avoid solvent degradation (post-combustion with amine-based solvents), or to a high level of recovery of sulfur compounds from the syngas in IGCC plants.

13.2.8.2 Nitrogen Oxides – NO_x

In post-combustion capture concepts, NO_2 needs to be removed since it can react with amine-based solvents and cause degradation. NO_2 accounts, however, for only ~10% of the NO_x, making the net impact of its removal limited. A major factor will be the increased use of fuel due to the efficiency penalty. Such an increase may result in higher levels of NO_x (/kWh) for the whole power sector (Tzimas et al., 2007; Koornneef et al., 2010). Studies in the literature of pre-combustion concepts report both lower and higher NO_x values, compared to similar plants without CO_2 capture (e.g., IEA GHG, 2006; Davison, 2007; US DOE/NETL, 2007a). The levels of NO_x reported are dependent on the performance of the gas turbines and the efficiency penalties. NO_x emissions in oxyfuel concepts are expected to be very low, due to a reduction of fuel NO_x and inhibition of thermal NO_x (Croiset and Thambimuthu, 2001; Tan et al., 2006) and removal of NO_x during CO_2 purification (White et al., 2008).

13.2.8.3 Ammonia – NH_3

Changes in NH_3 levels are only relevant for post-combustion capture. Formation of NH_3 is the result of reactions between flue gases and monoethanolamine (MEA)-based solvents as a consequence of oxidation or elevated temperatures.

13.2.8.4 Particulate Matter – PM

The emission of particulate matter from natural gas-fired cycles in general can be considered negligible. In the case of coal-fired plants, significant reductions are expected for the post-combustion capture process since low levels of PM are necessary to assure a stable capture process. However, in terms of emissions/kWh, there may be an overall increase in PM emissions as a result of increased use of fossil fuel due to the efficiency penalty. PM in IGCC plant cycles without CO_2 capture is already low due to high removal efficiencies in the gas cleaning section. Preliminary estimates indicate that the application of pre-combustion capture may lower further PM emissions (US DOE/NETL, 2007a). Also, for coal-fired oxyfuel concepts, PM emissions are estimated in the literature to be lower per kWh, compared to conventional pulverized coal-fired power plants.

13.2.8.5 Volatile Organic Carbon – NMVOC

Quantitative estimates for the impact of CO_2 capture on the level of NMVOC emissions are absent in the (open) literature. It is therefore not possible to indicate whether and to what extent CO_2 capture technology will affect the net level of these emissions.

13.2.9 Water Consumption

Water consumption will increase as a consequence of additional fuel use to make up for the energy penalty and the demand of the CO_2 capture system itself. For instance, coal-fired power plants with post-combustion capture (MEA-based) have large cooling water make up requirements, while increased water demand in IGCCs with pre-combustion capture is mainly driven by the increased cooling load required to further cool the syngas and steam for the water gas shift reactor and the increase auxiliary load (US DOE/NETL, 2009a). The impact on water use appears larger for PCs and NGCCs than for IGCCs and oxyfuel. Ranges reported in the literature indicate relative increases in water use, compared to similar plants without capture, between 50–95% for PC with post-combustion capture, 30–50% for IGCC with pre-combustion capture, and 30–35% for oxyfuel with CO_2 removal (US DOE/NETL, 2007a; US DOE/NETL, 2007b; RECCS, 2008). Water use could be reduced by using dry cooling instead of wet cooling, even to levels below those of wet cooled plants without CCS. However, operating power for a given heat load in a dry cool-based system can be four to six times larger than that for an optimized wet system (Maulbetsch, 2002) and this could result in an increase in the energy penalty in the power plant.

13.2.9.1 Waste and By-products from CCS

As a consequence of increased fuel consumption, it is expected that waste streams such as bottom ash, fly ash, boiler slag, and reclaimer waste will increase with the implementation of CO_2 capture. Relative increases reported in the literature for power plants are between 20–40% (bottom ash/fly ash); 18–29% (slag); 18–25% (sulfur); and 31–47% (gypsum) (US DOE/NETL, 2007a; Davison, 2007; Rubin et al., 2007). Depending on market conditions, gypsum (from PC plants) and sulfur (from IGCC plants) may be considered sub-products instead of waste.

Reclaimer waste generated in post-combustion capture processes may become a point of concern. This waste, containing heat stable salts, heavy metal corrosion inhibitors, and absorption solvents among others, is considered hazardous. Amounts of reclaimer waste for post-combustion with amine-based solvents are reported in the range of 1.6–4.5 g/kWh (Rubin et al., 2007; Koornneff et al., 2008; Schreiber et al., 2009; Korre et al., 2010). This amount could be even higher, depending on the rate of solvent slip stream. Thitakamol et al. (2007) have indicated that an increase of 0.5–2% in the slip stream could result in a factor four increase in the amount of reclaimer waste.

13.2.10 Capture Conclusions

To make a large contribution to CO_2 emissions reductions, capture technologies are needed both for new sources and existing sources. The same technology is unlikely to be optimal for both situations. Four approaches are available for capture from the power and industrial sources. Three of them – the so-called post-combustion capture, pre-combustion capture, and oxy-combustion capture approaches – produce CO_2 gas with a relatively small concentration of contaminants. This needs to be compressed for transport to a storage location. All have been separately demonstrated; some are used routinely today for other applications, but little experience is available for integration and optimization with power production or most industrial applications. The fourth approach, mineralization, produces solids whose composition depends on the specific process. Mineralization is much less mature than the other capture technologies. Mineralization of CO_2 is an attractive option because the end product is a carbonate rock, thus avoiding the need to store large amounts of CO_2. However, mineralization requires large volumes of rocks to provide a source of magnesium (or other cations) and is more expensive and energy intensive than other options. If a use for these minerals is not found, they will become a waste that must be managed.

Today's capture and compression technology has a parasitic energy requirement of 15–30% of the electricity generated from combustion sources. This increases the cost of capture, the use of valuable energy resources, and the upstream impacts of energy supply. Progress is being made on reducing electricity requirements for capture and compression, but more progress is needed to make CCS less energy intensive.

Impacts of CO_2 capture on other air pollutants are highly dependent in the capture approach used. SO_2 emissions are expected to be very low for power plants with CO_2 capture. In the post-combustion concepts, NO_x emissions are believed to be largely unaffected by the capture process while for oxyfuel capture these emissions are expected to be very low. For pre-combustion, consensus on the possible effects seems to be absent. Only post-combustion capture NH_3 emissions are estimated to significantly increase (with more than a factor of 20 for conventional amine solvents). This aspect will have to be addressed by the facilities and, while technology already exists which could abate these emissions, it will have an impact on the investment costs. PM emissions are expected to increase per kWh as a result of the efficiency penalty. There is little experience in the power generation sector with operating capture facilities. Capture facilities are large chemical processing plants. Operating these facilities requires different expertise than operating steam boilers and turbine generators. Building the expertise and experience to integrate power production and CCS to provide electricity with the high reliability expected today will require significant capacity building in the power generation sector.

The capture of CO_2 directly from air has also been proposed. Air capture is appealing for a number of reasons, namely: capture facilities could be co-located with ideal storage locations; emissions from nonpoint sources could be captured; and emissions from noncompliant parties could be offset. However, the low concentration of CO_2 in the air makes capture with today's technology expensive and energy intensive. The high cost of direct air capture compared to capture from concentrated point sources makes it unlikely that air capture will play a role in CO_2 emission reduction until far into the future.

The cost of capture is challenging to determine, but is estimated to range from US\$50 to over US\$150/tCO_2 avoided, depending on the type of fuel, capture technology, assumptions about the baseline technology, and whether it is the first plant or the n^{th} of a kind. Costs of capture for first generation CCS power plants available in the early 2020s are estimated to be about \$45/tCO_2 avoided for coal and \$115/tCO_2 avoided for natural gas. The combined cost of capture and compression would increase the cost of power production by about 50% to over 100%. The costs of early demonstration projects are likely to be significantly higher. Worldwide, large investments in improving capture technologies are being made by governments and the private sector. It remains to be seen whether these investments are sufficiently large to quickly reduce costs and energy requirements for capture and compression, particularly those investments in fundamental research, which could produce technological breakthroughs with dramatic improvements.

13.3 Carbon Dioxide Transport

13.3.1 Introduction

One common requirement for all CCS schemes is the need to transport CO_2 from the capture to storage sites. CO_2 can be transported by land via pipelines, motor carriers, or railway, or by water via ships or barges. Each of the individual possibilities can be considered mature, but their integration at large-scale will be complex; in fact, the scale and the speed at which transport networks will be needed are regarded as the main challenges for CO_2 transport (IPCC, 2005; IEA, 2008a).

Experiences in CO_2 transport by truck or ship are mainly found in the food and brewery industry. CO_2 is generally transported as a compressed liquid (e.g., -50°C, 0.7–0.8 MPa). The transport of CO_2 by ship or train will require the development of loading and unloading infrastructures and temporary CO_2 storage in steel tanks or rock caverns, which make the options costly. R&D is being carried out to increase the cost-effectiveness of the option, for instance by using integrated tug barges instead of ships. Although this concept has not been demonstrated, it could theoretically eliminate the need for intermediate storage, reducing cost and logistic complexity (Haugen et al., 2009). Though transport of CO_2 via ships or trains is not regarded as the preferred option for large-scale systems (e.g., IPCC 2005; MIT, 2009), it may prove to be cost effective during a transition phase (when pipeline networks are not yet available) and on a case-specific basis (specific combinations of pipeline, ships, and/or trucks).

CO_2 transport by pipeline is currently considered the most mature transport option. There are currently some 5800 km of CO_2 pipelines in operation in the United States (Parfomak and Folger, 2008). These pipelines transport CO_2 in the liquid or dense phase (CO_2 pressure above 7.38 MPa), are land-based and sectioned (typically less than 30 km), are generally made out of carbon steel, transport relatively clean CO_2, do not use internal coating, and mainly transport CO_2 for EOR purposes (Oosterkamp, 2008). The IEA estimates that about 150,000 km of dedicated CO_2 pipelines will be needed in the European Union. In the United States, up to 37,000 km of CO_2 pipelines will be needed between 2010 and 2050 (Dooley et al., 2009). Given its importance, the focus of this section is on pipeline transport.

Gas compression is well developed around the globe and uses mature technologies, as described in Section 13.2.4. CO_2 needs to be compressed generally from atmospheric pressure, at which point it exist as a gas, up to a pressure suitable for pipeline pressure in either the liquid or "dense" phase regions, depending on the temperature. In the gas phase, a compressor is required, while in the liquid/dense phase, a pump can be used to boost the pressure. It is generally assumed that the cut-off pressure for switching from compressor to pump is 7.38 MPa (McCollum and Ogden, 2006). At this pressure and at temperatures lower than 20°C, CO_2 would have a density of between 800–1200 kg/m^3. At these conditions, larger mass per unit volume can be transported, since CO_2 would behave as a liquid and have liquid-like density while having the compressibility and viscosity of CO_2 in the gas phase. As an example, a 30-inch pipeline could transport about 5 MtCO_2/yr in gas phase. In the liquid or dense phase, the same pipeline could transport about 20 Mt/yr.

13.3.2 Transportation Operational Issues

13.3.2.1 Pressure Drop

As CO_2 flows through a pipeline, there is frictional loss. For single phase flow, the pressure drop (ΔP) depends on the pipe's inner diameter, CO_2 flow velocity, viscosity, and density, and the pipe's roughness factor. At constant temperature, pressure drop in a typical 20-inch pipeline transporting CO_2 in dense phase is about 30 kPa/km (Essandoh-Yeddu and

Gulen, 2008). In order to maintain the inlet pressure to the pipeline, it is necessary either to increase the pipeline inlet pressure to levels that secure that after losses CO_2 would still have at least 7.38 MPa or to install boosters every 100–200 km to make up the pressure losses.

13.3.2.2 Corrosion

CO_2 and components such as SO_2, NO, and H_2S may form acid compounds in the presence of water that are highly corrosive. Furthermore, H_2S could react with carbon steel to form thin films of iron sulphide (FeS). FeS may dislodge at times and coat the inside surface, decreasing heat transfer efficiency and potentially causing operational problems in the compression units. Control of water content by dehydration is therefore essential for safe and cost-effective pipeline operation. Other possibilities to minimize corrosion are material selection (e.g., stainless steel instead of carbon steel), use of corrosion inhibitors, use of protective coating, and cathodic protection. These possibilities will increase pipeline costs.

13.3.2.3 Hydrate Formation

In the presence of water, CO_2 and H_2S may form hydrate compounds, which can block the line and plug and damage equipment. Hydrate formation can largely be stopped by drying the CO_2 and removing the "free water" that is present. Maximum allowable water content recommended in the literature is in the range of 50–500 ppm (Visser et al., 2007).

13.3.2.4 Operating Temperatures

CO_2 pipelines' operating temperatures are generally dictated by the temperature of the surrounding soil or water. In northern latitudes, the soil temperature could reach below zero in winter and to 6–8°C in summer, while in tropical locations, soil temperatures of 20°C are common. At the discharge of compression stations, after-cooling of compressed CO_2 may be required to ensure that the temperature of CO_2 does not exceed the allowable limits for either the pipeline coating or the flange temperature (McCoy, 2008). CO_2 cools dramatically during decompression, so pressure and temperature must be controlled during routine maintenance (Gale and Davison, 2003).

13.3.2.5 Impurities

Depending on the source of the flue gas and the type of CO_2 capture process, CO_2 streams may contain trace concentrations such as H_2S, SO_2, NO_x, O_2, CO, HF, Hg, N_2, and Ar. These impurities might have an impact on (Visser et al., 2007; McCoy, 2008; Oosterkamp, 2008):

- *the physical state of the CO_2 stream*, affecting the operation of the compressors, pipelines and storage fields;
- *CO_2 compressibility*, which is non-linear in the range of pressures common for pipeline transport and is highly sensitive to any impurities such as H_2S or CH_4. Changes in compressibility may result in the reduction of the CO_2 volume that can be transported;
- *CO_2 density*, since impurities such as N_2, O_2, H_2, Ar, and CH_4 reduce the density of the flow, which in turn reduces the CO_2 volume that can be transported;
- *pipeline integrity*, for instance, by producing hydrogen of sulphide-induced stress cracking;
- *safe exposure limits* required for the pipeline; and
- *minimum miscibility pressure* of the CO_2 in oil, which could affect the possibilities to use CO_2 for EOR.

13.3.3 Cost of Transportation

CO_2 transport costs are a function of pipeline length, diameter, material, route of the pipeline, and safety requirements, among other things. Figure 13.5 shows relations between capital costs, levelized cost, and CO_2 flows outlined in the literature.

The transport of CO_2 by pipeline benefits from economies of scale: i.e., average costs decrease as scale increases. The amount of fluid that can flow through a pipeline increases non-linearly with diameter, so larger diameters are preferred to smaller ones. Pressure drop, ΔP, is inversely related to the diameter. Lower pressure drops translate to lower costs, since costs to compress or pressurize a fluid are linearly related to ΔP. Finally, the marginal cost of constructing a pipeline decreases with diameter (Bielicki, 2008; MIT, 2009). Economies of scale regarding the transport of large amounts of CO_2 by pipeline indicate that it may be more efficient to encourage hub-and-spoke transport systems than point-to-point systems. Returns to scale are, however, not constant; i.e., they do not continually increase as the system expands (Figure 13.5b). The point at which economies of scale are reached is case dependent. Some studies found that economies of scale are reached with annual CO_2 flow rates in excess of 60 Mt/yr (e.g., van den Broek et al., 2010), while other studies report lower values, e.g., 10 Mt/yr (Heddle et al., 2003). The increase in costs with scale is partly due to the increase in material costs. McCoy (2008) reports that doubling pipeline diameter would result in a three-fold material costs increase. This is a concern for most investors, due to the high price fluctuations of steel in recent years (Parformak and Folger, 2008). For example, in late 2001, steel prices were about US$600/t. By late 2007, it was US$1400/t. Studies in the literature have also shown a high variability in pipeline costs depending on the length assumed (e.g., McCollum and Ogden, 2006; Perfomak and Folger 2008). In this regard, CO_2 pipeline costs may present the costs component in integrated CCS schemes with the greatest potential variability (IPCC 2005; MIT, 2007).

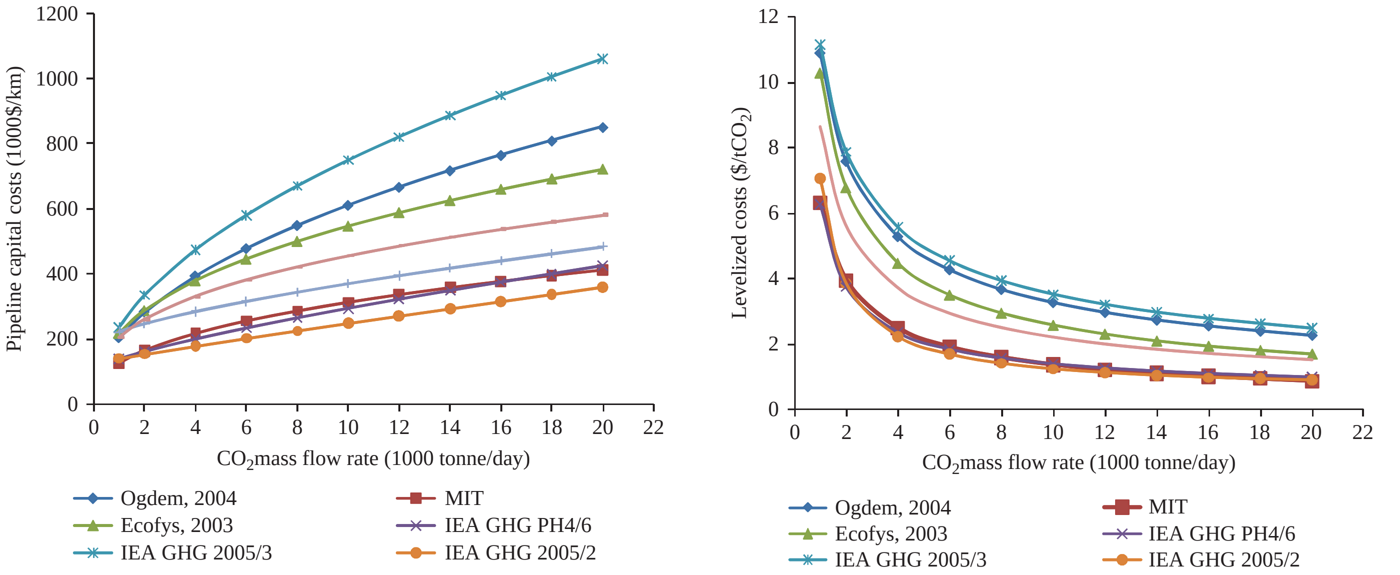

Figure 13.5 | Comparison of pipeline costs (a) and levelized costs (b) for a pipeline with a length of 100 km. Costs are reported in $US_{2005}$$. Source: McCollum and Ogden, 2006.

13.3.4 Transportation Safety

Several studies indicate that CO_2 transport by pipeline does not pose a higher risk than is already tolerated for transporting hydrocarbons (e.g., Heinrich et al., 2004; Hooper et al., 2005; Damen et al., 2006). For instance, cumulative failure rates reported in the literature for CO_2 pipelines range from 0.7–6.1 per 10,000 km/yr, which is in the same range of failure rates reported for hydrocarbon pipelines (Koornneef et al., 2009). Currently there are no minimum standards for pipeline quality CO_2 for CCS purpose. Such standards could depart from those already used in existing CO_2 pipelines. However, since most of those pipelines (e.g., EOR in the United States) predominantly run through sparsely populated areas, the impact of a potential incident is limited. Existing standards and risk assessment models will have to be modified to take into account the vicinity to densely populated areas. Additional measures can include (Skovholt, 1993; Koornneef et al., 2009):

- appropriate monitoring facilities and safety systems, e.g., sectioning valves to reduce the quantity of CO_2 that could leak out and shorter distances between valves near populated areas;
- safety zones on both sides of the pipeline. Ranges recommended in the literature vary between less than 1 m and 7 km;
- increased pipe wall thickness near populated areas; and
- protection from damage (e.g., burying the line).

13.3.5 Conclusions

From a technical point of view, transport of CO_2 by pipeline and ship has successfully been conducted for many years, indicating that issues associated with the design and operation of CO_2 transport can be addressed. Nevertheless, the transport of CO_2 for geological storage also has challenges that need to be addressed. Factors of concern for the appropriate and safe management of CO_2 pipelines include water content, hydrate formation, corrosion, two-phase flow, and toxic components. Benefits of scale indicate the development of pipeline networks as an optimal strategy for the medium and long term. The challenge remains with the scale and speed at which transport networks will need to be constructed, often through densely populated areas. Further development and validation of models that deal with the operation of CO_2 pipeline networks and the management of external safety is therefore necessary.

13.4 Carbon Dioxide Storage Science and Technology

13.4.1 Introduction

Carbon dioxide storage in deep geological formations has emerged over the past 15 years as a feasible component in the portfolio of options for reducing GHG emissions. Five commercial projects now operating provide valuable experience for assessing the efficacy of carbon storage. These projects, in addition to more than 100 CO_2-EOR located primarily in North America, provide a growing experience base for assessing the potential for geological storage. However, if CCS is implemented on the scale needed for large reductions in CO_2 emissions, one Gt or more of CO_2 will be sequestered annually – a 250-fold increase over the amount sequestered annually today. Effectively sequestering these large volumes requires building a strong scientific foundation for predicting the coupled hydrological-geochemical-geomechanical processes that govern the long-term fate of CO_2 in the subsurface. In addition, methods to characterize and select storage sites, subsurface engineering to optimize performance and cost, safe operations, monitoring technology, remediation methods, regulatory oversight, and country-specific institutional approaches for managing long-term liability will all be needed.

13.4.1.1 Options for the Storage of CO_2

Geological formations are not the only option considered for CO_2 storage. Beginning in the early 1990s, there was a great deal of interest in storing CO_2 in the ocean. Two different approaches were pursued: biological sequestration via ocean fertilization and direct injection of a concentrated stream of CO_2.

Scientific experiments have been conducted to evaluate whether adding iron to the ocean could increase biological productivity, thus increasing the rate of ocean uptake CO_2. In 2001, the Southern Ocean Iron Experiment was conducted in the southern Pacific (Buesseler et al., 2004). Results from this and similar experiments showed rapid increases in biological productivity, but many questions remain regarding long-term ecosystem impacts and the effectiveness of this technique for lowering atmospheric CO_2 concentrations. Consequently, at the present time, ocean fertilization is not under serious consideration for large-scale CCS.

CO_2 can also be injected into the mid-depth ocean (1000–3000 m deep), which enables storage for hundreds to thousands of years before returning to the atmosphere via ocean circulation. The injected CO_2 would dissolve and be transported with ocean currents. Alternatively, it could be injected near the ocean bottom, to create stationary "pools" of CO_2. The potential capacity for ocean storage is large – on the order of a trillion tonnes of CO_2 (IPCC, 2005). Little ocean storage research is still being actively pursued. Concerns about unknown biological impacts, high costs, impermanence of ocean storage, and concerns regarding public acceptance have decreased interest and investment in this technology over the past five years.

Hybrid storage schemes that rely on a combination of ocean storage and geological storage have also been proposed recently (Schrag, 2009). For a sufficiently cold ocean, at water depths of greater than 3000 m CO_2 transitions from being lighter than water to heavier than water. Under these conditions, CO_2 would remain on the ocean bottom; however, over time the CO_2 would dissolve into the ocean water, leading to ocean acidification and gradual release back into the atmosphere. To prevent dissolution of CO_2, it is proposed to inject the CO_2 under a thin layer of ocean bottom sediments, thus combining aspects of geological and ocean storage. This relatively new idea is the subject of research and is much less well developed than conventional geological storage.

It has also been suggested that CO_2 storage could be combined with subsea production of methane hydrates (Ohgaki et al., 1996). As methane is being released from the hydrate structure, CO_2 could replace it. In principle not only would this provide a secure storage option, but it would increase hydrate production as well. This idea is in the early stages of conceptual development.

Due to its comparative maturity, geological storage will be the focus of the remainder of this section.

13.4.2 Geological Storage in Deep Underground Formations

13.4.2.1 Technology Description

Under a thin veneer of soils or sediments, the earth's crust is made up primarily of three types of rocks: igneous rocks, formed by cooling magma from either volcanic eruptions or magmatic intrusions far beneath the land surface; sedimentary rocks, formed as thick accumulations of sand, clay, salts, and carbonates over millions of years; and metamorphic rocks of either origin that have undergone deep burial with accompanying pressure and thermal alteration.

To date, sedimentary rocks, located in so-called sedimentary basins, have been the primary focus for geological storage of CO_2 because the storage on geological timescales has already been proven through the presence of oil and gas accumulations in them. Sedimentary basins underlie much of the continents and are co-located with many major large CO_2 emission sources (see Figure 13.6). Until recently, storage in sedimentary basins has been the exclusive focus of geological storage technology and capacity assessments. However, in the past five years there has been a significant effort to understand the potential of volcanic rocks, primarily basalt, for the storage of CO_2 (McGrail et al., 2006; Kumar et al., 2007). Experiments testing the feasibility of storage in basalt are underway in Iceland, India, and two locations in the United States. Motivation for evaluating storage in basalt is two-fold: first, some countries with large CO_2 emissions, such as India, Brazil, and the United States, are underlain primarily by basaltic rocks, and second, it is hypothesized that a large fraction of the stored CO_2 would be converted to stable minerals, assuring permanent storage.

Sedimentary basins often contain many thousand meters of sediments where the tiny pore spaces (10^{-3}–10^{2} μm) in the rocks are filled with saltwater (saline aquifers) and where oil and gas reservoirs are found. An example of a cross section through a sedimentary basin is shown in Figure 13.7. Sedimentary basins consist of many layers of sand, silt, clay, carbonate, and evaporite (rock formations composed of salt deposited from evaporating water). The sand layers provide storage space for oil, water, and natural gas. The silt, clay, and evaporite layers provide the seal that can trap these fluids underground for millions of years and longer. Geologic storage of CO_2 would take place deep in sedimentary basins trapped below silt and clay layers, much in the same way that oil and natural gas are trapped today (Holloway, 1996; Gunter et al., 2004). Within sedimentary basins, possible storage formations include oil reservoirs, gas reservoirs, saline aquifers, and even coalbeds (see Figure 13.8).

