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Geological Input to Selection and Evaluation of CO_2 Geosequestration Sites

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ABSTRACT

Coal, oil, and natural gas currently supply about 85% of the world's energy needs. Unfortunately, the burning of these fossil fuels is the major source of anthropogenic carbon dioxide, which is also the main greenhouse gas released to the atmosphere. One promising means by which to reduce CO_2 emissions, and so the atmospheric buildup of CO_2, is geosequestration. Geosequestration, also known as carbon capture and storage (CCS), involves the long-term storage of CO_2 in deep subsurface geological reservoirs. Geosequestration comprises several steps that include the capture of CO_2, the transport of CO_2, the injection of CO_2 into suitable reservoirs, and finally, the storage and monitoring of the CO_2 that has been introduced into the reservoir.

Geological input into the evaluation of storage sites, including injection, storage, and monitoring and verification of volumes and movement of CO_2 plumes, is critical for acceptance of CCS technologies. Detailed characterization and realistic modeling of reservoir and seal properties, as well as of rock and fault integrity, will permit a more viable analysis of risks associated with the subsurface containment of injected CO_2. Geosequestration can be a significant factor in the portfolio of CO_2 emissions reduction strategies because by reducing CO_2 emissions while still allowing for the continued use of fossil fuels, geosequestration buys time for the transition to renewable energy sources.

INTRODUCTION

Coal, oil, and natural gas currently supply about 85% of the world's energy needs. Moreover, given the relatively low cost and abundance of fossil fuels together with the huge sunken investment in fossil-fuel-based infrastructure, fossil fuels will likely continue to be used for at least the next 25 to 50 yr. The burning of fossil fuels is, however, the major source of anthropogenic (man-made) carbon dioxide (CO_2). Carbon dioxide is the main greenhouse gas released to the atmosphere (Intergovernmental Panel on Climate Change [IPCC], 2005).

Geosequestration, also known as carbon capture and storage (CCS), is a means to reduce anthropogenic CO_2 emissions to the atmosphere. Geosequestration involves the long-term storage of captured CO_2 emissions in deep subsurface geological reservoirs. Carbon sequestration can be pursued as part of a portfolio of greenhouse gas abatement options, when this portfolio also includes improving the conservation and efficiency of energy use and

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Table 1. Storage capacity for several geological storage options.*

Reservoir Type	*Lower Estimate of Storage Capacity (Gt CO_2)*	*Upper Estimate of Storage Capacity (Gt CO_2)*
Oil and gas fields	675**	900**
Unmineable coal seams in ECBM† recovery	3–15	200
Deep saline formations	1000	Uncertain but possibly 10,000

**The storage capacity includes storage options that are not economical (from IPCC, 2005).*
***These numbers would increase by 25% if undiscovered oil and gas fields were included in this assessment.*
†ECBM = enhanced coalbed methane.

utilizing nonfossil energy forms such as renewable (solar, wind, and tidal) and nuclear energy (Kaldi, 2005). Geosequestration may contribute significant reductions to anthropogenic CO_2 emissions. Estimates by the IPCC indicate that a technical potential of at least about 2000 billion metric tonnes of CO_2 storage capacity in geological formations likely exists (Table 1) (IPCC, 2005).

Geosequestration comprises several steps: first, the CO_2 is captured at the source, which can be a power plant or other industrial facility; the captured CO_2 is then transported, typically via pipeline, from the source to the geological storage site; next, the CO_2 is injected deep underground via wells into the geological reservoir; and finally, the CO_2 is stored in the geological reservoir, where its movement is carefully monitored and the quantity stored is regularly verified (Figure 1). The capture, transport, and injection processes do require additional energy to be expended (and hence more CO_2 is emitted); however, the net CO_2 emission reduction is still a significantly large volume to make deep reductions in anthropogenic greenhouse gas emissions. For example, a power plant with CCS could reduce net CO_2 emissions to the atmosphere by approximately 80–90% compared to a plant without CCS (Figure 2) (IPCC, 2005).

CARBON DIOXIDE CAPTURE

Carbon dioxide capture can be conducted at a point (stationary) source of CO_2 such as a power plant. Carbon dioxide capture involves capturing the produced CO_2 instead of allowing it to be released to the atmosphere. This captured CO_2 is then compressed to make it more dense and much easier, and less costly, to transport to the geological storage site.

Anthropogenic CO_2 that can be captured is produced by three main types of activity: industrial processes, electricity generation, and hydrogen (H_2) production. Industrial processes that lend themselves to CO_2 capture include natural gas processing, ammonia production, and cement manufacture. Note, however, that the total quantity of CO_2 produced by these processes is limited. A

