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Environmental Assessment of Geologic Storage of CO_2

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1.0 Executive Summary

Initiatives to reduce and prevent carbon dioxide (CO_2) from reaching the atmosphere have led to new technological approaches aimed at mitigating climate change. One such technique involves actively capturing CO_2 emissions from large stationary sources like power plants and storing them in underground geologic reservoirs such as depleted oil and gas fields, deep saline aquifers and unminable coal beds. The Clean Air Task Force contracted the Massachusetts Institute of Technology's Laboratory for Energy and the Environment to survey the status of functionally similar processes and assess potential environmental issues associated with transport and geologic storage of CO_2 captured from large stationary sources.

Though still a relatively new idea in the context of climate change mitigation, the practice of injecting CO_2 into underground reservoirs has been occurring for many years. For example, CO_2 has been injected into petroleum reservoirs for Enhanced Oil Recovery (EOR) since the 1970's. By 2000, there were a total of 84 operations worldwide (72 in US) involving enhanced oil recovery using CO_2 floods (Kinder Morgan, 2001). CO_2 has also been injected and stored in underground formations for the purpose of disposal as acid gas (H_2S, CO_2 and other impurities from gas separation plants). Although the original intention of acid gas injection (AGI) was to dispose of H_2S (hydrogen sulfide), a peripheral benefit has been the storage of CO_2.

Transportation, injection and storage of CO_2 have been commonplace in the oil and gas production industry for decades. Further understanding of CO_2 storage can be gained from analyzing other functionally similar activities, such as natural gas underground storage. This cumulative knowledge and experience has enabled Statoil, a Norwegian oil and gas producer, to implement CO_2 injection and storage at its Sleipner Field in the North Sea. Another example is EnCana's Weyburn Field, the first explicit EOR/sequestration project designed to integrate the dual application of EOR and long-term geologic storage of CO_2.

As the evidence indicates, there is a great deal of expertise and knowledge about the handling, injecting and storage of CO_2. This paper is intended to inform policy makers and others concerned with climate change about the opportunities and challenges associated with storing CO_2 in geologic reservoirs as a way to reduce CO_2 concentrations in the atmosphere. To this end, we begin this paper with some general background on geologic storage of CO_2, followed by an assessment of the potential environmental and public safety issues associated with this activity. We then attempt to provide insight into a CO_2 storage regime by drawing out lessons from functionally similar operations in the oil and gas industry. Finally, we discuss the current research efforts focused on improving our understanding of CO_2 storage and provide recommendations for moving forward.

Our overall conclusions can be summarized as follows:

- The technologies and practices associated with geologic CO_2 sequestration are all in current commercial operation, and have been so for a decade to several decades. Such commercial operations include enhanced oil recovery, acid gas injection, natural gas storage, and CO_2 pipeline transportation. No major "breakthrough" technological innovations appear to be required for large scale CO_2 transportation and storage.

- Experience in these four analogous practices suggests no insurmountable environmental issues. The *immediate and local* risks associated with near term leakage have been effectively addressed. Expanding geologic storage of CO_2 to a much larger scale – as would be required for widespread application to large point sources of CO_2 emissions – will require incorporating and, where possible, improving upon current industry operations and government regulation "best practices" in regulating public safety and environmental impacts from these extant storage and transportation activities.

- A significant *global* environmental risk associated with large scale geologic storage of CO_2 is the potential for long term leakage – thus undoing the climate-protecting goal. By definition, there can be no definitive answer to the size of this risk, since analogous activities have been only occurring for the last three decades. However, over this period of time, there is no evidence to suggest that large scale leakage will occur. Observations of commercial field experience and sequestration demonstration projects in progress or about to begin should provide information that can help better bound this risk.

- Environmental and public safety risks associated with geologic carbon storage should be addressed by industry, government and the research community by focusing on three particular areas.

  - First, before large-scale storage activities come to fruition, a better understanding of the long-term implications and behaviors of CO_2 in the subsurface is needed. Opportunities to study these issues are now available in Western Canada at the many acid gas injection sites and in the United States at the more than seventy CO_2 flooding operations. Newly designed experiments will also play a role in furthering our knowledge and understanding about the risks involved.

  - Next, government should commit more resources to promote opportunities that entice CO_2 storage while developing appropriate regulatory regimes, training programs, and risk management strategies. Again, insights can be gained through a more detailed study of the four analogs presented in this paper. In each case, operations began at a relatively small scale and evolved into larger and more complex operations.

  - Finally, consortia of industry, government and the research community should devote significant resources aimed at informing and educating the public about the benefits and uncertainties associated with geologic storage of CO_2. Educating the public is essential to allow it to make informed judgments about the benefits and uncertainties involved in geologic storage of CO_2.

2.0 Background

The rationale for carbon capture and storage is to mitigate global climate change given current infrastructure and energy sources. Fossil fuels are the dominant source of the global primary energy demand, and will likely remain so for the rest of the century. In fact, fossil fuels supply over 85 percent of all commercial energy; the rest is made up of nuclear and renewable energy (hydro, biomass, geothermal, wind and solar energy). At present, great efforts and investments are being made by many nations to increase the share of renewable energy demand and to foster conservation and energy efficiency improvements. The transition from fossil to renewable energy, however, will take significant time. Therefore, many observers believe that addressing climate change concerns during the coming decades will likely require significant contributions from carbon capture and storage (Wirth *et al*., 2003).

Carbon capture and storage should be viewed as an important complement to improving energy efficiency or increasing use of non-carbon energy sources, and not as an alternative. Climate change can be more effectively addressed with a broad portfolio of technologies and strategies at our disposal. Because local circumstances often determine which technologies are adopted and at what cost, a broad suite of technologies and strategies is needed.

Successful CO_2 storage requires not only the appropriate operational expertise and technology, but also the identification and use of suitable geologic reservoirs. Such reservoirs must have the right combination of characteristics, which include but are not limited to location, capacity and containment ability. Reservoirs that appear to demonstrate a particular suitability for CO_2 storage include deep (greater than 800 meters) saline aquifers, unminable coal seams and depleted oil and gas reservoirs. A geographical distribution of these potential reservoirs is illustrated in Figure 2-1 and Figure 2-2.

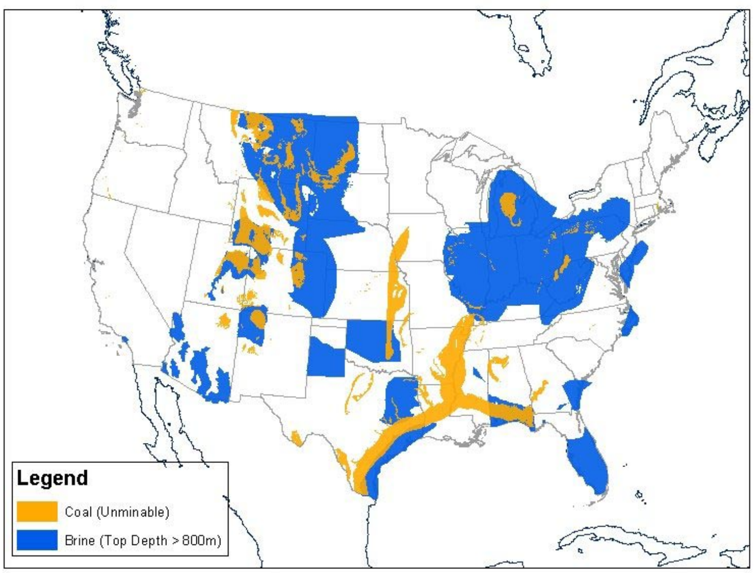

Figure 2-1: Illustration of Aquifers and Coal Seams. Aquifers deeper than 800m and some coal seams may be suitable for CO_2 storage. Existing databases on these formations are not comprehensive, so additional geologic storage opportunities may exist that are not indicated above. Data Sources: (1) Coal Fields of the Conterminous United States, 1996. USGS Open-File Report OF 96-92. (2) University of Texas, Bureau of Economic Geology. Brine Aquifer Database http://www.beg.utexas.edu/environqlty/co2seq/

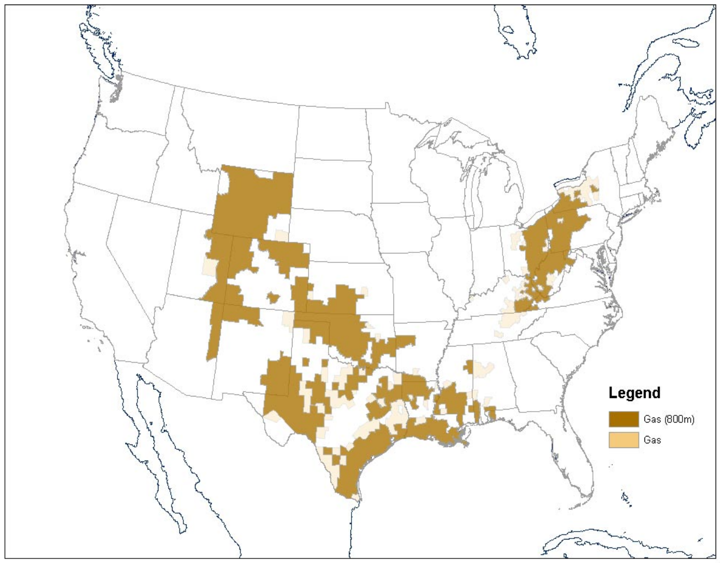

Figure 2-2: Illustration of Gas Reservoirs. Gas reservoirs deeper than 800m may be suitable for CO_2 storage. Data Source: NETL, DOE. GASIS, Gas Information System. GASIS CD http://www.eea-inc.com/gasis.html

Although the figures do not represent a complete picture of potential storage sites, they do illustrate a reasonably wide geographical distribution of potential storage reservoirs across the United States, with the highest concentration of reservoirs in the central and southern states. Other suitable reservoirs (primarily aquifers) may exist in other areas but are not yet represented in national-level databases. Importantly, a significant portion of aquifers and nearly all gas reservoirs are located at depths of 800 meters or more. This depth is generally regarded as the minimum injection depth for CO_2 storage so that the appropriate reservoir pressure (greater than the critical pressure of CO_2) can be maintained. The gas reservoirs shown in Figure 2-2 have trapped gases and other fluids for literally thousands of years, thus it seems reasonable that these same reservoirs could be used for the safe long-term storage of CO_2.

The capacity of potential storage reservoirs is a critical variable. Identified geological sinks for CO_2 have the capacity to hold hundreds to thousands of gigatons of carbon (GtC), and the technology to inject CO_2 into the ground is well established. Although we can determine the location of these reservoirs fairly easily and reliably, it is more difficult to estimate their actual capacity for CO_2 storage with an equal degree of certainty. Based on knowledge acquired from years of drilling in the oil and gas industry, most researchers believe that underground storage capacity in suitable formations exceeds 1000s of GtC (1 GtC = 1 billion metric tonnes carbon) worldwide. This compares to around 6-7 GtC of worldwide human induced emissions released into the atmosphere each year. Despite the uncertainties and data gaps involved with estimating the actual capacity for CO_2 storage in these reservoirs; it seems safe to assume that geologic storage capacity in the US tops 100 GtC and could exceed 1000 GtC. Table 2-1 shows estimates from the Department of Energy (1999) and Beecy *et al*. (2001) of potential US carbon storage capacity.