Figure 13.6 | Geographical relationship between CO_2 emission sources and prospective geological storage sites. The dots indicate CO_2 emission sources of 0.1–50 $MtCO_2$/yr. Prospectivity is a qualitative assessment of the likelihood that a suitable storage location is present in a given area based on the available information. This figure should be taken as a guide only, because it is based on partial data, the quality of which may vary from region to region, and which may change over time and with new information. Source: IPCC, 2005.

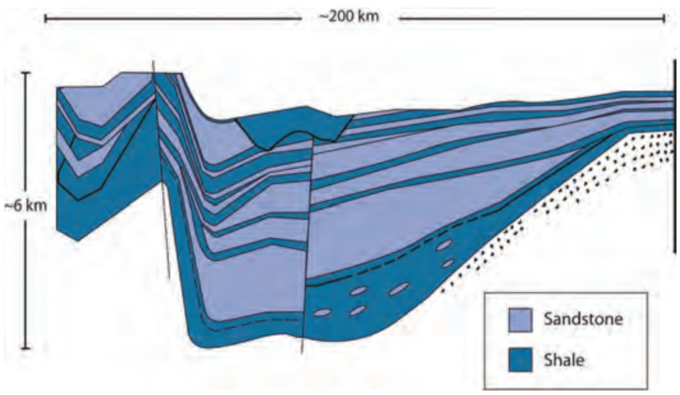

Figure 13.7 | Cross-section of the San Joaquin Valley, California, showing alternating layers of sand and shale. Sand layers provide storage reservoirs; shale layers provide seals.

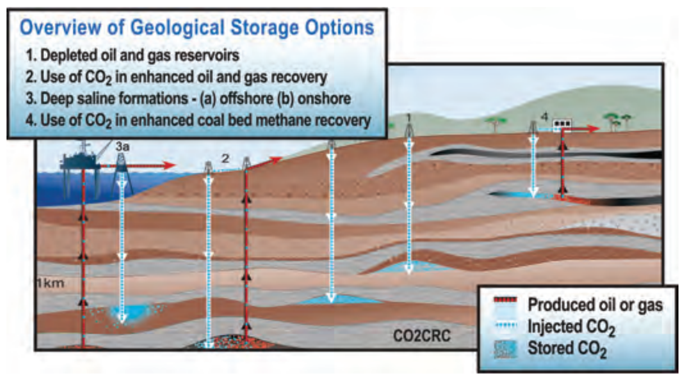

Figure 13.8 | Options for geological storage within a sedimentary basin, including oil and gas formations, saline aquifers, and coalbeds. Source: modified from IPCC, 2005.

The presence of an overlying, thick, and continuous layer of shale, silt, clay, or evaporite is the single most important feature of a geologic formation that is suitable for geological storage of CO_2. These fine-textured rocks physically prevent the upward migration of CO_2 by a combination of viscous and capillary forces. Oil and gas reservoirs are found under such fine-textured rocks and the mere presence of the oil and gas demonstrates the presence of a suitable reservoir seal. In saline aquifers, where the pore space is initially filled with water, after the CO_2 has been underground for hundreds to thousands of years, chemical reactions will dissolve some or all of the CO_2 in the saltwater and eventually some fraction of the CO_2 will be converted to carbonate minerals, thus becoming a part of the rock itself (Gunter et al., 2004). These so-called secondary trapping mechanisms that continue to increase storage security as time goes on have been the subject of significant scientific research over the past five years, with hundreds of relevant publications (Benson and Cole, 2008).

Capillary trapping, sometimes referred to as residual gas trapping, occurs primarily after injection stops and water begins to imbibe into the CO_2 plume. The mechanism immobilizes CO_2, slowing migration towards the surface as the trailing edge of the plume is immobilized. This mechanism is particularly important for storage in dipping formations that do not have structural closure. Studies by Ide et al. (2007) and Hesse et al. (2008) suggest that eventually all the CO_2 in a plume can be immobilized by this mechanism and develop analytical approaches for predicting how quickly this happens and how far the leading edge of the plume moves before it is immobilized.

The dissolution of CO_2 (and other flue gas contaminants) in saline aquifers can lead to the mechanism known as "solubility trapping." The solubility depends on several factors, most notably pressure, temperature, and salinity of the brine (see e.g., Spycher et al., 2003; Lagneau et al., 2005; Oldenburg, 2005; Koschel et al., 2006). For typical storage conditions, the solubility of CO_2 in brine ranges from about 2–5% by mass. Bench-scale experiments have shown that the dissolution of CO_2 is rapid at high pressure when the water and CO_2 share the same pore space (Czernichowski-Lauriol et al., 1996). However, in a real injection system, dissolution of CO_2 may be limited due to the variability of the contact area between the CO_2 and the fluid phase. The principal benefit of solubility trapping is that once the CO_2 is dissolved, it decreases the amount of CO_2 subject to the buoyant forces that drive it upwards. The amount of solubility trapping is expected to increase over periods of hundreds to thousands of years because the density of CO_2-saturated brine is several percentage points higher than the *in situ* brine, leading to convectively enhanced mixing and dissolution.

The third type of secondary trapping is known as "mineral trapping," which occurs when acidic brines enriched in dissolved CO_2 react directly or indirectly with minerals in the geologic formation, leading to the precipitation of stable secondary carbonate minerals (Gunter et al., 2004). This mechanism is potentially attractive because it could immobilize CO_2 permanently. However, a significant degree of mineral trapping could take thousands of years due to sluggish rates of silicate mineral dissolution and carbonate mineral precipitation, so the overall impact may not be realized until far into the future. Moreover, the amount of mineral trapping depends heavily on the mineralogical makeup of the storage reservoir rock. Rocks with large fractions of feldspar minerals are expected to have a significant amount of mineral trapping, while quartz-dominated reservoirs may have little to no mineral trapping.

Schematics illustrating the relative contribution of each of these mechanisms and the consequent increase in storage security over time are shown in Figures 13.9 and 13.10. The range of trapping contributions from each of these processes is highly site specific.

One of the key questions for geologic storage is: how long will the CO_2 remain trapped underground? There are a number of lines of evidence that suggest that for well-selected and -managed storage formations, retention rates will be very high and more than sufficient for the purpose of avoiding CO_2 emissions into the atmosphere (IPCC, 2005). Specifically:

- Natural oil, gas, and CO_2 reservoirs demonstrate that buoyant fluids such as CO_2 can be trapped underground for millions of years.
- Industrial analogues such as natural gas storage, CO_2-EOR, acid gas injection, and liquid-waste-disposal operations have developed methods for injecting and storing fluids without compromising the integrity of the caprock or the storage formation.

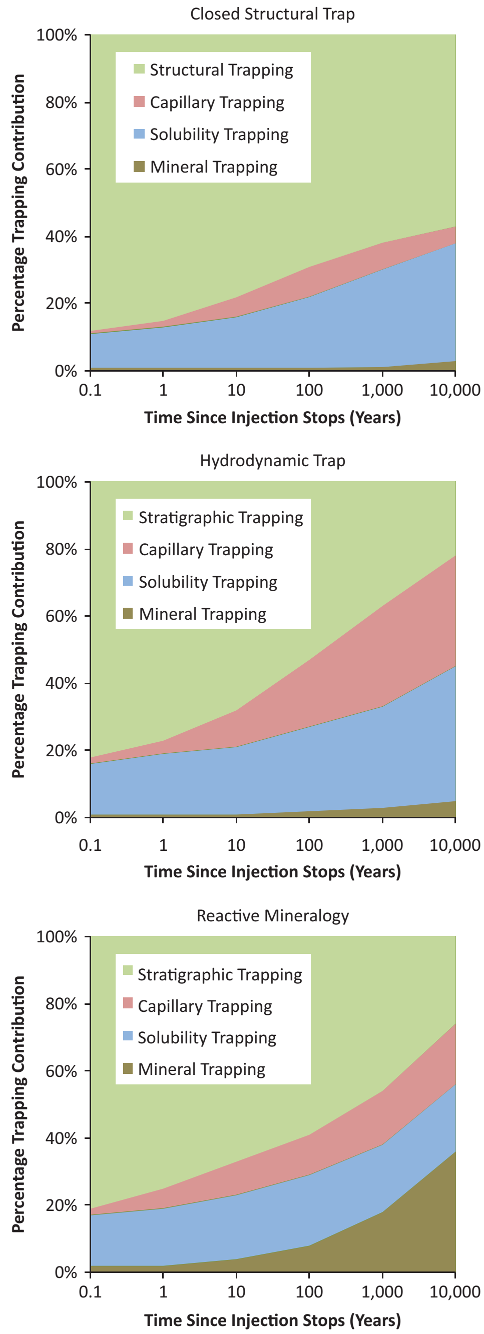

Figure 13.9 | Conceptual schematic showing trapping mechanisms and their evolution over a 10 thousand year period, as expressed as a percentage of the total trapping contribution (modified from IPCC, 2005). The relative importance of each trapping mechanism will be different depending on the attributes of the formation. For example, in a closed structural trap, which provides excellent containment beneath a dome-shaped seal, the secondary trapping mechanisms are comparatively small. In a formation with a dipping seal where the CO_2 moves upgradient due to buoyancy effects, the CO_2 will dissolve more quickly and a large fraction be subject to capillary trapping. For geological formations with a large fraction of reactive minerals such as feldspar or olivine, a significant fraction of the CO_2 may be converted to minerals.

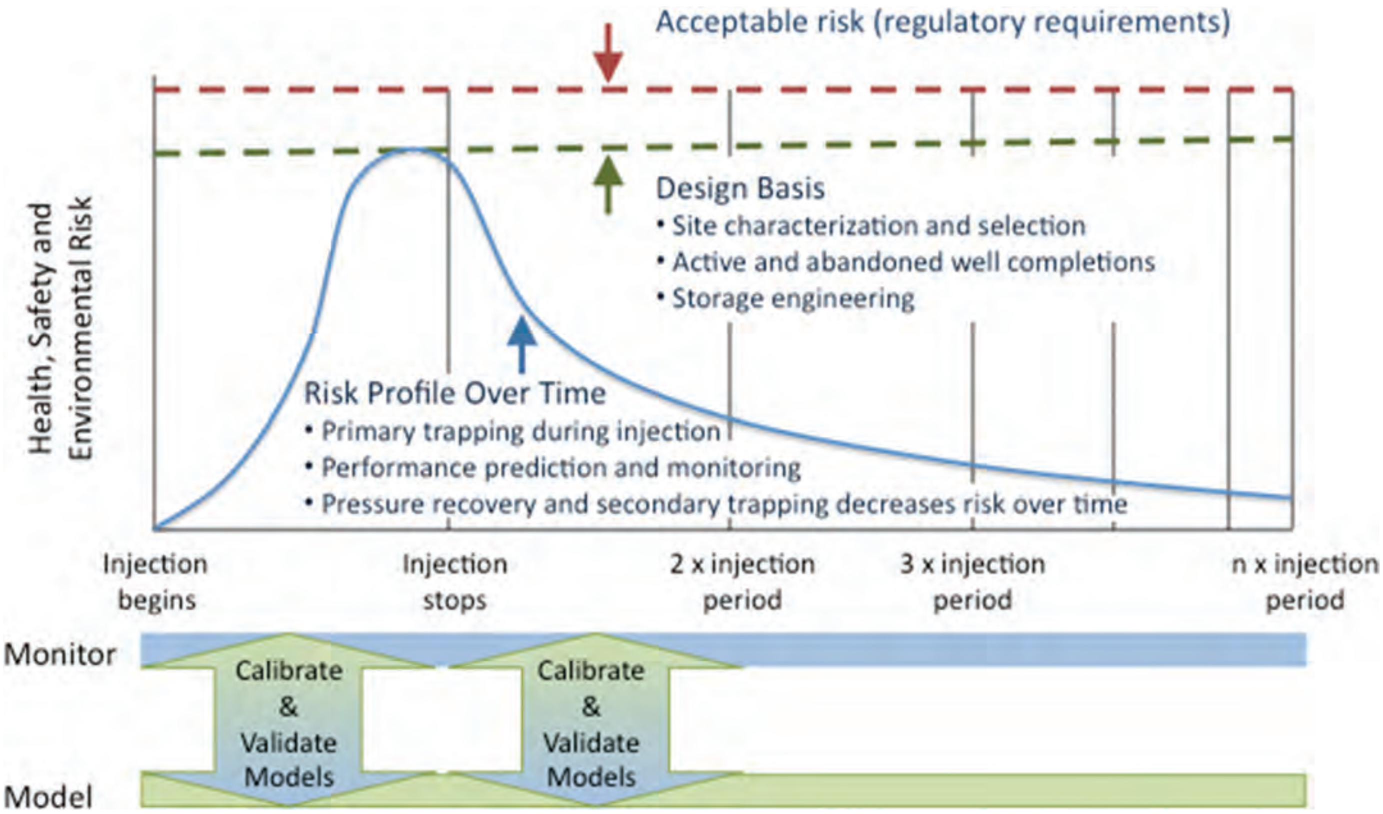

Figure 13.10 | Conceptual schematic illustrating the anticipated magnitude of health, safety and environmental risks over the lifetime of a typical geological storage project. Performance specifications, or acceptable risks, will be set by regulatory authorities. Projects will be designed to conform to regulatory requirements – or even lower depending in the design specifications. Primary risk management tools include site characterization and selection, identification and assessment of abandoned wells (including potential remediation), and storage engineering to ensure CO_2 containment and management of injection pressures. Actual risks will change over time, with growing risks during the early stages of the project, as CO_2 is first injected into the storage reservoir. Eventually, information gained from the combination of performance modeling and acquisition of monitoring data will provide assurance that the project is conforming to the design specifications – or remediation measures will be taken to address unforeseen risks. After injection stops, the pressure in the storage reservoir will begin to decrease, lessening the risk of CO_2 leakage or brine migration. Over time, as indicated in Figures 13.9a-c, secondary trapping mechanisms will further reduce the risks of health, safety and environmental impacts.

- Multiple processes contribute to long-term retention of CO_2, including physical trapping beneath low permeability rocks, dissolution of CO_2 in brine, capillary trapping of CO_2, adsorption on coal, and mineral trapping. Together, these trapping mechanisms increase the security of storage over time, thus further diminishing the possibility of potential leakage and surface release.

- Experiences with projects having large amounts of monitoring data, such as the Sleipner Project in the North Sea and the Weyburn Project in Saskatchewan, Canada, have demonstrated a high degree of containment.

The technology for storing CO_2 in deep underground formations is adapted from oil and gas exploration and production technology. For example, technologies to drill and monitor wells that can safely inject CO_2 into the storage formation are available. Methods to characterize sites are fairly well developed. Models are available to predict where the CO_2 moves when it is pumped underground, although more work is needed to further develop and test these models, particularly over the long timeframes and large spatial scales envisioned for CO_2 storage. Monitoring of the subsurface movement of CO_2 is currently being successfully conducted at several sites, although again, more work is needed to refine and test monitoring methods.

13.4.2.2 Existing and Planned CO_2 Storage Projects

Maps showing the location of current and planned CO_2 storage projects are shown in Figures 13.11a and 13.11b. Many of these are pilot tests or small-scale demonstrations. Today, each of five commercial projects store from about 1–3 $MtCO_2$/yr in deep geological formations at Sleipner, Weyburn, In Salah, Powder River Basin, Wyoming and Snøhvit (Torp and Gale, 2003; Riddiford et al., 2003; Moberg et al., 2003). The Sleipner, In Salah, and Snøhvit projects were designed with CCS as their primary purpose. The Weyburn and Wyoming projects designed initially as an enhanced oil recovery project but has evolved into a project that combines enhanced oil recovery with CO_2 storage. Today,

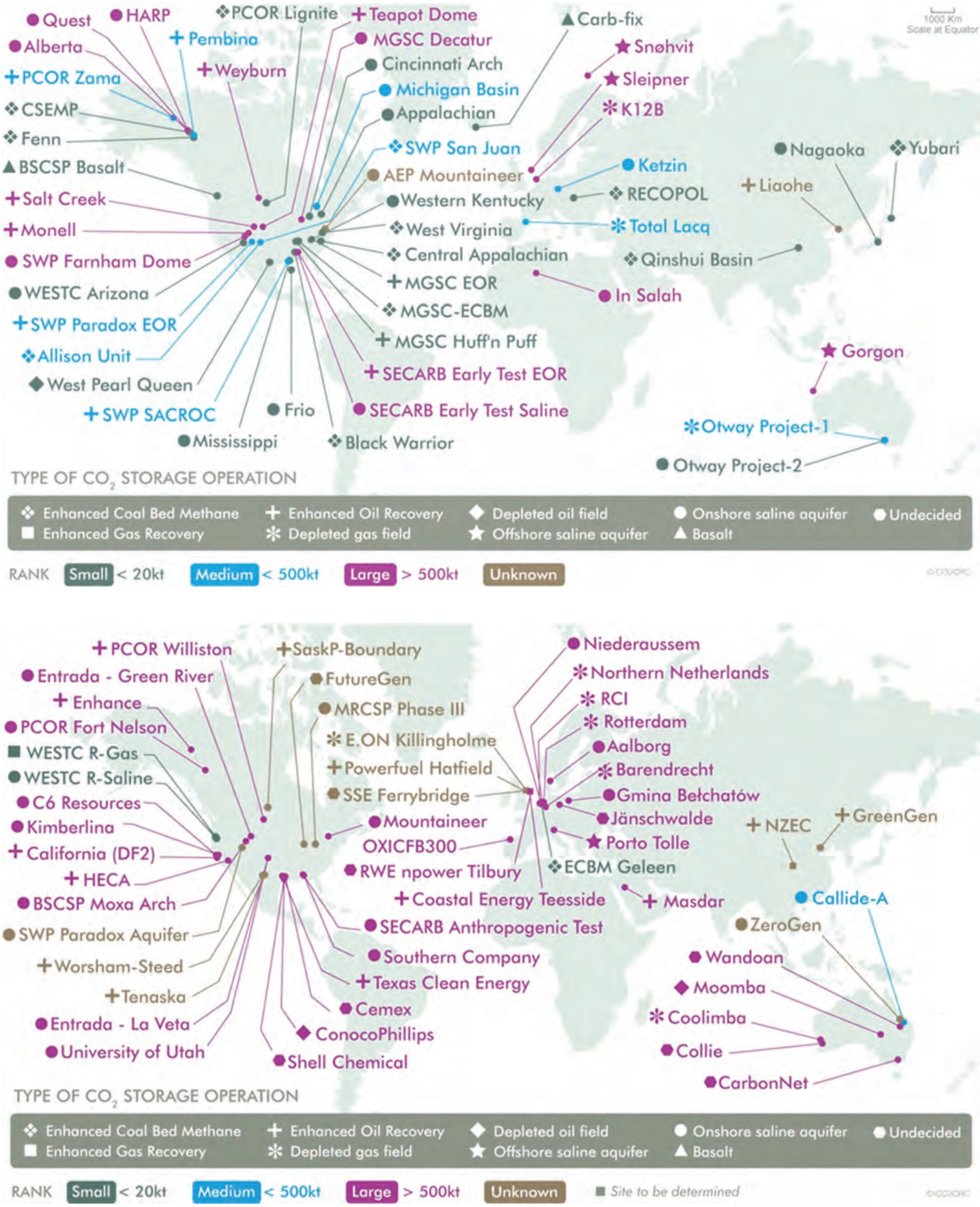

Figure 13.11 | (a) Location of existing CCS projects, including commercial projects, pilot tests, and demonstration projects. (b) Location of planned CCS projects, including commercial projects, pilot tests and demonstration projects (ES1). Source: courtesy of CO2CRC, 2011.

over 30 years of cumulative experience have been gained from these projects.

Sleipner Project, Norway

Beginning in 1996, Statoil initiated storage of approximately 1 $MtCO_2$/yr in a saline aquifer underneath the North Sea. Injection is carried through a single well screened near the base of the 200 m thick Utsira sandstone, at a depth of about 1 km beneath the sea level. The formation is highly permeable and porous, with a number of thin layers of shale distributed over the thickness of the formation. Injection has taken place with few difficulties. A comprehensive seismic monitoring program has provided invaluable information about the movement of CO_2 in the subsurface, demonstrating that CO_2 is securely trapped beneath a thick shale bed (Arts et al., 2010). After 16 years of injection, the plume covers an extent of about 15 km^2 and is moving slowly below the base of the seal. Numerous studies have compared predictions from computer models to observed migration, with reasonably good results as long as the geological complexity of the storage reservoir is included in the model (Bickle et al., 2007). Overall, the Sleipner Saline Aquifer Storage Project has done a great deal to generate confidence in the geological storage of CO_2.

Weyburn Project, Canada

The Weyburn Project in Saskatchewan, Canada combines CO_2-EOR and storage in a carbonate oil reservoir located north of the United States-Canada border. Beginning in 2000, PanCanadian Oil Company, and later Encana, initiated injection of a total of 2–3 $MtCO_2$/yr containing about 2% H_2S from the Dakota Gasification Plant into an array of wells designed to optimize oil recovery. The IEA Greenhouse Gas Program coordinates an extensive monitoring effort, including seismic imaging, geochemical sampling of produced brine, and soil gas sampling. The oil field is situated under a thick seal of anhydrite (salt formation), which is expected to provide an excellent seal. Results from the monitoring program document the movement of CO_2 in the reservoir (White el al., 2009), geochemical interactions between CO_2 and the carbonate rocks (Emberly et al., 2005), and the lack of detectable changes in soil gas composition associated with injection (Wilson and Monea, 2004). Overall, the Weyburn Project demonstrates effective retention of CO_2 in the oil field.

In Salah Project, Algeria

The In Salah Project in Algeria, initiated by BP, Sonatrech, and Statoil, is the most technologically complex storage project undertaken to date. CO_2 separated from natural gas is pumped back into the flanks of the gas reservoir from which the CO_2 is produced. Due to the low permeability of the reservoir rocks, three horizontal wells (with open intervals of 1000–1500 m) are used to inject CO_2 into the 20-meter thick reservoir at a depth of about 1800 m. Since 2004, about 0.7 $MtCO_2$/yr have been injected into the reservoir. In 2008, satellite-based land surface deformation monitoring enabled mapping of the region where pressure buildup was occurring, as documented by uplift on the order of 2 cm/yr. This discovery, confirmed now by many research groups, provides a new method for monitoring CO_2 storage projects (Vasco et al., 2008). These observations, combined with the detection of a small leak up an exploratory well, suggested that the flow of CO_2 is in part controlled by fractures in the reservoir (Iding and Ringrose, 2010). After the leak was detected, injection in the closest well was stopped while the exploratory well was plugged with cement and abandoned properly. Injection was started again after the well was plugged. The In Salah Project provides an interesting case study regarding the ability to detect and stop leaks, as well as illustrating how subsurface complexity controls CO_2 movement in the storage reservoir. Seismic data has been collected and is now being interpreted with regard to CO_2 movement.

Snøhvit Project, Norway

The Snøhvit Project, located in the Barents Sea north of Norway, is the most recently initiated project, with injection starting in 2008. Approximately 0.7 $MtCO_2$/yr is injected into a sub-sea saline aquifer situated underneath the producing gas reservoir. The storage facility is associated with a large liquefied natural gas project. The injectivity was initially lower than expected. The large pressure buildup leading to low injectivity was attributed to compartmentalization of the storage reservoir and a remedy has been implemented (Eiken et al., 2011).

CO_2 EOR Projects

Vast experience pumping CO_2 into oil reservoirs also comes from nearly 30 years of CO_2-EOR, with nearly 50 Mt injected in 2010. About 100 projects are underway worldwide, with the vast majority in North America. When CO_2 is pumped into an oil reservoir, it mixes with the oil, lowering the viscosity and density the oil. Under optimal conditions, oil and CO_2 are miscible, which results in the efficient displacement of oil from the pore spaces in the rock. An estimated increase in oil recovery of 10–15% of the initial volume of oil-in-place is expected for successful CO_2-EOR projects. Not all of the injected CO_2 stays underground, as 30–60% is typically produced back with the oil. On the surface, the produced CO_2 is separated from the oil and re-injected into the reservoir. If CO_2 is left in the reservoir after oil production stops, most of the CO_2 injected over the project lifetime remains stored underground. The majority of CO_2-EOR projects today uses CO_2 from naturally occurring CO_2 reservoirs. The high cost and limited availability of CO_2 has restricted the deployment of CO_2-EOR to those areas with favorable geological conditions and a readily available source of CO_2. A few projects use CO_2 captured from industrial sources, notably the Weyburn Project discussed above and the Salt Creek Project in Wyoming, which is injecting several million tonnes per year.

The recent high oil prices have spurred interest in expanding the application of CO_2-EOR. This possibility, together with prospects for obtaining tradable credits for storing CO_2, has attracted considerable interest by the oil and gas industry.

Other Planned Projects, Pilot Tests, and Small-Scale Demonstrations

As shown in Figure 13.11, there are more than 280 pilot tests, demonstration projects, and commercial projects that are underway or in the planning stages. Most of these are small-scale pilot tests, supported by government-industry partnerships and designed primarily to gain experience with site selection and monitoring and to increase our understanding of the behavior of CO_2 in the subsurface. Launching a commercial scale storage project takes many years and in some cases a decade or more, as a result of the need to characterize the site, obtain injection permits, secure financing, drill wells, and manage all of the other components of these large-scale engineering endeavors. Several large projects, notably the Gorgon Project in Australia (3–4 $MtCO_2$/yr), are under construction and are expected to begin operations in the next five years.

13.4.3 Storage Capacity Estimation

The distribution and capacity of storage reservoirs are two of the most important parameters with regard to the widespread deployment of CCS technology. If storage capacity is not sufficient or it is not co-located with large emission sources, CCS is unlikely to play a major role in reducing CO_2 emissions. The IPCC (2005) gathered worldwide capacity estimates and concluded that there is sufficient capacity to meet at least one hundred years (technical potential ranging from 200–2000 Gt) of needed storage capacity, but that the distribution was variable and not all nations or regions had equally good potential for storage. The storage capacity in oil and gas formations ranged from 675–900 Gt, in coalbeds from 3–200 Gt, and in saline aquifers from 1000–10,000 Gt (IPCC, 2005).