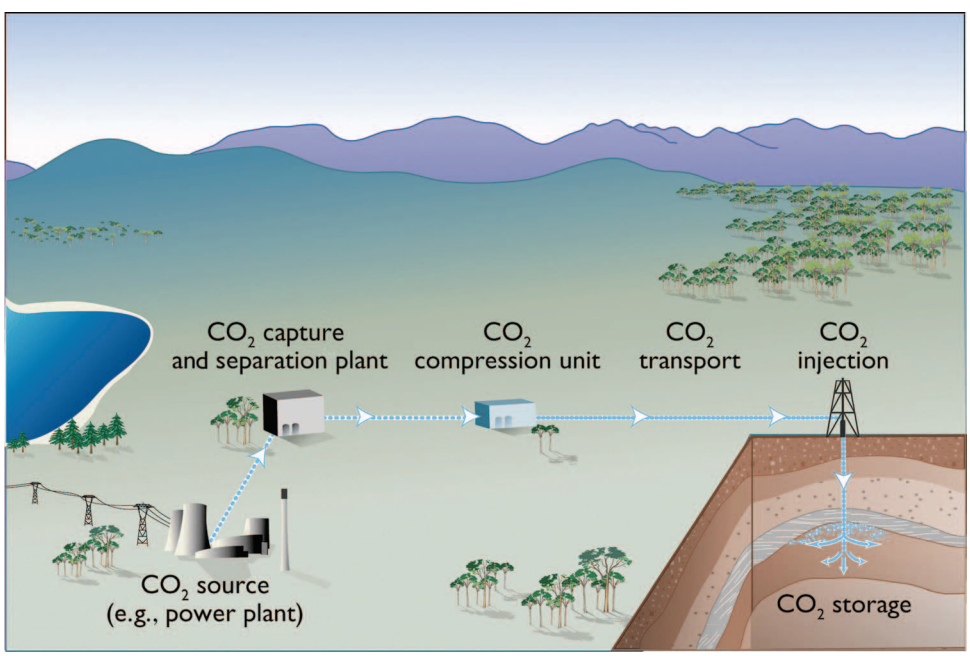

Figure 1. A simplified view of the steps involved in the geosequestration process (image courtesy of Cooperative Research Centre for Greenhouse Gas Technologies [CO2CRC]).

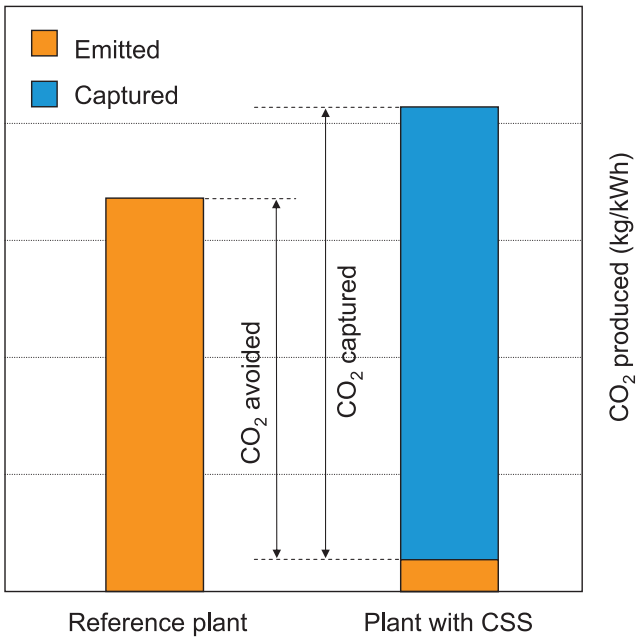

FIGURE 2. Comparison of CO_2 emissions from power plants with and without CO_2 capture and storage. A power plant with CCS (lower bar) has increased CO_2 production resulting from loss in overall efficiency because of the additional energy required for capture, transport, and storage. However, available technology can capture 85–95% of the CO_2 processed in a capture plant, resulting in a net CO_2 emission reduction (CO_2 avoided) of 80–90% compared to the reference power plant (upper bar) without capture. CCS = carbon capture and storage.

far larger source, accounting for one-third of total CO_2 emissions, is fossil-fueled power production. The types of power plants that are best suited to CO_2 capture are pulverized coal (PC), natural gas combined cycle (NGCC), and integrated gasification combined cycle (IGCC) plants (Davison et al., 2006). Finally, a potentially large future source of CO_2 for capture will be H_2 production, whereby the produced H_2 is used to fuel a hydrogen economy, i.e., it is used in turbines to produce electricity and in fuel cells to power cars. Technologies for capturing CO_2 from electricity generation fall into two general categories: postcombustion and precombustion (Kentish et al., 2006).

Postcombustion

Currently, the most widely used postcombustion technology for CO_2 capture is chemical absorption (Figure 3). This capture process involves the flue gas being blown through a solvent such as monoethanolamine (MEA) in an absorption column and the CO_2 in the flue gas being absorbed in the MEA solvent by the formation of a chemically bonded compound (Jassim and Rochelle, 2006). A very similar process using MEA has been used for decades to remove acid gases, such as CO_2 and hydrogen sulfide (H_2S), from natural gas streams (Franco et al., 2006). Chemical absorption is most likely to be used for PC and NGCC power plants (Roberts et al., 2005).

Precombustion

In the case of IGCC plants, using the precombustion CO_2 capture method of physical absorption would be possible (Figure 3). This capture method involves gasifying the coal to produce a synthetic gas (syngas) composed of carbon monoxide (CO) and hydrogen (H_2) (Veawab et al., 2002). The CO is reacted with water to produce CO_2 and H_2, and the H_2 is sent to a turbine to produce electricity. The CO_2 is captured by means of dissolving it in a physical solvent such as methanol. Several IGCC and coal gasification facilities exist worldwide to produce syngas and various other by-products. One such example of a gasification facility is an ammonia manufacturing plant (Kentish et al., 2006).

CARBON DIOXIDE TRANSPORT

Carbon dioxide transport involves moving, or transporting, the captured CO_2 from the CO_2 point source to the geological storage site. The CO_2 is typically transported in a compressed form via pipeline, although the CO_2 could also be transported by truck, rail, or in the case of a geological storage site located offshore, ocean tanker.

Transport via Pipeline

The CO_2 is transported via pipeline as a supercritical or dense phase fluid. Above the critical point, which occurs at a temperature of 31.1°C and a pressure of 7.38 MPa, CO_2 exists in the supercritical or dense phase. The CO_2 in this phase has a significantly higher density than either gaseous or liquid CO_2. Transporting the CO_2 in this phase, and also at higher density, has significant economic benefits (Shaw and Bachu, 2002).