Table 2-1: Table Estimated Potential US carbon storage capacity (GtC)

Formation Type	**DOE**	**Beecy *et al.***
Natural Gas Reservoirs	25	27
Deep Coal	10	15
Deep Saline Aquifers	130	Large*

*Large – can be defined on the order of 100s of GtC

As the estimates indicate, the capacity of geologic formations to store CO_2 is substantial relative to current annual emissions and should not be a limiting factor in the adoption of CO_2 storage. The geographic distribution of potential storage formations is sufficient to support significant carbon capture and storage projects. Furthermore, the technology to transfer carbon dioxide from an emissions source to a potential storage reservoir is well established. Within the U.S., there is an extensive network of pipelines specifically designed for the transport of CO_2. Despite the advantages with respect to the availability, capacity and accessibility of storage reservoirs, there are unresolved issues surrounding the environmental and safety impacts associated with the long-term storage of CO_2. These issues are the focus of this paper.

3.0 Identification of Environmental and Safety Concerns

CO_2 is a colorless, odorless gas. When injected into a deep geologic reservoir, CO_2 will have the tendency to ascend to the top of that reservoir. If that reservoir is not sufficiently sealed by impermeable cap rocks, CO_2 may eventually leak back to the surface. Since CO_2 is denser than air, it can accumulate just below the surface in soil voids or above the surface in depressions in the ground. Eventually, any CO_2 that is vented from the ground will be diluted in the air to ambient levels in the atmosphere, currently about 370 ppm.

Much has been written about the generic environmental and human health effects related to exposure to $CO_{2,}$ which is neither flammable nor explosive (Benson *et al*., 2002; Holloway, 1997; Smith *et al*., 2002). At low concentrations (less than 1% by volume), CO_2 causes no ill effects on humans, fauna or flora. In fact, CO_2 is essential for life, being a critical component in photosynthesis. Some greenhouses purposely elevate CO_2 levels in order to "fertilize" the plants. At concentrations of about 6% by volume, CO_2 can cause nausea, vomiting, diarrhea, and irritation to mucous membranes, skin lesions and sweating. At about 10% by volume, it will cause asphyxiation.

There are uncertainties associated with the long-term geologic storage of CO_2. These issues relate to potential long term ecosystem impacts, as well as and health impacts (see Appendix B for some of the questions that have been raised). While many of these questions cannot be answered definitively, the many years of injecting CO_2 into geologic formations for Enhanced Oil Recovery (EOR) and Acid Gas Injection (AGI) operations have not shown any significant adverse effects on the surrounding population, workers, animals and vegetation. Since geologic storage of CO_2 must deal with larger quantities and longer time-scales than experienced in the above operations, research is being conducted worldwide to address these concerns.

A storage system can be broken down into two general subsystems, namely *operational* and *in situ*. The operational subsystem is composed of the more familiar components of CO_2 capture, transportation and injection, which have been successfully deployed in EOR and AGI applications discussed in Section 4. Once the CO_2 exits the injection well and enters the reservoir (i.e., the *in situ* subsystem), the fate of the CO_2 is largely transferred to the forces of nature. Years of technological innovation and experience have given us the tools and expertise to handle and control CO_2 in the operational subsystem with high certainty and safety. While there is significant experience and knowledge to predict the behavior of CO_2 *in situ*, there is not the same level of understanding as in the operational subsystem.

3.1 Subsystem: Operational

The capture, processing, transport and injection of CO_2 are proven practices using established technologies. The risks are well understood and the risk management strategies are well developed.

Some of the most common risks are a consequence of well and pipeline failure. According to the US Office of Pipeline Safety, pipeline damage most often occurs from external activities (e.g. unrelated construction operations or farming activities) (Office of Pipeline Safety, 2001). The amount of CO_2 escaping from a pipeline is limited by the use of automated shutdown valves. If a rupture in the pipeline were to occur, a pressure sensor would automatically shut an upstream valve, limiting the amount of CO_2 that would escape from the pipeline. As long as the pipeline is in an open area, escaping CO_2 would be diluted and returned to safe levels by entraining air within minutes of a release. It is important to emphasize that unlike natural gas or oil, CO_2 is neither flammable nor explosive.

Corrosion of wells and pipelines is of concern, but these issues seem to be more relevant to older wells and pipelines than newer ones (Wehner, 2002). The newest materials and technologies are sufficiently corrosion resistant. Damage to a well can occur when mismanaged by operating under excess pressure or due to corrosion. Such damage is likely to impair operability of the well, but may or may not cause loss of containment of the injected CO_2. Other damage to a well can occur when it is reopened for uses other then its original intention. Many states prohibit well re-openings, but others with less rigorous regulatory requirements do not always ensure that the best engineering practices are employed.

Other causes of pipeline and well failure include failure or absence of complete seal between the casing and wall of the bore hole; venting from partially plugged abandoned wells; and improper deployment of shut-off capability and pressure monitoring systems. Although operator error may also cause leaks, such occurrences can be prevented if safe work and operating practices are followed. In addition to the occurrence of failures, insufficient performance of systems designed to detect such failures is also a risk.

None of these issues are new to industry and thus should not be major obstacles in the development of a geologic CO_2 storage regime. Section 4.4 contains an additional discussion of CO_2 pipeline operation and safety.

3.2 Subsystem: *In Situ*

There is less experience with the *in situ* subsystem than with the operational one. Carbon dioxide occurs naturally in literally thousands of CO_2 and hydrocarbon reservoirs around the world. Some of these reservoirs are very secure and have negligible leakage rates, while others vent significant quantities. One way to minimize impacts from geologic storage of CO_2 is to develop criteria to determine the best reservoirs. Below we review some of the concerns that have been raised concerning geologic storage of CO_2 and try to put these concerns in perspective. We are not at the point where all these issues can be answered definitively. That will only happen through further research (see Section 5) and experience.

3.2.1 Large Releases to the Surface

Occasionally, large releases of CO_2 to the surface occur from volcanic activities in the earth's crust. For example, Mt. Kilauea in Hawaii continuously emits about 1.4 million metric tonnes (Mt) per year of CO_2. Mt. St. Helens in Washington State erupted in 1980 with the emission of 1.8 Mt of CO_2. Mt. Pinatubo, Philippines, erupted in 1991 with the emission of 42 Mt of CO_2 (Benson *et al*., 2002). The hot gases laden with particles from these volcanic eruptions are lifted high up and dispersed into the atmosphere. While the particles and toxic gases (e.g. hydrogen sulfide) released in these eruptions may have caused health, ecological and climatic damage, the emitted CO_2 from these eruptions is not known to have caused harm to humans, animals or plants. This is because after dispersion in the atmosphere, the ground level concentrations of CO_2 do not reach harmful levels.

There have been large natural releases of CO_2 that have been fatal to people. When CO_2 is released rapidly into confined spaces, it results in elevated CO_2 concentrations that can cause asphyxiation. One of the examples cited most often is the 1986 release from Lake Nyos, a crater lake in the volcanic region of the Cameroons (Holloway, 1997; Stager, 1987). About 0.2 Mt of CO_2 were released in approximately one hour. Because of the topography, the resulting plume rolled down a valley toward a populated village, asphyxiating people and cattle. The key question is how relevant this type of natural release is to the practice of geologic storage of CO_2.

First, it should be made clear that the circumstances at Lake Nyos were very different than the circumstances one finds in geologic storage. At Lake Nyos, CO_2 slowly accumulated in the bottom of the stably stratified lake. The lake's ability to hold the CO_2 was finite, but the addition of CO_2 to the lake was not limited. Eventually, the CO_2 had to be vented, in the same way a balloon must pop if it is continuously filled with air. Magnifying the impact was the topography, which made it hard for the CO_2 to disperse to safe levels before it reached populated areas.

It is highly unlikely that such massive releases of CO_2 will occur from geologic storage of CO_2. Pressure excursions should occur only near the injection point and then the CO_2 should diffuse over large areas in the formation. In other words, Lake Nyos tended to concentrate CO_2, while injection into geologic formations will tend to diffuse the CO_2 as it moves away from the injection point. With proper site selection and operation, the chances of a massive release from the formation can be reduced further.

It is important to emphasize that even if a large CO_2 release did occur, the impact on health and the environment may still be negligible. The CO_2 will usually be dispersed harmlessly into the atmosphere, except when certain topographies (e.g., a valley) keep the CO_2 at elevated levels for an appreciable time. In that case, asphyxiation could occur. In any case, since CO_2 is not toxic, there will be no lingering impacts once the CO_2 release is over.

3.2.2 Slow Releases to the Surface

Diffuse CO_2 releases occur naturally and continuously in the form of earth degassing, biological respiration, and organic matter decomposition. For example, at Mammoth Mountain in California, approximately 530 tonnes per day of CO_2 are released. Here, the CO_2 accumulates in the depressions in the caldera, and causes some forest dieback. The CO_2 causes root function inhibition and oxygen deprivation due to high concentrations of CO_2 gas in the soil (Bruant *et al.*, 2002).

Storing CO_2 in geologic formations, especially near populated areas, raises concerns about the potential hazard of CO_2 venting slowly to the surface. Although storage reservoirs are selected to minimize leakage, it is possible that relatively small volumes of CO_2 may escape from them over time. In general, slow releases may go completely unnoticed because they can be quickly dispersed in the atmosphere. However, certain topographies or confined structures may act to concentrate the CO_2 to dangerous levels.

Slow releases can occur through transmissive faults or fractures, by pathways associated with incomplete plugging of an abandoned well, by penetrating the injection zone, or by migration pathways offered by a poorly sealed injection well. How much CO_2 leaks from these reservoirs over time is an active research topic. The rate will not be a simple logistic function (i.e., so many % per year), but a quite complex function (i.e., it could take centuries or longer for CO_2 to begin to leak). The leak rate will be very dependent on the reservoir characteristics, so good site selection is important. One study undertaken at the Rangely EOR Field in Colorado suggests that rates could be significantly less than 1% per century for good sites. There is also speculation that the trapping mechanisms of dissolution (CO_2 dissolved in the brines) or mineralization (reacting CO_2 to form solid mineral carbonates), which occur on decades to centuries time-scales, can lead to essentially permanent containment underground for much of the injected CO_2.

The nature of the release, terrestrial and weather conditions, proximity to humans and ecosystems, and the opportunity to accumulate are important factors in assessing the risks associated with CO_2 leakage from anthropogenic storage operations. Slow leaks may also impact an accounting system established to track carbon credits, but this issue is beyond the scope of this paper. In the oil and gas industry, CO_2 and other gases can be effectively contained through engineering analysis and design. Opportunities for hazardous accumulations can be identified beforehand, and operational failures can be managed through proper design, operation, and monitoring. Thus, the potential risks of geologic storage of CO_2 can be substantially mitigated. Further, post-injection monitoring can confirm that no significant leakage is occurring.

3.2.3 Migration within the Geologic Formation

Although there have been significant advances in understanding fluid behavior and formation integrity in the subsurface, there is still some degree of uncertainty. While various tests and models can be developed to fairly accurately predict key variables, there is always the potential for CO_2 leakage from the intended storage formation into another area in the subsurface. For example, hydrocarbon and groundwater contamination can occur if CO_2 migrates to other zones in the subsurface, or through the oil-water contact zone. When CO_2 penetrates a fresh water aquifer, it is possible that carbonic acid will form and some leaching of toxic metals from the surrounding rocks and minerals may occur (Bruant *et al*., 2002). Withdrawal of fresh water from aquifers overlying deep geologic repositories may require periodic chemical analysis in order to ascertain that such leaching has not occurred.

Enhanced Oil Recovery operations have experienced no significant losses of CO_2 to other zones in the subsurface, nor has any leaching effects or incompatibility with the formations been detected. However, EOR has only been practiced for a few decades, a relatively short time period in the context of CO_2 storage. It is conceivable that over the long term gradual leakage from the reservoirs may occur, and the leaked CO_2 may migrate and re-accumulate in shallower zones.

