CO₂ Capture and Storage—A Solution Within

Burning fossil fuels releases carbon dioxide into the atmosphere. Many scientists believe this contributes, at least in part, to the current upward trend in the Earth’s surface temperature. Capturing and storing carbon dioxide in the subsurface may be one of the most promising of the likely short-term solutions to stabilize and reduce atmospheric carbon dioxide concentration. The technology, although potentially costly, is available now and has been widely used in the oil and gas industry.

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The people of Earth have a problem. Our planet’s surface is warming at a rate that concerns many scientists and climatologists. Various models have predicted outcomes that beg for action. While the data clearly show that the Earth’s northern hemisphere is warming and there is strong evidence that anthropogenic—human influence on nature—effects exist, the predicted consequences are poorly understood and contested because the complexities and uncertainties in modeling are enormous. However, there is credible evidence that the current warming trend is partly due to the increased carbon dioxide [CO₂] concentration in the atmosphere from burning fossil fuels and other processes. With worldwide investment in, and dependence on, low-cost fossil fuels, it is uncertain whether we can extricate ourselves from this potentially dire situation, particularly when we consider the colossal financial burden associated with the restructuring necessary to significantly decrease fossil fuel use.

Global warming and its potential impact have been widely discussed in government, academia and industry, and covered extensively in science and technical journals. Between those who deny the problem exists and those who hyperbolize the global-warming consequences and required actions, there is a rational approach that relies on innovation and technology. A seed taking root in this valuable middle ground is the process of capturing and securely storing CO₂—also called CO₂ sequestration—that would otherwise be released into the atmosphere. This article discusses subsurface CO₂ storage and its potential role in the reduction of CO₂ emissions. We present case studies of CO₂ projects that explore the application of current oilfield technologies, and we examine some industry challenges that lie ahead.

CO₂ and the Climate
Since the late 19th century, the average global surface temperature has increased by 0.6°C [1.1°F], which according to the Intergovernmental Panel on Climate Change (IPCC), represents the largest warming rate for the last 1,000 years, as derived from ice-core and tree-ring data. The 20th century warming largely occurred in two periods, the first from 1910 to 1945, and the second from 1976 to the present (above right). While the global surface temperature has fluctuated throughout geological time, examination of ice cores shows that the latest warming is occurring with an increase in greenhouse gases (GHGs), which include CO₂, methane [CH₄] and nitrous oxide [N₂O]. Atmospheric concentrations of these GHGs increased drastically during the 20th century.

While CO₂ has a relatively small global-warming potential compared with other GHGs, the sheer volume of CO₂ released into the atmosphere as a by-product of burning fossil fuels makes it the largest contributor. Globally, over 23 billion short tons [21 billion metric tons] of CO₂, or 6.3 billion short tons [5.7 billion metric tons] of carbon, were released into the atmosphere in 2001 as a result of burning oil, gas, coal and wood. Some estimates place the total CO₂ emissions from oil, gas and coal at more than 35 billion metric tons [38.6 billion short tons] by 2025.

Sophisticated simulations have modeled future climate response to higher GHG concentrations. In global-climate models, some factors warm the Earth—positive forcing—while some factors cool the Earth—negative forcing. Each of these factors must be taken into account. For example, increased GHG concentrations and

processes that contribute to cloud formation. Of the large variety of complex and interactive 
source of uncertainty in climate modeling because not understood. Cloud cover remains a major 
(above). However, other forcing mechanisms are 
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Forcing factors for global warming. The effect on global warming caused by changes in concentration of some gas species, such as CO\textsubscript{2}, is well-understood, but the effects of solar activity and those of land use, which affects reflectivity or albedo, are poorly known. The global, annual-mean radiative forcing due to a number of agents is shown for the period from 1750 to the late 1990s. The height of the rectangular bar denotes a central or best-estimate value. The vertical line about the rectangular bar with “x” delimiters indicates an estimate of the uncertainty range. A vertical line without a rectangular bar and with “o” delimiters denotes a forcing for which no central estimate can be given owing to large uncertainties. The uncertainty range specified here is a best-guess and is not based on 

\begin{table}
\begin{tabular}{|c|c|c|}
\hline
Gas & Forcing & Level of scientific understanding \\
\hline
CO\textsubscript{2} & Large & Very low \\
Fossil fuel burning & Moderate & Very low \\
Biomass burning & Medium & Very low \\
Mineral dust & Small & Very low \\
Aviation-induced clouds & Small & Very low \\
Land use & Small & Very low \\
Solar & Small & Very low \\
\hline
\end{tabular}
\end{table}

\footnote{Forcing factors for global warming. The effect on global warming caused by changes in concentration of some gas species, such as CO\textsubscript{2}, is well-understood, but the effects of solar activity and those of land use, which affects reflectivity or albedo, are poorly known. The global, annual-mean radiative forcing due to a number of agents is shown for the period from 1750 to the late 1990s. The height of the rectangular bar denotes a central or best-estimate value. The vertical line about the rectangular bar with “x” delimiters indicates an estimate of the uncertainty range. A vertical line without a rectangular bar and with “o” delimiters denotes a forcing for which no central estimate can be given owing to large uncertainties. The uncertainty range specified here is a best-guess and is not based on statistics. A “level of scientific understanding” index represents the subjective judgment about the reliability of the forcing estimate, involving factors such as the assumptions necessary to evaluate the forcing, the degree of knowledge of the physical and chemical mechanisms determining the forcing, and the uncertainties surrounding the quantitative estimate of the forcing.}

tropospheric ozone levels are positive forcing, while increased tropospheric and stratospheric aerosols and cloud cover produce negative forcing. Some of these factors are well-understood, as for example, that of CO\textsubscript{2} concentrations (above). However, other forcing mechanisms are 

During the last decade, climate modeling has improved immensely, aided by steadily improving computing power and increased resources devoted to the global-warming phenomenon. Improved modeling is extremely important because it allows scientists to predict the scale, timing and consequences of global warming with greater certainty. After all, the consequences, along with technology and economics, will ultimately drive government and business decisions about how best to address the problem.