The transport of CO_2 by pipeline already occurs quite extensively in the United States as well as, to a smaller extent, in other countries where CO_2 is used for enhanced oil recovery (EOR) operations. In the United States, some 2400 km (1491 mi) of CO_2 pipelines to supply 72 EOR projects using CO_2 floods exist. Many of these pipelines have been in operation since the early 1980s (Shaw and Bachu, 2002). Most of the transported CO_2 is obtained from high-pressure, high-purity natural underground deposits, with a small percentage of the CO_2 from anthropogenic sources. The longest and one of the most significant CO_2 pipelines currently in operation is the Weyburn pipeline, which is 325 km (202 mi) in length and transports 2.7 million m^3 (95.3 million ft^3) of CO_2 per day from the Great Plains Synfuels plant in North Dakota, to the Weyburn CO_2-EOR project in

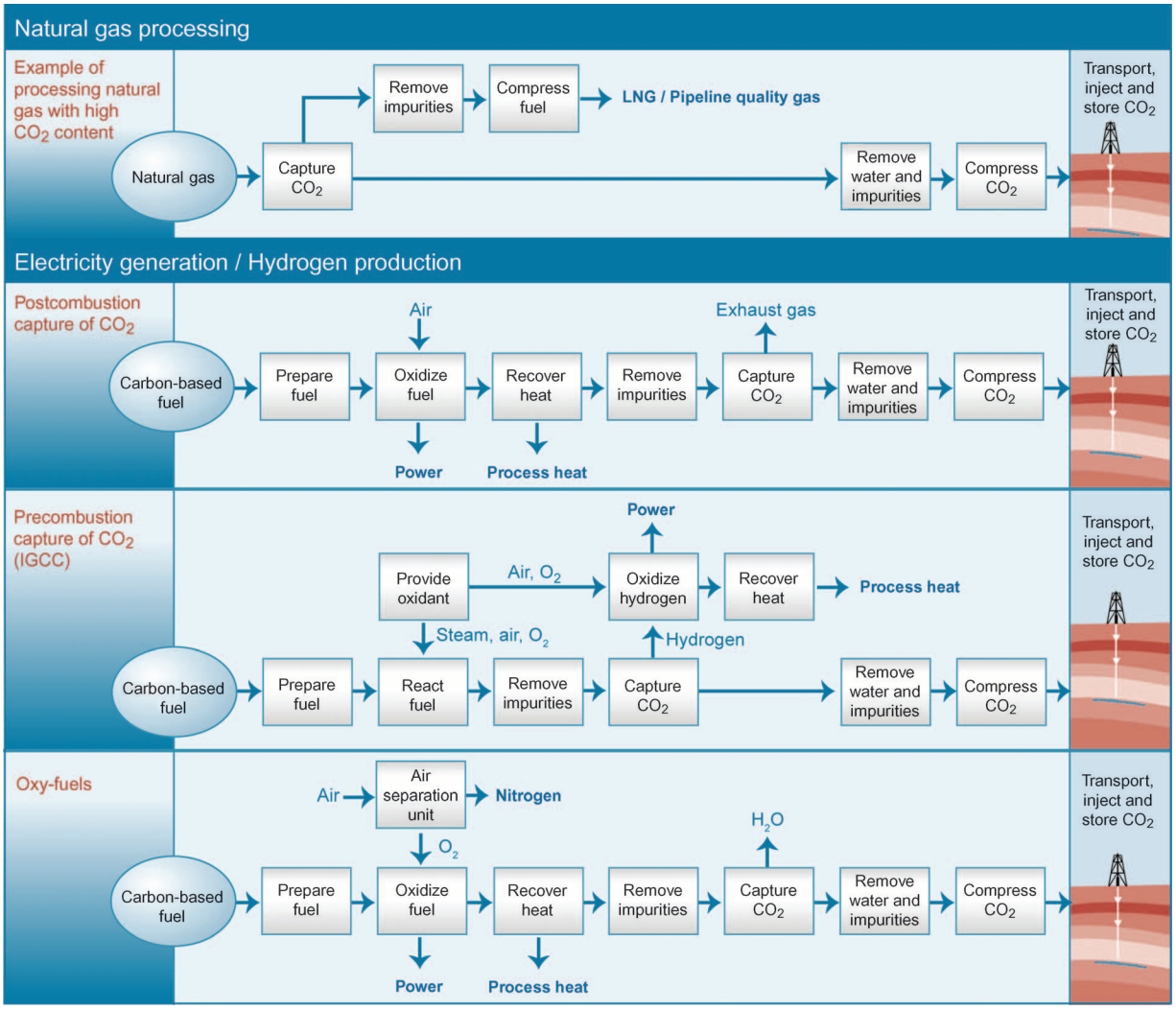

FIGURE 3. Overview of carbon dioxide capture processes (image courtesy of Cooperative Research Centre for Greenhouse Gas Technologies [CO2CRC]). IGCC = integrated gasification combined cycle; LNG = liquefied natural gas.

Saskatchewan, Canada (International Energy Agency [IEA], 2005).

CARBON DIOXIDE INJECTION

Carbon dioxide injection involves taking the CO_2 from the surface and injecting it deep underground into a reservoir rock. The CO_2 is injected into the reservoir via a single well or array of wells. Both EOR using CO_2 floods and acid gas injection (AGI) are mature technologies that involve significant quantities of CO_2 being injected underground and are therefore very good analogs for CO_2 injection as part of geosequestration activities. The first project using CO_2 for EOR began in 1972, and by 1999, 84 operational projects worldwide existed (72 in the United States) injecting an estimated total of more than 15 million t of CO_2 per year (Electric Power Research Institute [EPRI], 1999).