3.2.4 Seismic Events

Most EOR, AGI and underground natural gas storage operators are not overly concerned with inducing seismic events, primarily due to the low volumes of fluids being injected. However, larger volumes of injected fluid would increase reservoir pressure, displace other fluids and might induce seismic events (Holloway, 1996). Reservoir Induced Seismicity (RIS) is primarily a potential environmental and dam safety-related concern. The mechanism by which seismic activity is induced is generally understood, however the means to reliably predict such events are limited. One of the first recorded instances of induced seismicity occurred in 1966 as a result of disposal of contaminated fluids at the Rocky Mountain Arsenal in Denver, Colorado. Interestingly, the Canadian Induced Seismicity Research Group (CISRG) reported:

> "Not all seismic activity was proved to be connected with the fluid disposal, but awareness and social sensitivity brought the operation to an end because of environmental concern associated to increased social sensitivity rather than real threats" (Vladut, 1999).

CISRG argued that induced seismicity might be more of a concern in areas of low natural seismicity because induced events may have a greater impact than naturally occurring ones. Careful siting, using proper pressure guidelines and design requirements, understanding the geomechanical properties of the storage reservoir, and properly placing wells and pipelines can significantly reduce the risk of inducing seismic activity.

3.2.5 Other Risks

The Union of Concerned Scientists and others have raised concerns about the "deep hot biosphere," referring to biological communities within the potential storage formations (Union of Concerned Scientists, 2002). Studies conducted over the past two decades have documented that such communities are present deep in the subsurface, including depths where geologic storage of CO_2 is likely to occur. The structure (species of organisms present and how they interact with each other) and function (what they do in these environments) have only been studied in a few locations. However, in general, these deep biological communities are few in number and less active than communities in the comparable near-surface environments. The environmental significance of these communities is not likely to be a serious concern because they are unlikely to play an important ecosystem function and the "foot print" of geological storage is estimated to be small compared to the total amount of subsurface habitat available for these organisms. Even if a particular community is affected, the impact on the total biodiversity and ecosystem of the earth should be negligible (Benson, 2002).

It has been argued that the adoption of carbon capture and sequestration technologies will lead to lower CO_2 emissions, but also an increased use of fossil fuels. This increase would create a potential risk of enhancing the adverse effects of climate change in the event that these CO_2 storage reservoirs leaked (The Union of Concerned Scientists, 2002 and Wilson *et al*., 2003). First, on the leakage rate question, empirical evidence to date suggests that leakage rates at good sites may be negligible (see Section 3.2.2 above), although the multi-century risks are by definition unknown. Second, it must be recognized that this type of risk is different than the safety and environmental risks discussed above. While important, it is beyond the scope of this paper, which is focused on risks from direct exposure to stored CO_2. However, we believe that the risk created by increased fossil fuel use and thus greater carbon leakage can be managed and mitigated by an appropriate regulatory regime and a systems management approach with proper accounting. Essentially, this problem can be mollified by correctly valuing the benefits of CO_2 storage, even if storage is not permanent. Herzog, Caldeira, and Reilly (2003) provide a detailed discussion on assessing the effectiveness of temporary carbon storage. Their paper outlines the conditions under which temporary storage would be beneficial.

3.3 Current Status

While the risks of long-term storage of CO_2 in geologic reservoirs appear to be manageable, uncertainties in characterizing human health and environmental risks resulting from the operational and *in situ* subsystems are compounded by the extended time scales involved. As a result, further understanding is needed to develop the credibility necessary to bring this technological approach to fruition in a manner that is politically and socially acceptable. One way to better understanding is to learn from current experience with CO_2 transport and injection (see Chapter 4).

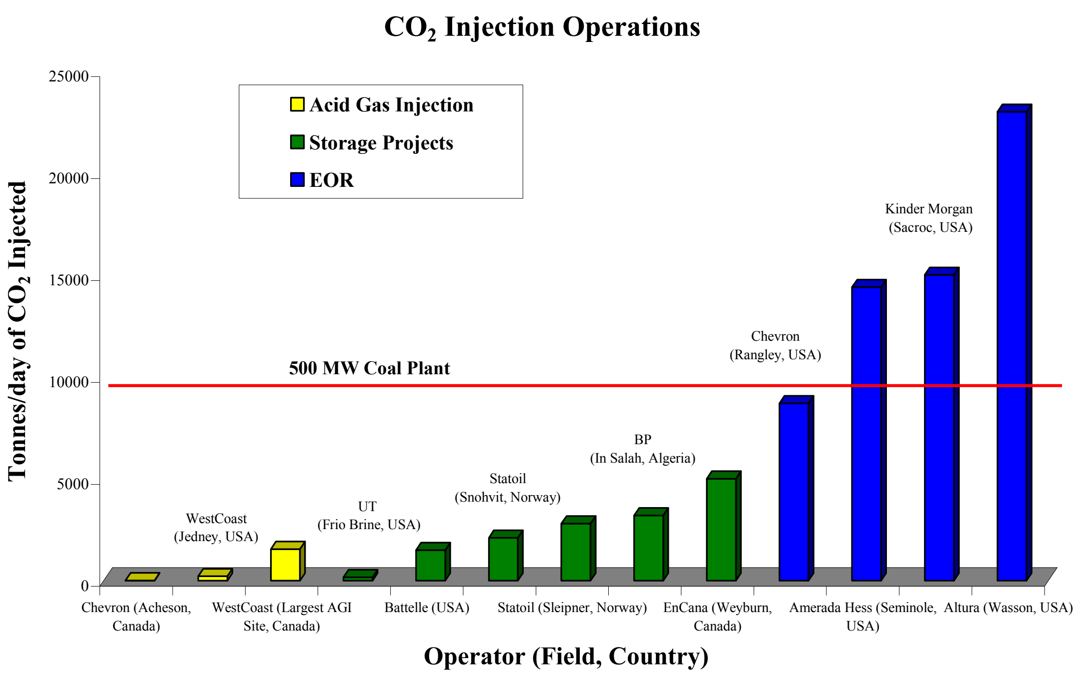

Figure 3-1: Comparison of CO_2 Injection Activities. Data from Hovorka (2002); Lock (2002); Maldal and Tappel (2002); Roche (2002); Riddiford, *et al*. (2002); Stevens *et al*. (2000).

Figure 3-1 illustrates the current magnitude of CO_2 injection activity in acid gas injection, direct CO_2 storage activities, and enhanced oil recovery projects. Details on the specific projects referenced in the figure will be discussed in subsequent chapters. The figure shows that storage-related activities are becoming quite substantial and will continue to increase in size in the future especially when a market for CO_2 emission allowances and CO_2 storage technology develops and/or government offers incentives for development. Although both acid gas injection schemes and current storage projects inject volumes below the projected sizes of future commercial storage applications, the largest EOR operations far exceed 10,000 tonnes per day, the approximate amount of CO_2 emitted by a 500 MW_e coal-fired power plant. Other significant operations, not shown in this figure, demonstrate the feasibility of high-volume fluid injection and storage into geologic reservoirs. For example, Florida municipal waste water is injected at a rate of about 0.5 billion tonnes per year while oilfield brine is injected at a rate of over 2 billion tonnes per year (Wilson *et al*., 2003). Total CO_2 emissions from US electricity generation topped 2 billion tonnes in 2000 (EPA, 2003).

4.0 Existing Operations and Technologies

Although geologic storage of CO_2 is still at an early stage, there has been extensive experience with four important analogs from the oil and gas industry: acid gas injection, enhanced oil recovery, natural gas storage, and CO_2 transport. All are functionally similar, and in some respects identical, to various aspects of CO_2 storage operations. For example, the major functional differences between acid gas injection schemes and Statoil's Sleipner project is the composition and volume of gas being injected into the geologic formation, and the types and depths of the formations used for storage.

World's First Major CO_2 Capture and Storage Project

Since 1996, Statoil, a Norwegian state-owned oil company, has been injecting carbon dioxide, a byproduct of natural gas recovery, into a 32,000 km^2 aquifer 800m below the floor of the North Sea. This innovative approach to greenhouse gas reduction was spurred in 1991 by a government imposed carbon tax on all carbon emissions from extraction activities on Norway's continental shelf. In order to avoid a 1 million Norwegian Krone (NOK) per day penalty, Statoil developed a carbon injection mechanism that stores the carbon dioxide in the underground aquifer once it has been removed from the natural gas.

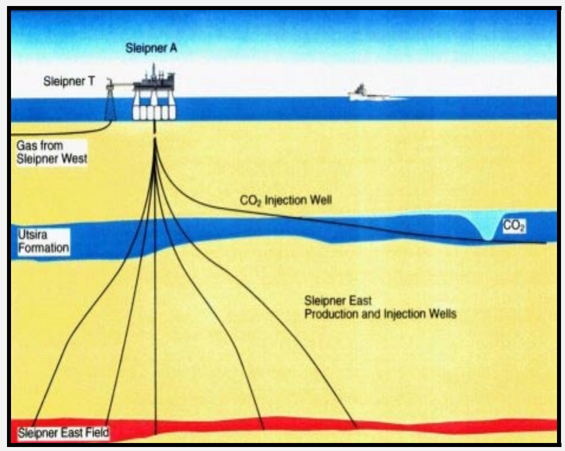

Figure from International Energy Agency, "Saline Aquifer CO_2 Storage," www.ieagreen.org.uk/sacshome.htm, May 2002

These analogs can offer insights about the safety, feasibility, environmental impacts, technologies, operations, engineering and economics of future geologic storage activities. In addition, these analogs are useful in identifying many of the political and regulatory drivers as well. However, it must be recognized that these analogs cannot by themselves offer a complete picture, as there will be some unique aspects to the geologic storage of CO_2.

In the next sections, this paper will present an overview of these four analogs and attempt to draw out some key lessons concerning their development and operation that can help the environmental impact assessment of the geologic storage of CO_2.

4.1 Acid Gas Injection

4.1.1 Operation

Driven by stricter hydrogen sulfide (H_2S) emissions regulations adopted in 1989, acid gas injection has become a popular alternative to sulfur recovery and acid gas flaring particularly in Western Canada. There are also a number of current projects elsewhere, including the United States and Abu Dhabi. Acid gas injection operations remove CO_2 and H_2S from an oil or gas stream produced from a geological formation, compress and transport the gases via pipeline to an injection well, then re-inject the gases into a different geological formation for disposal. In 2001, nearly 6.5 billion cubic feet (over 360,000 tonnes) of acid gas was injected into formations at more than 30 different locations across Alberta and British Columbia (Roche, 2002). Proponents of acid gas injection, which has become a predominant disposal method for H_2S, claim that these schemes result in less environmental impact than other alternatives for processing and disposing unwanted gases. Figure 4-1 shows all the acid gas injection sites operating in Alberta as of March 2002.