Similar to reservoir forecasting, climate modeling relies on history-matching and models. The models include both natural and anthropogenic effects to yield a reasonable match. Numerous scenarios based on future CO\textsubscript{2} emissions and other factors produce a wide range of outcomes. CO\textsubscript{2} concentration is predicted to increase from today’s level of 374 parts per million (ppm) to 550 to 1,000 ppm by 2100, resulting in a temperature increase of 2 to 4.5°C [3.6 to 8.1°F]. However, the “business as usual” scenario assumes that the world’s increased use of fossil fuels continues as in the past. Projecting this scenario to 2100 may be unrealistic, given the steady advance of technology, the decreasing supply and increasing cost of oil, the growing use of cleaner-burning natural gas, and renewable energy sources—for example, solar and wind power.

Climate-change predictions for modeling must be translated to actual climatic events on Earth and described in terms of human costs. Predictions based on conjecture include a rise in sea level that would flood low-lying coastal areas, impacting densely populated areas and natural habitats. Weather events, including floods and droughts, are predicted to radically change the world’s vegetated zones. Glacier and arctic ice-melting rates are predicted to increase, threatening to change ocean circulation patterns and reduce the number of cold-water marine species, such as cod and haddock. Studies also foresee an increase in human and animal diseases as a result of altering weather patterns.

There is some evidence that several of these symptoms of global warming are already occurring, making the estimation of both human and financial costs more urgent. However, many of these studies do not take into account man’s historical adaptive responses to climate changes, and some experts argue that the economic cost of adapting would be significantly less than the cost of drastic actions to stabilize the climate.

The debate on how likely and how severe the consequences will be remains unresolved.

The Earth’s atmospheric CO\textsubscript{2} content increases as a result of both natural and man-made emissions. This CO\textsubscript{2} remains in the atmosphere for several decades, and is slowly removed by natural sinks that store CO\textsubscript{2} for indefinite periods of time. Oceans store vast amounts of CO\textsubscript{2}, and vegetation and soils also produce a common sink mechanism. Nevertheless, it has become clear to many scientists that humans must work to diminish anthropogenic effects, primarily those derived from burning fossil fuels.

Coal is the world’s most abundant fossil fuel energy source. However, it also produces a large amount—around 40%—of CO\textsubscript{2} emissions from fossil fuels. It remains a primary concern for climate and environmental scientists, because in many regions, coal represents both a long-term and economical supply of energy, and is mainly burned for electricity generation in power plants. Innovative ways to reduce CO\textsubscript{2} emissions and their impact on the environment and climate are being developed to enable the continued burning of this important fuel (see “Produce Coalbed Methane, Hold the Carbon,” page 60).

Long-term remedies involve dramatic reduction or elimination of man-made CO\textsubscript{2} emissions from the burning of fossil fuels (next page, top). In the short term, this is not a realistic solution because the cost of switching to alternative sources of energy would be enormous and would, in itself, contribute to significant energy consumption. Moreover, there is no suitable replacement for oil, gas and coal currently available to power the world’s economies. Short-term options may involve reducing CO\textsubscript{2} emissions by using less energy through improved

\begin{figure}
\centering
\includegraphics[width=\textwidth]{climate_model.png}
\caption{Climate model output showing global temperature changes.}
\end{figure}
efficiency while moving to low- or no-emission energy sources. Many scientists believe part of the short-term—within the next few decades—solution is to capture and store CO₂ from the processes that create the largest or the most concentrated streams of CO₂ gas. Developing these man-made CO₂ sinks would allow the world to continue using its cheapest and most abundant energy resources while significantly reducing CO₂ emissions.

Capturing and Storing CO₂ Emissions

The technology to separate and store CO₂ is available now, but will require extensive investment in infrastructure and considerable measures to reduce its cost. The separation and compression of CO₂ from emission streams remain the most expensive part of the process and can occur before or after the combustion process. Currently, the most widely used process is based on chemical absorption to capture CO₂ from flue gas using monoethanolamine (MEA) solvent. Flue gas is bubbled through the solvent in a packed absorber column, where the solvent preferentially absorbs the CO₂. The solvent is heated as it passes through a distillation unit, stripping the CO₂ from the solvent. A concentrated gas that is 99% CO₂ is produced. This is a high-cost process, so other methods are being investigated to separate CO₂ from the solvent, including the use of microporous membranes. The joint industry CO₂ Capture Project (CCP) is a collaboration of eight energy producers, focusing on the development of technologies that would reduce the cost of carbon separation and capture.

New membranes that contain hollow polymeric fibers can be used in conjunction with amine systems. For instance, Air Liquide, a company specializing in the treatment and distribution of industrial gases, has developed a membrane technology that separates CO₂ from produced gas streams (right). The feed gas enters from the outside shell at a higher pressure than that of the internal sections. Differential pressure and selective permeation across the polymeric fiber membrane enable the separation of methane [CH₄] and CO₂. Air Liquide developed this technology as a compact, economical and environmentally friendly CO₂ capture alternative to amine-treatment processes.

Global CO₂ Emissions by Sector

- Percentages of CO₂ emissions produced by various economic sectors.
- Advanced filters. Membrane technology separates CO₂ from produced gas streams by keeping the feed gas on the outside shell at a higher pressure than that of the internal sections. Differential pressure and selective permeation across the polymeric fiber membrane enable the separation of methane [CH₄] and CO₂.

> Residue gas
59.8 bar
CH₄, C₂H₆, C₃H₈

> Permeate gas
3 bar
CO₂, H₂S, H₂O

> Feed gas
60 bar
CH₄, C₂H₆, C₃H₈, CO₂, H₂S, H₂O

Advanced filters. Membrane technology separates CO₂ from produced gas streams by keeping the feed gas on the outside shell at a higher pressure than that of the internal sections. Differential pressure and selective permeation across the polymeric fiber membrane enable the separation of methane [CH₄] and CO₂.