In 2005, the quality of information about storage capacity was highly variable, with only a few regions having undertaken systematic capacity assessments. Moreover, the IPCC report also highlighted the uncertainties with respect to the storage capacity of saline aquifers. No generally accepted methodology for saline aquifer capacity assessment was available (Bachu et al., 2007). Since that time, many nations have undertaken systematic capacity assessments, using more clearly documented methods (e.g., US DOE, 2010). Specifically, the majority of saline aquifer capacity assessments are carried out by identifying locations where the following criteria are met:

- deep sedimentary basins where permeable strata are present;
- depths are greater than 800–1000 m;
- seals are present above the storage reservoir;
- salinity exceeds specific standards (e.g. 10,000 ppm in the United States); and
- access is not otherwise precluded due to other beneficial uses (e.g., military bases, parks, etc.)

After these screening criteria are applied, the mass of CO_2 that can be stored is calculated by equations of the following type:

$$
\begin{aligned}
&Capacity = \rho_{CO_2} \cdot A \cdot T \cdot \Phi \cdot E\\
&where:\\
&\quad \rho_{CO_2} = density\ of\ CO_2\ (kg/m^3)\\
&\quad A = Area\ (m^2)\\
&\quad T = net\ sand\ thickness\ (m)\\
&\quad \Phi = porosity\\
&\quad E = Efficiency\ Factor
\end{aligned} \tag{2}
$$

The efficiency factor typically ranges from 0.01–0.05, or from 1–5% of the pore space of the rocks (NETL, 2010a). The efficiency factor is estimated based on the numerical simulation of a wide range of storage scenarios. Variations on these kinds of volumetric capacity estimation methods that account for a number of other factors are also being developed and applied. These factors include considering those areas where there is a structural closure that limits the migration of CO_2 (European method; USGS, 2010); multiphase flow dynamics (Juanes et al., 2010); and the amount of CO_2 dissolved in the saline aquifer. Capacity estimates using these different methods can vary significantly, particularly when accounting for only those regions with structural closure. Consequently, while much progress has been made with regard to capacity estimation, many uncertainties remain.

One of the largest questions regarding storage capacity is the extent to which saline aquifers without structural closure can be used for storage. Structural closure refers to the presence of a typically domed-shaped seal where buoyant fluids can accumulate. Arguments in favor of using these formations without closure rely on scientific theories indicating that CO_2 will be immobilized by a combination of capillary trapping, solubility trapping, and mineral trapping (IPCC, 2005). These processes gradually reduce the fraction of CO_2 that is free to continue moving after injection has stopped (Ide et al., 2007; Hesse et al., 2008; MacMinn and Juanes, 2009). In theory, once CO_2 stops moving, structural closure is not needed to securely trap CO_2 over geological time periods. Arguments against using portions of saline aquifers without structural closure focus on uncertainties about the extent and timing of these secondary trapping mechanisms. If these processes do not effectively immobilize the CO_2 quickly enough, CO_2 could migrate into drinking water aquifers or be released to the atmosphere. Additional understanding of these trapping processes through a combination of theoretical, laboratory, and field research is needed. The monitoring of existing projects described in Section 13.4.2.2 will also provide crucial insights into the long-term mobility of CO_2 in the subsurface.

Over the past several years, another issue has arisen with regard to capacity estimation. Several authors have suggested that pressure buildup in the storage reservoir will limit storage capacity (van der Meer and van Wees, 2006; Economides and Ehlig-Economides, 2009; Birkholzer and Zhou, 2009). For small- to moderate-size reservoirs that are completely sealed above, below, and on all sides, pressure buildups can be very large if even a small fraction of the pore space (~1% or more) is filled with CO_2, resulting from the extremely low compressibility of water. Overly large pressure buildup can lead to hydraulic fracturing of the reservoir and seal, thus limiting the maximum pressure buildup in the storage reservoir. For completely sealed reservoirs, pressure buildup would indeed limit storage capacity. The importance of pressure buildup constraints on capacity will depend on the degree to which completely sealed reservoirs are used for storage and how many such reservoirs exist. Most reservoirs are not completely sealed and only a top seal is absolutely essential and, perhaps, desirable. Additionally, several authors have also shown it is possible to extract water while storing CO_2 to control the extent of pressure buildup (e.g., Guénan and Rohmer, 2011). Consequently, the extent to which pressure buildup will limit storage capacity remains to be seen. Importantly, pressure limits on storage capacity should not be confused with pressure limits on injectivity, which is a very real constraint on the rate that CO_2 can be injected into a well.

13.4.3.1 Regional and Global Geological Storage Capacity Estimates

Table 13.2 summarizes the results from regional and national capacity assessments. Capacity estimates for oil and gas formations range from 996–1150 $GtCO_2$, coalbeds from 93–150 $GtCO_2$, and saline aquifers from 3963–23,171 $GtCO_2$. Current estimates suggest that global capacity will be at the high end of the range estimated in IPCC (2005).

Table 13.2 | Compilation of current storage capacity estimates. (Note this is not a complete accounting because capacity assessments have not been completed in many areas of the world. Additionally, common methods are not used and significant uncertainties in capacity assessment methodology remain. Different methodologies and assumptions have been used and comparisons between capacities for different regions should be viewed with caution.)

Region	Estimated Storage Capacity ($GtCO_2$)				Source	Note
	Depleted Oil and Gas Reservoirs	Saline Formations	Coal Seams	TOTAL		
North America	143	1653–20,213	60–117	1856–20,473	1	
Latin America	89	30.3	2	NA	14	a
Brazil	NA	2000	0.2	2000.2	2	
Australia	19.6	28.1	11.3	59	3, 4	b
Japan	0	1.9–146	0.1	2–146.1	5, 6, 14	
Centrally Planned Asia and China (CPA)	9.7–21	110–360	10	1445 -3080	7, 8, 9, 10, 17	c
Other Pacific Asia (PAS)	56–188	NA	NA	56–188	11, 12	d
South Asia (SAS)	6.5–7.4	NA	0.36–0.39	6.86–7.79	12	e
Former Soviet Union (FSU)	177	NA	NA	177	13	f
Sub-Saharan Africa	36.6	34.6	7.6	48.3	14	g
Middle East and North Africa	439.5	9.7	0	449.2	14	
Europe	20.22–30	95.72–350	1.08–1.5	117–381	15, 16	h
World	996 – 1150	3963 – 23,171	93 – 150			i

(a) All countries in Central and South America, including Brazil.

(b) The storage capacities are only in Australia. There is no storage capacity assessment in New Zealand.

(c) The numbers correspond to the storage capacity in China only. The numbers are not additive since they come from different references.

(d) The numbers correspond to the storage capacity in Indonesia only. No information was available for other countries.

(e) The numbers correspond to the storage capacity in India, Pakistan, and Bangladesh. The same report states that significant storage capacity exists in saline formations, but it has not been quantified yet.

(f) Does not include Estonia, Latvia, and Lithuania, even though they are former Soviet states. The capacity in the aforementioned states is considered in the European Union region.

(g) Includes Eastern, Western, and Southern Africa (not Northern Africa)

(h) Not all European countries are included in the Geocapacity Study. The countries that are NOT included in the Geocapacity study (specifically Finland, Ireland, Portugal, Switzerland, and Sweden) were individually studied, and no information was found about their CO_2 storage capacity.

(i) Equal to the sum of the values in Table 13.2 for oil and gas field, coalbeds and saline formations.

Source: (1) Carbon Sequestration Atlas of the United States and Canada, Second Edition, 2010 (2) Ketzer et al., 2007 (3) Carbon Storage Taskforce, 2009 (4) Bradshaw et al., 2004 (5) Nakanishi et al., 2009 (6) Takahashi et al., 2009 (7) PetroChina Company Limited, 2007 (8) Wang, L., 2010 (9) Lou, 2008 (10) APEC, 2005 (11) Indonesia CCS Study Working Group, 2009 (12) IEA GHG, 2008 (13) Zakharova, 2005 (14) Hendriks et al., 2004 (15) EU Geocapacity, 2008 (16) Anthonsen et al., 2009 (17) Dahowski et al., 2009.

13.4.4 Risks of Geological Storage of CO_2

Risks of CO_2 storage are typically separated into two broad categories: 1) risks associated with the release of CO_2 back into the atmosphere, and 2) health, safety, and environmental risks associated with the local impacts of the storage operations and potential leakage out of the storage reservoir.

The consequences of releases of CO_2 back into the atmosphere are that CCS would be less effective as a mitigation measure than anticipated and there would be financial liabilities associated buying credits or otherwise assuming responsibility for those emissions. Ultimately, these kinds of risks are associated with the duration and security of storage, which are addressed in Section 13.4.4.1. A particular complexity of CCS is that these financial liabilities are perceived to persist over periods of up to several hundred years or longer, but, as discussed in Section 13.4.4.1, the risk of releases to the atmosphere are greatest during the period of CO_2 injection, which for any particular project are limited to decades. Additionally, as discussed in Section 13.4.5, legal and administrative mechanisms for managing long term liabilities, well beyond the period of operation and post-injection assurance monitoring are being developed by governments worldwide.

The local health, safety, and environmental concerns of a CO_2 storage project are similar to those typically associated with producing oil and gas fields, such as road traffic, noise, habitat fragmentation, and infrequent uncontrolled releases from wells. In addition, if CO_2 or brine leaks out of the storage reservoir it may affect groundwater quality, and result in locally hazardous concentrations of CO_2 in the air and microseismicity if injection pressures are very high. The local health, safety, and environmental concerns for CO_2 storage projects are discussed in Section 13.4.4.2.

Because of the operational and technological similarities, the probability and consequences of risks from geological storage are generally assumed to be similar to those of existing activities such as oil and gas production, natural gas storage, and acid gas injection (IPCC, 2005). The risks are managed on a routine basis through a combination of operational controls, management oversight, monitoring, maintenance, regulatory oversight, and insurance. Similar practices are needed to manage the risks of geological storage. In fact, each of the five active projects described in Section 13.4.1 have successfully managed these risks.

Based on analogous experience from the natural gas storage industry, the three largest sources of risk for geological storage projects are inadequate site selection due to inadequate seal characterization, leakage up active or abandoned wells, and leakage through undetected faults or fractures in the storage reservoir seal.

With experience, site selection for the natural gas storage industry has improved to the point where these risks are relatively small. For natural gas storage projects, if a sufficiently thick seal with structural closure, low permeability, and high capillary entry pressure covers the entire extent of the storage project, the risks of leakage are small. However, in comparison, a typical underground plume of CO_2 may grow to extend over hundreds of km^2, far larger than the size of a typical natural gas storage project; this suggests that time and experience will be needed to perfect the site selection process.

Leakage up active and abandoned wells remains the largest concern from natural gas storage projects and indeed has resulted in a small amount of leakage from the In Salah Project (Mathleson et al., 2011). The potential for wellbore leakage from CO_2 storage reservoirs has been the subject of a large amount of experimental and theoretical research over the past five years (Gasda et al., 2004; Carey et al., 2007; Nordbotten et al., 2009; Duguid and Scherer, 2009). Clearly, if CO_2 encounters a wellbore that is not cemented to the rock, CO_2 can migrate up the annulus and, if left unchecked, can reach the surface. More problematical is the influence of CO_2 on a cemented well. Laboratory and theoretical studies suggest that chemical reactions with water and CO_2 can degrade cement, creating leakage pathways through a largely intact cement seal. On the other hand, several wellbores in active CO_2 reservoirs have been tested and suggest that cement degradation is minimal. Additional studies are needed to resolve this issue.

Leakage through undetected faults and fracture is another source of leakage risk. Usually a combination of well drilling, logging, pressure testing, and seismic imaging is used to assess the quality of the reservoir and seal. Under certain circumstances, particularly where the offset across a fracture or fault is small, a fault may go undetected. Site characterization methods are getting better all the time, decreasing the risk that this could occur. Nevertheless, this risk is usually minimized by avoiding storage projects in areas with known faulting or at least with no active faults. Over time, as the best storage sites are used, greater efforts will be needed to assure that undetected faults and fractures do not compromise the storage site.

13.4.4.1 Duration and Security of Storage

Based on our best scientific understanding of the processes controlling CO_2 migration in the subsurface, CO_2 should remain securely stored in the subsurface for geological time periods (thousands of years and longer) if the following conditions are met:

- The seal has a low enough permeability and high enough capillary pressure to prevent migration into the seal.
- CO_2 cannot migrate around the edge of the seal or through breaches in the seal caused by leaking wells, faults, or fractures.
- The injection pressure is low enough to avoid fracturing the seal.

While in principle these are straightforward enough to understand, the bigger challenge is to identify sites that meet these conditions. Subsurface geology is by nature complex and geological storage sites are by necessity large, with CO_2 plumes potentially covering hundreds of km^2. For this reason, it is not easy to provide an unqualified answer about the duration and security of storage. The IPCC (2005) dealt with this issue by making qualified statements about the retention of CO_2:

> "Observations from engineered and natural analogues as well as models suggest that the fraction retained in appropriately selected and managed geological reservoirs is very likely to exceed 99% over 100 years and is likely to exceed 99% over 1000 years" (IPCC, 2005).

This statement was unsatisfying to many people for several reasons. First, the statement was based on expert opinion as opposed to actual experience. Second, the quantitative measures appear to be somewhat arbitrary, using terms like "likely" and "very likely," which perhaps imply a greater degree of precision than is possible. Finally, the statement is somewhat circular, implying that a good outcome will be achieved if the "the job is done right" but without prescribing exactly how to do the job right. The question then becomes, what have we learned in the intervening five years that could shed further light on the issue of storage permanence, especially considering the tremendous amount of research carried out over the past five years, numerous pilot tests, and demonstration and commercial projects?

From the five existing commercial scale projects, available information indicates that overall, they have performed as expected, with little or no leakage, and leakage that did occur was caused by abandoned wells. Once identified, the leaking wells can be sealed. This suggests that it is possible to find sites that meet the conditions needed for secure storage. Monitoring methods have shown to be effective for tracking CO_2 and the pressure buildup caused by CO_2 injection. Calibrated models also reasonably replicate CO_2 plume movement. All of these build confidence in the security of storage and our ability to "do the job right." But, it is still early in the lifetime of the projects and more will be learned as time goes on.

From the vast amount of research and pilot projects, much has been learned about how CO_2 migrates through the subsurface and how CO_2 geochemically interacts with rocks and cement. Understanding and confidence are growing in the secondary trapping mechanisms' ability to immobilize CO_2 and increase storage security in the post-injection period. Many new and improved methods for monitoring are being developed and tested, improving our ability to detect even small amounts of leakage. Methodologies for characterizing sites have been proposed and are being tested in numerous demonstration projects around the world (WRI, 2009, NETL, 2010b, DNV, 2010). Leakage up abandoned wellbore remains the biggest vulnerability for otherwise high-quality sites.

In light of the progress made over the past five years, what new can be said about storage duration and security? Observations from *commercial storage projects*, engineered and natural analogues, as well as *theoretical considerations*, models, and *laboratory experiments*, suggest that appropriately selected and managed geological storage *reservoirs are very likely to retain nearly all the injected CO_2 for very long times, more than long enough to provide benefits for the intended purpose of CCS.*

13.4.4.2 Local Health, Safety, and Environmental Concerns for CO_2 Storage

CO_2 is used in a wide variety of industries, from chemical manufacture to beverage carbonation and brewing, from enhanced oil recovery to refrigeration, and from fire suppression to inert atmosphere food preservation. Because of its extensive use and production, the hazards of CO_2 are well known and routinely managed. Engineering and procedural controls are well established for dealing with the hazards of compressed and cryogenic CO_2.

While CO_2 is generally regarded as a non-toxic inert gas, exposure to concentrations in excess of several percent can lead to adverse consequences. In particular, since CO_2 is denser than air, hazardous situations arise when large amounts of CO_2 accumulate in low-lying, confined, or poorly ventilated spaces. While the chances of this occurring are very low, if a large amount of injected CO_2 were to escape from a storage site, it could present risks to health and the local environment. However, hazardous conditions would only persist several hundred meters from the site of the release, even for the largest possible leakage rates (Aines et al., 2009). Such releases could be associated with surface facilities, injection wells, or leakage from the storage formation itself. There may be small-scale diffuse leaks or leaks concentrated near the injection facilities. Leakage, if unchecked, could harm groundwater and ecosystems. Persistent leaks could suppress respiration in the root zone or result in soil acidification and eventually lead to tree-kills such as those associated with soil gas concentrations in the range of 20–30% CO_2 which have been observed at Mammoth Mountain, California, where volcanic out gassing of CO_2 has been occurring for several decades (Martini and Silver, 2002).

CO_2 storage projects are designed with the goal of avoiding these potential hazards. It is important, however, to have a comprehensive understanding of what could go wrong. Potential local health, safety, and environmental concerns from geological storage include the following. This list is approximately ordered with the largest to smallest risks, based on analogous experience from existing commercial operations:

- Occupational risks associated with well field operations. These risks are well understood both in terms of the nature of the risks and the frequency of occurrence. Overall, the injury rate for oil and gas field projects in the United States are lower than for many industries, but the severity is on the higher side, caused mainly by vehicle accidents (US Bureau of Labor Statistics (BLS, 2011), on-line database). For example, from the

2 The TRC is defined as the number of recordable injury and illness cases per 100 full-time workers.

period 2004–2007, the TRC (Total Recordable Case Rate) for the oil and gas production workers ranged from 1.4–1.7, as compared to 4.3–5.4 for all or the goods-producing industries.[2] For the same period, injuries or illnesses involving days away from work were 0.4–1.0 for oil and gas workers compared to 1.2–1.5 for all goods-producing industries.

- While CO_2 storage projects are expected to take place in storage reservoirs far deeper than drinking water aquifers, if CO_2 or brine leaks out of the storage reservoir it could migrate into drinking water aquifers. Risks of groundwater contamination include CO_2 intrusion into a fresh water aquifer, secondary contamination resulting from geochemical reactions between CO_2 and the aquifer rocks, from displaced saline brines, or in the case of storage in oil and gas fields (and potentially coalbeds), organic contaminants transported with the CO_2. In addition, risks will be site specific, depending on the hydrogeological environment and mineralogy of the rocks (Wilkin and DiGiulio, 2010). Of particular emphasis is the potential for brine migration even if no CO_2 leaks from the storage reservoir, which could increase the salinity and potentially the trace element content of drinking water sources (Nicot, 2008; Birkholzer et al., 2009). A significant concern is the large region over which the pressure will increase in the storage formation, a region far larger than the extent of the CO_2 plume. If abandoned wells or faults provide a conduit to short-circuit the seal, brine could invade a drinking water aquifer and degrade water quality. However, an extensive field study above one of the largest CO_2-EOR projects did not find any evidence of groundwater degradation due to CO_2 intrusion or brine migration (Romanak et al., 2010).

- Resource damage to nearby oil and gas fields or coalbeds, due to unwanted CO_2 migration into nearby mineral resources. The probability of these risks is low unless the storage reservoir is close to an oil or gas field.

- Ecosystem impacts in the event that CO_2 is released into soil, wetlands, or surface waters. If CO_2 is released to the surface, some local impacts to ecosystem productivity and function would be expected.

- Public safety risks from exposure to elevated CO_2 concentrations if CO_2 is released at the surface. The risks to the public will always be small compared to worker risk. Additionally, around the world there are many known sites of CO_2 releases into the atmosphere that pose little to no hazard, such as the Crystal Geyser site in Utah (Aines et al., 2009) and many sites in Europe (Beaubien et al., 2004; Voltattorni et al., 2006). However, if CO_2 leaks to the surface and accumulates in a low-lying area, exposure to even fatal concentrations of CO_2 is possible such as occurred at Mammoth Mountain, CA (Martini, and Silver, 2002). Risks from areas of known leakage can and are controlled by limiting access to the hazardous areas through signage and fences (Beaubien et al., 2004).

- Structural damage associated with land surface deformation or microseismicity. These risks are relatively well understood and should be managed by controlling the injection pressure to avoid unacceptable levels of microseimicity or land surface deformation. High-resolution remote sensing maps depicting subsurface faults, fractures, and fracture density patterns of geological storage sites may be prepared to understand the structure and associated risks. Regulatory oversight is needed to ensure the project is managed with proper controls.

Importantly, the five existing projects have experienced none of these environmental impacts. Even though an abandoned well that intersected the storage reservoir at In Salah was found to be leaking through a routine monitoring program, no health safety or environmental impacts resulted from this event (Mathleson et al., 2011).

Extensive industrial experience with injection of CO_2 and gases in general indicates that risks from geologic storage facilities are manageable by using standard engineering controls and procedures. Loss of well control, probably the highest risk event that could occur in a CO_2 storage project, is infrequent. For example, one study focused on the largest oil and gas producing region in California indicated an overall rate of one blowout/12,000 wells/yr (Jordan and Benson, 2008). Furthermore, this study showed that property damage and human health impacts were small from blowouts that did occur (Jordan and Benson, 2008). Regulatory oversight and institutional controls further enhance the safety of these operations, and ensure that the site selection and monitoring strategy are robust. Employed on a scale comparable to existing industrial analogues, the risks associated with CCS are comparable to those of today's oil and gas operations. Eventually, if CCS were to be deployed on the grand-scale needed to significantly reduce CO_2 emissions (billions of tonnes annually), the scale of operations would increase to become as large as or larger than existing oil and gas operations (Burruss, 2004). In this eventuality, experience gained in the early years of CCS would be critical for assessing and managing the risks of the very large-scale geological storage projects.

13.4.4.3 Monitoring and Risk Management

In the 2005 *IPCC Special Report on Carbon Dioxide Capture and Storage*, the authors concluded that "the local health, safety and environment risks of geological storage would be comparable to risks of current activities such as natural gas storage, EOR, and deep underground disposal of acid gas." To achieve this high level of performance, a comprehensive approach is needed to manage environmental, health, and safety risks throughout the life cycle of a storage project, from site selection past the operational lifetime of the storage project. Monitoring must play a key role to observe the behavior of the injected CO_2, calibrate and validate predictive models, and provide any early warning that leakage may be imminent. In the event of imminent or actual leakage, remediation measures such as plugging abandoned wells will be needed. A regulatory oversight capacity is needed to ensure due diligence for siting, engineering, operating, monitoring, and remediating storage projects. Finally, private and/or public sector mechanisms are needed to ensure financial responsibility for any short- and long-term liabilities created by the project.

Every storage project is likely to use a combination of monitoring techniques (e.g., geophysics, hydrology, geochemistry) that will, at a minimum, track migration of the CO_2 plume, detect leakage out of the storage reservoir, monitor injection rates and pressure, and detect microseismic activity. Technology for monitoring geologic storage of CO_2 is available from a variety of other applications, including the oil and gas industry, natural gas storage, disposal of liquid and hazardous waste in deep geologic formations, groundwater monitoring, food preservation and beverage industries, fire suppression, and ecosystem research. Many of these techniques have also been demonstrated at the five existing storage projects and many smaller-scale pilot tests around the world (e.g., Arts et al., 2004; Hovorka et al., 2006). Specific regulatory requirements for monitoring have yet to be established. The principle methods of monitoring are described below.

Geophysical Monitoring
Several geophysical monitoring methods can be used to monitor the location of the CO_2 plume. Seismic imaging can detect changes in compressional wave velocity and attenuation caused by the presence of separate phase CO_2. Electromagnetic imaging can detect decreases in electrical conductivity caused by the presence of CO_2 in the pore spaces of the rock. Gravity measurements are sensitive to the decrease in bulk density of the rock caused by the presence of CO_2. Seismic methods for monitoring have been used successfully at Sleipner, Weyburn, the Frio Brine Pilot, and the Otway Basin Pilot Project, as well as others (Arts et al., 2009; Hovorka et al., 2006; White, 2009; Pevzner et al., 2010).

Geochemical Monitoring
Two types of geochemical measurements can be deployed to monitor CO_2 injection. The first involves the use of direct techniques including measurements of brine chemistry and introduced or natural tracers in samples obtained from injection horizons in observation wells. The second involves monitoring the near-surface for possible CO_2 leakage in the immediate vicinity of injection and observation wells, as well as from soils and shallow wells within the injection area.

To date, geochemical methods have been used primarily for the pilot scale tests because of the important insights they provide about the geochemical interactions between CO_2 and the storage reservoir rocks (Kharaka et al., 2006a; 2006b). They have also been used extensively at the Weyburn Project (Emberly et al., 2005). The simplest monitoring systems include pH, alkalinity, and gas-compositions. Of these, pH is probably the most diagnostic indicator of brine-CO_2 interactions and typically exhibits marked decreases that correlate closely with the breakthrough of CO_2 to monitoring wells. Major, minor, trace elemental chemistry and stable isotope geochemistry are used to assess the extent of water-CO_2-rock interactions. Enrichments of constituents such as Fe, Mn, and Sr compared to pre-injection fluid concentrations have been shown to be indicative of mineral dissolution reactions occurring at depth during brine-CO_2-rock interactions (Emberly et al., 2005; Kharaka et al., 2006a; 2006b).

Monitoring of surface fluxes can also directly detect and measure leakage. Surface CO_2 fluxes may be measured directly with eddy covariance towers, flux accumulation chambers, and by techniques such as a field-portable, high-resolution infrared (IR) gas analyzers (Klusman, 2003; Miles et al., 2005; Lewicki et al., 2007; Lewicki et al., 2009; Spangler et al., 2010). A great deal of progress has been made to quantify detection levels, compare various surface monitoring approaches, and increase the number of options for monitoring CO_2 leakage at the surface (Spangler et al., 2010; Krevor et al., 2010).

13.4.5 Legal and Regulatory Issues for CO_2 Storage

There are a number of legal and regulatory issues that must be addressed before widespread deployment of CCS is adopted (IEA, 2007). If these issues are not addressed, they could become impediments to the deployment of CCS.

13.4.5.1 CCS Policy Context Related to Other Environmental Laws

From a regulatory and institutional perspective, any laws, regulations, and institutional changes that may affect CCS must be viewed within a larger regulatory framework. While not the emphasis here, it is important to note these other regulatory and legal requirements may impact CCS. For example, in the United States, these include, but are not limited to: Source Emission Regulations and Emerging Requirements; Clean Air Act after *Mass v. USEPA*; Tailoring Rule; USEPA policy guidance on BACT; USEPA GHG Reporting Rules; USEPA Conditional Exemption for CCS Under RCRA; DOT Regulations that May Impact Carbon Dioxide Pipelines; Safety (Department of Transportation); Siting (primarily state-based permitting); Rate Regulation; Safe Drinking Water Act under USEPA; and USEPA Underground Injection Control (UIC) Class II, V, and VI Rule (publication of Class VI rule will be specific to CCS). Solutions to the current institutional and legal issues facing CCS cannot be developed without considering the myriad of related laws and regulations and their intent.