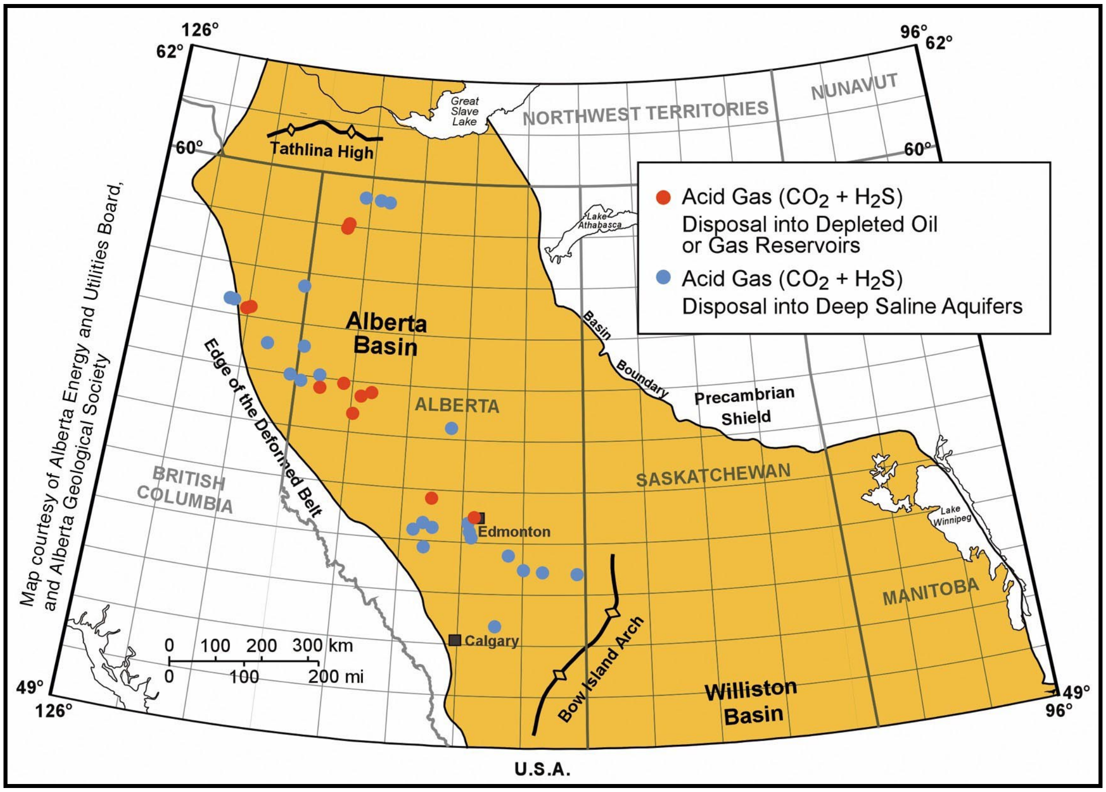

Figure 4-1: Acid Gas Disposal sites in Alberta, Canada. Map provided by Nickle's *New Technology Magazine*, September 13, 2002

In many acid gas projects, CO_2 represents the largest component of the acid gas stream. In some cases, CO_2 comprises over 90% of the total volume of gas injected for storage. Thus, by volume, many of the acid gas schemes are essentially small-scale CO_2 storage projects. By comparison, Statoil's Sleipner CO_2 storage project in the North Sea injects about 50 million standard cubic feet (MMscf) of CO_2 per day into a sub seabed aquifer, whereas most acid gas injection operations range between 50 thousand and 5 million scf per day. One of the newest acid gas injection schemes is quite large, approaching the size of Sleipner. This acid gas injection scheme, built in the summer 2002 by Westcoast Energy in northeastern British Columbia, injects 28 million scf per day of acid gas into a nearby depleted gas reservoir (Roche, 2002).

The advantages of acid gas injection include: elimination of sulfur transportation costs (transport costs have exceeded the price of sulfur in the past decade); reduced capital costs and operating costs (injection eliminates the need for sulfur recovery facilities); zero continuous sulfur emissions rates, CO_2 storage (CO_2 is usually emitted into the atmosphere during sulfur recovery);

and the ability to handle a wide range of H_2S/CO_2 composition ratios (Bosch, 2002). While acid gas injection can provide significant benefits in terms of cost savings and reduced air emissions, it is not suitable for every sour or waste gas disposal situation. Successful acid gas injection requires a nearby reservoir with sufficient capacity, porosity and permeability that is adequately isolated from producing reservoirs and water zones. These same constraints apply to CO_2 injection except that more care is required for the acid gas due to its inherent toxicity.

In Alberta, oil and gas producers are regulated by two main provincial bodies and the appropriate municipalities. Oil and gas operators are primarily governed by compliance standards established by the Alberta Energy and Utilities Board (EUB), which is charged with reviewing permit applications and regulating acid gas disposal activities under the authority of the Oil and Gas Conservation Act. The Alberta Environment Ministry, which carries out its work under the authority of the Environmental Protection and Enhancement Act and the Water Act, is also an active regulator, although it has fewer jurisdictions over the oil and gas industry. Regulations are well developed in the permitting, operating and monitoring phases of a project, with the permitting phase being the most extensive.

The EUB evaluates applications based on the need and location for the proposed facility, alternative pipeline and processing options, potential impacts associated with project development and consultations with industry and the public. To be approved, applications must demonstrate measures have been taken to encourage conservation of hydrocarbon resources, minimize environmental impacts, promote public safety and protect the owners of the mineral rights (Longworth *et al*., 1995). In the past, regulators and applicants have worked together closely to ensure compliance with these conditions. Prior to 1988 [when the EUB issued Informational Letter (IL) 88-13 stating that the allowable volume of acid gas flaring was reduced to 1 tonne/day of sulfur dioxide], sulfur recovery and incineration were the two most economical methods of sulfur disposal. Since then, acid gas injection technology has come into practice primarily as a result of declining sulfur prices and more stringent sulfur recovery requirements (Bosch, 2002; Carroll & Maddocks, 1999).

Historically, depleted and producing reservoirs have proven to be reliable containers of both hydrocarbons and acid gases over time. Boundaries, pressure limits and volume capacity of these reservoirs are usually well known (Chakma, 1997). The EUB requires operators to monitor H_2S and file operating reports on a regular basis according to IL 94-2. These regulations call for continuous monitoring of the fluid pressure and packer as well as monthly monitoring of the wellhead pressure, temperature and fluid at the injection well, and volumes of injected fluid. Moreover, twice a year, operators are required to report the results of monitoring, disposal well maintenance and overall performance (Longworth *et al*., 1995). Figure 4-2 shows a typical acid gas injection well house. At an injection site, the wells are normally covered with a shed like this to monitor and contain any H_2S release in the event of a leak or accident. This is one visible example of how operators have taken special measures to reduce the safety risks associated with acid gas injection.

Figure 4-2: Acid Gas Injection Well House, Acheson Field (Photo taken by the author August 29, 2002, courtesy of EnerPro Midstream Inc.)

Over the life of the project, annual subsurface pressure tests of the formation take place at the injection wellhead. This test involves stopping the flow to the well in order to conduct more extensive reservoir pressure and integrity tests (Lock, 2002). When problems arise, they are often traced to the well bore or the tubing. Well problems are straightforward to repair, but in the unlikely event of impairing the formation's integrity, no remedies are apparent short of shutting off the well, or possibly, extracting the injected gas. Although no acid gas injection scheme has been abandoned, there are no post-abandonment reservoir monitoring requirements in place at this time. Further, the sufficiency of subsurface pressure tests to determine a formation's integrity may be an area requiring additional investigation.

4.1.2 Safety and Environment

Safety concerns, at least at the operational level, focus on the management, monitoring and containment of H_2S. Aside from its corrosive nature, H_2S is a very toxic and flammable gas. At low levels, H_2S has a rotten egg smell and can paralyze the olfactory system at concentrations around 100 ppm. At levels above 300 ppm, H_2S is immediately dangerous to life and health (OSHA, 2003). Relatively little attention is paid to the CO_2 component of the acid gas stream, primarily due to low volumes and the non-toxic nature of CO_2. The storage of CO_2 in these acid gas schemes is a fortuitous benefit of H_2S disposal. One of the most important issues in developing acid gas disposal wells is the potential size of the Emergency Planning Zone, determined by modeling the plume size and potential for harm in the event of a H_2S release.

Although there are many significant health and safety risks associated with acid gas injection, they have been effectively managed by existing industry practices. Risk reduction strategies are primarily focused on H_2S containment. They include operator training and routine maintenance procedures, automated pressure monitoring and gas detection systems, automated emergency shutdown valves and response systems, effective regulatory enforcement and reporting and years of operating experience (Bosch, 2002; Maddocks, 2002). These practices provide a good template for future CO_2 storage projects.

Communication, Education and Responsiveness is Key

In Alberta, oil and gas production accounts for over 40% of the province's revenues, 60% of its total exports and provides employment for over 183,000 residents. At the Acheson facility, 3 miles outside Edmonton, EnerPro participates in and hosts various joint committees and regular meetings involving the public and nearby residents. These activities have facilitated more open communication and credibility with the public and allowed them to be more attuned to public concerns. Thus, oil and gas operators have faced relatively little public opposition even when they have disposed of waste gases underground so close to a major population center.

Environmental risks have also been reduced through high system reliability rates. To illustrate, on-line time for Chevron's four injection systems has averaged 99.2% (Bosch, 2002). These high reliability levels are critical, as backup emergency flaring systems are only permitted to operate for restricted periods of time before production must be reduced (Alberta Energy Utilities Board, 2002). On-line reliability has been achieved through preventative maintenance programs, operator training, high reliability motors, on site stocks of spare parts, and 24 hour maintenance personnel (Bosch, 2002; Maddocks, 2002).

Despite H_2S being much more toxic than CO_2, there have been no known incidents where significant harm has occurred as a result of an acid gas injection operation. When a problem has occurred, it has usually been the result of an operator error rather than mechanical failure. H_2S odor, aesthetic annoyance, emissions, flaring and machinery noise seem to be the most frequent sources of public complaint especially when operations are near residential units. In response, the industry has taken steps to address these concerns. For example, noise has been reduced with various technologies and by enclosures, while a significant number of the odor problems have been attributed to human error (e.g. valves that have not been completely closed) (Bezinett, 2002).

4.2 Enhanced Oil Recovery (EOR)

4.2.1 Operation

Enhanced oil recovery, like acid gas injection, provides considerable experience and insights for safe, reliable injection and storage of CO_2. A few differences between the two types of operations can be found in the phase characteristics and final destination of the CO_2. In acid gas disposal, CO_2 and H_2S are injected in the gaseous or supercritical form into a different geologic reservoir. In EOR, nearly pure CO_2 is injected as a liquid or dense gas into the producing formation. EOR operators call this a CO_2 flood.

In most EOR projects, much of the CO_2 injected into the oil reservoir is only temporarily stored. This is because the decommissioning of an EOR project usually involves the "blowing down" of the reservoir pressure to maximize oil recovery. This blowing down results in CO_2 being released, with a small but significant amount of the injected CO_2 remaining dissolved in the immobile oil. The Weyburn Field in southeastern Saskatchewan, Canada, is the only CO_2-EOR project to date that has been monitored specifically to understand CO_2 storage. In the case of the Weyburn Field, no blow-down phase is planned, thereby allowing for permanent CO_2 storage. Over the anticipated 25-year life of the project, it is expected that the injection of some 18 million tons of CO_2 from the Dakota Gasification Facility in North Dakota will produce around 130 million barrels of enhanced oil. This has been calculated to be equivalent to approximately 14 million tons of CO_2 being prevented from reaching the atmosphere, including the CO_2 emissions from electricity generation that is required for the whole EOR operation.

The first major CO_2 flood took place in 1972 in Scurry County, Texas. Since then, CO_2 floods have been used successfully throughout the Permian Basin, as well as in at least 10 other states. Outside the United States, CO_2 floods have been implemented in Canada, Hungary, Turkey and Trinidad (Kinder Morgan, 2001). In 2000, 84 commercial or research-level EOR projects were operational worldwide. Combined, these projects produced 200,772 barrels (bbl) of oil per day, a small but significant fraction (0.3%) of the 67.2 million bbl per day total of worldwide oil production that year. The United States, the technology leader, accounts for 72 of the 84 projects, most of which are located in the Permian Basin (Oil & Gas Journal, 2000; 2001). The five largest EOR operations, four of which are located in the Basin, combined for 47 percent of enhanced oil production from CO_2 flooding in 2000 (Oil & Gas Journal, 2001).