References:

5. The concentration of CO₂ is not uniform across the Earth. Higher concentrations are found in the northern hemisphere than in the southern hemisphere.
There are also methods to remove the CO\textsubscript{2} from fuels prior to combustion. In addition, separation of nitrogen from air using air-separation units prior to combustion reduces the emission of nitrogen oxides and sulfur oxides. Advanced fuel-conversion technologies produce hydrogen [H\textsubscript{2}] fuel from fossil fuels and capture CO\textsubscript{2} to mitigate emissions. For example, coal gasification uses solvents to produce carbon monoxide [CO] and H\textsubscript{2}. Reacting CO with water produces CO\textsubscript{2} and more H\textsubscript{2}. The CO\textsubscript{2} can be processed, transported and stored, while the H\textsubscript{2} fuels gas turbines for electricity generation and can be used in hydrogen fuel cells for transportation vehicles.

This technology is the core of projects like the US FutureGen project, a US$1 billion pilot program, and the European HyPOGEN project, to create a zero-emission, coal-fired power plant that sequesters CO\textsubscript{2} and produces H\textsubscript{2} for use in fuel cells.\textsuperscript{10} Separation infrastructure requires a large capital investment, and the technologies used must be appropriate for both the source and volume being processed.

There are several ways of storing CO\textsubscript{2} (above left). Some involve enhancing natural sinks in terrestrial ecosystems and oceans, such as reforestation on land and iron fertilization of oceans. One proposed method dissolves CO\textsubscript{2} into seawater and then injects the mixture into the ocean at depths between 1,500 and 3,000 m [4,920 and 9,840 ft]. Another method directly places CO\textsubscript{2} liquid deep in the ocean, exploiting the density contrast between liquid CO\textsubscript{2} and salt water. Despite the fact that the ocean represents the largest total storage potential, likely around 40,000 billion metric tons [44,000 billion short tons] of carbon, the possible environmental impact on marine life near the injection point is a major drawback. Ocean storage is unlikely to be the preferred mode, given that the environmental impact has not been adequately addressed. While the storage of the world’s anthropogenic CO\textsubscript{2} emissions will likely require the combination of many different storage options, the oil and gas industry has had little involvement in ocean-storage techniques. Many scientists view geological storage as the alternative that carries the lowest risk.

Given its vast experience in reservoir management and its extensive range of technologies, the oil and gas industry is poised to take a leading role in the storage of CO\textsubscript{2} in geological formations, such as depleted reservoirs, deep saline aquifers and coalbeds. Moreover, many joint projects are under way to assess the potential of subsurface storage.
Geological storage of CO₂ will be more efficient if it is in supercritical conditions. Carbon dioxide has a low critical temperature of 31°C [88°F] and a moderate critical pressure of 73.8 bar [1,070.4 psi] (previous page, bottom). Generally, this means that storage depths of 600 m [1,970 ft] or deeper are required.

In 2002, more than 24 billion metric tons [26 billion short tons] of CO₂ were released into the atmosphere as a result of fuel combustion. Geological storage capacity is estimated at hundreds to thousands of gigatons of carbon, equivalent to hundreds of years of storage at the current emission rate. The storage of CO₂ in the subsurface requires various technologies and types of expertise to characterize the storage zone and surrounding strata, to drill and accurately place wellbores, to design and construct surface facilities, to monitor wells and fields, and to optimize systems (above).

The Sleipner Project
While CO₂ has been used for enhanced oil recovery (EOR) for decades, CO₂ capture and storage (CCS) were first achieved in 1996 by Statoil and its partners in the North Sea Sleipner gas field, 250 km [150 miles] west of Stavanger, Norway. The field produces natural gas containing approximately 9% CO₂, but to meet specifications, the CO₂ concentration had to be reduced to 2.5%. Statoil must pay a Norwegian offshore carbon tax of 300 NOK—currently around US$45—per metric ton of CO₂ released into the atmosphere. Because Statoil is required to separate the CO₂, and incurs great...
expense when CO₂ is released, CCS became economically viable. To deal effectively with CO₂, Statoil captures and separates it using MEA solvent and then injects CO₂ into the Utsira formation using a single highly deviated injection well (above). The Sleipner project has been injecting 1 million metric tons [1.1 million short tons] of CO₂ per year into the overlying Utsira formation since September 1996 at a supercritical bottomhole flowing pressure of approximately 10.5 MPa [1,523 psi], which is below the Utsira fracture pressure. Since 1996, the Sleipner operation has injected over 7 million metric tons [7.7 million short tons] of CO₂ and the plan is to continue until 2020. Through the dedicated work of scientists and the support of industry, Sleipner represents the first industry-scale CCS project and the groundwork for successful future projects. The Utsira formation, a regional saline aquifer at a depth of 800 to 1,000 m [2,625 to 3,280 ft] below the seabed at Sleipner field, is...
composed of un cemented quartz and feldspar sand with porosities from 27% to 40% and permeabilities from 1 to 8 darcies. It contains thin layers of shale that act as permeability baffles.\textsuperscript{14} Its thickness ranges from 200 to 300 m [656 to 984 ft], and its total available storage volume, estimated at 660 million m\(^3\) [23.3 billion ft\(^3\)], could store 600 billion metric tons [660 billion short tons] of CO\(_2\).

Well logs indicate that the Utsira zone is well-defined, with sharp upper and basal contacts. An overlying caprock is several hundred meters thick, beginning with a shale layer and overlain by prograding sequences that grade from shales at the basin center to sandier facies towards the basin margins. The top of the caprock sequence consists mostly of glaciomarine clays and glacial tills. Close examination of seismic, log and core data suggests that this caprock sequence forms an effective seal over the Utsira formation.

Potential stratigraphic and structural barriers within the Utsira formation could affect CO\(_2\) migration dramatically. For this reason, an extensive characterization of the aquifer was paramount. Established in 1998 and supported under the European Commission’s Thermie Program, the Saline Aquifer CO\(_2\) Storage (SACS) project and the subsequent SACS2 project employed a multidisciplinary approach to develop “best practices” in the research, monitoring and simulation of CO\(_2\) migration in subsurface storage aquifers. An important part of the project involves the time-lapse monitoring of the CO\(_2\) storage volume using three-dimensional (3D) seismic surveys.