13.4.5.2 CCS Regulatory and Legal Issues and their Current Status

The most pressing issues facing CCS include long-term stewardship and related liability concerns; pore space (subsurface) ownership; monitoring, measurement, and verification protocols for accounting purposes and health, safety, and environmental oversight; and regulatory oversight. These issues are discussed in turn below.

Long-Term Stewardship and Liability
Liability associated with long-term management and/or ownership of a carbon storage facility is of great concern to the private sector. Two

types of liabilities can be distinguished: the health and safety related liability of releases of CO_2 on the long term potentially harming people or ecosystems, and the climate-related liability of releases of CO_2on the long term, contributing to climate change. For most phases of any geologic storage project, the risks and attendant insurability of the project phases are well known. However, although many models and analyses conclude that the long-term probability, post-closure, of a significant release of gas is low and major existing projects have proven to be very effective in storing CO_2, the long timeframes associated with storage extend beyond existing institutional experience.

The rationale for a government role in addressing (and possibly indemnifying) long-term liability is due to the belief that CCS is in the public interest and that long-term liability issues should not, at this early stage in the development of the industry, be a barrier to further development. For example, in the case of the FutureGen project in the US, the acceptance of long-term liability became a competitive tool for Illinois and Texas and was deemed beneficial to those competing states.

CO_2 must remain underground for a long period – thousands of years and longer – to meet the goals of atmospheric climate change amelioration. This is well beyond the historic lifespan of companies and most governments. This will require institutional, administrative, and regulatory approaches for long-term stewardship to protect the public and to properly assess the efficacy of the removal of CO_2 from the atmosphere. As a result, the major barrier for industry and its supporting financial community to undertaking CCS projects is the undefined and open-ended liability for any CCS project. Any organization accepting liability will likely (without the development of institutional initiatives) be held responsible for the expenses of continuing monitoring and verification activities, any mitigation or remediation required, and compensation for any damages if leakage occurs.

One option is to create an industry-supported fund managed by the goverment. Such an approach is under discussion in the United States. For example, bills have been introduced in the US Congress that would establish a carbon storage stewardship trust fund financed by fees from operators to ensure compensation for potential damages. Long-term liability schemes have been adopted for other industries, including bond provisions by the UIC program, trust accounts funded through fees to operators that are administered by state or industry organizations such as the Acute Orphan Well Account, the Price-Anderson indemnity program that pools risk for the nuclear industry, and the National Flood Insurance Program.

The most common option is for government agencies to take on the long-term responsibility for CCS sites. This approach has been agreed to in the member states of the European Union, Australia and Norway. In addition, some states in the United States have adopted legislation to accept limited liability, but there has been little consistency in the time frames or agreement as to where the liability should ultimately reside. States, including oil-producing states like Texas and Louisiana and coal-producing states like Wyoming and Montana, have enacted laws relating to CCS development. There are some common elements in these statutes:

- state policy declaration that CO_2 is a valuable commodity and that CO_2 storage provides a public benefit by reducing GHG emissions;
- a fee-based structure to cover the state's responsibility for administering long-term monitoring and oversight of CO_2 injection and storage;
- post-closure monitoring by the drilling or reservoir operator for a period of 10 years or longer;
- a certificate of completion to be issued by a designated state or federal agency, following permanent closure; and
- in some cases, a transfer of the state's responsibility for long-term (post-closure) monitoring and verification to the federal government after a designated period of years (e.g., 10 years or longer).

There are examples of governmental support for accepting CCS liability for the long-term in other countries. These include the Norwegian government acceptance of long-term liability from Statoil for the Sleipner project. Australian federal and state governments jointly accepted long-term liability for the Gorgon facility. In 2009, the European Parliament issued Directive 2009/31/EC on the geological storage of CO_2. Provisions in this directive are similar to those issued by other governments; particularly that financial security must be established for the operations and an anticipated post-injection phase of a minimum of 30 years. Liability may be transferred to a "competent authority" after a minimum of 20 years. "Competent authority," however, is not defined.

In summary, liability and the related long-term stewardship issues are potentially the most significant impediments to creating a global CCS industry. While some governments have taken a number of tentative steps toward solving this problem, it is currently unclear how the issue will be successfully resolved.

13.4.5.3 Pore Space (Subsurface) Ownership Issue Status

Specifically in the United States, there are a number of legal issues surrounding pore space ownership. In some other parts of the world, this is not an issue as the deep pore space is not owned by private individuals but by government.

There are a number of legal issues surrounding pore space ownership in the United States. While there is some interest in applying the same subsurface rules currently used for CO_2 ownership when it is considered a commercially-recoverable resource, most pore space laws and regulations are much more complicated in terms of federal or state ownership, mineral rights, and other subsurface regulation (CIEE, 2010). These rules and requirements can become complicated, but the key issues can be simply stated as:

- Who owns the pore space and can authorize CO_2 storage in them?
- How are ownership rights between surface and subsurface resolved?
- When does plume migration constitute trespass?
- How can rights to pore space be aggregated to enable large-scale projects, particularly in saline aquifers?

The answer to these questions varies from country to country, as discussed in Section 13.6, "Regional Outlook." However, regardless of the approach taken by a country, these issues need to be resolved before large-scale deployment of CCS is likely. In some regions like Europe and China, the State is the owner of the pore space. In this case, the resolution of these issues is comparably simple. These laws and requirements are either poorly developed or not developed at all in emerging economies, as will be addressed in the following section. In other regions, like North America, the situation is quite different.

In the United States, there is a body of statutory and case law that provides guidelines to resolving any issues associated with injecting CO_2 into deep subsurface saline formations. Original case law suggested that mineral rights ownership was to "the center of the earth." However, recent case law suggests that the answer is not as clear. This is based on a number of CCS-analog court cases that have legal, as well as scientific and technological, precedent. This includes natural gas storage, hazardous waste injection (under UIC regulations), fresh water storage in aquifers, and EOR. Much of current case law addresses "trespass," or the migration of materials from injection sites to the subsurface areas whose rights are owned by someone else. In some cases, under common tort law, the verdict has been that these trespasses interfered with possible future use of the subsurface formation. Thus, fines and penalties were assessed. In other instances, seemingly for the same type of trespass, it was judicially determined that there were no damages to the subsurface formation and, therefore, no fines or damages were assessed. For cases involving EOR or fresh water storage, these are deemed to be in the public interest and no fines were assessed. In cases where there are no mineral rights owners for the pore space, ownership devolves to the state. It is clear that new, more straightforward, laws will need to be enacted to clarify ownership, operation in the public interest, and legal recourse for CCS. Some states, such as Montana, Wyoming, and North Dakota, have taken the initiative to develop laws that clarify pore space ownership and liability with respect to CCS. In particular, these laws must clarify CCS's impact on saline formations and how the state will chose to regulate these resources and operations.

13.4.5.4 Monitoring, Verification, and Accounting (MVA) Protocols

There has been considerable discussion of Monitoring, Verification, and Accounting (MVA) at international level and national levels. This work is driven by three major public concerns. First, monitoring needs to be established to ensure public health and safety are maintained and not compromised by CO_2 releases. Second, national emissions are reported using uniform and documented protocols. The IPCC (2006) developed guidelines for inventory verification that included how to treat CCS projects. Third, as laws emerge mandating emission reductions (e.g., carbon taxes, cap-and-trade legislation, and performance standards), there will be verification and accounting protocols that determine that the volume of CO_2 that an organization is taking credit for is, in fact, staying underground.

Many international and national agencies have focused on this issue and a considerable body of information has been developed. A recent summary of these activities has been developed as part of a supporting background document for the Carbon Capture and Storage Blue Ribbon Panel in California (CIEE, 2010). However, these findings and data need to be translated into laws. The legal requirements are to ensure that human health and safety and other living systems (flora and fauna) will be protected. Thus, MVA protocols will have two purposes. The primary purpose will be measurement to allow for the proper crediting of CO_2 that is sequestered. However, monitoring protocols must also be developed to ensure that public health, safety, and the environment are properly protected. This will lead to emissions requirements for CCS projects.

Most importantly, there must be protocols developed that will allow for crediting organizations that sequester CO_2. These protocols will have value to the organizations, as they can take credit for CO_2 removed from emission streams as a means for capturing financial credits, either through cap-and-trade rules (similar to current sulfur dioxide rules) or minimizing taxes under a tax system. Until CO_2 is regulated and treated as a commodity, there will be no reason to inject it into saline formations. To treat it as a commodity, rules and regulations need to be developed under international MVA guidelines that allow for the crediting of CO_2 removal from emission streams. Similarly, when CCS is deployed under the clean development mechanism (CDM), MVA protocols will be needed to ensure that expected emission reductions are in fact achieved.

13.4.5.5 Regulatory Oversight

All of the requirements for regulation will eventually fall on regulatory agencies for enforcement and verification. There are several issues facing these agencies at this time.

Laws covering CCS implementation on a large commercial scale are under development worldwide. In the United States, the most important law appears to be the Underground Injection Control (UIC) Law. The US Environmental Protection Agency has developed regulations under the UIC for underground injection of CO_2 for the purposes of long-term storage. However, additional focused legislation to appropriately regulate and validate CCS activities is likely to be required.

The second issue facing any developer of CCS projects is the overlapping authorities for many of the phases of operations that define a CCS project (Tsang et al., 2002). For example, a thorough analysis of either the lack of jurisdiction or the existence of overlapping authorities has been done in California (CIEE, 2010). As stated above, many of the rules and regulations that CCS projects must operate under have not been promulgated. However, as noted in Section 13.1, many projects will face multiple jurisdictions and legal requirements, each of which will have different metrics for permitting. The nature of this issue could cause a developer to not move forward on a project, simply because the timeline associated with obtaining all regulatory approvals from multiple state and federal agencies is too long from a financing perspective.

An additional issue is the capability of regulatory agencies to meet the needs of new types of industrial projects such as CCS. Most agencies are significantly understaffed. Further, the rapid scientific and technical changes require agency staff to be better equipped to address new regulatory requirements. In fact, most agencies are becoming less adept at keeping staff that can stay abreast of these changes. In countries without existing regulatory authorities, the situation is even more challenging, as the regulatory infrastructure will need to be established. These issues are addressed in the "Regional Outlook," Section 13.6.

An additional issue related to those described earlier in this section is the need to develop regulations and institutional requirements that can address some of the issues described in the previous subsections. Continued lack of clarity on pore space ownership and trespass, post-closure liability, the extent of long-term stewardship, and MMV precision and accuracy requirements will preclude any large-scale development until resolved.

13.4.5.6 Summary of Regulatory and Legal Issues

Currently, many international, federal, and state legislative bodies understand the nature of these issues and are trying to develop legislation that can allow CCS to move forward. It will be critical over the early part of this decade to see if institutional and regulatory solutions can be developed to address legal and regulatory issues. Failure to do so could have a bigger impact on CCS than issues of carbon dioxide capture costs and the low, but uncertain, risks associated with CCS.

13.4.6 Cost of Storage

Costs for geological CO_2 storage consist of four elements: site characterization costs; project capital costs (e.g., costs for surface equipment for each well, cost of drilling, costs of additional CO_2 compression if required); operating and maintenance (O&M) costs; and monitoring, verification, and closure costs. Site characterization costs are lower for storage in oil and gas formations (compared to saline formations and deep coal seams), since the main characterization of these types of fields has already occurred during their exploration. Site characterization costs will be dependent on the area of review (aerial extent of plume spread in CO_2), which will be determined by regulatory regimes in place (Rubin et al., 2007). Drilling costs are mainly dependent on the number of wells (including water production wells if necessary), the injectivity of the field, and the allowed overpressure. O&M costs for CO_2 injection are assumed to be comparable to the costs of water injection for secondary oil recovery (Bock et al., 2003; Rubin et al., 2007).

Storage costs vary depending on numerous factors, including type of reservoir, existing information/infrastructure for the site, onshore versus offshore storage, extent of monitoring, and regional factors. Cost estimates found in the literature are limited to capital and operational costs, and do not include potential costs associated with long-term liability. Table 13.3 shows an overview of these costs by field type. A first assessment of global investment needed for CO_2 storage alone, under a stabilization scenario of 450 ppmv, indicate a range between US_{2009}\$0.8–5.6 billion in 2020, and US_{2009}\$88–650 billion in 2050 (IEA, 2009).

Table 13.3 | Overview of indicative geological storage costs published in the literature. The figures represent average data; when available, ranges are provided between brackets. Data is presented in US_{2008}\$/tCO_2 stored.

	Ecless et al., 2009	Heddle et al., 2003	Hendriks et al., 2004	IEA, 2008	IPCC, 2005	Kober and Blesl, 2010	McKinsey, 2008	Ramírez et al., 2010
Depleted gas and oil fields		(2–24)[a]	(1–11)	(10–25)	(1–14)	(1–21)		(1–20)
-onshore			3 (1–5)		(1–14)	5 (1–21)	6	(1–9)
-offshore			8 (5–11)		(4–9)	6 (4–12)	16	(4–20)
Aquifer	(2–7)	(1–15)	(3–14)	(10–20)	(0.2–33)	(2–35)		>25
-onshore			4 (3–8)		(0.2–7)	3 (2–15)	7	
-offshore			9 (7–14)		(1–33)	6 (3–35)	18	

[a] average value for depleted gas fields is \$6/tCO_2 and for depleted oil fields \$5/tCO_2

Estimates of storage costs derived from current commercial-scale projects are in the order of US$11–17/t$CO_2$ (Sleipner); US$20/t$CO_2$ (Weyburn) and US$6/t$CO_2$ (In Salah) (ITFCCS, 2010). CO_2 storage costs for EOR projects could be offset by the revenues provided by the additional gas or oil produced. In these cases, storage costs are determined by the marginal value of oil, the underlying production costs, and the potential cost of supply of CO_2. Currently, the largest single cost component in EOR projects is the purchase of CO_2 (IPCC, 2005; Kuuskraa and Ferguson, 2008). CO_2 purchase prices found in the literature are in the order of US$38–49/t$CO_2$. The large variability in the economics of EOR makes it difficult to provide representative levelized annual costs of CO_2 stored, and therefore large cost ranges are reported in the literature. For instance, Haddle et al. (2003) reported a range of –91–74 US_{2008}\$/tCO_2, while Hendriks et al. (2004) reported a range of –12–24 US_{2008}\$/tCO_2.

13.4.7 CO_2 Storage Conclusions

Storage in deep underground formations is the most mature storage option because it uses technology developed from over a century of oil and gas exploration and production. Ocean storage has also been studied; however, due to lack of permanence and potential environmental impacts, ocean storage is not being considered at this time. Stimulating the primary productivity of the oceans by adding trace nutrients (e.g., iron), so-called ocean fertilization, has also been proposed as a means of extracting CO_2 from the atmosphere. The long-term effectiveness of this method of removing CO_2 from the atmosphere is uncertain. Impacts to ocean ecosystems are unknown and potentially large.

Cumulative learning from over 30 years of experience is available from five active storage projects. Deep underground formations suitable for CO_2 storage are located in sedimentary basins and include depleted or depleting oil and gas fields, saline aquifers, and deep, unminable coalbeds. Other options for geological storage, such as storage in volcanic rocks, which rely on in situ mineralization for long-term storage, may be developed over time. Rapid in situ mineralization, a comparatively new idea, is the subject of fundamental research investigations that will take many years to mature. Ocean bottom sediments in very deep and cold water may provide an attractive option for emission sources near coasts or where other options are not available. However, this approach has not been tested and considerable research and demonstration will be needed before this option becomes available.

The permanence of storage in deep geological formations in sedimentary basins will depend on a number of factors, the most important one being the presence of a high-quality seal at the top of the storage reservoir. A very high degree of permanence (defined as retention of greater than 99% of the injected CO_2 over a period of 1000 years) is likely for sites that have good seals, are characterized and selected carefully, are operated to stay within a safety envelop to protect the seal and prevent well leakage, and are routinely monitored and regulated to ensure due diligence in all of the aforementioned activities.

The biggest health, safety, and environmental risks from geological storage are groundwater pollution, short-duration well failures, and leakage through undetected faults or fractures in the reservoir seal. These risks should be manageable, as they are similar to the risks that are routinely managed in the oil and gas industry. Some failures are, however, to be expected, especially in the early projects as experience in geological storage is growing. Worst-case environment, health, and safety impacts are likely to be less than the worst case accidents that occur in the oil and gas exploration and production industry because CO_2 is not explosive and it does not accumulate in ecosystems like oil does.

The cost of storage is highly variable, depending on the location of the project, the number of wells needed, whether the project is onshore or offshore, and if the project is in a hydrocarbon reservoir or saline aquifer. Costs from three of the existing projects are in the range of US$6–20/t$CO_2$.

13.5 Energy Systems Synergies and Tradeoffs Influencing CCS Deployment

13.5.1 Life Cycle Analysis of CCS

Life Cycle Assessment (LCA) is one of the most frequently used tools for evaluating the potential environmental impact of products and materials, since it allows upstream and downstream elements to be included in the analysis. For CCS, this implies that besides CO_2 capture, CO_2 transport, and CO_2 storage, the acquisition of the fuel (e.g., coal mining), its transport, and the materials and energy required for the capital equipment and the infrastructure throughout the complete chain are also included.

The most common categories examined in LCA-CCS studies are global warming potential (GWP), increase energy use, acidification potential, and eutrophication. Impact categories such as land use, habitat alteration, impacts on biodiversity, human toxicity and ecotoxicity, and photo-oxidant formation are not addressed by most studies. This, however, is not a unique feature for LCAs of CCS systems. It has already been reported that these impact categories are not (formally) addressed by most published LCAs and due to significant data gaps (e.g., Finnveden, 2000).

A comparison of key results recently published for different CCS technologies is shown in Table 13.4. The results indicate that CCS decreases the global warming potential (GWP) of fossil fuel-fired power plants by 65–85% depending on the technology selected. Indirect emissions are responsible for between 15–46% of the GWP and are mainly originated

Table 13.4 | Key results of selected LCAs for CCS chains.

Author	Type of technology			1. Key results			
				GWP	Primary energy demand	Acidification	Euthrophication
	CO_2 Capture	Trans.	Storage	gCO_2-eq/ kWh	MJ/kWh	gSO_2-eq/kWh	gPO_4^{3-}-eq/kWh
Koornneef et al., 2008[1]	PC-MEA	pipeline	CO_2 storage in gas field	1092 (PC) 837 (PC BAT) 243 (PC MEA)		2.76 (PC) 1.44 (PC BAT) 2.10 (PC MEA)	0.29 (PC) 0.16 (PC BAT) 0.29 (PC MEA)
Korre et al., 2010[2]	PC-MEA PC- K^+/PZ PC-KS-1	pipeline	CO_2 storage in aquifer	846 (PC) 179 (PC MEA) 160 (PC K^+/PZ) 152 (PC KS-1)		0.39(PC) 0.47(PC MEA) 0.31(PC K^+/PZ) 0.36 (PC KS-1)	0.04 (PC) 0.06 (PC MEA) 0.04 (PC K^+/PZ) 0.05 (PC KS-1)
Pehnt and Henkel, 2009	PC-MEA; IGCC-selexol; Oxyfuel	pipeline	CO_2 storage in gas field	940 (PC) 190 (PC MEA) 900 (IGCC) 150 (IGCC CCS) 145 (Oxy CCS)	8.0 (PC) 13.5 (PC MEA) 7.8 (IGCC) 9.5 (IGCC CCS) 11.0 (Oxy CCS)	0.65 (PC) 0.58 (PC MEA) 0.25 (IGCC) 0.35 (IGCC CCS) 0.13 (Oxy CCS)	0.05 (PC) 0.09 (PC MEA) 0.03 (IGCC) 0.04 (IGCC CCS) 0.01 (Oxy CCS)
RECCS, 2008	PC (MEA), Oxyfuel; Gas CC (MEA); IGCC (Rectisol)	pipeline	CO_2 storage in aquifer	792 (PC) 262 (PC MEA) 176 (oxy CCS) 396 (gas CC) 132 (gas CC MEA) 774 (IGCC) 244 (IGGC CCS)	7.7 (PC) 9.9 (PC MEA) 10.4 (oxy CCS) 7.0 (gas CC) 8.4 (gas CC MEA) 7.7 (IGCC) 9.5 (IGGC CCS)	0.85 (PC) 0.77 (PC MEA) 0.19 (oxy CCS) 0.56 (gas CC); 0.69 (gas CC MEA); 0.64 (IGCC); 0.84 (IGGC+CCS)	0.07 (PC) 0.08 (PC MEA) 0.10 (oxy CCS) 0.05 (gas CC); 0.07 (gas CC MEA) 0.05 (IGCC) 0.06 (IGGC CCS)
Schreiber et al., 2009	PC-MEA			852 (PC) 212 (PC MEA retrofit) 179 (PC MEA Greenfield)	10.0 (PC) 14.3 (PC MEA retrofit) 12.1 (PC MEA Greenfield)	1.2 (PC) 1.3 (PC MEA retrofit) 1.1 (PC MEA Greenfield)	0.140 (PC) 0.245 (PC MEA retrofit) 0.198 (PC-MEA Greenfield)

1: In this study the authors compare an average PC plant of 2005 with a PC using best available technologies (BAT) and a PC with post combustion capture.
2: In this study, two other solvents were analyzed besides MEA: a hindered amine (KS-1) and a promoted potassium carbonate (K^+/PZ).

in the fuel supply chain. Contributions due to capital equipment and infrastructure are estimated to be below 5%. Due to the energy penalty induced by CO_2 capture, there is a relative increase in total primary energy demand in the order of 20–40%, with up and down streams accounting for 15–30% of this increase. Impacts on the acidification and eutrophication potentials differ and are highly dependent on the type of technology examined. Gas and oxyfuel concepts tend to show better performances than coal-based systems, especially post-combustion concepts. However, the type of solvent selected appears as the main determinant on the environmental performance of post-combustion capture.

13.5.2 Potential Impacts of CCS on Reducing Vehicle Emissions (See also Chapter 12.4)

Several studies have been undertaken on well-to-wheels emissions of GHGs from vehicles (see Chapter 12). The IEA Greenhouse Gas R&D Programme undertook a study to assess the addition of CCS to transport fuel production, which was based on a well-to-wheels study undertaken by JEC, CONCAWE, and EUCAR (IEA GHG, 2005). The costs and CO_2-eq emissions of various transport fuel options are summarized in Table 13.5. The base case for calculation of the costs of GHG abatement is a typical European car, such as a Volkswagen Golf, with a gasoline port injection spark ignition engine (PISI). A study looking at just hydrogen options undertaken by the European HySociety project (Mulder et al., 2007) resulted in somewhat more optimistic results for CCS.

Production of Fischer-Tropsch (F-T) diesel and dimethyl ether (DME) from natural gas with CCS results in modest (22–31%) reductions in emissions compared to the gasoline base case. The percentage emissions reduction from the use of hydrogen produced from fossil fuels with CCS is 60–78%, depending on whether the fuel is coal or natural and whether fuel cells or an IC engine is used. Without CCS, some of the hydrogen production options would have emissions greater than the reference case. The fossil-fuel electricity cases with CCS result in the greatest emissions reduction (79–88%). The biomass-based cases result in negative net emissions, assuming the biomass is produced from sustainable sources, but the results should be viewed cautiously due to a

Table 13.5 | Potential impacts of CCS on reducing vehicle emissions

Pathway, Fuel	Vehicle	Emissions gCO_2-eq/km (mean)	Avoided cost relative to the gasoline base case €/tCO_2 avoided
Gasoline (base case)	PISI	165	0
Diesel (conventional)	DICI	159	-
CNG	PISI hybrid	109	281
DME	DICI hybrid	139	1076
CNG with CCS	PISI hybrid	101	247
FT diesel with CCS	DICI hybrid	129	1089
DME with CCS	DICI hybrid	114	762
Hydrogen: coal with CCS	ICE	66	479
Hydrogen: natural gas with CCS	ICE	49	296
Hydrogen: biomass with CCS	ICE	-261	109
Hydrogen: coal with CCS	Fuel cell	37	510
Hydrogen: natural gas	Fuel cell	93	827
Hydrogen: natural gas with CCS	Fuel cell	37	420
Hydrogen: biomass with CCS	Fuel cell	-147	189
Electricity: natural gas with CCS	Electric	20	805
Electricity: coal with CCS	Electric	34	918
Electricity: biomass with CCS	Electric	-118	468

PISI: Port injection spark ignition engine (Gasoline)

DICI : Direct injection compression ignition engine (Diesel)

CNG: Compressed Natural Gas

FT: Fischer-Tropsch

DME: Di-Methyl Ether

ICE: Internal Combustion Engine

whole range of factors, from indirect land use change to differing engine efficiencies with biofuels.

The costs of CO_2 abatement are in all cases substantially greater than the costs of abatement by use of CCS in fossil fuel power generation. For the cases where there are comparable data, the use of CCS reduces the overall costs per tCO_2 abated. The costs depend strongly on plant construction costs and fuel prices, which have been highly volatile in recent times, and in some cases the costs of technologies that have not yet been widely used, such as fuel cells and hydrogen storage in vehicles.

13.6 Regional Outlook for CCS

13.6.1 Methodology

This section discusses in four parts the activities in various regions in the field of CCS. Technical potential and source-sink matching comprise the presence of CO_2 sources amenable to capture, what is known about the storage capacity, and its proximity to CO_2 sources. The local aspects of economic viability of CCS in the region will be discussed under the section on factors influencing regional CCS costs. The economic activities that relate to CCS, such as oil and gas operations, related human capacity and education, and CCS-related R&D in the region, are addressed in the third part. Fourth, the developments related to legislation and policy are discussed. Last, there is a general discussion of politics and, where data is available, public perception.