The economically most viable option for light oil EOR is often CO_2 flooding, especially when naturally occurring CO_2 sources are available. Because large natural CO_2 deposits exist within reasonable distance from which CO_2 has been developed and transported to the Permian Basin, CO_2 flooding became the major EOR technology in the Basin. Once the initial infrastructure was put into place, multiple projects were able to tap into the CO_2 resource over a few decades. Naturally occurring CO_2 deposits can be found in other parts of the world, but in many cases the capital to initiate and develop the infrastructure to support EOR operations is not available. In Brazil, operators are planning to capture CO_2 from manufacturing sites because they cannot locate a natural source. However, in Croatia and Hungary, where natural CO_2 sources exist, operators are looking to develop EOR operations (Wehner, 2002).

Because of the high costs associated with producing, transporting, processing and injecting CO_2, EOR operators try to maximize oil production by using the minimum amount of CO_2 necessary to achieve the desired results. EOR projects are optimized by manually alternating between CO_2 and water injection in a water-alternating-gas (WAG) process (Figure 4-3) (Kinder Morgan, 2001). The WAG process helps overcome the problem of high CO_2 mobility within the formation, which greatly reduces the effectiveness of CO_2 flooding. High CO_2 mobility, caused by the lower density and viscosity of CO_2 relative to the reservoir oil, is responsible for undesirable phenomena known as gravity override and viscous fingering. Override and fingering reduce the efficacy of flooding by permitting the CO_2 to flow through areas that have already been swept. Swept areas are parts of the formation where CO_2 has already displaced the oil. Because water is less mobile than CO_2, the WAG process is able to improve the sweep efficiency by reducing CO_2 mobility. This, in turn, results in improved oil recovery while also preventing early CO_2 breakthrough in producing wells (EPRI, 1999; Klins & Bardon, 1991; Morel, 1991).

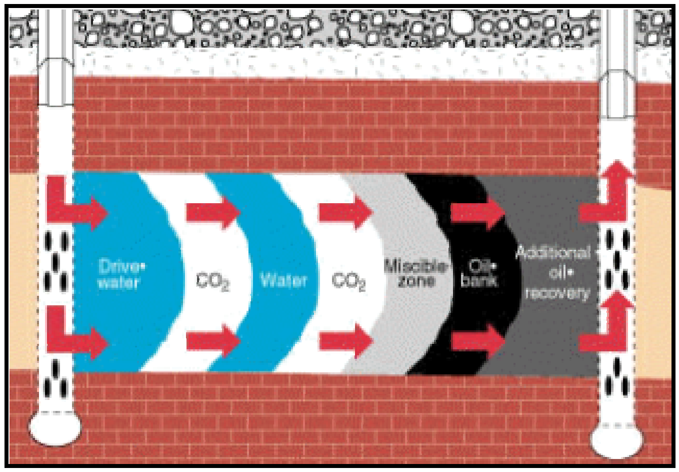

Figure 4-3: EOR Schematic - WAG Process, Kinder Morgan CO_2 Company, 2001

To further improve the effectiveness of CO_2 flooding, operators monitor CO_2 flow within the reservoir. Highly advanced geophysical surveys, which employ 4-dimensional, 3-component seismic reflection data, are employed to directly detect the movement of CO_2 within the systems over time. This information can improve oil recovery by enabling EOR operators to better direct CO_2 flow and reduce poor conformance (Stevens *et al*., 2000).[1] Further, some operators are now using improved cross-well seismic time-lapse technologies to monitor CO_2 movement in the reservoir (Wehner, 2002).

In addition to oil production and CO_2 injection processes, EOR project operators must also be skilled at reservoir management and oil, gas and water processing. Reservoir management integrates reservoir modeling, simulation, fluid and rock properties and recovery technologies along with the underlying geoscience technologies to ensure maximum profitable recovery of the company's oil and gas assets. The fluid recovered by EOR in addition to liquid crude oil, contains natural CO_2, a fraction of the injected CO_2, petroleum gases and H_2S. The natural gas is separated for resale, H_2S and CO_2 are separated, and the CO_2 is recycled for re-injection.

Gas processing at Amerada Hess' Seminole Unit, near Seminole Texas, began in 1983 when their Ryan-Holmes unit became operational. Currently, flow volume from the production field into the processing facility averages around 175 MMscf per day. This stream is composed of 85% CO_2, 15% hydrocarbons, and 0.6% H_2S. While essentially all the hydrocarbons are either reused or sold, the majority of CO_2 (145.9 MMscf per day) is sent to a distribution center where it is combined with additional CO_2 purchased from a third party and re-injected into the field. In

[1] Conformance refers to the gas injection process which often suffers from poor sweep due to the high mobility of injected gas. This reduces oil recovery and contributes to higher operating costs when injected gases breakthrough to production wells.

all, this EOR operation injects approximately 260 MMscf (over 5 times the volume of Sleipner) of CO_2 per day into various parts of the Seminole Unit. Operators currently estimate that around 1.5 trillion cubic feet (tcf) of CO_2 is stored in the geologic formation at any one time.

4.2.2 Safety and Environment

The techniques and technologies used for gas detection, pressure monitoring, safety training and public awareness in EOR operations are very similar to those used in acid gas injection. Environmental issues arising from CO_2 flooding seem to be minimal, though no environmental impact statements are required to confirm this hypothesis. Operators observe that some CO_2 is lost in the formation, most probably as a result of fingering or through the oil-water contact zone. EOR operators have estimated the total amount of CO_2 lost to the formation to be anywhere from negligible levels to around 5% (Wehner, 2002). Leakage around the injection well bore is the most likely source of a CO_2 loss. Figure 4-4 shows estimated leakage rates from the Rangely, Colorado field, which has been undergoing large-scale CO_2 injection since 1986. Again, pressure tests are used to detect leaks, and should one be found, zone isolation packers and cement are used to seal the leak zones.

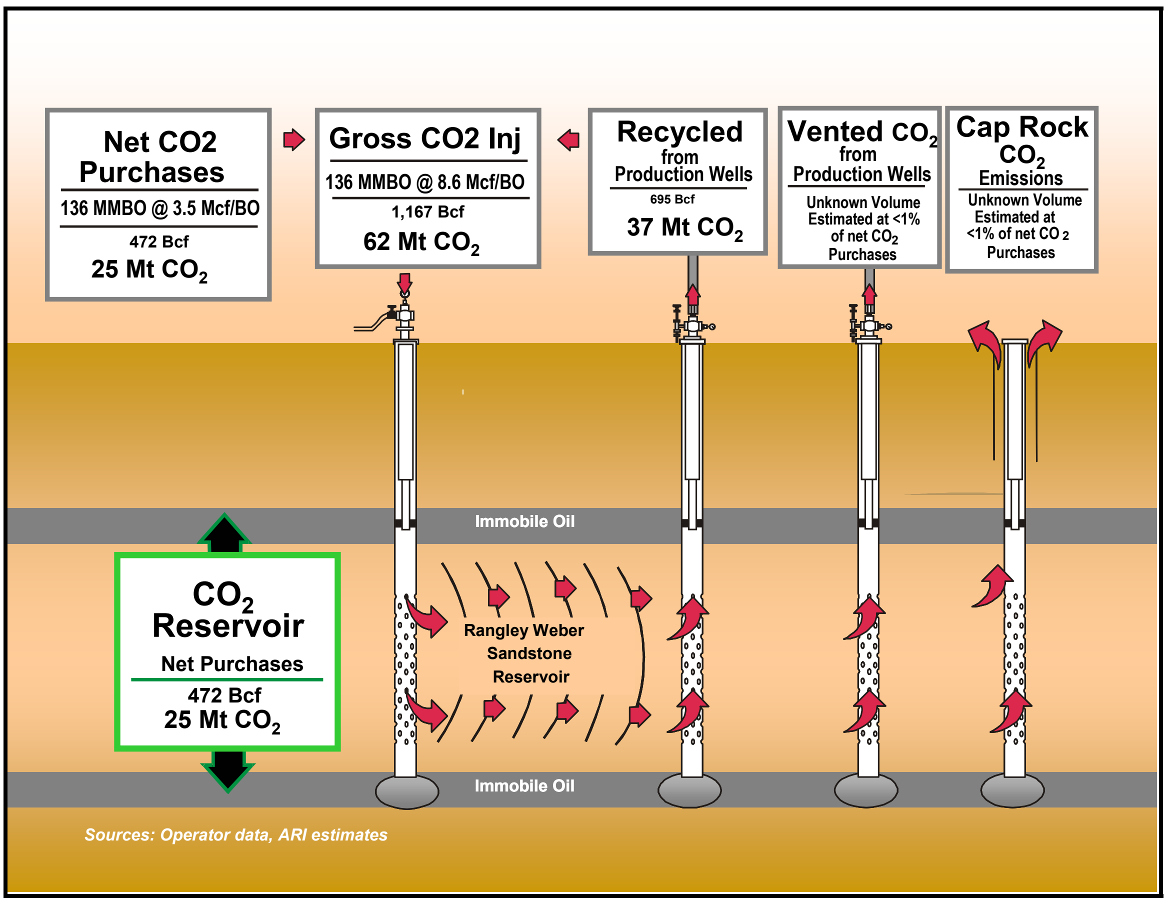

Figure 4-4: Rangely EOR Schematic Note: MMBO is million barrels of oil

Better coordination and teamwork between operators and emergency response crews have reduced response times and improved their ability to respond to threatening situations. For instance, in the Permian Basin, nearby operators conduct joint training exercises with emergency service personnel on a regular basis. Furthermore, EOR operators have been important contributors to local emergency teams by supplying them with additional equipment and resources for reducing response times and reacting to various situations. Teaming up by sharing costs, equipment and expertise is a valuable lesson for future storage operations.

Living with CO_2 Injection

This production well, in the center of the only public park in town, is located less than one hundred yards from the most affluent residential housing unit in the city.

These two production wells, located next to this house, are typical in Seminole, TX. Other wells located across the street from the high school and in the front yard of the city's hospital.

In the Permian Basin, public opposition to proposed EOR developments has been limited. Each year the company invests a great deal of resources in coordinating and practicing emergency response plans with local public services. Outreach is necessary as Hess maintains over 70 wells within Seminole's city limits. Each well is checked twice per day. In Seminole, almost everyone works or knows someone who works in the oil industry. In fact, well problems are often reported by people known to the operators.

EPA is charged with enforcing the requirements of the Safe Drinking Water Act and oversees the Underground Injection Control Program (UIC), which protects drinking water aquifers from contamination by underground injection of wastes (EPA, 2002). In most cases, the states have assumed primary regulatory authority for administration of the UIC program. This program defines five classes of wells based on waste type, injection activity, and proximity and relation to an aquifer. Class II wells, which control injection related to hydrocarbon production, cover EOR operations, as well as reinjection of oilfield brines. Class I wells control injection below drinking water reservoirs, and are the most restrictive and expensive to permit. Class I applications include injection of industrial liquid wastes and municipal wastewater. Class V wells are typically shallow wells for non-hazardous materials; they also control experimental injection applications.

In Texas, where the majority of EOR operations occur, the state gives tax breaks to companies who invest in CO_2 flooding regimes. However, these incentives are less important than the IRS Section 43 Investment Tax Credits equal to 15% of the qualified EOR costs (EIA, 2000). State law gives primary regulatory authority to the Texas Railroad Commission (responsible for oil and gas processing and gathering plants, wells, producing sites and pipelines) and the Texas Commission on Environmental Quality (TCEQ – responsible for air quality). The University Land System, which exists in Texas, is not a regulator but is in charge of leases and royalties on state lands. The Mineral Management Service deals with Federal leases and has significantly stricter regulations.