Schlumberger has acquired four seismic surveys supporting this study: first in 1994 before injection started in 1996, the second in 1999, the third in 2001, and a fourth in 2002 (above right).\textsuperscript{15} The location and migration of supercritical CO\(_2\) are visible, and geophysicists have determined from modeling and time-lapse (4D) seismic data that high impedance contrast allows detection of CO\(_2\) accumulations as thin as 1 m [3.3 ft]. The ability to observe such thin accumulations gives scientists confidence that no CO\(_2\) leakage is occurring beyond the overlying caprock. Schlumberger has been involved in data analysis and in the development of CO\(_2\) monitoring and simulation workflows.

As the key monitoring technology, seismic data have also shown the migration behavior of CO\(_2\) in the aquifer. Thin shale layers within the Utsira storage interval dramatically affect the CO\(_2\) distribution. Because of its buoyancy, CO\(_2\) is forced to migrate laterally for several hundred meters beneath the shale layers. Modeling shows that over long periods, as the brine becomes more enriched with CO\(_2\), the mixture grows denser than the water below, forming currents and enhancing dissolution.\textsuperscript{14} The physics of dissolution, segregation and mixing varies depending on the characteristics of the reservoir, and specific simulations are necessary.

Storage mechanisms involving dissolution from convective mixing of supercritical CO\(_2\) are thought to take from centuries to millennia.

Exploiting the impedance contrasts between the volume now containing CO\(_2\) and the volume previously containing only brine, scientists have built elastic models to simulate various CO\(_2\) accumulation scenarios.\textsuperscript{17} Geophysicists have

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analyzed and modeled seismic pushdown effects, which result from a reduction in compressional wave velocity through the CO₂ storage interval and which cause an increase in traveltimes for reflections within and below the CO₂ storage interval (below right). Project scientists believe that the CO₂ is distributed as a combination of thin high-concentration layers and dispersed CO₂. The modeled velocity pushdown due to the thin layers alone is lower than the observed pushdown. The difference, or residual pushdown, is attributed to the presence of dispersed, lower saturation CO₂ between the high-concentration layers.

The distribution of dispersed CO₂ can be calculated by mapping saturations to the residual pushdown. In addition, modeling reveals how storage temperature influences the estimation of total CO₂ volume. Pushdown volumes from time-lapse seismic data have been history-matched with various flow models to help define flow across the Utsira shale layers. This work has been instrumental in understanding the size and extent of the CO₂ bubble and the estimation of CO₂ volume.

The SACS project also investigated another long-term CO₂ storage mechanism associated with the subsurface called mineral trapping. Mineral trapping could occur when CO₂ reacts with noncarbonate, calcium-rich, iron-rich and magnesium-rich minerals to form carbonate precipitates. In the Sleipner case, drill-cuttings studies have shown that mineral trapping is not a major factor because of the limited reactivity between CO₂ and the Utsira formation. In addition, these studies have shown small porosity decreases observed at the base of the caprock could further enhance sealing on a very long time scale. Mineral trapping could be a significant geological storage mechanism in other reservoirs and would likely impact the porosity and permeability within the reservoir.

Before the SACS2 project completion in June 2002, the SACS and SACS2 projects had examined a full range of reservoir-characterization, monitoring and simulation problems and published their findings and recommendations in a Best Practice Manual. However, the work continues in a European Union-supported project called CO₂STORE, which began in February 2003. The latest project focuses on long-term storage aspects, other monitoring techniques and, with the knowledge gained from the Sleipner project, the development of site-specific plans for CO₂ storage elsewhere in Europe. Partnering with power producers, new CO₂STORE projects have been initiated in Denmark, Germany, Norway and the United Kingdom.

**Win-Win at Weyburn**

Enhanced oil recovery (EOR) using CO₂ has occurred since the 1970s, and has proved to be one of the most effective EOR methods in light-to-medium-oil reservoirs. Supercritical CO₂ has a density similar to that of oil, but with a substantially lower viscosity. In miscible floods, CO₂ mixes with the oil, causing the oil to swell and become less viscous. Higher pressures at the injector wells, coupled with the swelling oil, push the oil to producing wells, boosting oil production and recovery. In traditional EOR operations, concerns about the fate of the CO₂ after injection were secondary to its impact on production. Consequently, most operators did not attempt to determine the amount of CO₂ that was being stored, or that could be stored, and did not tailor monitoring, modeling and simulation efforts to characterize the behavior of CO₂ in the swept reservoir, much less after EOR was completed. Moreover, few EOR projects have injected CO₂ from anthropogenic sources to help reduce GHG emissions.

PanCanadian Resources, now EnCana Corporation, Saskatchewan Industry and

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Resources, the Petroleum Technology Research Center (PTRC) and the International Energy Agency (IEA) began a unique CCS project in 1999. It involved the transport of CO\(_2\) through a 325-km [202-mile] pipeline from a coal gasification facility 12.1 km [7.5 miles] northwest of Beulah, North Dakota, USA, to the Weyburn oil field near Regina, Saskatchewan, Canada (right). The Great Plains Synfuels Plant, operated by the Dakota Gasification Company, produces methane from the gasification of coal and the subsequent creation of methane from the purified product gases. Before the building of the pipeline, which is owned and operated by the Dakota Gasification Company, the plant released most of the CO\(_2\) that it produced into the atmosphere. Currently, this gas is compressed to a pressure of 15.2 MPa [2,200 psi] at the plant, delivered by pipeline to the Weyburn field under supercritical conditions—14.9 MPa [2,175 psi]—and injected into the subsurface. The CO\(_2\) is 96% pure, containing traces of hydrogen sulfide [H\(_2\)S], nitrogen [N\(_2\)] and hydrocarbons.