13.6.2 Europe

13.6.2.1 Technical Potential and Source-Sink Matching

From 2006–2009, a Europe-wide consortium of research institutes conducted a geological storage capacity estimate and mapped CO_2 point sources and prospective storage reservoirs over the 27 Member States, Norway, and several states in former Yugoslavia and the Balkans (Geocapacity, 2009). An overall estimate of prospective reservoirs yielded 360 $GtCO_2$ storage capacity, the majority in saline aquifers, and more than half in saline aquifers off the coast of Norway. Much of this storage capacity may not have trapping structures, making storage integrity less certain (see the discussion in Section 13.4.2.2). A more conservative estimate yields a storage potential of 96 $GtCO_2$ in saline aquifers, around 20 Gt in hydrocarbon reservoirs and another one Gt in coalbeds all over Europe.

In 2008, the European Union emitted 4.9 $GtCO_2$-eq, of which around 2.6 $GtCO_2$ are stationary CO_2 sources that could be amenable to capture, and 1.3 $GtCO_2$ is electricity production. The sources of CO_2 are widely distributed over Europe, although there is a concentration in the German Ruhr area, the Netherlands, the United Kingdom, and southern Poland (Geocapacity, 2009).

13.6.2.2 Factors Influencing Regional CCS Costs

Costs of CCS are built from capture and compression, transport, and storage costs. Capture and compression costs can be affected by the type of CO_2 sources – if there is a significant amount of high-purity, storage-ready CO_2 sources, capture costs can be kept low. If transport distances can be kept short and in sparsely populated, flat areas, this positively affects the transport costs. And if storage can be done in EOR, or in onshore fields where injection facilities are still usable, this reduces CCS costs as well. Other indirect factors that impact the siting, and therefore the costs, of CCS operations include population density and public perception, types of industrial activities, and access to resources.

In terms of the cost curve for CCS in Europe, there are a number of relevant factors. First, much of the storage potential in Europe seems to be located offshore and in saline aquifers. Therefore, storage costs may be higher, as saline aquifers are often not characterized well and offshore drilling adds to the costs. Second, the population and industrial density as well as the landscape in much of Europe make transport a relatively costly matter. Third, with relatively high consumer electricity prices, the cost increase of CCS compared to current electricity prices are relatively low compared to other countries: incremental cost of CCS for a typical residential consumer is estimated to be about 20%.

13.6.2.3 Technical and Human Capacity

Most countries in Europe are developed countries with a highly educated workforce. Several European countries have a significant oil and gas industry, with ensuing human and technical capacity on the underground. Many universities and research institutes in Europe conduct research and education related to various technical, economic, and social aspects of CCS. Although the capacity in Europe is considered high, in order to enable broad application of CCS, a larger base of CCS experts and practitioners will need to be developed over the years to come.

In terms of R&D, the European Union indicates that through 2009, €115 million was spent on CCS-related R&D activities through its major program.[3] In addition, member states invest significant sums in CCS R&D; the Netherlands, for example, has since 2003 spent and planned roughly €50 million on CCS research, which was matched by industry.[4] The Zero Emissions Platform (ZEP), a European platform for stakeholders of CCS, indicates that its industry members' investment in CCS-related R&D have amounted €635 million over 2003–2008.[5]

13.6.2.4 CCS Legal and Policy Initiatives

In December 2008, the European Parliament passed the "Climate and Energy package," a collection of new EU Directives including a commitment for the European Union to, by 2020, reduce GHG emission by 20% compared to 1990, use 20% renewable energy, and improve energy efficiency by 2% annually. Part of the package was legislation to enable CCS in the European Union. It consisted of a "Directive on geological CO_2 storage" and a series of modifications to other Directives that took away obstacles to CCS in, for instance, directives on landfills and on large combustion plants.[6] The geological storage directive outlines the legal conditions that any CO_2 storage project has to meet. The provisions are further detailed and implemented by the Member States.

The Climate and Energy package also modified the directive regulating the EU Emissions Trading Scheme (ETS), providing a carbon price incentive for CCS projects. However, due to various factors, carbon prices, steady at around US_{2010}\$14.64 halfway through 2010, remained too low to enable CCS (Sijm, 2009). In addition to the inclusion in the ETS, the European Union decided to reserve 300 million emission allowances, corresponding to the value of 300 million not emitted tCO2, from the "New Entrants Reserve" for demonstration of innovative energy technologies, which is widely considered to go mainly to CCS demonstration. In 2009, the European Union decided to grant around €1 billion to six demonstration projects as part of its economic recovery package in response to the 2009 economic crisis. Later, it was decided in addition to the economic recovery package to make available 300 million emission allowances from the New Entrants Reserve in the EU Emissions Trading Scheme for demonstration of innovative renewable and CCS projects. At a price of roughly 10 EUR/tCO2, this amounts to another EUR 3 billion in total. Combined, the EU hopes to enable up to 12 large-scale demonstrations of CCS by 2015. Most of these demonstrations are expected to be in the power sector, but some are intended to take place in industry.

3 CCS EII Implementation Plan 2010–2012. ec.europa.eu/energy/technology/initiatives/doc/ccs_implementation_plan_final.pdf.

4 www.co2-cato.nl/cato-2/program-overview.

5 CCS EII Implementation Plan, 2010. See ec.europa.eu/energy/technology/initiatives/doc/ccs_implementation_plan_final.pdf. It is unclear what is included in this number; it may include investments of European companies in CCS projects elsewhere, for instance BP's investment in the In Salah project.

6 Directive 2009/31/EC on the geological storage of carbon dioxide: eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:140:0114:0135:EN:PDF.

13.6.2.5 Discussion of CCS in the European Union

CCS is considered a political reality in the European Union. Many policy documents indicate the importance of the option to achieving the European Union's ambitious climate goals and steps have been undertaken to stimulate demonstration of CCS, establish a legal framework, and develop human and business capacity and knowledge. On the other hand, CCS in Europe experiences some of the strongest resistance. Although several environmental organizations support or tolerate CCS, others are vehemently opposed. In addition, companies and governments in Denmark, Germany, and the Netherlands have experienced strong public opposition to CCS demonstration projects by local inhabitants resulting in the cancellation of several projects.

CCS is not expected to become a reality all over the continent. R&D and policy activities are concentrated in a few active countries, including Norway, the Netherlands, Germany, Denmark, and the United Kingdom. Those countries are characterized by a strong fossil fuel tradition, high industrialization levels, a coastline on the prospective North Sea, a relatively high per capita national income, and a relatively well-developed environmental awareness. In addition, countries like France, Poland, Italy, and Spain have shown interest and have worked on the option. But CCS is not considered to be an option in countries with low storage potential, a small fossil fuel industry, and low incomes.

13.6.3 North America

13.6.3.1 Technical Potential and Source-Sink Matching

In 2008, the CO_2 emissions in the United States and Canada reached 5921.2 and 574 Mt, respectively. The Regional Carbon Sequestration Partnerships (RCSP), initiated by the US Department of Energy (US DOE), have been leading the efforts to determine the most suitable technologies, regulations, and infrastructure needed for CCS in different areas in North America. The *2010 Carbon Sequestration Atlas of the United States and Canada,* released by the US DOE and National Energy Technology Lab (NETL, 2010a), provides information about the currently estimated CO_2 emissions in 42 US states and four Canadian provinces, divided into the seven main partnership regions. The Atlas documents more than 4700 stationary CO_2 sources with total annual emissions of over 3200 Mt. Most of these emissions come from power generation (83%), followed by refining and chemical processes (6%), industrial processes (4%), petroleum and natural gas processing (3%), cement production (3%), and ethanol plants (1%) (NETL, 2010a).

Significant storage capacity has been documented in depleted and depleting oil and gas reservoirs, saline aquifers, and unminable coal seams throughout the seven partnership regions. The RCSPs document the location of almost 143 Gt of geologic CO_2 storage potential in 9667 oil and gas reservoirs distributed over 27 American states and three Canadian provinces. Similarly, the CO_2 geologic storage potential in unminable coal seams is estimated at 187–217 Gt, distributed over 24 states and three provinces. Finally, 3600–13,000 Gt is the estimated CO_2 storage potential in saline formations. The capacity estimation range in the case of coal seams and saline aquifers is primarily due to the uncertainty inherent in the calculation methodology (NETL, 2010a).

The National Carbon Explorer (NATCARB) is another initiative by the US DOE that aims to link CO_2 geological storage and emissions sites databases across several regional centers. NATCARB interactive maps show close proximity between CO_2 sources and sinks throughout North America where many CO_2 sources are located on or near CO_2 storage sites. Nevertheless, exceptions exist and source-sink matching is not very good, including parts of the US upper mid-west and northeast.

13.6.3.2 Technological Maturity

North America is among the leading regions in CCS activities. Today, many pilot projects exist, and commercial-scale projects are in the early stages of planning, the majority of which are in the United States. This includes pre-combustion, post-combustion, and oxy-combustion capture facilities, as well as geologic storage projects at the R&D, demonstration, and industrial/commercial scales (BRGM, 2009). In addition to CCS-related endeavors, a well-developed CO_2 infrastructure exists in North America, which facilitates the early deployment and testing of CCS. In this regard, EOR through CO_2 injection (CO_2-EOR) is implemented widely in the United States and Canada. The 2008 World EOR Survey issued by the Oil and Gas Journal lists 100 ongoing CO_2-EOR projects in the United States and seven projects in Canada (Koottungal, 2008).

13.6.3.3 Factors Influencing Regional CCS Costs

As mentioned before, the geographical distribution of sources and sinks plays a major role in determining the economic competitiveness and feasibility of CCS deployment. To start, most of the currently implemented and proposed CCS-related projects in North America are onshore, and, as noted previously, many CO_2 point sources are located either on or close to potential geologic storage formations. Both factors favor economic implementation of CCS. Equally important, both the United States and Canada have conducted several studies to investigate the effect of population density, environmental factors, and topography on the cost of CCS implementation. In 2010, NETL published *Site Screening, Selection, and Initial Characterization for Storage of CO_2 in Deep Geologic Formations*, which aims to provide a framework and an overview of processes for selecting suitable sites for geologic storage. The proposed framework discusses several aspects related to site screening, site selection, and initial characterization. Among other important topics, the document investigates the effect of protected and sensitive areas (wetlands, source water protection areas, protected areas, and protected species); population centers; existing resources development; and pipeline right-of-way on the feasibility of CCS deployment (NETL, 2010b). Similarly, *Carbon*

Dioxide Capture and Storage: A Compendium of Canada's Participation (Natural Resources Canada, 2006) lists several studies and R&D projects that aim to optimize the economic aspects of CO_2 transportation network and infrastructure design, including: *Optimisation of integrated CO_2 capture, transportation, and storage in Canada (Waterloo),* and *Integrated economic model for CO_2 capture and storage (ARC and others).*

In 2009, more than 80% of US energy use was fossil fuel based, and almost 60% was from oil and coal (US EIA, 2010a). Similarly, more than 77% of Canada's energy use in 2008 was fossil fuel based. As of 2010, Canada's oil reserves are the second largest in the world after Saudi Arabia, and a significant portion of these reserves is unconventional CO_2-intensive oil shale (US EIA, 2009). As such, both countries are highly dependent on fossil fuels, which, in the absence of earlier, cheaper, low-carbon alternatives, improves the economic attractiveness of CCS as an effective climate change mitigation option.

13.6.3.4 Human Capacity, Research and Development

Several governmental agencies, academic institutes, and industrial/commercial businesses in the United States and Canada are actively involved in CCS and are conducting CCS-related R&D locally and internationally. In the United States, the Department of Energy, specifically the Office of Fossil Energy (FE) and NETL, are guiding local and international research initiatives on CO_2 geologic sequestration. FE/NETL is directly supporting more than 75 research projects across the United States and internationally. The CCS R&D network database of the Global CCS Institute (GCCSI) shows that a total of 209 organizations in the United States are involved in CCS R&D, the majority of which is related to CCS technologies (GCCSI, 2011b). Canada is actively involved in CCS R&D through 25 CCS research centers (including eight universities with substantial engagement); 23 companies that are developing, testing, using, or analyzing the effects of CCS technologies; and 13 governmental programs supporting CCS projects. In that regard, 59 CCS-related projects in Canada are led by universities, 42 are led by government research agencies (including provincial research organizations), 23 are led by industry (a category that includes any for-profit company) and two are led by nongovernment organizations (Natural Resources Canada, 2006). Similar to the United States, the CCS R&D network database of the GCCSI shows that a total of 58 organizations in Canada are involved in CCS R&D, the majority of which is related to CCS technologies (GCCSI, 2011b).

In addition, the United States and Canada take part in international collaboration on CCS. Both countries are members of the Carbon Sequestration Leadership Forum (CSLF), GCCSI, and the *IEA Greenhouse Gas* R&D Programme (IEAGHG). Both countries are also engaged in bilateral and multilateral agreements promoting CCS, including the US-China Fossil Energy Cooperation Protocol; the National Energy Technology Laboratory-Korea Institute of Energy Research Memorandum of Understanding (Smouse, 2007) the CO_2 Capture Project; and Weyburn-Midale Monitoring Organizations (Natural Resources Canada, 2006). All aforementioned research endeavors, as well as the pilot CCS projects and the well-developed industrial and energy infrastructure discussed in the section above, contribute significantly to building a skilled human capital that is competently educated about CCS and would be expected to play a major role in advancing this technology. In that regard, both the United States and Canada are also investing in developing, supporting, and initiating educational opportunities (conferences, workshops, publications) that guide various stakeholders on how to engage the public and raise awareness and support for CCS-related activities. (Natural Resources Canada, 2006; The ECO ENERGY Carbon Capture and Storage Task Force, 2008; US DOE/NETL, 2009b).

13.6.3.5 CCS Legal and Policy Initiatives

Several regulatory frameworks contribute to the deployment of CCS. Regulations governing the deployment of CCS-related activities have been proposed and are currently considered in both the United States and Canada. In July 2008, the US EPA published the Federal Requirements under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells Proposed Rule. This proposal, which applies to owners or operators of CO_2 injection wells, establishes a new class of wells, as well as minimum technical criteria for the geologic site characterization, fluid movement, area of review and corrective action, well construction, operation, mechanical integrity testing, monitoring, well plugging, post-injection site care, and site closure, to ultimately protect underground sources of drinking water (USEPA, 2010). More recently, in March 2010, a bill titled the Carbon Capture and Sequestration Deployment Act of 2010 was introduced in the US Congress. The bill aims to "provide financial incentives and a regulatory framework to facilitate the development and early deployment of CCS technologies, and for other purposes. (IIIth US Congress, 2010)" On the other hand, even though no comprehensive national legislation specifically addressing CCS has been proposed yet in Canada, several of the Canadian CCS activities are adequately regulated under the oil and gas legislation (IEA, 2010b). In 2009, the Government of Alberta introduced the Carbon Capture and Storage Funding Act, which aims to "encourage and expedite the design, construction and operation of carbon capture and storage projects in Alberta." (Province of Alberta, 2009a).

In March 2012 the EPA issued the first Clean Air Act performance standand for carbon pollution from future power plants (epa.gov/carbonpollutionstandanrd). The Standard limits emissions to 1000 lbs CO_2/MWh (454.4 kg CO_2/MWh), which is about one-half of the typical emissions from a coal-fired power plant and about equal to typical emissions from a combined cycle natural gas power plant. The Standard applies to all power plants that will be constructed beginning 12 months hence. In the short term this will encourage the deployment of natural gas power generation over coal-fired generation. Over the long run, if natural gas power generation over coal-fired generation. Over the long run, if natural gas prices rise above the level where coal generation plus 50% CCS is economically competitive, the Standard will encourage the deployment of CCS.

These CCS-specific legal frameworks are part of both countries' efforts to manage carbon emissions, and in their national policies that promote CCS as a major contributor to climate change mitigation. While there is no nationwide commitment to reduce emissions in the United States, both the American Power Act (2010) and the American Clean Energy and Security Act (2009) propose forming a nationwide cap-and-trade program and creating other incentives and standards for increasing energy efficiency and low-carbon energy use (US EPA, 2010). In Canada, even though no national legislative framework addressing CO_2 emissions reduction has been officially proposed, get several provinces have adopted legislation that tax or cap CO_2 emissions. In 2003, Alberta introduced the Climate Change and Emissions Management Act, requiring companies to reduce the intensity of their GHG emissions by 12% and providing funding for CCS-relates activities (Province of Alberta, 2009b). Ontario introduced regulations for a cap and trade system in 2009. Similarly, in 2009, Quebec introduced a bill that provides a framework for a provincial GHG emissions cap-and-trade scheme (Quebec National Assembly, 2009), and British Columbia introduced a carbon tax in 2008 (Legislative Assembly of British Columbia, 2008).

Another important legislative aspect that affects the deployment of CCS is subsurface resources ownership and mineral rights. In the United States, no national legislation exists to regulate subsurface and pore space ownership, especially for the purpose of CO_2 geologic storage. Nevertheless, taking into account that property rights are generally regulated at the state rather than the federal level, some states have taken the initiative to address the issue of pore space ownership. In 2008, Wyoming enacted legislation that gives the ownership of subsurface pore space in the state to the owners of the surface (Duncan et al., 2009). In Canada, no specific legislation regulates subsurface rights and pore space ownership. Nevertheless, the Canadian Mineral Resources Act gives the Crown (and thus the federal government) ownership over "all minerals existing or which may be found within, upon or under lands in the province. (Government Canada, 2009)."

Equally important, both the United States and Canada have devoted large amounts of federal funds to promote the deployment of CCS. In 2009, the United States announced US$2.4 billion funding for CCS projects (USDOE, 2008). Similarly, Canada committed to more than US_{2009}\$48 million funding for CCS R&D initiatives and around US_{2009}\$2 billion for large-scale demonstrations. Here is it important to note that the Government of Alberta announced a US_{2010}\$1.9 billion fund to encourage the large-scale deployment of CCS (Mourits, 2009). Along with budget allocations, both countries have taken the effort to raise public awareness and analyze the community's perspectives on CCS through focus groups and interviews. In the US, some studies found that factors such as past experience with government, existing low socioeconomic status, desire for compensation, and/or perceived benefit to the community contribute to shaping, along with the risks associated with CCS technology, the public opinion on CCS deployment (Bradbury et al., 2009). In Canada, several studies have been conducted and several initiatives have been taken to enhance public engagement in discussions about CCS deployment in Canada (Natural Resources Canada, 2006).

13.6.4 China

13.6.4.1 Technical Potential and Source-Sink Matching

In 2007, China ranked first in global CO_2 emissions with 6538 Mt (IEA, 2008a). Electricity and heat production, as well as industrial manufacturing, contribute to the majority of these emissions, followed by residential use, transportation, and others. In 2000, the IEA estimated China's CO_2 emissions from stationary sources to be almost 3000 Mt, projected to increase up to 4600 Mt in 2010. The power sector contributes more than 90% of stationary CO_2 emissions, and 73% of these emissions come from coal-fired power stations. In 2005, the six largest CO_2 point sources existed in China, all of which are power stations emitting a total of 227 $MtCO_2$ annually. Other CO_2 point sources include iron, steel, ammonia, cement, ethylene, and ethylene oxide facilities as well as refineries. Until 2005, 77 pure CO_2 sources existed in China, forming attractive early opportunities for low-cost CO_2 capture (APEC, 2005).

Significant storage capacity has been documented in depleted and depleting oil and gas reservoirs, saline aquifers, and unminable coal seams. The *CO_2 Storage Prospectivity of Selected Sedimentary Basins in the Region of China and South East Asia* report, issued by Asia Pacific Economic Cooperation in 2005, identifies several potential storage basins with high, intermediate, and low prospectivity (APEC, 2005). An overall storage capacity of 1445 $GtCO_2$ has been reported in China by APEC, and more recent investigations indicate the capacity may be as high as 3080 $GtCO_2$ (Dahowski et al., 2009). In more detailed studies, depleted and depleting oil and gas fields storage potential has been estimated to be 9.7–21 Gt, which makes it a short-term sink for a small fraction of China's CO_2 emissions from stationary sources (approximately 3–7 years of storage capacity based on 2007 emissions level) (Wang, 2010). Geological storage potential in unmineable coal seams is estimated to be approximately 10 $GtCO_2$, including 4 $GtCO_2$ in Ordos, 2 $GtCO_2$ in Turpankumul, and more than 1 $GtCO_2$ in Dzungaria (Wang, 2010). In fact, one study reports that CO_2 storage capacity by enhanced coalbed methane (ECBM) can be up to 12.08 $GtCO_2$ (Petra China Company Limited, 2007). Finally, 110–360 $GtCO_2$ is the estimated CO_2 storage potential in saline formations (Wang, 2010; 240, 2008). A more recent assessment suggests there is a capacity of about 3080 $GtCO_2$ in China, with all but 780 $GtCO_2$ available on shore (Dahowski et al., 2009).

The aforementioned APEC report shows that most large CO_2 point sources (10–55Mt/yr) are located either on or close to high- and intermediate-prospectivity storage basins. Thus, the distribution of major CO_2 stationary point sources and analyzed storage basins throughout China shows reasonable proximity between sources and sinks and some potential for source-sink matching.

13.6.4.2 Technological Maturity

China continues to develop the technological infrastructure required for CCS deployment. The NETL reports eight CCS projects in the country, many of which are currently active. This includes pre-combustion capture, EOR, and ECBM, at the R&D, demonstration, and industrial/commercial scales (Wang, 2010; BRGN, 2009). In this regard, CO_2-EOR is being actively developed, and more than 10 pilot projects have been implemented. In addition to increasing oil production, some of these projects aim to test permanent storage of injected CO_2, such as the Research on Exploitation of Natural Gas with Higher CO_2 Concentration, CO_2 Storage and Comprehensive Utilization of Resources in Jilin Oil Field project, which was initiated in August 2007. This rapid development of pilot projects enhances China's capability of early deployment and testing of CCS (Luo, 2008).

According to the US Energy Information Administration (US EIA), China's total oil and gas production in 2007 reached 192.2 t/yr (4.0 million bbl/day) and 69.2 billion m^3/yr (2,446 bcf), respectively. Since 1987, oil production and consumption in China increased by almost 25% and 350%, respectively, and both gas production and consumption increased by almost 500% (US EIA, 2010b). As such, it would be reasonable to argue that China's experience in oil and gas exploration and production and rapidly developing energy infrastructure help in the early deployment of CCS.

13.6.4.3 Factors Influencing Regional CCS Costs

As mentioned before, many of the currently proposed CO_2 storage sinks in China are onshore, and many CO_2 point sources are located either on or close to potential geologic storage formations (APEC, 2005). Both factors favor economic implementation of CCS. Nevertheless, even though several CCS pilot projects are currently implemented, the design and layout of the potential CO_2 infrastructure and transportation network in the country are not fully investigated yet. Accordingly, little information exists on the effect of population density, landscape topography, and environmental factors on the construction of the CCS infrastructure.

Still, China's significant dependence on coal in fueling its economy and energy sector favors the country's adoption of CCS as an economically attractive option to reduce CO_2 emissions. According to the IEA *World Energy Outlook* in 2007, coal accounts for approximately two-thirds of China's energy needs, 80% of its electricity fuel mix, 50% of its industrial fuel use, and 60% of its chemical fuel use. In addition, oil and coal account for 81.6% of the country's overall energy demand in 2005; renewable energy (including nuclear) accounts for less that 14% of the energy demand. In terms of future projections of energy use, China generated around 622 GW of electricity in 2006, with additional installed capacity of 100 GW since 2005. Over 90% of this capacity increase was coal-fired. By 2030, the electricity generation capacity is expected to increase up to 1755 GW, Taking into account that China's domestic coal reserves are the second largest in the world, and given the coal's relatively low price, some studies suggest that even with strong policy incentives for energy efficiency, renewables, and other low carbon technologies, coal will remain a major contributor to China's energy fuel mix for the coming two decades. Thus, CCS is expected to be a major, option for reducing China's CO_2 emissions as part of its efforts to combat climate change (FIndlay et al., 2009).

13.6.4.4 Human Capacity, Research and Development

Several Chinese governmental agencies, academic institutes, and industrial/commercial businesses are actively involved in many aspects of CCS both locally and internationally. CCS-related research initiatives have been authorized, initiated, and supported by governmental agencies, including: Research for Utilizing Greenhouse Gas as Resource in EOR and Storing It Underground (Project 973), supported by the Major State Basic Research Development Program of the People's Republic of China, and Carbon Capture and Storage Techniques (Project 863), supported by the National High Technology Research and Development Program of China (Wang 2010). In addition, many aspects of the CCS technology are investigated by Chinese academic institutions, including: CO_2 absorption, CO_2 adsorption, membrane separation, membrane adsorption, CO_2 storage, and others (Wang, 2010). China National Offshore Oil Corporation and PetroChina are also active participants in CCS research (Wang 2010). China National Offshore Oil Corporation supports a project investigating the utilization techniques of CO_2 on large-scale. PetroChina is involved in several projects promoting CCS, including: the aforementioned Project 973, Pilot Test of CO_2 EOR and Storage in Jilin Oil Field, and Research on Phase Theory of Multiphase and Multi-component during CO_2 Flooding Process (Shen and Jiang, n.d.) In this regard, the CCS R&D network database of GCCSI shows that a total of 18 organizations in China are involved in CCS R&D, the majority of which is related to CCS technologies (GCCSI, 2011b).

In addition to the local efforts, China is actively engaging in international collaboration on CCS initiatives. For example, China is a member of the Carbon Sequestration Leadership Forum (CSLF), GCCSI, and the Asia Pacific Partnership on Clean Development and Climate Change. In addition, China is collaborating with the European Union through the Cooperation Action within CCS China-EU, Geo-Capacity, and Support to Regulatory Activities for Carbon Capture and Storage. Similar collaboration efforts exist between China and the United Kingdom through Near Zero Emissions Coal, Australia through the China-Australia Geological Storage, and the United States through some projects supported by the US EPA (Findlay et al., 2009). All aforementioned research efforts, as well as the vigorously developing energy sector, discussed in the section above, contribute to building a competently educated human capital that would be expected to play a major role in advancing CCS development. In that regard, China have both hosted and participated in several conferences and workshops that educate and train on CCS topics and guide various stakeholders on how to engage the public in CCS activities.