4.3 Natural Gas Storage

4.3.1 Operation

Natural gas storage activities can also provide insight into operations, risks and management strategies relevant to geologic CO_2 storage. Natural gas, similar to $CO_{2,}$ will tend to rise within a storage structure. Critical differences include the time scales for management, injection and withdrawal rates and the types of reservoirs suitable for storage.

Natural gas was first injected and stored in a partially depleted gas reservoir in 1915. Since then, underground natural gas storage has become a relatively safe and increasingly practiced process to help meet seasonal as well as short-term peaks in demand (EIA, 1995). Because depleted oil and gas reservoirs were not readily available in the Midwest, saline aquifers were tested and developed for storage in the 1950's. Between 1955 and 1985 underground storage capacity grew from about 2.1 trillion cubic feet (Tcf) to 8 Tcf[2] in response to consumption increases and a changing nature of demand (EIA, 1995). However, since 1985, total storage capacity has stabilized at around 8 Tcf while the capability to deliver the natural gas to market has increased (EIA, 1995). To put these numbers in perspective, total gas consumption in the US exceeded 22 Tcf in 2000 and is expected to increase rapidly over the next 20 years, which will mean new pipelines and storage expansions (Tobin, 2001). Figure 4-5 shows natural gas storage operations by type in the United States.

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[2] Since CO_2 stored underground will be much denser than natural gas, 8 Tcf of natural gas capacity is roughly equivalent to the storage space needed to hold the CO_2 emitted annually from all the power plants in the United States.

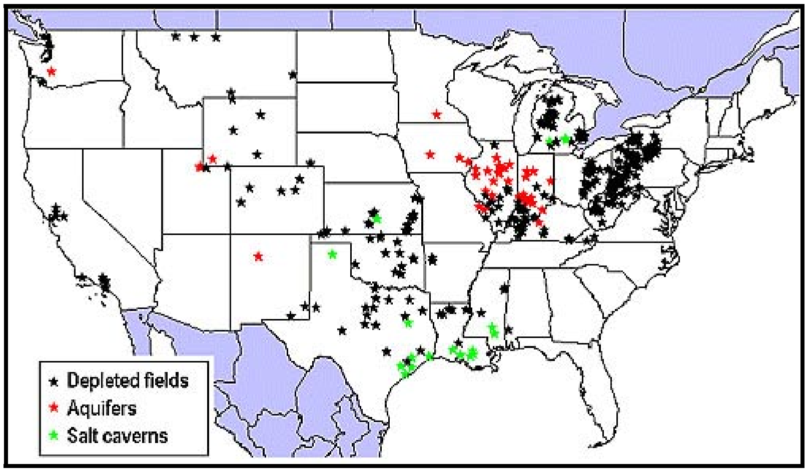

Figure 4-5: Natural Gas Storage by Type, National Energy Technology Laboratory, "Transmission, Distribution and Storage Natural Gas Infrastructure – Storage ," [online document] 2002, [cited September 26, 2002] http://www.fetc.doe.gov/scng/trans-dist/ngs/storage-ov.html

While depleted oil and gas reservoirs are the most widely available and frequently used natural gas storage facilities in the United States, salt caverns and natural aquifers can also be suitable. Not only are oil and gas fields abundant, but they are often more convenient and less costly storage sites, as developers are able to utilize existing wells, gathering systems and pipeline networks for storage and delivery operations (Tobin, 2001). Saline aquifers could offer the greatest potential for CO_2 storage. For example, saline aquifer storage capacity is estimated on the order of 10,000 gigatons, whereas the storage capacity for CO_2 in depleted oil and gas reservoirs is estimated at only 1000's of gigatons (Klara, 2002). Since salt caverns would have to be mined, they are considered too expensive to be used for CO_2 storage.

4.3.2 Safety and Environment

Well leaks resulting from mechanical failure are the most common problem in the natural gas storage business. Fortunately, most of these problem wells can be repaired, reconditioned, or plugged (Benson *et al*., 2002). An example of the potential damage caused by natural gas leakage occurred in 2002 in Hutchinston, KS when natural gas migrated from a damaged well pipe and resulted in explosions that killed two people and caused millions of dollars of damage to downtown businesses. The source of the gas was a damaged well pipe from a 1992 reopening which converted an abandoned salt cavern from propane to natural gas storage. A recent report concluded that since 1993 the gas leak coupled with pressurization levels exceeding recommended limits, caused the natural gas to escape and migrate more than 9 miles. The gas accumulated under the city and vented through old abandoned wells ("Report Links," 2002). While this example shows how gas can migrate and re-accumulate, the catastrophic results are not analogous to CO_2 storage since CO_2 is not flammable.

Several federal and state agencies have regulatory authority over underground storage and transportation of natural gas in the US. Typically, the operations of storage facilities and intrastate pipelines are regulated at the state level; however, the Federal Energy Regulatory Commission (FERC) regulates facilities serving interstate markets (Tobin & Thompson, 2001).

The US Department of Transportation's Office of Pipeline Safety (OPS) is concerned with safety, operational procedures and new developments of the pipeline system (Tobin, 2001).

Most natural gas storage operations face relatively little large-scale public opposition even though most operations are near urbanized areas. The most frequent problems arise from general quality of life issues, namely odor complaints originating from the additives in the natural gas. For the most part, occupational training programs and an occasional public meeting are standard practice, but extensive public outreach programs do not seem to be common in the industry. A significant number of people are not aware that they live on or near underground storage sites (Johnson, 2002).

4.4 CO_2 Pipeline Transportation

4.4.1 Operation

Numerous large natural deposits of CO_2 have existed underground for millions of years and demonstrate that stable long-term storage of CO_2 can be achieved (Holloway *et al*., 1996). In the last twenty years, many of these CO_2 accumulations have been exploited commercially for use in EOR operations. An extensive CO_2 pipeline network has been built and now stretches nearly 2,000 miles, mostly in the United States (Gale, 2001). As a result, the technology, operations and risks associated with CO_2 transport are well understood.

Pipelines designed to transmit gases, liquids, and supercritical fluids are used in a wide variety of applications and are generally viewed as safe vehicles to transport commodities in both urban and rural settings. For most pipelines, including those designed for the transport of supercritical CO_2, the ability to maintain adequate pressure is important for good operations. This can be achieved by recompressing the CO_2 at certain points along the pipeline. Not all pipelines require recompression. For example, the Weyburn pipeline, which transports CO_2 over 200 miles from an industrial facility in North Dakota to an EOR site in Saskatchewan, Canada, operates without a recompression system (Hattenbach *et al*., 1999).

The Canyon Reef Carriers pipeline, one of the first pipelines constructed specifically to deliver CO_2 for EOR operations, is an example of a long running, safe and reliable CO_2 pipeline. Initiated in 1972, the Canyon Reef Carriers pipeline has experienced relatively few failures (with no injuries) during its 30 years of operation. The pipeline, which extends 140 miles from McCamey, Texas, to Kinder Morgan's SACROC field is 16 inches in diameter and has the capacity to deliver up to 240 MMcf of CO_2 per day (Kinder Morgan, 2001). The Val Verde Pipeline, pictured in Figure 4-6, is an 82-mile, 10-inch diameter pipeline which has the capacity to transport 125 MMcf per day of anthropogenic CO_2 from four gas treating plants to the Canyon Reef Carriers pipeline, which is then used for EOR operations.

Figure 4-6: Val Verde Pipeline, Petro Source Carbon Company, cited October 11, 2002 at http://www.petrosourcecorp.com/HP_co2/

4.4.2 Safety and Environment

CO_2 pipeline safety should be considered in the context of natural gas and hazardous liquid pipelines. While the networks of CO_2 pipeline are well developed, the mileage of CO_2 pipelines in the United States is a fraction of the mileage of natural gas and hazardous liquid pipelines. Compared to the 2,000 miles of CO_2 pipelines, there are over 333,000 miles (536,000 km) of natural gas transmission pipelines and 155,000 miles (249,000 km) of hazardous liquid pipelines in the United States (Gale, 2001). Table 4-1 provides statistics for pipeline incidents in the United States between 1994 and 2000.

Table 4-1: Pipeline Statistics for the United State 1994-2000

Pipelines	Natural Gas	Hazardous Liquids	CO_2
Number of Incidents	510	1220	5
Number of Fatalities	21	16	0
Number of Injuries	75	66	0
Property Damage	\$135 million	\$370 million	\$54,000
Number of Incidents per 1000 km of Pipeline per year	0.14	0.69	0.23

Source: Gale (2001)

It is difficult to draw direct comparisons but the data in Table 4-1 suggests that CO_2 pipelines are as safe as natural gas pipelines (Gale, 2001). The US regulatory authority, the Office of Pipeline Safety reports that most natural gas pipeline accidents were caused by damage inflicted from an outside source (mainly excavation equipment) (Office of Pipeline Safety, 2001). Figure 4-7 illustrates that outside forces also contribute significantly to hazardous liquid pipeline failure.

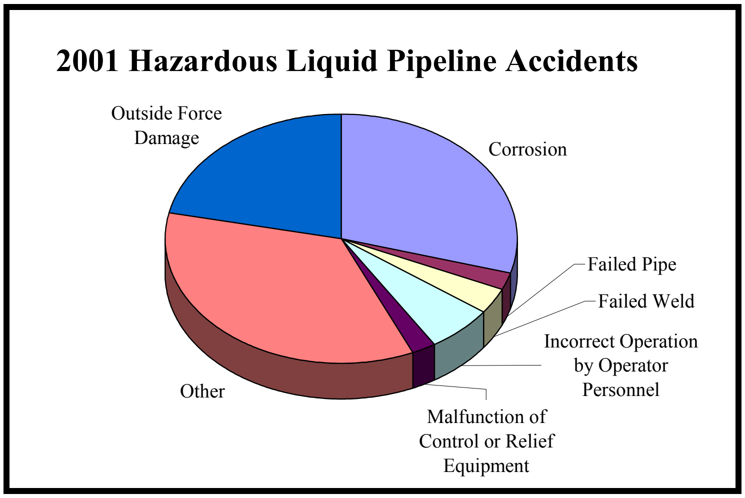

Figure 4-7: Hazardous Liquid Pipeline Accidents, data from Office of Pipeline Safety[3]

Title 49 of the Code of Federal Regulations, Parts 190-199 embodies the regulatory framework for ensuring the safety and environmental compliance of pipeline transportation. This regulatory framework is well developed and reflects a great deal about what is known in transporting materials via pipeline. Under Federal Regulations, CO_2 pipelines are classified as "High Volatile/Low Hazard" and "Low Risk" (Gale & Davison, 2002).

Once built, safety concerns associated with CO_2, natural gas and hazardous liquid transportation via pipeline are generally well understood. Risk management strategies are incorporated into the design, construction and operation of current and future pipelines. Quick human response time is an essential part of risk management, if an operator or other responsible party does not report the damage immediately, leaks may occur over long periods of time or more serious failure may result years later.

CO_2 pipeline best practices include but are not limited to selecting sites and methods that reduce the probability of accumulation resulting from leakage or injection well failure. Best siting practices would involve selecting a site with sufficient ventilation (e.g. open areas) to prevent accumulation. An additional measure to reduce risk could include adding chemical odorants, like those added to natural gas, which help in detecting leaks especially around more populous areas. This technique has had a positive impact on leak detection at the Weyburn facility and its supplying pipeline (Gale & Davison, 2002).

CO_2 transport is a widely practiced and accepted technological application not only for EOR but also for industrial and commercial purposes. Moreover, procedures to determine the risks of pipeline failure are well established (Gale, 2001). Extraction, transportation, processing and injection of CO_2 are common business operations today and appear to be adaptable to handle larger-scale geologic storage operations.