Discovered in 1954, the Weyburn field produces oil from the Midale carbonate reservoir at an average depth of 1,419 m [4,655 ft] within the Mississippian-age Charles formation (below).
The Midale reservoir is 30 m [98 ft] thick and includes, from deepest to shallowest, the Midale Vuggy zone, the Midale Marly zone, and the Midale Evaporite. The most extensive seal above the injection interval is the low-permeability Lower Watrous formation. The Midale Vuggy zone has been largely swept by waterflood operations, which began in 1964. However, the Midale Marly zone has lower permeability, lower sweep efficiency and still contains significant volumes of recoverable oil. Horizontal wells have targeted the bypassed pay within the Midale Marly zone since 1991, and this zone remains the focus of current CO2 EOR operations. The field’s original oil in place has been estimated at approximately 223 million m³ [1.4 billion bbl] and, prior to the start of CO2 injection in September 2000, it had produced 55 million m³ [346 million bbl] of oil from primary and waterflood production.

The Weyburn field covers 180 km² [70 sq miles]. With more than 1,000 wells, including vertical producer wells, vertical water-injection wells, horizontal producer wells, horizontal CO2-injection wells and abandoned wells, reservoir control from well logs is extensive. Additionally, more than 600 wells have been cored, and production and injection data provide a complete historical record of the field.

In July 2000, IEA launched a comprehensive geological study of the Weyburn CO2 storage site. The IEA concluded that the geology of Weyburn field is suitable for long-term CCS, that the primary reservoir seals are competent, forming thick and extensive barriers to upward fluid migration, and that faults and fractures in the region show no fluid conductance. Risk-assessment modeling suggests that only approximately 0.02% of the initial CO2 in place after EOR operations are complete will migrate above the reservoir in 5,000 years. Of this CO2, most will diffuse into the overlying caprock, and none will reach near-surface strata containing potable aquifers. Moreover, the cumulative leakage through existing wells in the field is expected to be less than 0.001% of the initial CO2 in place.

ECLIPSE 300 reservoir simulation software was used to investigate the long-term migration behavior of CO2 in the Weyburn reservoir. A detailed reservoir model incorporating 75 injection patterns was inserted into a much larger geological model, extending several hundred meters below the reservoir to the ground surface about 1,500 m [4,920 ft] above the reservoir. ECPLISE 300 software was used to simulate dispersion, diffusion and advection of water, hydrocarbons and CO2 within this region for 5,000 years beyond EOR.

A time-lapse seismic monitoring program is improving understanding of CO2 flow behavior in the reservoir. Encana ran a baseline 3D seismic survey in August 2000, prior to the start of CO2 injection. Two multicomponent time-lapse surveys have been integrated with crosswell seismic data, acquired by the Lawrence Berkeley National Laboratory, and vertical seismic profiles (VSPs), acquired by Schlumberger, to define the fluid-migration dynamics at a much higher resolution than standard seismic techniques. The time-lapse seismic results have correlated with the CO2 flood-front movements, supported by production and tracer data.

Scientists tested new passive seismic monitoring technology in the Weyburn field. In 2003, an array of eight triaxial geophones was installed in a vertical well planned for abandonment. Data acquisition, which began in August 2003, has detected discrete microseismic events associated with the injection of CO2 and demonstrates yet another possible monitoring technology for CO2 storage operations.

On a daily basis, 3 million m³ [106 MMcf], or 5,000 metric tons, of CO2 are transported and injected into the Weyburn oil field to provide secure CO2 storage and to improve oil recovery. As of March 2004, about 3 billion m³ [106 Bcf] of anthropogenic CO2 has been injected, and over the project’s lifetime an estimated 22 million metric tons [24 million short tons] of anthropogenic CO2 will ultimately be stored in Weyburn field. On the production side, Encana estimates an additional 20.7 million m³ [130 million bbl] of produced oil will be recovered over the next 30 years as a result of the CO2 storage project.

Daily production is anticipated to reach 4,770 m³/d [30,000 B/D] by 2008, compared with 1,590 m³/d [10,000 B/D] had the CO2 flood not been initiated (above).

Sitting on Top of a Solution
An important field experiment entered its CO2-injection stage in September 2004. Designed to test storage modeling, monitoring and verification techniques, the project is intended to lower the cost, risk and time to implement a geologic CO2 storage project. More specifically, the project has several specific aims: to demonstrate that CO2 can be injected safely and stored securely, to determine the subsurface distribution of CO2 using various monitoring techniques, and to validate models and gain the appropriate level of experience to advance to large-scale injection.

The project is funded by the US Department of Energy (DOE) National Energy Technology Laboratory. The Bureau of Economic Geology (BEG) at the University of Texas at Austin is the lead institution; it is supported by GEO-SEQ, a research consortium that includes Lawrence
Berkeley National Laboratory, Oak Ridge National Laboratory, Lawrence Livermore National Laboratory, United States Geological Survey (USGS) and the Alberta Research Council. The consortium selected Schlumberger to provide formation evaluation, monitoring and sampling expertise. BP provides project review and assumes an advisory role during the experiment.

The selected site is 30 miles [50 km] north-east of Houston, in the South Liberty oil field. The brine-filled injection zone is a stratigraphically complex deltaic and strandplain sandstone interval within the Oligocene-age Frio formation and sits on the southeast flank of a salt dome. The Frio C sand interval dips to the south and is isolated above and below by shales and is bounded to the north and south by northwest-dipping faults (below). The injection zone, from 5,050 to 5,080 ft [1,539 to 1,548 m], has a measured pressure of 2,211 psi [15.3 MPa], a temperature of 134.5°F [57°C], and contains no hydrocarbons. The interval is heterogeneous, maintains log porosities from 17% to 37%, and shows varying permeability estimates, from 14 to 3,000 mD. The sequence is overlain by the Anahuac shale, which is a 246-ft [75-m] thick regional shale considered to be a competent seal.

Site selection is a significant aspect of the Frio project because of its proximity to one of the highest CO2 emission areas in the USA. The Gulf Coast margin has a large concentration of power plants, refineries and chemical manufacturing plants, which emit roughly 520 million metric tons [579 million short tons] of CO2 every year. Fortunately, because of extensive hydrocarbon exploration in this area, similar brine-filled sands are known to exist, making the project site especially relevant to practical emission-reduction strategies. The CO2 storage capacity of the Frio sands in this region has been estimated at between 208 and 358 billion metric tons [229 and 395 billion short tons].