13.6.4.5 CCS Legal and Policy Initiatives

Although no specific mandates currently exist to regulate CCS activities in the country, China's national policies promote CCS as a major climate change mitigation option. *China's National Climate Change Programme* report, issued in 2007 by the National Development and Research Commission, states that strengthening the development of advanced and suitable technologies such as carbon dioxide capture, utilization, and storage is one key area to combat climate change (CNDRC, 2007). However, China Roundtable Meeting Notes from the IEA CCS Roadmap shows that the CCS profile in the Chinese climate and energy policy is currently low, due to its high cost and perceived status as an emerging option for GHG mitigation that requires more R&D (OECD/IEA, 2009). In terms of subsurface resources, pore-space ownership, and mineral rights, the Chinese constitution and the Mineral Resources Law of China explicitly state that the "mineral resources are owned by the state." The State Council exercises the state ownership over the mineral resources. In 1996, the National Mineral Resources Commission was established to strengthen the central government's control over mineral resources and protect its mineral rights (Chinese Government, 2003).

Another important aspect affecting the deployment of CCS is governmental funding. Currently, only a modest funding is provided by the Chinese Ministry of Science and Technology on CCS R&D. The government is not providing support to CCS due to its high cost and energy penalty. In that regard, some suggest that it would be valuable to develop a roadmap for China's development of CCS, which would particularly focus on early opportunities for profitable CO_2-EOR and explain the costs and benefits of a progressive expansion of the Chinese CCS industry from early demonstration. In addition, the Chinese government can be expected to increase expenditure on CCS if international funding resources become available (OECD/IEA, 2009). Still, money alone cannot ensure a wide deployment of CCS; public support is an essential element too. Some studies have been conducted to raise public awareness and analyze the community's perspectives on carbon capture and storage. The results showed that the awareness of CCS was low among the surveyed public in China, compared to other clean and renewable energy options. Further analysis of the results shows that the community's understanding of the characteristics, risks, and potential regulations of CCS are all important in predicting and promoting CCS public acceptance (DUAN, 2010).

13.6.5 Sub-Saharan Africa

13.6.5.1 Technical Potential and Source-Sink Matching

The short-term technical potential for CCS is generally considered low as the amount of CO_2 point sources amenable to capture are limited. With the exception of South Africa, many sub-Saharan countries lack large, energy-intensive industries, coal- or gas-fired power production and other stationary CO_2 sources. Most countries have very low or even negative GHG emissions. According to the 2006 version of the IEA GHG database on CO_2 point sources, sub-Saharan Africa has a total of 155 point sources, 79 of which are power and 76 cement, iron and steel, ethylene and ammonia, amounting to some 241 $MtCO_2$ emissions from power and some 46 $MtCO_2$ industrial emissions (IEA, 2008c). Of both, around half of the emissions originates in South Africa.

In the future, CO_2 emissions in Africa are projected to rise. IEA (2009) projects CCS activities in Africa from around 2030 onwards. Several African countries have an abundance of coal and plan to use it.

Geological storage potential for CO_2 in sub-Saharan Africa is generally not known, as no comprehensive assessments have been carried out. However, various countries have known sedimentary basins or have done underground exploration for other economic reasons, such as hydrocarbon exploration or searching for underground drinkable water reservoirs in arid areas. For instance, it is likely that oil-exporting countries along the west coast of Africa, such as Nigeria, Angola, and Gabon, have areas of high geological storage prospectivity (IPCC, 2005) but also a country like Mozambique with oil and gas exploration (ECN, 2010).

South Africa has done a focused geological storage atlas. Although the atlas was not public at the time, some early results can be conveyed (Cloete, 2010). South Africa does not appear to have an abundance of suitable sedimentary basins, and early results suggest that the coal fields in the northeast (northern Karoo), where most of the large-scale emission sources are, also do not appear prospective.

13.6.5.2 Factors Influencing Regional CCS Costs

Literature around costs of CCS in sub-Saharan Africa is sparse. What is remarkable is the presence, however, of the largest single high-purity source of CO_2 in the world: around 30 $MtCO_2$ from a Sasol-operated coal gasification plant in South Africa (Cloete, 2010; Surridge, 2010). This could be an early opportunity if suitable storage capacity can be found nearby.

In oil-producing countries, in the longer term, potential for EOR might exist but such suggestions are highly hypothetical at the moment and not supported by literature.

13.6.5.3 Technical and Human Capacity

South Africa has an unofficial target of realizing one demonstration plant for CCS by 2020 and developing the technical and human capacity for this demonstration along the way. The main instrument for developing human capacity is the South African Centre of Excellence on CCS, founded in 2009 during a conference on CCS, which was also attended by representatives from surrounding countries. The Centre, however, still needs to gain critical mass. In addition, there is capacity on CCS within South African companies such as Sasol and Eskom. Additionally, South African industry representatives support the CO2CRC in Australia.

In Africa broadly, a few capacity building activities have taken place. In 2007, two regional workshops were held on CCS and CDM, one aimed at West Africa in Dakar, Senegal and the second focusing on Southern Africa in Gaborone, Botswana (ECN, 2010). In 2010, country workshops were held in Botswana, Mozambique, and Namibia. There is no R&D on CCS taking place in sub-Saharan Africa.

13.6.5.4 CCS Legal and Policy Initiatives

There are no sub-Saharan countries with any developments toward legislation on CCS. The only potential incentive for CCS might have come through the CDM. Botswana and South Africa are the only sub-Saharan countries that have mentioned CCS in their submissions to the UNFCCC for the Copenhagen Accord. The World Bank is interested in providing financing for feasibility studies on CCS in Botswana. Capacity for regulatory permitting of CCS projects in sub-Saharan Africa is currently largely absent, and apart from capacity building efforts mentioned above, little is being undertaken now to change this.

13.6.5.5 Discussion of CCS in Sub-Saharan Africa

CCS in sub-Saharan Africa is an option for the longer term, given the presence of coal in southern Africa that is projected to be used to fulfill the continent's growing energy and development needs. Before CCS can be realized, human and technical capacity needs to increase, regulation and policy need to be developed, and better insight in geological storage capacity is needed. South Africa is most progressed with a demonstration plant anticipated for 2020 and a pathway toward it. Also in South Africa, short-term, low-cost CCS potential may exist in the form a large coal gasification plant if suitable storage reservoirs can be found within a reasonable distance.

13.6.6 Former Soviet Union

13.6.6.1 Technical Potential and Source-Sink Matching

CO_2 emissions related to fuel combustion in the Former Soviet Union (FSU) region decreased by 34% from 1990 to 2008, reaching 2427 Mt, while population grew by 8%. Russia's emissions declined by 27% to 1594 Mt and Ukraine by as much as 55% to 310 Mt. Energy supply decreased by 27% over the same period in the FSU, with a first period of decline from 1990 to 2000, followed by an expansion from 2000 onwards. Electricity and heat production contributed in 2008 to 50% of the emissions from fuel combustion, followed by manufacturing (17%) and transport (14%). Gas represented 50% of the emissions, declining by only 7%, to be compared with coal (-42%) and oil (-57%). Given the abundance of natural gas resources in the region, applications of CCS would be mostly limited to storage from fuel transformation and natural gas-fueled power plants. A number of gas fields in the Caspian region have relatively high CO_2 and/or H_2S content, and some of the field developments have been delayed due to the issue of sour gas handling.

An assessment of sources and sinks matching in the Baltic States has been made within the EU-funded Geocapacity and CO2NET East projects (Shogenova et al., 2008). There are 24 large sources of CO_2 emissions (greater than 0.1 Mt/yr), with Estonia's upstream production (associated with the extraction and use of oil shales) amongst the largest. While there are no suitable storage areas in Estonia, several prospective formations exist in the Baltic sedimentary basin, with solubility trapping capacities in the range of 13 Gt.

Russia is the country with the single highest storage potential after the United States, with more than 2000 Gt; the capacity of depleted oil and gas fields in the Western Siberian Basin alone is in the order of 150–200 Gt. However, given the distribution of CO_2 emissions (mostly located in the European part of Russia) and the potential storage sites, distances for pipeline transport of 2000–4000 km have to be considered, significantly increasing the cost for the CCS chain.

13.6.6.2 Technological Maturity

The Russian oil and gas and petrochemical industries have a long experience with CO_2 capture, transport, and storage. Use of CO_2 from anthropogenic sources has been investigated since the early 1980s in Russia (Kuvshinov, 2006). Large-scale pilot tests have been carried out to inject CO_2 and other flue gas for enhanced oil recovery. Areas that have promising source and sink matching include the onshore Black Sea area (oil fields near Krasnadar), the Baskortostan (near Ufa), Tatarstan (near Samara), and Perm oil fields. Enhanced coalbed methane potential also exists in the coal fields in the southern part of Russia, but given the current levels of oversupply in gas markets, the application of technology in those prospects is unlikely.

13.6.6.3 Factors Influencing Regional CCS Costs

The cost of CO_2 transport and subsurface injection is well-documented in the FSU, given the volume of oil and gas operations in the region.

13.6.6.4 Human Capacity, Research and Development

In addition to the EU FP6-funded projects for CCS potential in the Baltic States, a call for proposals for clean coal applications has been made in 2010 by the European Commission to explore the potential for some of the Caspian states, including Kazakhstan. In Russia, several technological institutes related to oil and gas production have in-house capabilities for CO_2-EOR, as well as subsurface knowledge. The oilfield service sector has also developed the capabilities to use the building blocks of site assessment for CO_2 storage.

13.6.6.5 CCS Legal and Policy Initiatives

Emission levels decreased significantly during the economic collapse that followed the separation of the FSU states. Therefore, there are no incentives for Russia to use CCS, except if appropriate international mechanisms allowed a monetization of storage. While the current efforts are directed toward gas flaring reduction as a priority, political willingness exists for promoting CCS. The 2006 G8 Summit in St. Petersburg included a joint statement from the Russian Academies of Science promoting research, development, and demonstration in the areas of carbon dioxide storage for energy sustainability.

13.6.7 Australia

13.6.7.1 Technical Potential and Source Sink Matching

CO_2 emissions related to fuel combustion in Australia increased by 56% from 1990 to 2009, reaching 417 Mt, while population grew by 25% (EIA on-line data base). The single largest contributor is stationary sources (particularly coal-fired power station), with 2006 total stationary emissions around 280 $MtCO_2$.

Like most countries, Australia is pursuing a broad portfolio approach to GHG mitigation, although it currently excludes nuclear power from the portfolio. It has in place a Mandatory Renewable Energy Target (MRET) of 20% of electricity from renewables by 2020 and a longer-term goal to reduce emissions by 60% from 2000 levels by 2050. It also has a range of mitigation options under consideration, such as biomass, enhancement of soil carbon, fuel switching (coal to natural gas), and greater energy efficiency. Important though all these measures are, the reality is that at present the rate at which they are being implemented is not keeping pace with the rise in demand for electricity, with most of that increase in demand being met from increased use of coal.

Australia has abundant gas reserves, but currently coal-fired power generation is cheaper than gas in the absence of a price on carbon. In 2011 the Australian governments announced a carbon tax for the 500 top emitters of US_{2011}\$24. However, a carbon price in the range US\$20–30/tCO_2 is unlikely to produce a marked change in consumer behavior or significant deployment of CCS in Australia in the short term. At the same time, there is widespread recognition that given Australia's high level of economic dependency on inexpensive coal for power generation (and its coal exports), it potentially has more to gain than most countries from the successful deployment of CCS. In the short term there is scope for replacing some coal-based power generation with gas, with a commensurate decrease in GHG emissions, and almost certainly this will happen to some extent. In addition, given Australia's move to 20% renewable power, there is likely to be increased use of gas to handle the intermittency of wind power. Gas substitution may provide some reprieve from ever-increasing emissions in the next decade, but in the longer term gas, like coal, becomes part of the greenhouse problem, as gas-related CO_2 emissions rise. There may also be some increase in the use of biomass, particularly for COGEN. However, whether it is coal-, gas-, or even biomass-based power generation, the likelihood is that CCS will play a future role. With this in mind, Australia has taken a number of recent CCS initiatives, including an update of its storage potential through the Carbon Storage Taskforce (CST, 2009).

The major sources of CO_2 are located primarily in eastern Australia, where the major population centers are located, although it is anticipated that the emissions will grow significantly in northwestern Australia as new LNG production comes on stream along with other industrial developments. The Carbon Storage Taskforce (CST, 2009) has identified 10 concentrations of stationary emitters, with sources sufficiently close together that a "hub approach" to CCS may be feasible. There is, or will be, some storage potential in depleted oil and gas fields, estimated by the Taskforce (CST, 2009) at 16.5 $GtCO_2$, most of which is offshore. The depleted fields of the Bowen-Surat Basin in southeast Queensland are the most prospective onshore, with the Gippsland Basin the most prospective offshore region. However, many of the fields are still some years away from being depleted, and therefore overall, the potential for storage in depleted oil or gas fields is quite modest in the short to medium term. CO_2-EOR is regarded as having only very limited potential because of the light nature of Australian crude oil.

The major CO_2 storage opportunities for Australia lie in saline aquifers. The Taskforce (CST, 2009) has determined the technical storage capacity (at 90% confidence level) as 10.9–87.5 $GtCO_2$ for eastern Australia, using storage efficiencies of 0.5% and 4%, respectively, and for western Australia the capacities are 12.3 $GtCO_2$ (0.5% efficiency) and 98.5 $GtCO_2$ (4% efficiency). Total storage capacity is estimated at between 33 and 226 $GtCO_2$, suggesting adequate storage capacity for at least this century and possibly for several centuries, assuming a storage rate of 2–300 $MtCO_2$/yr. It is important to treat these figures with caution, as knowledge of many saline formation systems is still quite limited. Nonetheless, the values do provide confidence that Australia has sufficient storage potential to meet its CCS needs for many years to come.

13.6.7.2 Factors Influencing Regional CCS Costs

Most of Australia is quite sparsely populated with widely dispersed CO_2 sources, which adds significantly to the cost of CCS infrastructure. However, as pointed out earlier, there are a number of emission hubs, where a coordinated approach could be taken to CCS in order to bring down costs. The most extensively investigated hub is that of the Latrobe Valley in eastern Victoria, where brown coal-fired power stations collectively produce one of the largest regional sources of CO_2 in the country. The Gippsland Basin, located only 150 km away, is an excellent prospect for large-scale CO_2 storage with a technical storage capacity of 4–5 $GtCO_2$ at the P90 level, assuming a conservative storage efficiency of 0.5%. Therefore, it is highly likely that a Latrobe-Gippsland source-sink could function very effectively for the remainder of this century. South Central Queensland may also offer similar opportunities, using the Bowen-Surat Basin. Other source-sink matches are also possible with some of the natural gas/LNG-related sources offering effective CCS options for the future. Some of the other emission nodes are less favorably located for nearby large-scale storage, with transport distances in excess of 500 km being contemplated in some instances, such as New

South Wales. Therefore, in some areas, the need for large-scale long distance pipelines will add considerably to the cost of CCS. Those costs will be increased by the need for recompression over long distances with substantial power requirements.

The possible impact of CO_2 storage on other resources could also add to the cost of CCS and result in delays in implementation. For example, while the Latrobe-Gippsland source-sink hub is the highest ranked in terms of storage capacity and cost, it is also a major oil and gas producing basin and will be for quite some years to come. Careful management of CO_2 storage would obviously be necessary to ensure that there is no adverse impact on oil or gas production. In the case of some of the Queensland storage options, the major concern is to ensure that any CO_2 storage does not adversely impact on the significant fresh water resources of the Great Artesian Basin.

The Taskforce (CST, 2009) summarizes the main factors affecting the economics of CO_2 storage as "location (the distance from the CO_2 source to the storage location determines pipeline costs), reservoir depth (influencing well costs) and injectivity parameters (notably permeability and differential pressure, which determine the number of wells needed)." As a result of these factors, CCS costs vary considerably throughout Australia, ranging (for transport plus storage only) from less than US$10/t$CO_2$ avoided for the Victorian Latrobe-Gippsland option to more than US$100/t$CO_2$ avoided for the proposed New South Wales Sydney-Cooper proposal.

The further challenge to deployment in Australia and elsewhere is to establish the appropriate business model for taking the hub concept forward. Several models are under consideration at the moment, including as a government-owned utility, as a public-private partnership, and as a privately-owned utility. There is general agreement on the need for any pipeline network to have excess capacity to handle future growth in emissions, but at the same time, there are no agreed mechanisms to pay for that upfront investment to provide the excess capacity. Finally, in many parts of Australia, as in many parts of the world, there is a lack of knowledge of the deep geology of many sedimentary basins, which in turn makes it difficult to provide a confident assessment of storage capacity. Paucity of geological information represents a significant investment risk in many areas. The Taskforce (CST, 2009) has proposed a national program of precompetitive storage assessment costing in excess of US$250 million, and there is no question that such a program would be extremely useful, but for the present the program remains unfunded.

On a more positive note, while knowledge of CCS in the Australian community is limited, there have been extensive programs to inform the wider community on CCS through the activities of state and federal governments, CO2CRC, and CSIRO. As a consequence, there is no entrenched community opposition to CCS. Indeed, Australia has had an operational storage project, the CO2CRC Otway Project, underway since March 2008, which has been able to proceed with a significant level of local support and which has received national media coverage. Therefore, while every CCS project will need to involve the community in a careful and considered manner, there are no obvious showstoppers at this time in terms of community concerns regarding the technology.

13.6.7.3 Human Capacity, Research and Development

Australia has a strongly developed skills base in the resource sector, particularly in the geosciences, materials science, and engineering, all of which are skills directly relevant to CCS.

Research and training in CCS commenced in Australia in 1998 through the Petroleum Cooperative Research Centre and its Geodisc Program and greatly expanded from 2003 onwards through the successor Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC). Through this Centre, there is an unusually broad and active program of collaborative research involving most of the major universities as well as CSIRO and Geoscience Australia. The Centre also works closely with overseas research bodies. Through CO2CRC and its collaborating universities, a large number of people have been trained in CCS. More recently a number of the bodies within CO2CRC have also developed their own specific research activities, but the Centre is still the main research body that brings CCS research together. CO2CRC is currently funded to 2015 and, with a combination of industry and government funding and in-kind contributions from research providers, has an annual budget of US$20–25 million for its research into CO_2 capture transport and storage.

CSIRO, Australia's main research body, has a CCS program focused in particular on post-combustion capture of CO_2 with several pilot projects underway. It is also engaged in research into CO_2 storage, although most of that is through its collaboration with CO2CRC.

Geoscience Australia (the Federal Geological Survey), together with a number of the State Surveys, have a national program underway to assess storage capacity and develop infrastructure plans.

Australia has been active in the development of CCS training and capability in a number of countries, particularly in East Asia, where a number of courses have been delivered by CO2CRC, GA, and GCCSI.

At present, the Government of Australia has chosen to use direct financial assistance to take CCS forward, and the states have a similar though more modest approach. At the state level, the planning approval process has also acted as a way of ensuring that projects consider CCS as a mitigation option. However, up to now, the primary focus of the government, and to some extent industry, has been to provide funding through a range of CCS initiatives that will run until 2015 or beyond.

In late 2009, the federal government announced the formation of GCCSI with an initial annual contribution of US_{2005}\$ 65.5 million (A_{2009}\$ 100 million) from Australia for four years and the hope that other countries might contribute at some stage in the future. The GCCSI is not involved in research and is focused on global deployment of CCS and the aim of the G20 countries to have 20 large-scale CCS projects by 2020.

The Australian National Low Emissions Coal Research and Development is a recent joint government-coal industry initiative. US_{2010}\$245 million will be made available over five years to 2015–2016 to support low emission coal technology demonstrations in Australia and to understand and address the deployment risks that early demonstration projects may face.

The National Low Emission Coal Council (now called the National CCS Council) was established in 2008 to provide guidance to the government on the overall direction of CCS development and deployment in Australia. The initial focus on coal had the effect of leaving the oil and gas industry largely out of the deliberations, despite the importance of that sector to future CCS deployment. This has now been addressed and in future initiatives will deal more broadly with CCS. The related Carbon Storage Taskforce has involved the oil and gas industry and has now produced a valuable report for a national carbon mapping and infrastructure plan, which, if implemented, will produce a major national assessment of opportunities for geological storage.

The federal government's CCS Flagships Program, should help to accelerate the deployment of large-scale integrated CCS projects in Australia through federal grants totaling US_{2005}\$ 1.0 billion (A_{2009}\$ 1.3 billion). Along with matching industry and state funding, it is expected that this will fund two large-scale CCS projects. Bids are currently being assessed from project proponents. Along with the Flagships Program, the Australian Government has established a companion Education Infrastructure Fund, totaling approximately US_{2005}\$ 130 million (A_{2009}\$ 100 million), to support research partnerships between the Flagships and research institutions, with CSIRO, and CO2CRC the designated Lead Research Organizations.

13.6.7.4 CCS Legal and Regulatory Initiatives

Australia has established an offshore regulatory regime for the geological storage of CO_2 for offshore areas under federal control. Victoria has its own onshore CCS legislation in place and several other states are in the process of defining onshore regulations for CO_2 storage. Western Australia has to date taken a project-specific approach to regulation to enable it to permit CO_2 storage under Barrow Island as part of the Gorgon LNG Project. The issue of long-term liability has proved complex in Australia, as it has with most jurisdictions. However, an agreed process is now in place to transfer offshore storage liability to the federal government at the conclusion of offshore injection and once a number of other performance criteria have been met. The onshore approach to long-term liability (under State jurisdiction) is less clear and varies from state to state. In Victoria, a regulatory regime under the R&D provisions of the EPA enabled the CO2CRC Otway Project to go ahead, but under the more recent CCS-specific provisions of that state's GHG legislation, it would be much more difficult to take such a research project forward. Therefore, one of the clear lessons from the Australian experience is to ensure that regulations take full account of the research needs of CCS. Nonetheless, overall Australia is probably more advanced than most other countries in the development of CCS legislation.

13.6.7.5 Australian CCS projects

A combination of various state and federal financial initiatives, coupled with general recognition of the importance of CCS to the Australian economy and the Australian resource and power industry, has resulted in a number of planned or proposed projects, which are summarized below and in Figure 13.11b.

The Callide Oxyfuel Project in Queensland involves oxy fuel conversion of an existing 30MW unit at Callide A (currently underway) with power generation and capture of CO_2 commencing in 2013. A second stage of the project may involve the injection and storage of captured CO_2 into a saline aquifer or depleted oil/gas fields over about three years, commencing in 2013, but as yet a suitable site has not been identified. The cost estimate for the project is approximately US_{2010}\$218 million. The project involves CS Energy, IHI, Schlumberger, Mitsui, J-Power, and Xstrata, with extra funding from the Australian Coal Association and the Australian and Queensland governments.

The CarbonNet Project in Victoria, a CCS Flagship Project proposal, is for the development of the infrastructure for a storage and transport hub in the Latrobe Valley. It is coordinated by the state of Victoria. It aims to collect, transport, and store 3–5 $MtCO_2$/yr from Latrobe Valley industry, including coal-fired power plants (and may involve both pre- and post-combustion capture), with storage in the Gippsland Basin.

The Collie South West Hub Project in Western Australia is a CCS Flagship Project proposal coordinated by the state of Western Australia. It aims to store up to three $MtCO_2$/yr captured from industrial and power plants located southwest of Perth. At the present time, the biggest challenge the project faces is identification of a suitable storage site.

The CO2CRC Otway Project in Victoria is Australia's only operational storage demonstration project. Injection of CO_2 from a nearby gas well, initially into a depleted gas field at a depth of two km, began in April 2008 with injection of 65,000 tCO_2-rich gas to date. A major program of monitoring and verification has been implemented. A new well was drilled in early 2010 and a new phase of injection has been initiated. The A\$60 million project, which is supported by 15 companies and seven government agencies, involves researchers from Australia, New Zealand, Canada, Korea, and the United States. Partners include major gas, coal, and power companies, research organizations and governments.

Additional financial support is provided by the Australian Government, the Victorian Government, and the US DOE through Lawrence Berkeley National Laboratory.

The Coolimba Project of Aviva Corporation Ltd is an early stage proposal in Western Australia for 2x200 MW coal-fired base-load power stations with the plant built ready for conversion to CO_2 capture. Sequestration sites have been sought for the storage of about 3 MtCO_2/yr, but the project is presently suspended.

The Gorgon Project of Chevron (operator), Shell, and Exxon is at the early construction stage. It involves a major storage project linked to the Gorgon LNG Project. The separated CO_2 will be injected under Barrow Island at a depth of about 2.3 km, with injection of 3–4 MtCO_2/yr. A total of 125 Mt will be injected over the life of the project. A data well has been drilled, and a major study of the subsurface is underway. All government approvals have been granted, and the final investment decision for the project to proceed has been made. A number of contracts have been awarded, and construction is underway. The storage component of the project will cost in excess of A$1 billion.

Galilee Power has an early stage proposal for a new 900 MW coal-fired power station incorporating CCS with storage of captured CO_2 in the Galilee Basin. Prefeasibility studies are underway, but activity is quite limited at the present time.

A post-combustion capture plant is operating at International Power's Hazelwood Power Station in Victoria. The solvent capture plant began operation in 2009 and is capturing and chemically sequestering CO_2 at a nominal rate of 10,000 tCO_2/yr. This project is partly funded by the Australian and the Victorian Governments.

The Latrobe Valley Post Combustion Capture Project (LVPCC) in Victoria is developing technologies for post-combustion capture from coal-fired power stations in the Latrobe Valley. The LVPCC involves International Power, Loy Yang Power, CO2CRC, and CSIRO and is partly funded by the Victorian Government. It comprises work at the Hazelwood Power Station by CO2CRC and by CSIRO at Loy Yang.

The H3 Capture Project, Hazelwood, Victoria, led by CO2CRC, is based at International Power's Hazelwood plant and exploits synergies with the Hazelwood Capture Project. A range of solvents and different process configurations are being tested using the solvent post-combustion capture plant. In addition, post-combustion techniques using adsorbent and membrane technologies are being developed, using two purpose-built rigs.

The Loy Yang Project in Victoria involved a CSIRO mobile pilot post-combustion capture facility. This has begun operation at Loy Yang Power Station and is capturing around 1000 tCO_2/yr. The facility investigated a range of solvent technology for CO_2 capture and has now concluded the research.

At the CO2CRC/HRL Mulgrave Capture Project in Victoria, CO_2 emissions were captured from HRL's research gasifier at Mulgrave in a pilot-scale pre-combustion project. The capture technologies were evaluated to identify which are the most cost-effective for use in a coal gasification power plant. Partners included CO2CRC and HRL, with funding from the Victorian Government. The research has now been concluded.