CARBON DIOXIDE STORAGE

Carbon dioxide storage involves keeping the CO_2 secured deep underground in a geological reservoir. Carbon dioxide can be stored geologically in a variety of different options (Figure 4). These include depleted oil and gas fields, EOR, deep saline formations, deep unmineable coal seams, enhanced coalbed methane recovery (ECBMR), and other opportunities such as salt caverns (Cook, 1998; Bachu and Gunter, 1999; Cook et al., 2000; IPCC, 2005).

The CO_2 can be geologically stored in oil and gas fields once they have been depleted and are no longer producing or can be used to enhance oil recovery in fields that are still producing. The main advantages of storage in depleted oil and gas fields are that the containment potential of the site has been proven by the retention of hydrocarbons for millions of years and typically large amounts of geological and engineering data

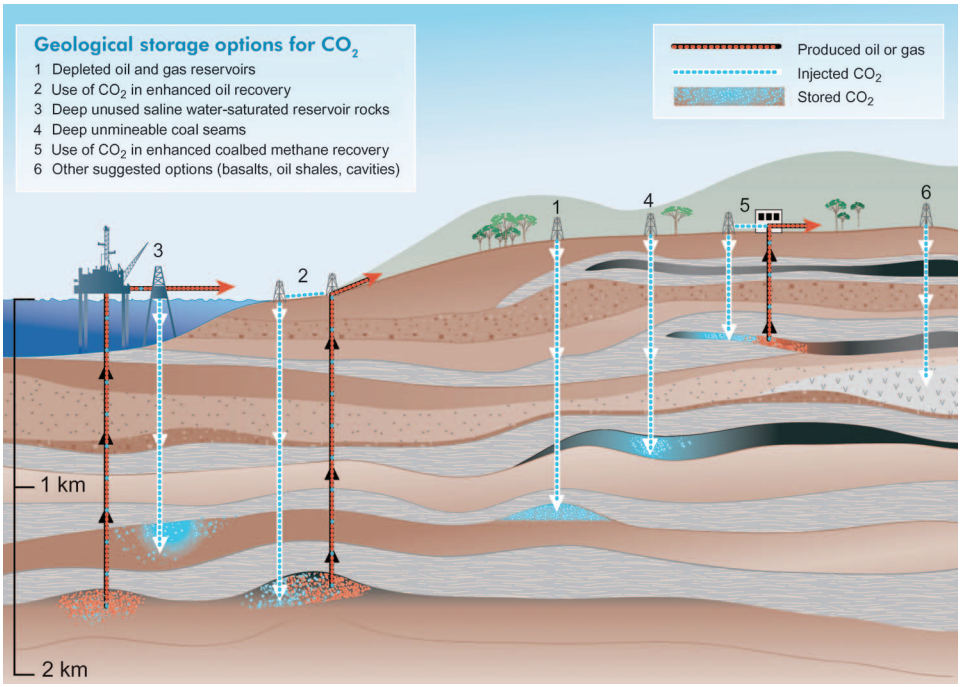

FIGURE 4. Options for the geological storage of CO_2 (image courtesy of Cooperative Research Centre for Greenhouse Gas Technologies [CO2CRC]).

are available for detailed site characterization (Holloway and Savage, 1993; IPCC, 2005). Possible drawbacks may be the physical size of the structural or stratigraphic trap (i.e., potential storage capacity may be limited), the possibility that pore-pressure depletion has led to pore collapse (which will reduce the potential storage capacity), and the timing of availability of depleted fields with respect to the source of CO_2 (Bradshaw and Rigg, 2001; Bradshaw et al., 2002; Streit and Siggins, 2005). In EOR, the CO_2 is used to incrementally increase the amount of oil extracted by either immiscible (not mixed) or miscible (mixed together) flooding, thus providing an economic benefit while additionally storing CO_2. As with depleted oil and gas fields, the potential storage capacity may be limited because of the physical size of the field (Islam and Chakma, 1993; Cook et al., 2000; IPCC, 2005).

The CO_2 storage in coalbeds is very different from the storage in oil and gas fields or saline formations because the trapping mechanism is by adsorption as opposed to storage in rock pore space. The CO_2 is preferentially adsorped onto the coal micropore surface, displacing the existing methane (CH_4) (Gunter et al., 1997; Bradshaw and Rigg, 2001; IPCC, 2005). The CO_2 can be geologically stored in coalbeds that are considered economically unmineable or can be used to enhance coalbed methane recovery. Technical challenges for CO_2 storage in coal seams include the ability to inject the CO_2, caused by the typically low permeability characteristics of the coal cleat system (especially with increasing depth and coal maturity), and the economic viability, caused by the large number of wells that may need to be drilled (Gunter et al., 1997; Bradshaw and Rigg, 2001; IPCC, 2005).

Saline formations are deep sedimentary rocks saturated with formation waters that are unsuitable for human consumption or agriculture. They have been identified by many studies as one of the best potential options for CO_2 geological storage (e.g., Bachu, 2000; Bradshaw et al., 2002). Possible drawbacks of saline formations are that the containment potential of the seal is commonly untested and limited amounts of data are commonly available for site characterization. However, their main advantages are that they are distributed widely over the world and their potential storage capacity is large (Koide et al., 1992; Hendriks and Blok, 1993; Rigg et al., 2001; IPCC, 2005).