The experiment will be conducted in the volume around two wells: an existing well now used as a monitoring well; and a new injection well, drilled and completed 100 ft [30 m] downdip of the monitoring well in July 2004. To ensure the mechanical integrity of the existing observation well, which was drilled in 1956, a workover was scheduled. Because conventional portland cement tends to degrade when exposed to CO2, the cement quality was investigated using a cement bond log and the USI UltraSonic Imager device to determine the need for remedial work. The Frio interval in the monitoring well was perforated from 5,014 to 5,034 ft [1,528 to 1,534 m] and completed, including the installation of a Schlumberger electrical submersible pump (ESP), which would later be used during aquifer drawdown tests between the two wells. Given the fact that a lack of wellbore integrity could lead to a rapid path for CO2 leakage, further evaluation of the long-term performance—over hundreds of years—of cement when exposed to supercritical CO2 has been undertaken.

The newly drilled injection well gave the project members an opportunity to evaluate the Frio section using modern openhole logging technology, including porosity and resistivity from the Platform Express integrated wireline logging tool. Mechanical properties were obtained using the DSI Dipole Shear Sonic Imager tool. The FM1 Fullbore Formation MicroInSight device defined a structural dip of 10° to 20° to the south, and was used to identify formation complexities that could influence...
fluid flow. The FMI log showed no evidence of natural fractures within the interval between the faults.

The MDT Modular Formation Dynamics Tester measured pressure, determined fluid mobility and acquired formation water samples in the Frio and surrounding formations. Core-derived permeabilities compared well with permeability calculations from MDT tests (above). Project scientists required knowledge of the formation-water salinity to properly interpret future continuous and time-lapse RST Reservoir Saturation Tool measurements, a key technology for quick detection of CO2 breakthrough.

The injection well was completed in June 2004 and was approved as a Class 5 Experimental Well by the Texas Commission for Environmental Quality. The USI tool was used to evaluate the cement job from total depth to surface to ensure that no CO2 leakage would occur at the borehole.

Extensive geological and petrophysical characterizations were critical in developing accurate earth and fluid-flow models, helping ensure optimal experimental design and aiding postinjection model verification. A preliminary injection test was conducted with water and tracer in the weeks prior to the start of the CO2 injection stage. Breakthrough occurred in nine days for this preliminary injection test and suggests an average permeability of 2,500 mD, in good agreement with core data.

The injection of 3,000 metric tons [3,333 short tons] of CO2 from a nearby refinery occurred over a three-week period. Time-lapse monitoring of the borehole fluid will occur periodically throughout the remainder of 2004. The small-scale experiment—small injection volumes and closely spaced wells—facilitates the timely delivery of high-confidence results, and will help prepare for larger scale injections in the future.

Numerous CO2 monitoring techniques have been investigated for use at the Frio experiment site. The assessment of these techniques requires response modeling that evaluates changes in reservoir characteristics as injection proceeds. For example, the use of crosswell electromagnetic (EM) technology, electrical resistance tomography (ERT) and tiltmeters has been considered. An EM baseline survey was completed prior to the injection of CO2. Direct CO2 monitoring is accomplished by measuring the capture cross section and the carbon/oxygen ratio with time-lapse logging of the RST device.

The utility of adding chemical tracers to the CO2 has also been analyzed. On land, where the number of potential monitoring wells is high, tracers help scientists study CO2 transport processes and breakthrough behavior. Additionally, tracers provide monitoring assurances that help bolster regulatory and public acceptance, necessary in all CO2 storage operations. Common tracers include noble gases such as argon, perfluorocarbons and anomalous amounts of the natural stable isotopes of carbon and oxygen [13C and 17O]. These natural stable isotopes usually occur in small, but predictable, concentrations in CO2. Sampling of the downhole fluid and testing for tracers will detect the arrival of specific CO2 volumes at a monitoring well.

Crosswell seismic and VSP surveys have been selected to monitor the subsurface volume between the injector and the monitor wells. These seismic techniques, along with RST measurements, will be performed in time-lapse mode to validate models, track CO2 migration and detect crosswell breakthrough of CO2. The VSP data will be used to map the areal extent of
the CO₂ plume and to validate the interpretation of a 3D seismic survey.

The Frio project is a major collaborative effort between government, business and institutions to test current monitoring technologies and validate the models used to simulate both CO₂ storage capacity and migration behavior. In addition, this project lays the groundwork for future CCS projects beneath this high-emissions region of the Gulf Coast.

Power Plant Emissions

The Ohio Valley CO₂ Storage Project is a collaborative endeavor to examine the potential for CO₂ storage beneath another high-emissions region of the USA. Initiated in November 2002, the project is supported by the US Department of Energy’s National Energy Technology Laboratory (NETL), Battelle Laboratories, American Electric Power (AEP), BP, the Ohio Coal Development Office of the Ohio Air Quality Development Authority, Pacific Northwest National Laboratory and Schlumberger. Technical support also comes from West Virginia University, the Ohio Geological Survey and Stanford University.²⁶ The Ohio Valley area relies heavily on large hydrocarbon-base power plants for electricity generation.

The goal of this project is to identify and characterize reservoirs near major CO₂ emission sources and to assess the potential for subsurface CO₂ storage in the region. Mountaineer Power Plant in New Haven, West Virginia, USA, was chosen as a project site because it sits above potential geologic storage targets deep in the Cambrian and Ordovician strata. The plant, which is operated by AEP, produces 1,300 MW of power from pulverized coal, and emits over 7 million short tons [6.4 million metric tons] of CO₂ annually.²⁷ This project represents the first effort to assess subsurface CO₂ storage targets from a surface site located within the power plant facility. As a result, the project has encountered many technical, regulatory and stakeholder issues that were not seen during previous CCS projects.

A complete geologic characterization was required to establish whether the target intervals possessed the properties necessary for successful and secure storage of injected CO₂. Project partners acquired a two-dimensional (2D) seismic survey to define the geological structure and confirm the continuity of the main seismic horizons away from the site. The survey quality was considered good. Special processing steps minimized background noise from the power plant and coal conveyor belt.