The Munmorah PCC Project in New South Wales has investigated the post-combustion capture (PCC) ammonia absorption process, and the ability to adapt it to suit Australian conditions. Tests to capture up to 3000 tCO_2 have been successfully completed. Partners involved in this project are Delta Electricity, CSIRO, and the ACA. The pilot plant has now been relocated to another site and a larger-scale demonstration project, incorporating geological storage, is under consideration.

CSIRO and Tarong Energy have installed a post-combustion capture pilot plant using an amine-based solvent at Tarong Power Station near Kingaroy, Queensland. The pilot plant will capture 1500 tCO_2/yr over a two-year research program. Construction has commenced.

Stanwell and Xstrata Coal are proposing the Wandoan Project, Queensland as a CCS Flagship Proposal. Identification of suitable storage sites in the Surat Basin of Queensland is being undertaken by the consortium.

13.6.8 Latin America

13.6.8.1 Technical Potential and Source-Sink Matching

CO_2 emissions related to fuel combustion in Latin America increased by 70% from 1990 to 2009, reaching 1212 Mt, while population grew by 32% (EIA on-line data base). Latin America includes South America, including Brazil, and Central America, including Mexico and the Caribbean. The region is a major oil producer; Mexico and Venezuela jointly produced 7.2 % of worldwide crude oil in 2009 (IEA, 2010a), and Brazil is up and coming as an oil producer and exporter. EOR is clearly seen as a possibility. Almost all countries in Latin America have CO_2 sources from cement production, refineries, and power, although much of the power in the region originates from renewables, in particular hydropower. Several of the larger countries have steel and ammonia plants and ethylene production. As companies are starting to explore EOR in the region, they are looking for high-purity CO_2 sources. In Mexico, an ammonia plant has been explored, and in Brazil, biomass production is being explored.

Except for Brazil, no comprehensive CO_2 storage atlas or assessment has been done in Latin America, although in Mexico and Argentina several reservoirs have been explored for EOR or storage. In Brazil, the CARBMAP project (Rockett et al., 2011) has done a rough assessment of sources, pipeline corridors, and reservoirs.

An additional possibility in the Latin American region is the combination of biomass and CCS (Möllersten et al., 2003). According to the IEA GHG (2008) database on CO_2 emissions, the CO_2 emissions from ethanol and biomass production are around 72 $MtCO_2$/yr, all of them in Brazil. These sources are high-purity and therefore amenable to capture, but also relatively small-scale at ca. 100,000–150,000 tCO_2 per source per year. Most of the sources are in the São Paulo region, relatively close to the ocean shore, although it is unclear at this point whether there might actually be storage potential close by. The Global Environment Facility may fund a small-scale bioethanol CCS project in Brazil.

13.6.8.2 Factors Influencing Regional CCS Costs

Distances are large and currently it is unclear whether there is storage potential and where it is. In Mexico and particularly Brazil, much of the EOR potential is likely to be offshore, negatively affecting costs.

13.6.8.3 Technical and Human Capacity

CCS does not have a long history in the Latin American region, but capacity has increased over the past five years. Countries like Mexico and Venezuela, with a significant oil industry, have some embedded capacity. In Brazil, a dedicated CCS center was established, the Brazilian Carbon Storage Research Center at the Pontifical Catholic University in Porto Alegre. Research is also done at the Sindicato da Industria Carbonifera de Santa Catarina (SIECESC). The Brazilian Carbon Storage Research Center's capabilities are clear from publications in peer-reviewed journals (e.g., Ketzer et al., 2007). The Center is partly funded by Petrobras, which is building up capacity internally for CCS and for CO_2-EOR.

13.6.8.4 CCS Legal and Policy Initiatives

There are no known legal or policy initiatives in Latin America. The Global CCS Institute commissioned a study, which examined current initiatives in Brazil (GCCSI, 2009b). This study reported that in Brazil, there is existing legislation for pipelines, environment impacts, and mining that would apply to CCS operations, but no major barriers were identified. Similar conclusions were drawn for Mexico (GCCSI, 2009c). In terms of policy incentives, the CDM may be a driver for low-cost opportunities provided the conditions in the latest UNFCCC decisions can be fulfilled.

13.6.8.5 Discussion of CCS in Latin America

CCS plays a minor role in the climate and energy debates in most Latin American countries. It is only seriously considered in Argentina, Brazil, and Mexico. In those countries, the first demonstrations are likely to be from industrial CO_2 sources rather than power, as much of the power in the region originates from renewables and there is some potential for low-cost capture opportunities. Although in private and academic sectors capabilities are being developed, legal and regulatory frameworks are still absent in all countries. It appears that either EOR or international instruments, potentially CDM, with which the region has had some success, will be the main drivers for CCS in the coming years.

13.6.9 Middle East and North Africa

13.6.9.1 Technical Potential and Source-Sink Matching

CO_2 emissions related to fuel combustion in the Middle East and North Africa (MENA) region increased by 128% from 1990 to 2007, reaching 1770 Mt, significantly outpacing population growth over the same period (+44%). Over 95% of those emissions were related to the use of oil and gas, with oil-based transport and gas-based power generation having the largest growth over the last two decades. Given the abundance of natural gas resources in the region (and its lack of coal resources), applications of CCS would be mostly limited to storage from fuel transformation, and natural gas-fueled power plants. A number of gas fields in the MENA region have relatively high CO_2 and/or H_2S content, and some of the field developments have been delayed by the issue of sour gas handling. In North Africa, the main potential for capture is in Algeria, Libya, and to a lesser degree, Tunisia. Both in Salah Gas and Gassi Touil projects in Algeria have a CO_2 content as high as 10% with nearby storage reservoirs. In Libya most of the potential is from offshore fields with a potential of use of CO_2 for EOR, while in Tunisia the largest gas field in the country (Miskar) has nearly 13% CO_2 content. In the Middle East 60% of the proven gas reserves have more than 100 ppm of H_2S and/or 2% CO_2 (IEA, 2008b). Other opportunities for capture in the areas are in fuel transformation, particularly gas-to-liquids, as well as in the growth of gas-fired power plants, and in the developing petrochemical sector.

While no detailed study of storage potential has been made in the area, the global assessment performed points to a highly favorable sedimentary environment for the MENA region. The Middle East represents the largest future potential for storage in depleted fields with the five biggest sites having a combined 180 Gt of capacity. With the caveat that deep saline aquifers are poorly understood, combined storage capacity ranges for the MENA region are estimated at (IEA, 2008a) 200–1200 Gt for oil and gas fields and 50–550 Gt for saline formations.

The region has the highest potential incremental recovery from CO_2-EOR, with estimates of additional volumes of oil ranging from 80–120 billion barrels (IEA, 2008a). Given the lack of availability of CO_2 and the incremental cost, attempts to develop this tertiary method in the region are still limited. In 2009 Saudi Arabia announced plans for a CO_2-pilot project in a waterflood of the Arab-D reservoir (Ghawar field) that could be started in 2013 with the injection of 0.8 $MtCO_2$/yr, but stressed that the country did not need EOR on a large scale at this point. In the United Arab Emirates, a pilot project (the first in the Middle East) was started by

Abu Dhabi Company for Onshore Oil Operations (ADCO) at the end of 2009 for the injection of CO_2 in the Northeast Bab's Rumaitha carbonate reservoir, while a study was launched in 2010 to use CO_2 for EOR in the Lower Zakum oil field in Abu Dhabi.

13.6.9.2 Technological Maturity

Efforts to reduce the emission of GHGs from upstream operations have been ongoing for the last two decades, including a significant reduction in gas flaring. The MENA region has the first large-scale CCS projects outside of the Organisation for Economic Co-operation and Development with the BP-Sonatrach-Statoil In-Salah Gas project (see Section 13.4.2.2.3). The region also benefits from the experience gained in both surface and subsurface processes from the oil and gas industry. Turkey had one of the earliest CO_2-EOR project in the heavy oil field of Bat Raman. In 2009 the Abu Dhabi Future Energy Company confirmed plans for a major initiative to reduce emissions from the Emirates by half using CCS. The first phase of the project would involve the capture of up to 5 $MtCO_2$/yr from three sources (a gas-fired power plant, a steel mill in Mussafah, and an aluminum smelter at Taweelah). The plan also includes the development of a specific pipeline network and the injection in Abu Dhabi National Oil Company's oilfields.

13.6.9.3 Factors Influencing Regional CCS Costs

The cost of CO_2 transport and subsurface injection is well-documented given the volume of oil and gas operations in the region. The feasibility and optimization of Water Alternating Gas processes in enhanced oil recovery still requires detailed evaluation, as the conditions of EOR operations in North America are significantly different: well spacing, reservoir heterogeneity, and thickness, along with crude gravity, all play an important role in the incremental oil recovery with CO_2. Also the development of interstate pipeline networks would allow further cost optimization. The MENA region has ample and widely distributed storage capacity, which would allow matching sources and sinks relatively easily. What remains to be determined is the potential for the region to host the emissions from nearby European sources.

13.6.9.4 Human Capacity, Research and Development

In November 2007, the Organization of Petroleum Exporting Countries (OPEC) announced pledges for a US$750 million fund to develop clean energy technologies, in particular CCS, with the participation of Saudi Arabia, Kuwait, Qatar, and the United Arab Emirates. Several initiatives have been started in the region to develop technological capabilities, including the Masdar project, and the recently created Qatar Carbonates and Carbon Storage Research Centre. Many international workshops have been convened in the region to increase awareness and assess which areas of research are most appropriate in the Middle East context. Efforts to promote technology transfer in the region have been led by the Society of Petroleum Engineers and other professional societies, along with OPEC and national organizations.

13.6.9.5 CCS Legal and Policy Initiatives

Saudi Arabia and other OPEC countries have successfully negotiated for the inclusion of CCS as a Clean Development Mechanism, allowing developed countries to offset their emissions. While awareness in the region about carbon abatement rationales and options is generally low, there is also the concern by governments to prevent a strong curbing of hydrocarbon use, which may impact the region's economic growth. Therefore, options such as fuel switching for natural gas or CCS rank amongst the highest.

13.6.10 Japan

13.6.10.1 Technical Potential and Source-Sink Matching

In 2007 Japan emitted almost 1214 $MtCO_2$. The industrial sector, led by iron and steel manufacturing, contributes to the majority of the emissions (451 Mt), followed by transportation (257 Mt), commercial sector (215 Mt), residential sector (201 Mt), and energy conversion sector (90 Mt) (Aoshima, 2009). Thermal power stations, iron and steel manufacturing plants, and cement plants are the three major stationary sources assessed for CO_2 capture (Nakanishi et al., 2009).

A storage capacity of 146.1 $GtCO_2$ has been reported in Japan (Nakanishi et al., 2009; Takahashi et al., 2009). A total of 27 potential storage areas are being investigated throughout the country, four of which correspond to regions with large emission sources: Tokyo Bay, Ise Bay, the Osaka Bay area, and northern Kyushu (Nakanishi et al., 2009). Studies identify 18 saline aquifers that can be suitable for CO_2 with storage capacity ranging between 0.01–7 Gt per saline aquifer. However, the accuracy of evaluating storage volume and effectiveness varies significantly among the identified saline formations (Ogawa et al., 2009). Existing oil and gas reservoirs and formations investigated by exploration wells and seismic surveys are estimated to have a storage capacity of approximately 36.2 Gt. Other formations, investigated by seismic surveys only, are expected to store around 109.9 Gt (Nakanishi et al., 2009; Takahashi et al., 2009). The spatial distribution of major CO_2 stationary point sources and analyzed storage basins throughout Japan shows close proximity between sources and sinks and some potential for source-sink matching (Takahashi et al., 2009).

13.6.10.2 Technological Maturity

Japan continues to develop the technological infrastructure required for CCS deployment. Eight CCS projects are completed and/or currently active. This includes post-combustion capture, ECBM, and storage projects, at the R&D, demonstration, and industrial/commercial-scales (BRGM, 2009; Lund et al., 2008). Post-combustion capture has been implemented in Japan since 1991 to capture CO_2 emissions from Nanko power facility in Osaka. Recently, several post-combustion capture projects have been implemented in coal and gas power plants and chemical facilities. Between 2000 and 2007, the Nagaoka project involved a successful storage of 10,400 tCO_2 in a 1000 m deep saline aquifer. Also, in 2002, the first ECBM project was launched in the country with the aim of injecting CO_2 in 6–9 m thick coalbed 900 m underground in Yubari, Hokkaido (Lund et al., 2008). This rapid development of CCS projects improves Japan's experience in CCS and enhances its capability of early deployment and testing of CCS.

According to the US Energy Information Administration (US EIA), Japan has little domestic oil and natural gas reserves, which makes it the second-largest net importer of crude oil and largest net importer of liquefied natural gas in the world. In 2007 the country's total consumption of oil reached almost 5 million bbl/day (249 Mt/yr), compared to 130,000 bbl/day (6.47 Mt/yr) of production. Similarly, the total consumption of natural gas in the same year was about 100 billion m^3 (3.5 trillion cubic feet), only 1 billion m^3 (32 billion cubic feet) of which is produced domestically. Nevertheless, Japan has developed significant experience in the oil and gas industry by leading in technology and equipment development, establishing a robust refining infrastructure, and participating in exploration and production projects overseas. Today, Japan's refining capacity is the second-largest in the Asia-Pacific region, and almost 15% of the country's oil imports come from Japanese-owned concessions around the world, primarily in the Middle East (US EIA, 2010). As such, it would be reasonable to argue that Japan's experience in oil and gas exploration and production enhances the country's capability of developing CCS infrastructure both locally and internationally.

13.6.10.3 Factors Influencing Regional CCS Costs

As mentioned before, many of the currently proposed CO_2 storage sinks in Japan are onshore, and most CO_2 point sources are located either on or close to potential geologic storage formations (Nakanishi et al., 2009). Today, even though several CCS pilot projects are currently implemented, the design and layout of the potential CO_2 infrastructure and transportation network in the country has not been fully investigated (Nakanishi et al., 2009). Nevertheless, the safety aspects of CCS projects, as well as the effect of topography and various environmental factors on the cost and effectiveness of CCS implementation, have been recently addressed in a study by the Carbon Dioxide Capture and Storage Study Group within the Industrial Science and Technology Policy and Environment Bureau at the Japanese Ministry of Economy, Trade and Industry. In addition to detailing the geological requirements for safe storage of CO_2 at a large demonstration-scale, the study suggests a CO_2 transportation standard, a regulatory framework for assessing operations' safety, a methodology for environmental impact assessment of CCS-related activities, and a list of monitoring techniques to track CO_2 before and during injection for safe operation of a CCS demonstration project (Japan CCS Study Group, 2009).

According to the US EIA, around 83% of the total energy use in Japan in 2005 was met by coal, oil, or natural gas; renewable energy accounts for about 4% of the energy demand. Electricity production is estimated to increase from almost 245 GW in 2007 to around 305 GW in 2030, 40% of which will be generated from fossil fuels (compared to 59% in 2007) (US EIA, 2010). Thus, even with strong policy initiatives and major technological developments that incentivize for the implementation of energy efficiency, renewable energy, and other low carbon technologies, fossil fuels will remain a major contributor to Japan's energy fuel mix for the coming two decades. Although not the only option, CCS is expected to be a major, economically feasible tool to reduce Japan's CO_2 emissions as part of its efforts to combat climate change (Ministry of Economy, Trade and Industry of Japan, 2010).

13.6.10.4 Human Capacity, Research and Development

Japanese governmental agencies, academic institutes, and private industrial/commercial businesses are actively involved in CCS-related endeavors both locally and internationally. At the governmental level, CCS-related research initiatives have been initiated and supported by governmental agencies within the Ministry of Economy, Trade and Industry, Ministry of Science and Education, Ministry of Environment, and the Prime Minister Cabinet Office, with plans to reduce 100 $MtCO_2$ emissions through CCS by 2020 (Lund et al., 2008). Two major government initiatives are the CO_2 Storage Research Group within the Research Institute of Innovative Technology for the Earth under the Ministry for Environment, Trade and Industry (see RITE, 2011) and the New Energy and Industrial Technology Development Organization (Lund et al., 2008). The private sector is also promoting CCS initiatives either individually or in collaboration with the Japanese Government. In 2008 the Japanese CCS Company Ltd was launched by 29 power and energy firms in Japan to advise the government on the feasibility CCS implementation. Electric utilities, industrial firms, and private Japanese international companies have also funded research projects to develop advanced capture technologies and investigate ocean sequestration (Lund et al., 2008). In this regard, the CCS R&D network database of the Global CCS Institute shows that a total of 32 organizations in Japan are involved in CCS R&D, the majority of which is related to CCS technologies (GCCSI, 2011b).

In addition to the local efforts, Japan is actively engaged in international collaboration on CCS initiatives. Japan is a member of CSLF, GCCSI, and IEA CCS roadmap. In addition, Japan is collaborating with China on an EOR project that involves capturing 1–3 $MtCO_2$ from the Harbin thermal power plant in Heilungkiang Province to be injected and stored in Daqing Oilfield, China's largest oil field. The Yantani

IGCC project is another example of collaboration between both countries where Japan is primarily involved through Mitsubishi Heavy Industry. In addition to China, Japan is collaborating with Vietnam on the White Tiger CCS Project, Malaysia on Bintulu CCS Project, Australia on CS Energy Oxy-Fuel Project, and United Arab Emirates on JODCO EOR project. All aforementioned initiatives contribute significantly to building a competently educated human capital that would be expected to play a major role in advancing CCS technology (Lund et al., 2008).

13.6.10.5 CCS Legal and Policy Initiatives

Although there is currently no specific regulations, for carbon capture and storage activities in the country, Japan's national policies promote CCS as major climate change mitigation option. The *Cool Earth-Innovative Energy Technology Program* report, issued in March 2008 by the Ministry of Environment, Trade and Industry, identifies CCS as one of the major technologies that need to be focused on and developed in order to achieve substantial reductions in CO_2 emissions by 2050. The report includes CCS on the top of 21 priority-technologies to support. The program lays out a multiphase plan to concurrently accelerate technological enhancement, reduce cost, implement large-scale projects, maintain strong international collaboration, and draft domestic regulations and laws between 2020 and 2050 (Ministry of Economy, Trade and Industry, Japan, 2008).

Another important aspect affecting the deployment of CCS is the sufficiency of governmental funding. Currently, modest funding is provided by the Japanese Ministry of Economy, Trade and Industry to the Office of Environmental Affairs whose R&D budget was 5.66 billion Yen (~US$50 million) in 2006 and 4.3 billion Yen (~US$37 million) in 2007, with main focus on two areas: ocean/saline aquifer storage and clean coal technologies. Another US$10 million was allocated for international coal utilization projects by the New Energy and Industrial Technology Development Organization (Lund et al., 2008).

Studies show that the Japanese population is still not very well informed about CCS as an option to mitigate climate change: almost 68.8% of the population is not familiar with CCS, compared to less than 5% for solar or wind energy. Public media seems to have great impact on people's awareness, as 72% of the people learn about CCS from either television programs or newspapers. In that regard, four major factors are found to shape people's perception about CCS: concern about risk and leakage, understanding of effectiveness of CCS, responsibility for mitigation of CO_2, and concern about use of fossil fuel. Surveying the Japanese public opinions shows that people have a positive attitude toward the implementation of CCS, but they become less supportive when asked about CCS implementation in specific applications and locations. As such, it is unlikely that the Japanese public would voice strong opposition against CCS implementation in the future, but educating people about the CCS technologies and associated risks would play a major role in increasing public acceptability (Itaoka et. al., 2011).

13.6.11 Conclusions from the Regional Outlook

Technical potential of CCS on a global level is promising but on a regional level is differentiated. Much more work is required to realistically assess storage capacity on a worldwide, regional, and subregional basis. The information available to date indicates that there is sufficient worldwide capacity for storing at least 100 years of emissions from stationary sources in deep geological formations. On a regional basis, the distribution of deep geological formations is highly variable. In general, those regions with large fossil fuel resources, particularly oil and gas, have the largest storage potential. Some regions, including the Former Soviet Union, Northern Europe, North America, and the Middle East, have large storage capacity. Other areas, notably India, and parts of Southeast Asia, seem to have more limited geological storage capacity.

How and when CCS becomes an economically feasible option depends on the matching over time between CO_2 sources and sinks in specific regions. Besides the technical potential, the matching will depend on factors such as the electricity mix, the regulation of industry, national targets for CO_2 abatement, national and regional targets for renewables, local policies regarding nuclear power, and the existence of economic incentives. CCS comes at a cost and therefore requires appropriate incentives. Many institutional factors influence the degree to which CCS is implemented, including environmental regulations, mineral and property rights, carbon credits for CCS, international trading of carbon credits, and resolution of long-term liability issues.

13.7 Public Perception and Acceptance of CCS

The deployment of CCS technology relies on a myriad of interactions among technologies, markets, institutions, policies, regulations, and society (IPCC, 2005). Confidence about the technical feasibility of CCS has been growing, yet like any technology its deployment will be influenced by many social factors. Experiences with other technologies suggest that if public acceptance of a technology is lacking, large-scale global deployment is inhibited (Renn et al., 1995; Cormick, 2002; Kalaitzandonakes et al., 2005). Likewise, public perception and support will be critical if CCS technology is to achieve its potential as a GHG mitigation strategy (IEA, 2008a). As the number of CCS-related projects grows, and the potential for CCS technology to contribute to reducing CO_2 emissions becomes more prominent in societal debates, issues related to the public perception and social acceptance of this technology are becoming more salient. Public engagement and communication on CCS is therefore an increasingly important issue as large-scale deployment advances. This section outlines key public perception issues based on scholarly research and real world CCS projects. Additionally it presents lessons learned from public engagement in the proposed and existing CCS projects.

13.7.1 What is Public Perception in the CCS Context?

13.7.1.1 Definition of 'Public'- What Does Public Constitute in the Context of CCS?

In the context of CCS, the term 'public' encompasses diverse subgroups or 'publics' – referring to general public, globally or within the vicinity of a project. The public also includes other segments of society such as policymakers, regulators, industry, academia, NGOs, and media, which helps the general public or communities form an opinion.

There are different dimensions of how public perception is formed and influenced –narrowly, at the project level, and more broadly, at national and global levels. At the project level, public perception and support for CCS technology will be influenced by the regulatory processes that are in place to ensure public participation in the decision-making. The direct public engagement at the project level is likely to happen through a variety of mechanisms during the different stages of a project, depending on the legal requirements or social norms in the country where the project is planned. For example, a common mechanism for public engagement includes public hearings as a part of the project approval process. These are the more concrete interactions with the public, focusing at a specific project level.

The policy debate surrounding CCS technology is the other dimension that will define broader public perception of the technology. The public is generally represented by and organized in non-governmental organizations, such as environmental NGOs, community groups and the like. How governments and other stakeholders perceive CCS, as part of their national climate change mitigation strategies, and how they frame national and international policies, will also affect the public's perception and support of the technology.

13.7.1.2 Introduction to Research Methods and Issues around Public Perception of CCS

Public perception of CCS technology has been assessed through numerous research and case studies, conducted across the world at national as well as project-specific levels. These research studies have relied on different research methods such as survey instruments, focus groups, mental model approach, factor analysis, information choice questionnaires, and discrete choice analysis to identify public perceptions of CCS at the broader societal level. Most of the studies use one or a combination of three methods: a written or digital survey method, focus or discussion groups, and experiments. In surveys, experimental surveys and experiments respondents are often given written information to read. In focus or discussion groups participants are often informed by researchers, experts or handouts, or a combination thereof (Huijts, 2003; Curry et al., 2004; 2006; Palmgren et al., 2004; Shackley et al., 2005; Sharp et al., 2006; Reiner et al., 2006; Best-Waldhober et al., 2006, Ha-Duong et al., 2009; Itaoka et al., 2004; 2006; 2009). More recently, the public has also been engaged at the specific project level (see case studies summarized in Table 13.8), although the motivations behind engaging the public living in the vicinity of the projects are slightly different than broad national-level social science-based research. The project-level public engagement aims for making better project decisions, supporting the successful design and implementation of the proposed project and, in some cases meeting the regulatory requirements.

13.7.2 Public Perception of CCS Technology

13.7.2.1 A Summary and Analysis of Research Conducted over the Past Few Years to Assess Public Perception of CCS across the World

The numbers of research studies to assess public perception of the technology around the world have grown over the past five years (for a review, see Reiner, 2008; Ashworth et al., 2007). At the broad societal level, these studies show consistency in some areas and differences in others. Both across jurisdictions and over time, all studies show that the vast majority of the public is not aware of CCS and even fewer understand the technology, its risks and benefits (Johnsson et al., 2009; Reiner et al., 2006). Differences, however, generally arise in the level of public understanding and support for CCS across countries (Reiner et al., 2006).

13.7.3 An Overview of CCS Public Perception Survey Research

Most of the studies to assess public perception of CCS have been conducted in industrialized countries. Studies to evaluate public acceptance and support of CCS in the major coal-dependent emerging economies are practically nonexistent. This can be attributed to very few to almost no CCS projects in these countries due to limited R&D, lack of government support for projects, and in those areas where projects exist, limited regulatory and institutional capacity to engage the general public.

The studies to assess public perception of CCS around the world and their findings are summarized below:

- In the Netherlands a study conducted in 2003 (Huijts, 2003) indicated that residents not living above a likely CO_2 storage site had neutral to positive attitudes about CCS but were less supportive to its development in their community or nearby, suggesting "Not In My Back Yard" (NIMBY) characteristics of public perception of CCS.
- The survey conducted by MIT to assess general public perception of CCS in the United States (Curry et al., 2004; 2007) confirms very low public awareness of CCS. The internet-based survey among samples of 1200 respondents conducted in 2003 and 2006 reveals that more

than 90% of the respondents had never heard of CCS and the results were largely consistent during both survey periods. Support for CCS is also linked to public attitudes about fossil fuel alternatives such as renewable energy, efficiency measures, and demand reduction.