[3] Corrosion includes both internal and external corrosion while "other" refers to sabotage, natural disasters, mechanical failure, etc.

4.5 Lessons Learned

A number of practical lessons can be learned from studying current activities in the oil and gas industry that are relevant to geologic storage of CO_2. Some of the key practices that could be implemented from the outset include safety and operator training procedures, emergency response plans, automated shutdown systems and important management strategies for public relations and gas processing. These are critical practices now employed in existing CO_2 and non-CO_2 related operations.

Apart from the practical insights, a more general theme has emerged from looking into these analogs: activities similar or identical to those involved in high-volume geologic storage of CO_2 have been managed successfully for decades. Three points deserve special attention:

1. Low-volume geologic storage of CO_2 has successfully occurred in the form of enhanced oil recovery since the early 1970s and also under the practice of acid gas injection since 1989. Specific knowledge and expertise now exists for effective management of CO_2 storage.

2. All four analogs evolved incrementally into major operations over time. For instance, the first acid gas injection operation injected roughly 10 tonnes per day in 1989. Today, the largest acid gas injection scheme injects nearly 1,400 tonnes per day into a depleted gas field. The development of a geologic CO_2 storage regime will most likely follow the same evolutionary path for scaling up in size.

3. Through research, experience and public outreach, operators and regulators have successfully managed the risks, benefits and public apprehension associated with these activities.

5.0 Current Research & Way Forward

5.1 Current Research

At the start of the 1990s, the field of carbon capture and storage consisted of a handful of research groups working in isolation. Finding funding was difficult, as this field was not one of the research priorities of traditional funding sources. This has all changed over the last decade. Today, there is an interconnected, international research community, with a high level of collaboration and increased funding sources. Equally important, industry is taking a major role in analyzing and developing these technologies. The primary goals of this research are to reduce the uncertainties associated with CO_2 storage by achieving a better understanding of the following general themes: 1) the behavior of CO_2 in the subsurface, 2) the long-term implications of CO_2 storage and potential leakage, and 3) proper long-term monitoring and control methods and technologies.

Perhaps the most significant development has been the Sleipner project, the first commercial application of emission avoidance through the use of carbon capture and storage technologies. In addition, many other research level and commercial-scale CO_2 storage projects are being studied for their efficacy in containing CO_2 in geologic formations. Most notably, Encana's Weyburn EOR project is now being studied to assess the long-term implications of CO_2 storage and monitoring. Other new and significant storage activities include BP's In Salah Gas Project in Algeria, Statoil's Snøhvit gas operation and proposed experiments by the University of Texas and Battelle Memorial Institute. These projects and others around the world are focusing on health, safety and environmental assessments, reservoir characterization and modeling, monitoring, verification and cost minimization.

In order to meet internal firm emissions commitments, BP and Sonatrach have designed an integrated emissions mitigation plan for the In Salah gas project that has allowed them to capture and sequester CO_2 in the subsurface. In order to export the produced natural gas, operators must first remove a high concentration of CO_2 from the produced gas stream. It is estimated that over the life of the project, over 450 billion cubic feet (25 million tonnes) of CO_2 will be extracted from the produced natural gas stream (Riddiford *et al*., 2002). During the design phases, project leaders considered a variety of storage options by evaluating the reservoir's demonstrated seal integrity, capacity, reservoir properties and pressure. As a result, the aquifer region of the Krechba Carboniferous reservoir was selected because of the extensive characterization operators had of the reservoir as a result of other well penetrations and a 3-D seismic image that provided them with a sound understanding of the geology in the prospective storage reservoir. This project should generate important information about reservoir selection and predicting CO_2 behavior in the reservoir.

Another project involving the extraction and storage of CO_2 from a natural gas stream is Statoil's Snøhvit project. Again, high concentrations of CO_2 must be removed before the gas is sold to market. Over the 30-year life of the project, the CO_2 removed will represent nearly 2% of total Norwegian emissions (Maldal & Tappel, 2002). During the design phase, developers considered 1) releasing CO_2 into the atmosphere, 2) ocean storage, 3) underground storage and 4) injection for EOR. Once the underground storage option was chosen, operators evaluated four possible storage formations and selected the Snøhvit Tubåen Formation because the formation had already been characterized from a previous operation. Reservoir modeling predicted a low probability of vertical CO_2 migration due to a thick gas water contact zone between the producing and storage formations. Low vertical migration could also be due to a good reservoir seal or a thick package of shale separating the storage formation and the producing formation. During the project life, CO_2 monitoring has been proposed by deepening a producing well and using it for observation. In addition, a feasibility study of 3D Seismic monitoring is scheduled, as this type of monitoring has proven effective for CO_2 monitoring in saline aquifers. The Tubåen Formation located 60 meters below the producing formation is expected to store 23 million tons of CO_2 (Maldal & Tappel, 2002).

Additional field tests currently in operation include the Frio Brine project on the Texas Gulf Coast and a Battelle Memorial Institute field assessment in the Ohio River Valley. Sponsored by the University of Texas, the Frio Brine experiment is designed to produce a great deal of technical information based on monitoring and modeling small-volume CO_2 injection and storage over a shortened time period (on the order of 5000 tonnes over 3 weeks) (Hovorka & Knox, 2002). The project, initiated in August 2002, is designed to demonstrate the feasibility and safety of injecting CO_2 into a brine formation, evaluate the distribution of injected CO_2 and gain experience for large-scale injection projects (Hovorka *et al*., 2003). After careful site selection, the experiment was permitted as an Underground Injection Control (UIC) Class 5 experimental well. However, project planners were permitted to submit the shorter application for a Class 5 well in addition to a report detailing project and engineering practices usually included in a UIC Class 1 well permit. Although no impact is anticipated, project leaders will also work with the Texas Railroad Commission to assess the impact on oil production. Due to the experimental nature of the project, the Bureau of Economic Geology, the state survey, has hosted public informational meetings, rather than conducting them through the traditional channels of the Texas Commission on Environmental Quality (TCEQ), which requires a lengthier process. Project leaders anticipate that future schemes will either require a Class 2 well permit, where injection occurs into a productive reservoir for EOR or Enhanced Gas Recovery, or a Class 1 well for injection into a brine formation away from producing areas (Hovorka, 2002). Due to the scientific nature of the project, there will be significant opportunity to gain additional information from the measurements and instrumentation employed.

With support from the Department of Energy and other sponsors including AEP, the Ohio Coal Development Office, BP, Schlumberger, the Ohio Geological Survey and the University of West Virginia, Battelle Memorial Institute will conduct exploratory field tests at the Mountaineer Power Plant in West Virginia by late 2003. The scope of this project includes site assessments, seismic surveys, drilling, testing, deep well development, reservoir modeling, technology deployment and preparation of regulatory permits for a potential CO_2 storage and monitoring facility (Gupta *et al*., 2002). The project group has been engaged in an extensive public outreach and educational program since the announcement was made. Thus far, stakeholder feedback has generally been positive.

The Department of Energy's National Energy Technology Laboratory is supporting a geologic sequestration field test in Hobbs, NM in collaboration with Sandia National Laborartory, Los Alamos National Laboratory, and Strata Production Company. The project, using CO_2 supplied by Kinder Morgan CO_2 Company, LP, began with the injection of 2,100 tons of CO_2 over 52 days into a reservoir owned by Strata. Researchers are currently monitoring the movement of the CO_2 through the reservoir using three-dimensional surveying technologies. They hope to use the collected data to enhance the accuracy of storage capacity prediction models.

On the international level, the International Energy Agency set up an implementing agreement to establish the IEA Greenhouse Gas R&D (IEA GHG) Programme. Launched in November 1991, the IEA GHG Programme currently has 17 member countries plus 8 industrial sponsors. This international collaboration aims to identify and evaluate technologies for reducing emissions of greenhouse gases arising from the use of fossil fuels, as well as ocean and geologic storage methods. From the outset, the primary technical focus of the IEA GHG Programme has been carbon capture and storage.

Other projects around the world in the process of addressing the key questions and uncertainties associated with storage include the CO_2 Capture Project; GEO-SEQ, led by Lawrence Berkeley National Lab; the Alberta Research Council projects; Geological Disposal of CO_2 (GEODISC); Saline Aquifer CO_2 Storage (SACS); and the RECEPOL Project. A one-page summary of each of these projects can be found in Appendix C.

Alternatives to geologic CO_2 storage are also being researched. These methods include injecting and storing CO_2 directly into ocean waters, fertilizing ocean water with iron to enhance the ocean's natural CO_2 uptake, inducing more rapid mineralization of CO_2 and utilizing CO_2 as raw material in industrial processes. These alternative approaches are discussed in greater detail in Appendix D.

Current research activities and proposed experiments are continuously adding to our level of knowledge and understanding about the environmental and human safety issues attributed to geologic storage. A well-funded and active community is working hard to address many of the critical questions and uncertainties laid out by many other experts and observers of the field. Although progress is being made, more research is needed, particularly with regards to the *in situ* subsystem, in order to ensure the safe and effective use of geologic storage technology.

5.2 Way Forward

Geologic storage of CO_2 is a promising strategy for climate change mitigation because it can build upon the knowledge and experience gained in the oil and gas industry. The analogs presented along with the identified risks provide some useful insights to developing a CO_2 storage regime as part of a broader portfolio of strategies designed to mitigate climate change. Management strategies used by oil and gas operators can be adopted to allow relatively rapid scaling up of CO_2 storage projects from smaller-scale pilot programs to larger volume operations.

Risks should be addressed by industry, government and the research community by focusing on three particular areas. First, before large-scale storage activities come to fruition, a better understanding of the long-term implications and behaviors of CO_2 in the subsurface is needed. Opportunities to study these issues are now available in Western Canada at the many acid gas injection sites and in the United States at the more than 70 CO_2 flooding operations. Newly designed experiments will also play a role in furthering our knowledge and understanding about the risks involved.

Next, government should commit more resources to promote opportunities that entice CO_2 storage while developing appropriate regulatory regimes, training programs and risk management strategies. Again, insights can be gained through a more detailed study of the four analogs presented in this paper. In each of these cases, operations began at a relatively small scale and evolved into larger and more complex operations.

Finally, consortia of industry, government and the research community should devote significant resources aimed at informing and educating the public about the benefits and uncertainties associated with geologic storage of CO_2. Educating the public is essential to allow it to make informed judgments about the benefits and uncertainties involved in geologic storage of CO_2.

The viability of CO_2 storage will no doubt be determined by the complex linkages between environmental, economic, technical, political and social forces. Specifically, these policy issues include establishing the appropriate economic incentives for business; developing effective and consistent regulatory regimes; addressing public safety concerns and shaping public opinion; leveraging existing technologies and knowledge bases; better understanding environmental and human safety risks; and developing effective risk management strategies. Design choices need to be based on qualitative as well as quantitative risk attributes while the policies for moving forward with geologic storage of CO_2 need to be augmented with targeted communication strategies.

Researchers should continue to work to produce better science in order to help reduce some of the uncertainties we face moving forward. Science and technological progress has given us the confidence to think realistically about CO_2 storage and has given us the tools to develop it in a safe and effective way. We can learn a great deal from the analogs in the oil and gas industry and will continue to improve our ability to manage the uncertainties by pursuing and encouraging sound and open research in this area.

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Appendix A – Peer Review Process

This paper was reviewed by 6 technical experts in the field of carbon sequestration: Sally Benson, Lawrence Berkeley Labs; Peter Cook, Australian Petroleum Cooperative Research Centre; Bill Gunter, Alberta Research Council; Haroon Kheshgi, ExxonMobil Research and Engineering Company; Vello Kuuskraa, Advanced Resources International and Arthur Lee, Chevron Texaco.