The next step in the site-characterization process involved acquiring downhole measurements across potential injection intervals. In 2003, a 9,190-ft [2,800-m] exploratory well was drilled on the Mountaineer plant site to evaluate deep CO₂ storage potential (left). The main targets included the basal sandstone overlying the Precambrian igneous rocks, high-porosity zones within the otherwise low-permeability carbonates such as the Copper Ridge dolomite, and the Rose Run sandstone and the Beekmantown dolomite.

Prior to this, few wells had been drilled to test these deep intervals in this area of the Appalachian basin. Formation-depth predictions based on seismic data and regional geology


provided a reasonable match to drilling results, despite the scarcity of data. Extensive openhole logging and coring programs determined formation properties, such as mineralogy, porosity, permeability, water saturation and salinity, mechanical properties and the presence of natural fractures. In conjunction with porosity and resistivity measurements, formation mineralogy was defined by the NGS Natural Gamma Ray Spectrometry tool. Permeability and grain-size data, and a lithology-independent porosity were acquired by the CMR Combinable Magnetic Resonance sonde. Also, the FMI tool was used to identify natural fracturing and structural complexities that might affect injectivity. In addition, engineers used the MDT device to acquire formation-pressure and permeability data, and to take fluid samples. While one MDT test was successful, a packer failure compromised the data quality during the other tests.

Fullbore core testing and analysis also played a crucial role in the complete characterization of the target intervals. A total of 293 ft [90 m] of core was taken across the Beekmantown dolomite, Rose Run and basal sandstones. Fullbore coring was not practical in zones with slow coring rates, so the Mechanical Sidewall Coring Tool (MSCT) was used later to take sidewall cores in those intervals. Detailed core analysis and petrography examined important small-scale characteristics, such as sedimentary structures, porosity types, grain sizes and mineralogy. Core porosity and permeability were also measured. The fullbore cores provided material for CO2-flood and relative-permeability experiments, and geomechanical tests.

Wireline logs across the Rose Run sandstone. Log analysis shows the Rose Run sandstone interval consists of sand with interbedded dolomite layers (Track 1). Porosity streaks in the Rose Run sandstone exceed 12% (Track 3), and permeabilities calculated from the CMR Combinable Magnetic Resonance data reach 10 mD (Track 2). The FMI Fullbore Formation MicroImager data show the interbedded nature and vertical complexity of the Rose Run interval (right).
Using seismic measurements, openhole logging technology and core testing, this reservoir characterization program identified the most promising zones for testing at a larger reservoir scale. Straddle packers isolated selected zones for testing and retrieving water samples. Injectivity, or minifracture, tests helped engineers determine hydraulic fracture-pressure thresholds in potential injection zones and also helped them calculate the maximum sustainable pressure in the caprock.

The wide range of measurements at different volume scales revealed that the investigated formations were continuous but fairly heterogeneous. The basal sandstone was the most homogeneous zone, but had low porosity and permeability values and was not a suitable injection target at this site. However, several other zones showed injection potential that could be used for future tests of CO₂ injection and monitoring, and potentially even for long-term CO₂ storage. For example, the Copper Ridge dolomite section contains thin intervals with good porosity and high permeability, and warrants further investigation to determine its areal extent. The Rose Run sandstone showed sufficient permeability, but the porosity was variable, limiting its potential CO₂-storage volume. While the Beekmantown dolomite exhibited thin layers with good porosity and permeability, the gross CO₂ storage volume in this formation was low at this location. In addition, formation-water analysis indicated high salinities—300,000 mg/L [2.50 lbm/gal]—indicating that, at these depths and pressures, CO₂ solubility in brine water could be severely reduced.
The Ohio Valley CO₂ Storage Project demonstrates the importance of thoroughly evaluating potential CO₂ storage zones on a site-specific basis. While the injectivity in individual zones appeared to be low, the combined injection potential in multiple zones seems to be sufficient for medium- to large-scale injection tests. In addition, commercial-scale injection is possible with the use of multilateral well and reservoir-stimulation technologies. Tests also showed that the containment of CO₂ would not be compromised.

This project clearly demonstrated the value of advanced logging measurements, such as those provided by the CMR and FMI tools, to quickly ascertain formation properties and characteristics so that more costly testing can be directed to the most promising intervals. This CCS project, like the others, emphasizes gathering information and multidisciplinary collaboration. The project also provides a protocol for characterizing deepbasin sedimentary sequences that have sparse data but high potential.

Produce Coalbed Methane, Hold the Carbon

Unmineable coal seams have been identified as another potential storage volume site for anthropogenic CO₂, with an estimated CO₂ storage capacity at 7.1 billion short tons [6.4 billion metric tons]. Given coal’s intrinsic storage potential and the growth in coalbed methane (CBM) exploitation, placing CO₂ in coal seams is an attractive possibility.

In dry-core tests, CO₂ adsorbs at nearly twice the rate—sorption separation factor—of CH₄, making CO₂ injection an efficient production-enhancement technique in CBM reservoirs, also called enhanced coalbed methane (ECBM). In some experiments in which the moisture content of the coal has been reconstituted, the observed CO₂ sorption was significantly less. Nonetheless, added production, as a result of CO₂ injection, could offset some, or all, of the cost associated with injection operations.

The complexity of coal necessitates extensive study at subsurface conditions. Coal is often heterogeneous and could possibly promote unpredictable sweep behavior. For example, CO₂ breakthrough at a producing well might occur along the most connected and extensive fracture—or cleat—networks.

Other concerns unique to ECBM are currently being investigated. Special care must be taken when drilling and completing both injection and production wells for ECBM. In many cases, producing wells may be converted to injection wells. Coal frequently breaks out during drilling, or are stimulated by cavitation, increasing the likelihood of compromised cement jobs, poor isolation and loss of containment. A large percentage of CBM producing intervals have been stimulated by hydraulic fracturing. Hydraulic fractures that extend too far outside the target interval may allow CO₂ leakage, putting containment at risk. Also, replacing CH₄ with CO₂ causes coals to swell, changing the stress conditions in the coals and surrounding layers.