The main geological constraints for finding the right place to store CO_2 include a porous and permeable reservoir rock overlain by an impermeable cap rock. Because the stored CO_2 is less dense than the formation water, it will naturally rise to the top of the reservoir, and a trap is needed to ensure that it does not reach the surface. The CO_2 can be trapped by several different mechanisms (such as structural or stratigraphic, hydrodynamic, residual gas, solubility, and mineral trapping), with the exact mechanism depending on the specific geological conditions. Structural or stratigraphic trapping relates to the free-phase (immiscible) CO_2 that is not dissolved into formation water. When supercritical CO_2 rises upward by buoyancy, it can be physically trapped in a structural or stratigraphic trap in exactly the same manner as a hydrocarbon accumulation. The nature of a structural or stratigraphic trap depends on the geometric arrangement of the reservoir and seal units. The CO_2 can be hydrodynamically trapped in

horizontal or dipping reservoirs with no defined structural closures when the dissolved and immiscible CO_2 travels with the formation water for very long residence (migration) times of the order of thousands to millions of years (Bachu et al., 1994). Residual gas trapping occurs when the saturation of CO_2 falls below a certain level and it becomes trapped in the pore spaces by capillary pressure forces and ceases to flow (Ennis-King and Paterson, 2001; Holtz, 2002; Flett et al., 2005). Solubility trapping relates to the CO_2 dissolved into the formation water (Koide et al., 1992). The time scale for complete dissolution is critically dependent on the vertical permeability and the geometry of the top seal but is predicted to occur on a scale of hundreds to thousands of years (Ennis-King and Paterson, 2002). Mineral trapping results from the precipitation of new carbonate minerals following the interaction of the CO_2 with the in-situ formation water and the minerals of the host rock (Gunter et al., 1993). This storage mechanism is the most permanent of the trapping types discussed because it renders the CO_2 immobile (Bachu et al., 1994).

In any geological storage site, the injected CO_2 will ultimately be trapped by several of the mechanisms described above. The type of trapping that occurs, and when, is dependent on the dynamic flow behavior of the CO_2 and the time scale involved. With increasing time, the dominant storage mechanism will change and typically the storage security also increases. Figure 5 shows how the initial storage mechanism will dominantly be physical structural and stratigraphic trapping of the immiscible-phase CO_2. With increasing time and migration, more CO_2 is trapped residually in the pore space or is dissolved in the formation water, increasing the storage security. Finally, mineral trapping may occur after the geochemical reaction of the dissolved CO_2 with the host rock mineralogy, permanently trapping the CO_2.

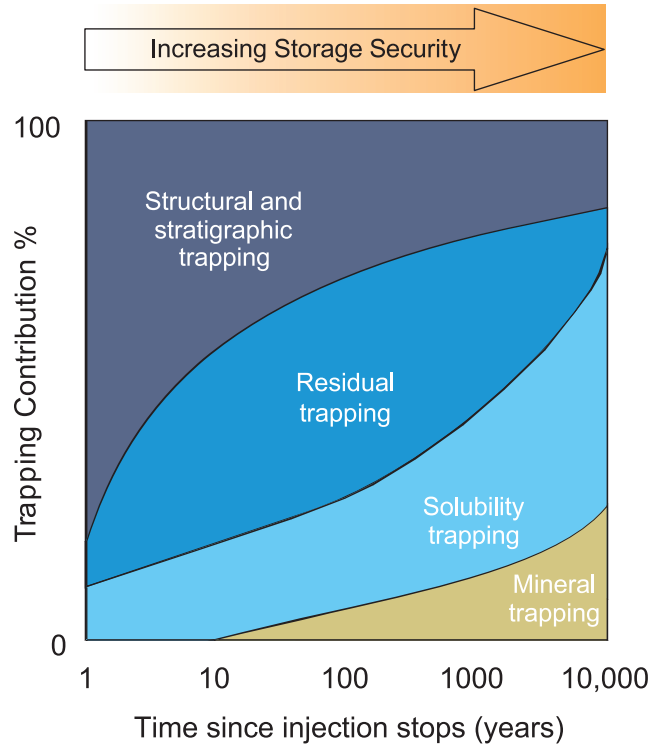

FIGURE 5. Schematic representation of the change of dominant trapping mechanisms and increasing CO_2 storage security with time.

SITE CHARACTERIZATION

The subsurface behavior of CO_2 is influenced by many variables, including reservoir and seal structural geometry, stratigraphic architecture, reservoir heterogeneity, relative permeability, faults and fractures, pressure and temperature conditions, mineralogical composition of the rock framework, and hydrodynamics and chemistry of the in-situ formation fluids (Root, 2007). The nature of geological variability means that each potential storage site needs to be assessed individually; however, a similar workflow can be applied to all site evaluations. The geological complexity of any potential CO_2 storage site is best addressed by a multidisciplinary research effort, which can provide an integrated and comprehensive site evaluation for the geological storage of CO_2 (Gibson-Poole et al., 2005; Gibson-Poole, 2009).

Different levels of site characterization can be undertaken depending on the maturity of the project (Figure 6). Initially, a regional characterization process is needed to establish the potential of an area for CO_2 geological storage before an actually site location is selected. Sedimentary basins across a state or country can be screened and ranked as to their overall suitability for CO_2 storage, using criteria suggested by Bachu (2003), such as tectonic setting, basin size and depth, intensity of faulting, hydrodynamic and geothermal regimes, existing resources, and industry maturity. Once a basin has been identified as suitable, a regional assessment can be undertaken to locate possible storage sites (Bradshaw and Rigg, 2001; Rigg et al., 2001; Bradshaw et al., 2002) (Figure 6). The stratigraphy is reviewed to identify suitable rock combinations that may provide reservoir and seal pairs, and data gathered to assess five key factors: storage capacity (will it meet the volume requirements of currently identified CO_2 sources, e.g., pore volume, area, and temperature or pressure?); injectivity potential (are the reservoir conditions viable for injection, e.g., permeability, porosity, and thickness?); site details (is the site economically and technically viable, e.g., onshore or offshore, distance from source, and depth to top reservoir?); containment (will the seal and trap work for CO_2, e.g., seal capacity and thickness, trap type, and faults?); and existing natural resources (are there viable