- A 2004 study in the United States by Carnegie Mellon University (Palmgren et al., 2004) found that people were significantly less willing to pay for CCS than for any other major option to reduce CO_2 emissions, including new nuclear power plants.
- Studies in the United Kingdom (Shackley et al., 2005; 2007) found "slight support" for CCS in concept but also a belief that as a standalone policy "CCS might delay more far-reaching and necessary long-term changes in society's use of energy."
- A 2006 survey of 900 respondents in Australia (Miller et al., 2007) found that although most respondents believe it is very important to reduce greenhouse gas emissions at a national level, many are "neutral" toward CCS as a strategy. This study found that approximately 40% of the public believes CCS would be "a quick fix that would not solve the greenhouse gas problem." A less representative but more recent Australian study confirmed those average results (Ashworth et al., 2009).
- A 2006 study in Canada (Sharp et al., 2006) found low awareness of CCS in a survey among 1972 respondents in Canada. Although between 10% of respondents in Alberta and Saskatchewan and 15% of respondents in the rest of Canada said they had heard of CCS, very few were able to correctly identify the problem that will be addressed by CCS.
- Reiner et al. compared the awareness of CCS in the United States, United Kingdom, Sweden, and Japan (Reiner et al., 2006). The four samples in this study were mostly drawn at random from the countries' adult population and consisted of at least 742 respondents per sample. The study found low awareness of CCS in all four countries, ranging from 22% of respondents confirming they had heard or read about CCS in Japan to as little as 4% in the United States.
- A recent survey of 1076 respondents in France revealed that a vast majority of respondents were not strictly opposed of CCS but were more suspicious than supportive. The study also showed that a vast majority of respondents had not heard of CCS and only 6% of a representative sample was able to define the term (Ha Duong et al., 2009).
- A recent study in Switzerland (Wallquist et al., 2009) investigating lay people's concepts of CO_2 and CCS showed that some people were worried that CO_2 might cause cancer or even that CO_2 leaking from storage might cause DNA changes. These kinds of misconceptions are not likely to be anticipated by experts and therefore less likely to be investigated in polls or surveys or addressed in information about CCS technology.
- Other surveys in the Netherlands conducted in 2006, 2007, and 2008 (Best-Waldhober et al., 2006; 2008; Lambrichs, 2008) showed similar results. Depending on the kind of CCS technology that the three samples, a total of 918 respondents, were asked about, between 51.2–91.4% of respondents stated they were unaware of the technology.
- The survey research conducted in Japan (Itaoka et al., 2004; 2006; 2009; Tokushige et al., 2007) suggests very limited understanding of CCS technology among the respondents. The effectiveness of CCS (i.e., its effect on CO_2 emission reduction) and perception of potential benefits of CCS were the two most influential factors for public acceptance of CCS.

Some researchers have considered traditional questionnaire methodologies less suitable for examining public perceptions of CCS because with limited or no knowledge about an issue there is a risk of producing variable responses or in some instances "pseudo opinions" (Best-Waldhober et al., 2009). Malone et al. (2009) further state that, "because of the inherent difficulty of providing information in an unbiased way, surveys may be compromised at the outset if they seek to educate." Providing respondents with elaborate, understandable, recent, accurate, and balanced information on CCS technologies as well as their consequences and context is difficult and highly time- and resource-consuming. Most studies can only partially overcome these issues and are thereby unable to rule out susceptibility to bias. Therefore, the opinions found in these studies should be interpreted with care.

13.7.3.1 The Role of Information

Studies found that in some cases, when information was provided solely as part of a questionnaire, individuals were more negative toward the technology. Conversely, when information was provided with increasing depth and interactivity, individual attitudes toward CCS tended to be more positive. Some studies have tried to address this by providing respondents with information about CCS to see how informed and uninformed perceptions of CCS vary among the general public. In the United States, a survey of over 100 respondents shows that exposure to information about CCS technology increased the public level of understanding as well as support for advancing the technology (Stephens et al., 2009). Another study conducted in the Netherlands tested traditional survey methodology on a sample of 327 respondents and information choice questionnaires on 995 respondents (where information about CCS is provided to the respondents) and reported that the public is more supportive of the technology after processing relevant information (Best-Waldhober, 2009). Similar results were obtained from Japan, where a survey administered on a sample of 1006 adults in Tokyo revealed that additional information, prior to the survey, led to increased support for the technology (Itaoka, 2006; 2009).

13.7.3.2 Which Actors Are Trusted?

Research by Ashworth et al. (2006), Mors (2009), and Terwel (2009) shows that the relative trust individuals place in the information source is a key factor influencing acceptance of CCS. People put more

Table 13.6 | Strengths and weaknesses of existing public perception research.

Strengths of existing public perception research	• Successful identification of public's concerns and issues about CCS • A range of methods have been tested to assess public perception of CCS in different countries, which has not only provided insights into how public perceives CCS but also shed light on advantages and disadvantages of using different research methods • The results of public perception research has provided some guidance to policy makers and project developers • Comparison beginning to occur across countries to identify cultural similarities and differences toward CCS • Meaningful dialogue is more successful in engaging public–some activities have ventured beyond survey research
Weaknesses of existing public perception research	• Large focus on survey research in comparison with meaningful engagement and communication about CCS • Many activities directed at students, and as a subset of lay public, their views are not necessarily representative of the society • Little emphasis on evaluating perception of public toward CCS in developing countries • Lack of coordination among researchers in conducting public perception research • Limited investment and funding for CCS public communication research

Source: Ashworth et al., 2007; Reiner, 2008.

trust in environmental NGOs than in industrial organizations or the government. The previous experience with the organizations or the actors involved, concerns over accountability, and openness can also play important roles in shaping public trust (Reiner, 2008). The communication strategies by untrustworthy stakeholders may result in negative public attitudes toward CCS. Additionally, communication about CCS may result in more positive perceptions when stakeholders work together to provide information to the public rather than as separate "stand alone" organizations. The role of the CCS community, as an epistemic community, is also thought to play a role in the perception of the technology (Stephens et al., 2011).

13.7.3.3 Analysis of Existing Public Perception Research

The conclusions that can be drawn from the CCS public perception research studies depend on the kind and quality of the information as well as the method used. Methods using some kind of discussion group often have the advantage of giving insight into the perceptions lay people have of CCS technology, which might be very different from the perceptions of experts. The downside is that these kinds of methods are expensive and time-consuming, which often leads to only a few small discussion or focus groups being used, resulting in conclusions that cannot be generalized to the larger population (Shackley et al., 2005). Surveys with representative samples do not have this disadvantage. However, surveys often use a restricted set of questions leading to a restricted set of possible answers. This restriction might lead to missing certain issues that the experts or researchers had not thought of but that may be important to the public (Curry et al., 2006; Best-Waldhober, 2006; Itaoka et al., 2006; Malone et al., 2009).

Some studies have analyzed the existing CCS public perception research and communication activities, illustrated in Table 13.6 (Ashworth et al., 2007; Reiner, 2008). They conclude that little work has been done to inform the general public about CCS and the majority of activities have been surveys used to inform research, policy, and environmental NGO communities. Beyond the survey there has been very little communication activity targeted at the general public, and as a result overall public awareness of CCS is still low. The total investment in communication of CCS also remains significantly lower compared to the allocated budgets of the CCS technological research and development programs. Limited budgets have adversely impacted the scope and methodology employed for public perception research. On the positive side, the existing research provides some useful insights into similarities and differences on how the public perceives CCS across nations, globally, and locally. The studies also provide an understanding of issues of public concerns regarding CCS.

13.7.3.4 Public Perception of CCS at the Global Level

Globally, the understanding and support for CCS among the public remains low. The public opinion on CCS varies based on socioeconomic status, level of education, culture, and professional backgrounds. The results of several studies suggest that people with a higher education background have more positive attitudes toward the technology. Conversely, those of lower socioeconomic background and education levels tend to be more skeptical (Bradbury et al., 2009). Likewise, the energy industry seems to be more supportive of CCS whereas some environmental advocacy organizations and local public interest groups have come out openly against CCS. Other major environmental NGOs favor CCS along with a broad portfolio of GHG mitigation options. The lower understanding of CCS is attributed to limited engagement and lack of open and honest communication with the public about the technology. In some cases, the lack of awareness regarding CCS is also tied to the public's limited understanding of and belief in climate change (Parfomak, 2008). Some studies tried to place CCS in a broader context by investigating whether the public considers CO_2 emissions as a problem to be solved. Giving people several societal issues to rank, Curry et al. (2007) report that protecting the environment was the eleventh highest ranked priority for Americans (out of 18 issues), while Palmgren et al. (2004) respondents ranked "reducing climate change" as the lowest social priority of the 15 choices provided them. Although general awareness regarding climate change and its implications are reported to have been increasing worldwide, there are some parts of society that still do not believe or give credibility to anthropogenic climate change as a pressing global problem.

13.7.3.5 Public Perception of CCS at the Local Level

When it comes to siting a CCS project in their vicinity, the public tends to become more reluctant and often negative in their support for the technology. Research study in Japan and the Netherlands reported that the public seems to be supportive of CCS but expressed NIMBY concerns when asked if they would support a CCS project in their community (Itaoka et al., 2004; 2006; Huijts, 2003). The existing research and experience with engaging the public in the vicinity of the proposed CCS projects demonstrate that at the local level, public support or opposition to CCS is motivated by both concerns as well as benefits of the technology. For example, some communities perceive CCS projects as economic opportunities and hence support the project in their vicinity (Hund et al., 2009), while others may focus upon the unfair distribution of hazards and hence oppose a project in their vicinity (Bradbury et al., 2009; Simpson, 2009) (see case studies Table 13.8).

13.7.3.6 What Are the Public's Main Concerns Regarding CCS?

The public's concerns about CCS stem in part from the lack of understanding of the role of technology as a climate change mitigation option and its potential environmental health and socioeconomic risks.

At the specific project level, the public is concerned about potential impacts of siting a CCS project in their community. A recent study across the three regional carbon sequestration partnerships in the United States (Bradbury et al., 2009) identified a range of social concerns regarding CCS among local communities (see Table 13.7). In addition to fear of underground CO_2 storage risks, the public expressed lack of trust in government authority and the private sector as a source of information and raised concern about the fairness of CCS implementation procedures. The public was also concerned about being neglected or ignored if the project turned out to be more harmful than expected. Concerns also varied based on the potential impacts of a proposed CCS project at the individual level; thus local landowners in the vicinity of proposed projects are concerned about the effect of conducting seismic surveys on their property, the effect of potential CO_2 seepage, and other issues.

13.7.3.7 Factors Affecting Public Perception of CCS

Public opinion and support for CCS is influenced by several factors such as cultural, educational, and socioeconomic background; past experience with other energy infrastructure and development projects; perceived risks and benefits of CCS technology; and influence by media and other stakeholders such as academia, NGOs, and industry.

Table 13.7 | An overview of public concerns regarding CCS technology.

Public concerns about CCS	• Safety risks of CO_2 leak • Contamination of ground water • Upfront impacts of increased coal mining • Effect on local environment including plants and animals near site • Assumption that CO_2 is explosive or poisonous • Effect of conducting seismic survey on their property General concerns: • Availability of enough storage sites • Long-term viability and who is liable for stored CO_2 • Lack of infrastructure to support large-scale deployment • Diversion of interest and funding from alternative energy • Lack of clarity on issues such as pore space ownership • Cost-economic concerns • Risk of unknown technology
CCS benefits as cited by public	• It could provide a good bridge to the future • If successful, can avoid large quantities of CO_2 from getting into atmosphere • Allows continued use of fossil fuels which provides economic advantage for some countries or regions • Helps clean up coal-based power plants • Allows emissions to be reduced without changing lifestyle too much

Source: Ashworth et al., 2006; Bradbury et al., 2009.

13.7.3.8 Stakeholder Perception of CCS Technology

Besides understanding the general public's view of CCS, some studies have also assessed other stakeholders' perceptions of the technology. Usually those stakeholders are grouped in environmental NGOs, academia, government, and industry. However, there can be more specific groupings, such as environmental justice groups in the United States, the financing industry, or different ministries in countries that affect the overall government position. Surveys have been used to assess the views and concerns of stakeholders on CCS, but study of position papers can also lead to insights.

A global study (IEA Working Party on Fossil Fuels, 2007) evaluated stakeholder perceptions toward CCS across North America, Australia, the European Union, New Zealand, Japan, China, South Africa, and India and found relatively low levels of awareness of and support for CCS in developing countries compared to industrialized countries. The study also highlighted concerns and issues around CCS such as costs, lack of policy incentives and regulatory frameworks, and local risks of safety. It also found a growing interest in CCS among stakeholder groups in most regions. These findings are roughly consistent with the conclusions of a study specifically on stakeholder perceptions in Germany (Fischedick et al., 2008) with the exception of public acceptance: 65% of respondents in the German study flagged that as "very important," but it was not mentioned as a survey outcome in the IEA Working Party study.

A research study in Europe evaluated the perspectives of different stakeholder groups on CCS in more detail (Shackley et al., 2008) through a survey conducted among 512 respondents from most European countries.

The sample was not representative as the number of respondents was much greater from countries with an active CCS community, such as Norway, than from countries with low levels of CCS engagement, such as Hungary. The survey results showed that majority of the sample was moderately supportive of CCS and believed that it had a role to play in their own country's plans to mitigate carbon emissions. Safety risks were seen as a major concern by environmental NGOs, but much less so by other stakeholders.

An NGO survey was also done in the United States, where perceptions of national-level NGOs were inventoried through semistructured interviews supplemented by content analysis of their documents (Wong-Parodi et al., 2008). It was found that while all NGOs are committed to combating climate change, their views on CCS as a mitigation strategy vary considerably. Some NGOs, such as Greenpeace (2008), oppose CCS, arguing that it will become available too late, that costs and energy use are forbiddingly high, and that liability issues cannot be feasibly addressed. Other NGOs, particularly US environmental NGOs such as the Natural Resources Defense Council and the Environmental Defense Fund, but also the Norwegian Bellona Foundation (Stangeland et al., 2006), are generally favorable or even very supportive of CCS, although they generally warn of the risks.

In developing countries, the situation differs. A study to assess stakeholder perceptions of CCS in India (Shackley and Verma, 2008) revealed very low government support for CCS, whereas industry was fairly enthusiastic about demonstrating the technology. The study showed very limited interest and engagement by the NGO community. A multi-stakeholder survey of 700 participants in Brazil (Cunha et al., 2006) reported high support for technology from government and academia. Brazilian NGOs were less supportive of the technology, and the lay public is generally not aware of CCS. A specific case of acceptance of CCS is the support for the technology for inclusion in the Kyoto Protocol's Clean Development Mechanism. Stakeholder and government perceptions varied greatly on that matter, citing concerns over immaturity of the technology and lack of sustainable development benefits (de Coninck, 2008). For example, although Brazil is not opposing CCS in general, it opposed including CCS in the CDM.

Environmental NGOs often indicate the possibility of diverging attention and resources away from renewable energy and energy efficiency toward CCS as a major issue, as this would delay a fully sustainable energy system (Greenpeace, 2008). In the European Union study (Shackley et al., 2008) this was also evaluated, resulting in 51% of the respondents thinking there would be no such negative impacts on improving energy efficiency and reducing energy demand; 44% thought there would be some effect; very few thought such effects would be large. The study clearly indicated that NGO respondents were much more concerned about the implications for renewable energy than other stakeholders.

A relatively new area of study is how the CCS expert community itself generates and assesses information and communicates with the lay public. The CCS community is growing rapidly, exemplified by increasing attendance of conferences, expanding specific academic journals, and a long list of companies joining organizations like the Global CCS Institute. The internal communication on CCS, within the community, generally has a positive tone and is rarely critical of the technology, or of advocacy work done by CCS experts. This signals a community that is conveying a strong and coherent message on CCS to policymakers but that also, potentially, has a complacent attitude toward the technology itself, which is strengthened by the group process in the community. This signals a community that is conveying a strong and coherent message on CCS to policymakers but that also, potentially, has a complacent attitude toward the technology itself, which is strengthened by the group process in the community (Coninck, 2010; Stephens et al., 2011).

13.7.4 Implications of Public Perception for CCS

13.7.4.1 Implications of Not Acting on Public Perception of CCS

In the last few years, evidence has arisen on public perception of CCS projects in communities which provides information about what might happen if governments and project developers failed to act on public perception. The project portfolio shows mixed results. Some CCS demonstration projects were well received by the community and have been able to move forward, while others encountered local public opposition, which in several cases contributed to cancellation or stalling of the project. The case studies provide insight into what affects a community's and individual's views on CCS and on CCS projects and what the crucial factors are that may lead to the community being receptive or rejecting of a project.

A selection of the most notable and best-documented CCS demonstration projects and project plans is given in Table 13.8. It also reviews motivations behind public support or opposition.

13.7.4.2 Lessons on Public Engagement and Communication

The existing experience engaging the public indicates that at the local level, public acceptance and support for CCS is largely driven by the potential socioeconomic benefits of the project activity. In cases where the public is not supportive of a project, there is public concern about potential environmental, health, and economic impacts of deploying CCS in their vicinity. Clearly, when it comes to actually siting a project in a community, potential risks of CCS dominate over the public's concern about the potential impacts of global warming. Some studies have analyzed the existing public engagement and communication activities around CCS broadly as well as at specific project levels (Reiner, 2008; Ashworth et al., 2006; 2007; Simpson and Ashworth, 2009; Hund et al., 2009) and provide some useful recommendations for public engagement on CCS. In addition, the experience engaging with communities in the proposed and existing CCS projects (for example Table 13.8) also provide some useful lessons on public engagement, as summarized below:

Table 13.8 | A summary of some proposed CCS projects and motivation for public support or opposition.

Project	Location	Public Support	Motivations behind Public Perception
FutureGen	Illinois, USA	Yes	Industry and Government funded first-of-a-kind-in- the-world project 'cool factor', public recognition of socioeconomic benefits of the project to the community (Bielicki, 2008; Hund and Judd, 2008; Hund and Greenberg, 2010; Greenberg, 2009)
Wallula Energy Resource Center	Washington, USA	Yes	Focus on win-win attributes of the projects such as potential social and economic benefits (Hund, 2009)
Jamestown	New York, USA	No	Concerns regarding unproven geologic storage capacity, support for renewable rather then coal-fired power plant; community believes coal-fired plant will be environmentally and economically unsustainable (Simpson, 2009)
Carson	California, USA	No	Communities past experience with industries in the area and perceived environmental concerns (Stephens et al., 2009)
Barendrecht	Netherlands, EU	No	Concerns regarding added burden of another industrial facility on the environment, style of communication with public–lack of transparent and honest engagement with communities (Brunsting and Mikunda, 2010)
Vattenfall	Germany, EU	No	Concerns regarding health and environmental risks of potential CO_2 leakage, lack of large scale demonstration, diversion of funding and interest away from alternative energy, extra burden on consumers (Slavin and Jha, 2009)

- It is important to communicate with the public about CCS technology in the context of climate change mitigation and present it as a tool in a portfolio of options including renewables, energy efficiency, and demand reduction (Hund et al., 2009; Bielicki and Stephens, 2008; Simpson, 2009; Best-Waldhober, 2009; Itaoka et al., 2009).

- Honest, transparent, and clear communication is critical in establishing trust with the public. In addition, when providing information it is always better to respond to the questions and concerns expressed by communities (Simpson and Ashworth, 2009; Hund et al., 2009; Bielicki and Stephens, 2008; Simpson, 2009; Brunsting and Mikunda, 2010; and Greenberg, 2009).

- CCS is a new technology with little operational experience. Additional field tests and a demonstrated ability to mitigate risks should they arise will be necessary to improve the public's perception of risk from CCS technologies (Singleton et al., 2009). In addressing public concern about a proposed CCS project, it is important to communicate openly about potential or perceived risks and present a mitigation plan in cases where necessary to make the public aware of measures that can be taken to tackle those risks (Slovic et al., 1993).

- Engaging the public early on in the vicinity of a proposed CCS project is crucial as opinions may be slow or difficult to change once formed (Hund and Judd, 2008; Hund, 2009; de Coninck and Feenstra, 2009; Bielicki and Stephens, 2008).

- Concentric communication and engagement with the public involving thought leaders and influence groups such as local NGOs and media, in addition to general members of public, is important for successful public engagement around a proposed project (Hund and Judd, 2008; Hund, 2009; Greenberg, 2009).

- There is no one-size-fits-all approach; different publics will require different engagement and communication strategies (Bielicki and Stephens, 2008).

13.8 Summary and Conclusions

Over the past decade, there has been a remarkable increase in interest and investment in CCS. A decade ago, there was only one operating project, little corporate or government investment in R&D, and no financial incentives to promote CCS. Today there are over 234 projects of various sizes and stages of development. Many companies have significant investments in technology development, and governments around the world have committed billions of dollars for R&D, scale-up, and deployment. The coming decade will be critical in the technology development and the ultimate role this option plays in reducing GHG emissions. While the outlook is quite promising, there are a number of economic, scientific, and social challenges ahead.

CCS involves the integration of four elements: CO_2 capture, compression of, transportation to the storage location, and isolation from the atmosphere by pumping it into appropriate saline formations, oil and gas reservoirs, and coalbeds with effective seals to keep it safely and securely trapped underground. Storage in other rock types such as basalts, oil and gas shales, and subsea bed sediments may also be possible, but much less is known about their potential. Component technologies are in different stages of development, some fully mature, such as compression, and some such as storage in saline formations, in the early stages of demonstration.

Three approaches are available for capture from the power and industrial sources that produce CO_2 gas with relatively small concentration of contaminants: post-combustion capture, pre-combustion capture, and oxy-combustion capture. All have been demonstrated; some are used routinely today for other applications, but little experience is available for integration and optimization with power production or most industrial applications. Considering full life cycle emissions, CCS technology can reduce up to about 65–85% of CO_2 emissions from fossil fuel combustion from stationary sources. CCS is applicable to the power generation and the industrial sectors (see also Chapter 12). In the future, CCS may contribute significantly to the transportation sector via hydrogen production and/or electrification of light duty vehicle and public transport, or through reducing emissions from biofuel production processes (see Chapter 17 for analyses on different pathways).

Successful experiences from five ongoing projects demonstrate that, at least on this limited scale, CCS can be safe and effective for reducing emissions. Moreover, relevant experience from nearly 40 years, currently at the rate of 45 $MtCO_2$/yr for enhanced oil recovery, also shows that CO_2 can safely be pumped and retained underground. Our best understanding of storage security can be summarized as follows:

> *Observations from* ***commercial storage projects****, engineered and natural analogues as well as* ***theoretical considerations****, models, and* ***laboratory and field experiments*** *suggest that appropriately selected and managed geological storage* ***reservoirs are very likely to retain nearly all the injected CO_2 for very long times, more than long enough to provide benefits for the intended purpose of CCS.***

A five- to ten-fold scale-up in the size of individual projects operating today would be needed to capture, transport, and store emissions from a large (500–1000 MW) coal-fired power plant. A thousand fold scale-up in size of today's CCS enterprise would be needed to reduce emissions by billions of tonnes per year (Gt/yr). Herein lies one of the major challenges for CCS, which raises a number of issues. Specifically, is there sufficient capacity to store these large quantities of CO_2? What will this cost? And finally, what are the institutional, economic, and technical constraints for implementing CCS on this scale? Regional factors are likely to play a major role in the extent and timing of CCS implementation. Furthermore, the scale and speed at which CO_2 transport networks will need to be built, often through densely populated areas, will pose a challenge. Although successful experiences with CO_2 transport in the past indicate that issues associated with the design and operation of such networks can be addressed, aspects such as impurities, fluctuating demand, and securing stable operational conditions (e.g., avoiding two-phase flow) need to be further addressed.

On a regional basis, storage capacity and the quality of information is highly variable. The Former Soviet Union, Northern Europe, North America, and the Middle East appear to have the largest storage capacity. Other areas, notably Japan, India, and parts of Southeast Asia appear to have more limited geological storage capacity. The IPCC 2005 Special Report concluded there is sufficient capacity to store 100 years of emissions at the high end of the technical potential (2000 Gt). Recently, more detailed capacity estimates suggest that capacity will be on the high end of the IPCC range, but there is still considerable debate about how much storage capacity actually exists. The debate is particularly significant about saline formations, which are believed to have the greatest capacity. Research, geological assessments, and most importantly commercial-scale demonstration projects, will be needed to improve confidence in and reliability of capacity estimates.

Costs of capture for first generation CCS power plants available in the early 2020s are estimated to be about \$45/tCO_2 avoided for coal and \$115/tCO_2 avoided for natural gas. Estimates vary widely depending on whether the plant is the first or n^{th}-of-a-kind, the type of fuel, capture technology, and assumptions about the baseline technology. Capital costs and parasitic energy requirements of 15–30% are the major cost drivers. Research is underway to lower costs and energy requirements. Early demonstration projects are likely to cost more. Due to high costs, CCS will not take place without strong incentives to limit CO_2 emissions. Access to capital for large-scale deployment will be a major factor limiting the widespread use of CCS, particularly if the policy regime for emission reductions and regulatory requirements for storage – especially long-term liability for stored CO_2 – remains uncertain. Estimated costs of storage range from US\$2–35/tCO_2 and experience from operating projects fall in the middle of this range of US\$6–20/tCO_2. Transportation costs are highly site specific, depending on the transport distance and size of the pipeline. Assuming a 500 MW coal plant emitting about 4 $MtCO_2$/yr and an onshore pipeline transport over a distance of 100 km, costs for transport are estimated to range from US\$1.25–3.5 tCO_2. Overall costs of CCS including capture, transportation and storage are estimated to range from US\$50–70/tCO_2 avoided for coal based electricity generation. This could increase the cost of generating electricity by an estimated 50–100%.

The environmental risks of CCS appear to be manageable, but regulations are needed to ensure due diligence over the life cycle of the project, most importantly: siting decisions, operating guidelines, and monitoring and closure of a storage facility. Many members of the public have concerns about the safety and effectiveness of CCS. More CCS projects and education are needed to establish a convincing safety record.

Social, economic, policy, and political factors may limit deployment of CCS if not adequately addressed. Critical issues include ownership of underground pore space, long-term liability and stewardship, GHG accounting approaches and verification, and regulatory oversight regimes. Significant progress is being made by governments and the private sector on all of these issues. Government support to lower barriers for early deployments is needed to encourage private sector adoption. Developing countries will need support for technology access, lowering the cost of CCS, and developing workforce and regulatory capacity for permitting, monitoring, and oversight. CCS, combined with biomass gasification, can lead to net removal of CO_2 from the atmosphere, which is likely to be needed to achieve atmospheric stabilization of CO_2 and may provide an additional incentive for CCS adoption.

Finally, public support for CCS is crucial for large-scale deployment. Today, the public remains largely unaware of the purpose and nature of CCS technology. Much work remains in this area.

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