The depth of coalbeds considered for CO₂ storage is also crucial. Experience from CBM production shows that the productivity of coals significantly degrades below 5,250 ft [1,600 m], because at those depths cleats close and permeability decreases. This reduces injectivity at injection pressures below the coal fracture pressure. Laboratory testing and field-scale simulations have investigated changes in coal-storage properties with variations in stress and water saturation.

While the global CO₂ storage capacity of coalbeds is much smaller than that of deep saline aquifers, the potential CBM production benefits from injecting CO₂ make this option attractive. However, many questions remain. Energy producers and CO₂ storage experts continue to study the benefits and challenges of CO₂ ECBM. CONSOL Energy, the largest producer of high-Btu bituminous coal in the USA and a CBM producer, is conducting a seven-year project to inject CO₂ into coal seams in West Virginia. Burlington Resources and BP are both studying ECBM in the San Juan basin, USA. Many important projects and studies are ongoing in Europe, including in France, Germany, The Netherlands and Poland. Special ECBM potential exists in those countries that have vast coal resources, such as Canada, Australia and China, prompting numerous projects and initiatives.

What the World Needs Now

The acidity of CO₂ can corrode downhole tubulars and degrade cement. While not considered toxic, high concentrations of escaped CO₂ above ground or in freshwater aquifers could cause damage. Because the storage of CO₂ must be long term—hundreds or thousands rather than tens of years—the bar has been raised for well construction.

There is no better example of how oilfield technology must respond to the challenges of CO₂ storage than cementing technology for well construction. Portland cement is the most common material used in well cementing. When CO₂ is dissolved in water, approximately 1% of the CO₂ forms dissociated carbonic acid (H₂CO₃), which reacts chemically with the compounds in the hydrated portland cement matrix, such as calcium silicate hydrate gel (C-S-H) and calcium hydroxide [Ca(OH)₂]. The major reaction products are calcium carbonate and amorphous silica gel. The set cement gradually loses strength and becomes more permeable. As a result, cement failures have been reported during the many years of CO₂ EOR experience (next page).


34. The Kyoto Protocol is an international environmental agreement that establishes country-by-country emissions targets for greenhouse gases. The Protocol requires industrialized countries to reduce their emissions by an average of 5.2% below 1990 levels by 2010. The Protocol will enter into force on the 90th day after the date it is ratified by at least 55 countries accounting for at least 55% of the total carbon dioxide emissions, as calculated in 1990. As of April 15, 2004, 122 countries had ratified or acceded to the Kyoto Protocol and accounted for 44.2% of baseline CO₂ emissions.


and this confidence is the core issue associated with monitoring. Monitoring CO₂ migration in the subsurface volume has come a long way in a short time, and involves advances in seismic measurements and processing techniques. Other subsurface methods, such as passive seismic monitoring and crosswell electromagnetic imaging, show tremendous promise. Surface detection of CO₂ leaks is an active area of research, although less mature than subsurface monitoring.

The capture, transportation and storage of CO₂ are not risk-free, but if these are properly planned, operated and monitored, risk can be reduced substantially. Seventy years of experience in natural gas storage operations have resulted in extremely low leakage rates. Consequently, today there are more than 600 natural gas storage facilities, many near population centers.

To be successful in reducing emissions, several key factors must be addressed for the capture and storage of CO₂. Secure storage would likely be required for hundreds of years, eclipsing the anticipated lifespan of today’s oil and gas infrastructure. Economics is a major factor. The costs associated with CO₂ separation, transportation and storage must be minimized. The risk to health and the environment should also be minimized, and practices used to capture and store CO₂ must be in accordance with laws and regulations. Moreover, gaining the trust of the public, the media and nongovernmental organizations requires open and transparent dissemination of information to facilitate education. Even if these general principles are achieved, the economic task ahead is monumental.

The USGS estimates that the total CO₂ gas-emissions volume from fossil fuels in the USA, which produces roughly 24% of the world’s CO₂ emissions, is around 114 Tcf [3.2 trillion m³] per year. This volume is almost five times the total annual US natural gas consumption. To meet the conditions of the Kyoto Protocol by 2015, the US would have to reduce emissions by 500 million metric tons/yr [550 million short tons/yr]. This equates to almost twice the annual US natural gas production, and it would require the infrastructure to process, transport, inject and store the CO₂. As large as that seems, the storage of CO₂ represents only 20 to 30% of the total costs of CO₂ sequestration.

Today, multinational cooperation is evident in the Carbon Sequestration Leadership Forum (CSLF). The CSLF focuses on the policy and technical framework needed to ensure the success of CCS in the coming decades. The CSLF is involved in information exchange, planning, collaboration, research and development, public perception and outreach, economic and market studies, regulatory and legal issues, and policy formulation.

Large CCS projects, like the Sleipner field project, are under way or in the planning stages. For example, the In Salah gas field in Algeria, the Gorgon gas field in Australia and the Snohvit field in the Barents Sea are targeting saline aquifers. Strategic small-scale projects also play an important role in developing technologies and experience for CCS site monitoring and verification, as for example, the Ketzin project in Germany and the K12 B project for enhanced gas recovery (EGR) offshore The Netherlands. For CCS to become an acceptable option to reduce CO₂ emissions, projects like these are crucial and will become more numerous with additional knowledge and experience. Clearly we need more time—time to study the global problem at hand and to make the best decisions based on a reasonable degree of certainty. We also need time to develop new forms of renewable energy sources to eventually supplant fossil fuels. Additional investigation of CO₂ capture and storage sites is needed to bridge that gap, allowing the continued use of our most abundant and cost-effective energy resources. This would help in advancing world economies, which is key to the development of technologies that may ultimately help stem global warming. The capture and secure storage of CO₂ may be viewed as a way to buy some extra time. The technology and expertise to store CO₂ in the subsurface are available now and come from within the oil and gas industry. —MGG