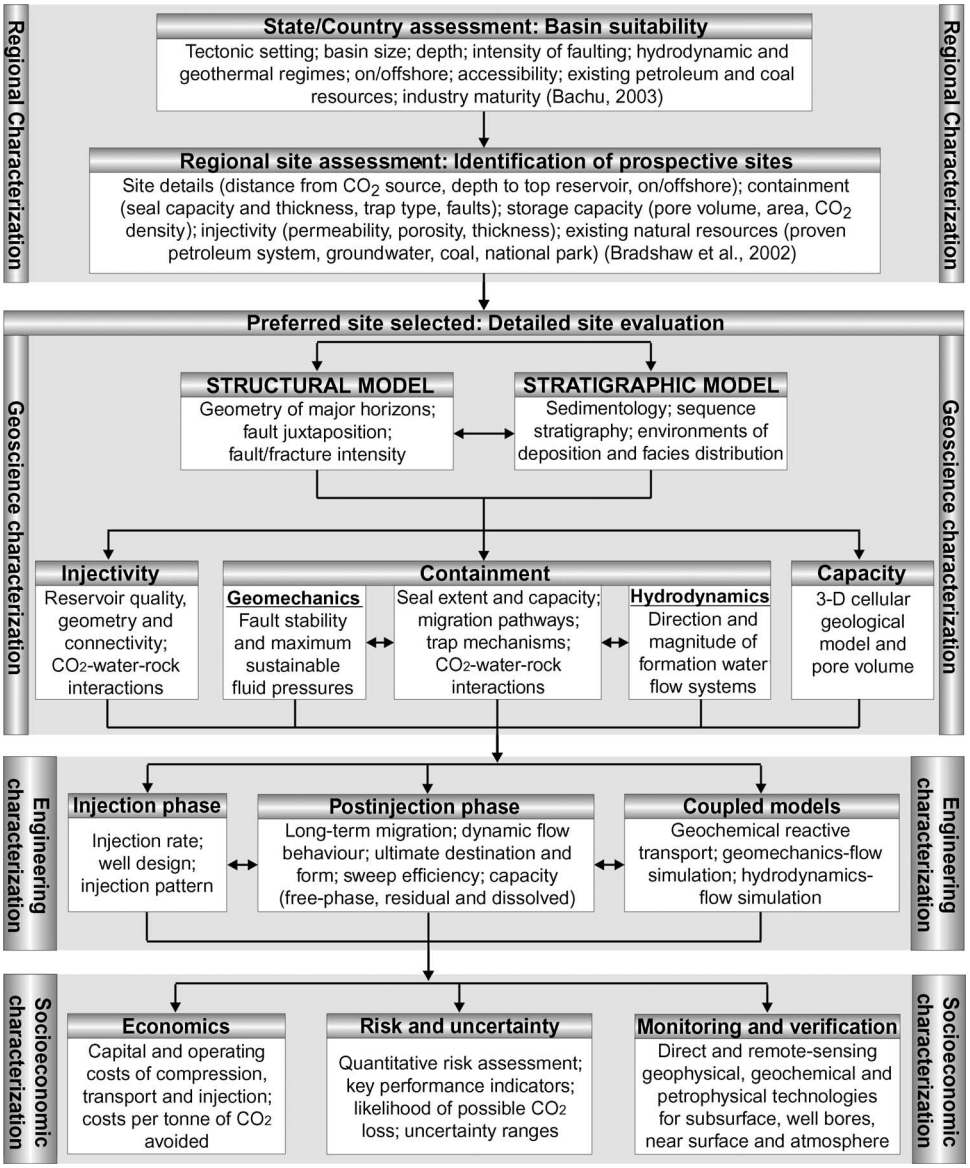

FIGURE 6. Site characterization methodology for the geological storage of CO_2 (from Gibson-Poole, 2009).

natural resources at the site that may be compromised, e.g., proven petroleum system, groundwater, coal, or other natural resource?) (Bradshaw and Rigg, 2001; Rigg et al., 2001; Bradshaw et al., 2002). These five factors provide a useful ranking scheme for describing the key elements of any potential CO_2 geological storage site and can be used to compare and contrast the relative merits of one potential site over another site.

Once a preferred site has been selected, it can proceed to a detailed site evaluation (Gibson-Poole et al., 2005; Gibson-Poole, 2009), the first step of which is the establishment of a structural and stratigraphic framework (Figure 6). A sequence-stratigraphic approach is adopted because it focuses on key surfaces that allow lithofacies distributions to be predicted. This is vital in understanding the likely distribution and connectivity of reservoirs and seals. Of the five key factors discussed above, the ones that require detailed geological assessment are injectivity, containment, and capacity. Injectivity issues include the geometry and connectivity of individual flow units, the nature of the heterogeneity within those units (i.e., the likely distribution and impact of baffles), and the physical quality of the reservoir in terms of porosity and permeability characteristics. Containment issues include the distribution and continuity of the seal, the seal capacity (maximum CO_2 column height retention), CO_2-water-rock interactions (potential for mineral trapping), potential migration pathways (structural trends, distribution and extent of intraformational seals, and formation water flow direction and rate), and the integrity of the reservoir and seal (fault and fracture stability and maximum sustainable pore fluid pressures). Potential CO_2 storage capacity can be assessed geologically in terms of available pore volume; however, the efficiency of that storage capacity will be dependent on the rate of CO_2 migration, the dip of the

reservoir, the heterogeneity of the reservoir and the potential for fill-to-spill structural closures encountered along the migration path, and the long-term prospects of residual gas trapping, dissolution into the formation water, or precipitation into new minerals. The geologically calculated pore volume provides the basis for numerical flow simulations of CO_2 injection and storage, which will give a more accurate assessment of how much of the available pore volume is actually used (sweep efficiency).

The engineering characterization phase continues on from the geoscience characterization (Figure 6). Short-term numerical simulation models of the injection phase are needed to provide data on the injection strategy required to achieve the desired injection rates (e.g., number of wells, well design, injection pattern). Postinjection-phase numerical simulations evaluate the long-term storage behavior, modeling the likely migration, distribution, and form of the CO_2 in the subsurface. Coupled simulation models, such as geochemical reactive transport, can also be undertaken to further evaluate the CO_2 storage potential of a site.

The final stage in a detailed site evaluation is the socioeconomic characterization (Figure 6). This includes economic modeling to establish such aspects as the likely capital and operating costs, as well as the cost per metric ton of CO_2 avoided. Risk and uncertainty analysis is crucial to establish whether a selected site can be classed as a safe and effective storage site for thousands of years. The design of a monitoring and verification program is dependent on the geological characteristics of the selected site and needs to be carefully evaluated to produce an optimum program both in terms of efficiency and cost.

GEOLOGICAL INPUT TO SITE CHARACTERIZATION

The ideal characterization of geological storage sites for CO_2 requires a thorough integration of all geoscientific data. Data types change depending on the stage of characterization. Regional assessment requires low-resolution, long-range data sets, such as two-dimensional (2-D) seismic and stratigraphic drill holes. However, site-specific assessment requires more detailed data such as high-density 2-D or 3-D seismic, core, and many wells and logs. These different types of data are commonly available from petroleum exploration and production.

The regional data sets should be reviewed to evaluate the structural configuration and regional distribution of lithofacies. This is best done using a large 2-D seismic data set complemented with available well-log control and petrophysical data. The aim during this phase is to identify reservoir units with appropriate storage properties (such as adequate porosity for storage of substantial volumes of CO_2 and permeability for injectivity and subsequent dissemination into the pore system) overlain by suitably extensive and thick seals.

The high-density data sets are needed to evaluate the reservoir and seal geometries and architectures of the identified storage site in more detail. The aim of a full data set integration and interpretation is to assess the migration pathway of injected CO_2 as well as to assess the potential storage volume. This is best done by building a detailed static 3-D reservoir model, which can be upscaled for dynamic fluid flow simulations. Various iterations of the dynamic simulations should be incorporated by an integrated team to better understand the geological effects on CO_2 injection, migration, and storage.

Data challenges are frequently encountered when trying to assess geological storage sites for CO_2 because either the basin under assessment has not been explored by the petroleum industry or, more typically, the site under investigation lies just off-structure and thus commonly outside the major structurally controlled hydrocarbon fields with their dense data sets. In addition, data challenges are also common because of incomplete data sets, data loss, or simple data deterioration with time. Two types of solutions can be considered to overcome the data challenges. The best but most costly solution is data acquisition. Paying several millions of dollars for drilling a well is common, whereas the acquisition and processing of seismic data are equally expensive. A far more cost-effective but also less accurate method of overcoming data challenges is to use outcrop and subsurface analog data sets to model the subsurface geology at the storage site. Analog data sets are useful in that they provide generic quantitative data of a range of parameters paramount to a specific geological setting. For example, analogs can be used to predict sand body and shale geometries, connectivities, and heterogeneities. They can also be used for providing ranges and distributions of porosities and permeabilities and for providing estimates on likely seal capacities. Analog data sets to characterize geological storage sites for CO_2 are currently the most affordable and accessible data sets for reservoir characterization.

MONITORING

In addition to the careful selection of the subsurface formation, a comprehensive monitoring system needs to be put in place to verify that the CO_2 remains in the subsurface. Monitoring of the activities of stored CO_2 includes an extensive range of established direct and remote sensing technologies, including petrophysical, geophysical, and geochemical methodologies deployed on the surface and in the borehole. These are used for repeated assessments from a reservoir, containment,

wellbore integrity, near-surface, and atmospheric perspective (Dodds et al., 2006). Wellbore properties such as pressure, temperature, resistivity, and sonic responses can be recorded in injection and observation wells. Geophysical monitoring involves quantification of 3-D and seismic time-lapse imaging of the plume and its migration. This is done using an array of methodologies, including vertical seismic profile (VSP), microseismic data, electromagnetic imaging (EM), and gravity to track the movement of CO_2 in the subsurface (Dodds et al., 2006). This process involves calibration with laboratory determination of in-situ geophysical properties associated with CO_2 and developing predictive forward modeling of the behavior of CO_2. Detailing results of such modeling and possible acquisition effects on seismic imaging are provided by Arts et al. (2009), who describe the injection of CO_2 in the Utsira Sand at Sleipner (ongoing since 1996 with almost 10 million t of CO_2 injected to date).

Nonseismic techniques, such as electrical properties, the monitoring of injection processes with changes in stress state, and detecting potential fracture processes through passive seismic measurements, may also be added to the monitoring array. Including geochemical and hydrodynamic sampling to ensure that the injected CO_2 has not leaked from its container and hence verify the integrity of seals is also important. Adding tracers to the injected CO_2, combined with sampling at surface localities, allows rapid detection of any seepage or leakage in the unlikely circumstance that this should occur. Near-surface and surface (soil, water well, and atmospheric) monitoring devices, including tracer and isotope analysis, can be deployed to determine the flux and composition of CO_2 and to distinguish anthropogenic and natural sources of CO_2 from injected CO_2.

RISKS

Risks surrounding CO_2 geosequestration are summarized by Bowden and Rigg (2004). Essentially, the main concerns relate to the potential for unanticipated CO_2 leakage either caused by unanticipated CO_2 movement up the wellbore or along an unexpected geological migration path or caused by induced or natural seismicity. The risks associated with CO_2 storage, although considered very low, are characterized by a greater degree of uncertainty than those connected with CO_2 transport and injection. This is because of the fact that once the CO_2 enters the geological reservoir, its fate is transferred from mostly human control to a natural system. Although most of the existing knowledge of CO_2 behavior in the subsurface exists from the long history of CO_2 floods associated with EOR, the risks associated with large-scale storage are at a different scale. The quantities of CO_2 stored for EOR floods are smaller, and the CO_2 residence times are shorter than required for large-scale carbon geosequestration. For geosequestration of CO_2, the risk of leakage depends on not only the likelihood of existence of potential leakage pathways (such as wells, faults, permeable zones in the seal, etc.), but also the likelihood that these potential pathways will intersect CO_2 while it is in a mobile phase and finally the likelihood that the potential leakage pathway will leak (Rigg et al., 2006). As many containment risk assessments are benchmarked against an impact of 1% leakage over 1000 yr (IPCC, 2005), the frequency, duration, and volume of potential leakage events need to be assessed for this time frame (Rigg et al., 2006).

Any geological CO_2 storage project resulting in a catastrophic release of CO_2 is highly unlikely. This is because the pressure of CO_2 injected into a geological reservoir reduces as it moves away from the injection well and is diffused over large areas of the formation, thus avoiding large pressure buildups (Streit and Hillis, 2002). No record of a catastrophic CO_2 release from a natural CO_2 deposit to date is observed, and any potential release from a CO_2 storage project should be preventable through careful site selection, operation, and monitoring. The critical geological input to minimize the risk of such occurrence is seal analysis and geomechanics. The CO_2 column height calculations can be used to assess the safe storage volumes of CO_2 at any storage site (Daniel and Kaldi, 2009), whereas geomechanical analysis of the faults can be used to assess the maximum sustainable pore fluid pressures at potential storage sites (Streit and Hillis, 2004). Understanding the rock fluid interaction potential between CO_2 and contacted minerals is also important. The CO_2 creates carbonic acid when it mixes with H_2O, and the risk of whether this could potentially result in the chemical erosion of some seal lithologies leading to leakage needs to be addressed. In most instances, because of their low permeability and capillary properties, CO_2 is unlikely to enter seals. Therefore, any potential reactions are likely to be limited to the base of the seal. In addition, because the pH buffering capabilities of the seal lithology are generally greater than the dissolution capabilities of carbonic acid, reactions are likely to be mineral precipitation instead of dissolution, thus leading to seal capacity enhancement instead of degradation (Watson et al., 2005).

Induced seismicity is not expected to be a significant problem at geological CO_2 storage sites. Induced seismicity has been documented during hydrocarbon production, EOR, AGI, natural gas storage, and waste injection operations (Wallroth et al., 1996; Maxwell et al., 1998; Jupe et al., 2000). These induced seismic events have been caused by poor engineering practices such as the injection of the CO_2 at too high a pressure, which in turn can result in microfracturing of the reservoir rock and/or small movement along existing fracture lines. Note, however, that most of the recorded events have been of a very small magnitude and have caused no harm.

Moreover, the risk of induced seismicity can be reduced through careful siting and placement of injection wells, adherence to proper pressure guidelines, and a sound understanding of the geomechanical properties of the storage reservoir. A range of technologies can be identified by a rigorous process of risk assessment and conformance to clearly identify performance criteria, which can be subsequently verified. These criteria are agreed in conjunction with the regulatory authorities to manage the project through all phases, addressing responsibilities and liabilities and providing assurance of safe storage to the satisfaction of the public at large.

CONCLUSIONS

The selection of potential CO_2 geosequestration sites uses techniques developed dominantly in the petroleum industry for the exploration and development of hydrocarbons. The geological input into the site selection, characterization, risking, and monitoring is paramount. Detailed site evaluation requires an accurate assessment of structural and stratigraphic configuration of trap, faults, reservoir, and seal lithologies. Sedimentological and sequence-stratigraphic principles are used to determine facies distributions on a basin scale and to characterize the reservoir and seal at the reservoir level. A detailed high-resolution sequence-stratigraphic and sedimentological analysis integrating all available data is optimal. However, data coverage at many potential sites is sparse, and a detailed characterization of the subsurface needs to rely heavily on modern and outcrop analogs. Numerical simulation, using realistic geological input parameters, is used to model the flow behavior of CO_2 in the subsurface. Monitoring of the stored CO_2 includes petrophysical, seismic, and geochemical methodologies. Wellbore properties such as pressure, temperature, resistivity, and sonic responses need to be recorded in injection and observation wells. Seismic monitoring using an array of methodologies allows the tracking of movement of CO_2 in the subsurface. Geochemical sampling at both surface and subsurface will allow rapid detection of any seepage or leakage, should this occur.

Geosequestration could be a significant factor in any portfolio of options for CO_2 emissions reduction. By reducing CO_2 emissions while still allowing for the continued use of fossil fuels, carbon geosequestration allows time for the transition to renewable energy sources from fossil fuels. Effective geosequestration of CO_2 involves capture of CO_2 at stationary source locations, transportation of CO_2 from the source to the geological storage site, injection of CO_2 into subsurface reservoirs, storage of CO_2 in the subsurface, and effective monitoring and verification of CO_2 storage. Given the large number of known geological formations suitable for geosequestration, the opportunity exists for significant volumes of CO_2 storage around the world. Much of the technology needed for carbon geosequestration projects is ready today. The key elements in its deployment are going to be economics, politics, and public perception.

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