Appendix B – Environmental Questions

Critical Questions for CO_2 Storage

David Hawkins, National Resource Defense Council

- Do scientists have a complete inventory of unanswered technical issues?
- Do they have a research program to address them?
- What are the timelines for research deliverables and how do those match up with plans to conduct demonstrations?
- What are the remedies if leak rates are greater than design assumptions?
- How will we know if leaks are greater than design criteria?
- How long will the cement in well casings last? How do we know the answer is accurate?
- What are other pathways for carbon to reach the surface?
- Do I have to worry about CO_2 collecting in my basement like radon?
- What will happen if there is an earthquake near a repository?
- What is the probability of detecting and locating significant leaks?
- How large must a local leak be to be detected using currently contemplated monitoring methods?
- Who will keep track of how well the entire system is performing on a global basis?
- What are the robust monitoring schemes? How much will they cost? To whom will costs and operational responsibility be assigned?
- Who is responsible for maintaining a repository if the original companies go out of business?
- How will we design systems to inform population hundreds of years from now of the locations of carbon storage reservoirs so they do not accidentally penetrate them?

Hawkins, David, "Passing Gas: Policy Implications of Leakage from Geologic Carbon Storage Sites," Natural Resources Defense Council, Washington DC, 2002

Key Issues and Risks

Union of Concerned Scientists

Environmental Risks:

- Given the energy penalty associated with storage, if stored CO_2 is re-released over long times scales, atmospheric concentrations will increase

- Continued reliance on fossil fuel and environmental impacts at fossil fuel extraction sites

- Environmental impacts associated with pipeline development

- Unknown impacts on the biological communities in the storage sites

- Insufficiently understood contamination of "sweet-water" aquifers overlying brine formations into which CO_2 is being dumped

- Unknown impacts on biological communities that live in deep saline formations and other storage sites

Direct Risks to Humans:

- Catastrophic venting from storage sites

- Potable water contamination

- Induced Seismicity

Union of Concerned Scientists, "Policy Context of Geologic Carbon Sequestration," [online article] 2002, [cited September 13, 2002] http://www.ucsusa.org/index.html

Appendix C – Major Geologic Storage Projects

CO_2 Capture Project

The CO_2 Capture Project (CCP) is an international effort funded by a consortium of 8 energy companies, led by BP. The project objectives of the CCP are:

- Achieve major reductions in the cost of CO_2 Capture and Storage:
    - 50% reduction when applied to a retrofit application
    - 75% reduction when applied to a new build application
- Demonstrate to external stakeholders that CO_2 storage is safe, measurable, and verifiable
- Progress technologies to:
    - Be able to facilitate at least one large scale application in operation by 2010
    - 'Proof of concept' stage by 2003

To do this, they established working groups on the key topics, including Post-Combustion Capture Technologies; Pre-Combustion Capture Technologies; Oxyfuels Capture Technologies; Storage, Monitoring, and Verification (SMV) for Geologic Sequestration; and Economic Modeling; and Policy & Incentives.

Partners and Sponsors: *Industrial partners* – BP, ChevronTexaco, ENI, Norsk Hydro, EnCana (formerly PanCanadian), the Royal Dutch Shell Group of Companies, Statoil and Suncor Energy; *Government Co-Funding* – U.S. DOE, the European Union's Energy and Transport Directorate (DG TREN), and the government of Norway (Klimatek programme).

Contractors: 25 individual contracts covering 31 principal investigators in the SMV group alone.

Budget: The overall budget for all working groups is $24 million/3yrs.

Focus: The primary focus of the SMV working group is on geologic storage and EOR projects.

Goals: Proof of concept by 2003 and one large-scale application in operation by 2010.

Approach: Multiple contracts, initially with a broad scope, and later focusing on the most promising approaches and technologies. Currently, the project is focusing and selecting the most favorable approaches for further development. The project is now entering its final phase and is scheduled to end in December 2003.

Web Reference: http://www.co2captureproject.org

The Weyburn CO_2 Project

The Weyburn CO_2 Project is an integrated CO_2 monitoring and EOR project. Injection of CO_2 into a carbonate oil reservoir in southeastern Saskatchewan, Canada, began on September 22, 2000. Prior to injection, substantial baseline data (3D-seismic, VSP, cross-well, single-well seismic and geochemical sampling) were obtained from the field. At the present time, the monitoring project continues to evaluate the distribution of CO_2 in the carbonate reservoir and is determining the chemical reactions occuring within the reservoir between the CO_2 and the reservoir rock and fluids. The Weyburn Project is divided into 4 categories with the following purposes:

- Fluid Studies
    - Establish the changes in fluid properties within the reservoir over time
- Short-Term Simulation
    - To provide an integrated reservoir simulation
- Long-Term Simulation
    - To provide a model to assess long-term performance of sequestration process
- Technology Development
    - To develop technologies to improve mobility control and detection of CO_2

Sponsors: EnCana (formerly PanCanadian), Saskatchewan Petroleum Research Incentive Program, and the Canadian Government's Climate Change Action Fund, Natural Resources Canada, USDOE, and the European Community, SaskPower, Nexen Canada, TotalFinaElf, Chevron Texaco, BP, Dakota Gasification Co., TransAlta Utilities, Engineering Advancement Association of Japan.

Contractors: *Canada* - Saskatchewan Energy & Mines, Saskatchewan Research Council, University of Alberta, University of Calgary, University of Saskatchewan, University of Regina, Alberta Research Council, J.D. Mollard and Associates Ltd., Geological Survey of Canada, Hampson Russel-Veritas, Rakhit Petroleum Consulting, Ecomatters Inc., Canadian Research Institute, Saskatchewan Industry & Resources; *Europe* - British Geological Survey (Britain), Bureau de Recherches Geologiques et Minieres (France), Institut Francais du Petrole (IFP) (France), Danish Geological Survey (Denmark), Quintessa Ltd., (Britain); *USA* - Lawrence Berkeley National Laboratory, Lawrence Livermore National Laboratory, North Dakota Geological Survey, Colorado School of Mines, Monitor Scientific (Colorado)

Budget: U.S. $14.8 million/4yrs (Canadian $23.3 million/4yrs).

Focus: Monitoring injected CO_2 of an EOR project in the Weyburn Field.

Goals: Verify long-term storage capacity of an oil reservoir, refine CO_2 movement prediction and verification practices, understand migration and leakage risks, improve CO_2 storage capacity and narrow down the economics of storage.

Approach: The use of seismic characterization and geochemical studies

Web Reference: http://www.ptrc.ca/projects/weyburn.htm

GEO-SEQ

The GEO-SEQ Project is a broad-focused sequestration project with the goal of developing the "technology and information needed to enable the application of safe and cost-effective methods for geologic sequestration of CO_2 by the year 2015." The three broad goals of the program are:

- Reducing the cost of sequestration.
- Decreasing the risk of sequestration.
- Decreasing the time to implementation.

To achieve these goals, nine individual subtasks are currently underway:

- Development of methods to co-optimize EOR and sequestration.
- Development of carbon-sequestration-enhanced gas production from natural gas reservoirs.
- Evaluation of the effects of SO_X and NO_X on geochemical reactions between CO_2, water, and reservoir rocks.
- Identification of geophysical techniques for monitoring CO_2 migration in the subsurface.
- Field testing of geophysical-monitoring techniques.
- Development of tracer techniques for monitoring the interaction between CO_2, water and reservoir rocks.
- A reservoir simulation-code comparison study for predicting the fate of CO_2 in the subsurface.
- Enhancement of simulation models for carbon- sequestration-enhanced coal-bed methane recovery.
- Improved capacity assessment for brine formations.

Sponsors: *Industrial partners* – ChevronTexaco, EnCana (formerly known as Pan Canadian Resources), BP-Amoco, Statoil, Alberta Research Council Consortium; *Government Co-Funding* – U.S. DOE (National Energy Technology Laboratory).

Contractors: Three National Labs (LBNL, LLNL, ORNL), Stanford University, US Geological Survey, Texas Bureau of Economic Geology, Alberta Research Council (ARC), UC Berkeley, UC Davis, the University of Texas, the University of Tennessee, and the University of Calgary.

Budget: The overall budget is $14.25 million/3yrs.

Focus: This project began with a broad focus which included lowering sequestration costs and risks, decreasing time to implementation, and addressing the issue of public acceptance. The future focus for GEO-SEQ will be on measurement, monitoring and verification.

Goals: Developing the technology and information needed to enable safe and cost-effective geologic sequestration by the year 2015.

Approach: Multiple studies such as sequestration optimization methods, monitoring technologies, simulations, and capacity assessment.

Web Reference: http://esd.lbl.gov/GEOSEQ/

Alberta Research Council (ARC) Projects

The ARC consortium sequestration program is three fold and includes the following research topics:

- CO_2 Enhanced Coalbed Methane Recovery (ECBM)
  - Pilot site at Fenn-Big Valley, Alberta
  - 5-spot, full-scale pilot in planning
- Geologic Sequestration of CO_2 – EOR and Aquifers
  - Monitoring of aquifer disposal
  - Geochemical modeling
  - Mineral and hydrodynamic trapping
- Acid gas reinjection
  - Waste stream from sour gas plants (~90% CO_2)
  - Examining net CO_2 emissions on 31 possible sites

Numerical models for sequestration in coal beds are in development and examination of the best regional areas for storage is in progress. Phase property distributions of CO_2 are being developed in the P-T space of the reservoirs in Alberta. In addition, the ARC is involved as a research contractor on the GEO-SEQ and Weyburn projects.

Sponsors: Various Industrial and government sponsors.

Contractors: Alberta Research Council.

Budget: U.S. $5 million/2yrs (Canadian $8 million/2yrs).

Focus: The work of the Alberta Research Council is focused mainly on end-use projects.

Goals: Three EOR demos in the next 3 yrs, full-scale ECBM pilot.

Approach: Field work in addition to some simulation models.

Web Reference: http://www.arc.ab.ca/envir/Greenhouse.asp

Geologic Disposal of Carbon Dioxide (GEODISC)

GEODISC is a program underway since 1999 by the Australian Petroleum Cooperative Research Center (APCRC), a collaborative petroleum research organization consisting of members from industry, government, and research institutions. The purpose of the GEODISC project is to:

- Lower the cost of geologic sequestration by:
  - Developing innovative optimization methods for sequestration technologies with collateral economic benefits (such as enhanced oil recovery (EOR), enhanced gas recovery (EGR), and enhanced coalbed methane production).
  - Understanding and optimizing trade-offs between CO_2 separation and capture costs, compression and transportation costs, and geologic sequestration alternatives.
- Lower the risk of geologic sequestration by:
  - Providing the information needed to select sites for safe and effective sequestration.
  - Increasing confidence in the effectiveness and safety of sequestration through identifying and demonstrating cost-effective monitoring technologies.
  - Improving performance-assessment methods to predict and verify that long-term sequestration practices are safe, effective, and environmentally acceptable.
- Decrease the time to implementation of geologic sequestration by:
  - Pursuing early opportunities for pilot tests with our private sector partners.
  - Gaining public acceptance.

The eleven research modules include: (1) regional analysis, (2) specific studies at 2-4 locations, (3) experimental studies on the CO_2-water/brine-rock systems, (4) petrophysical studies, (5) development of a coupled chemical-dynamic-kinetic model, (6) monitoring CO_2 injection, (7) risk assessment, (8) economic model, (9) international cooperation, (10) natural analogs and (11) education & training.

Sponsors: BHP Billiton, BP, ChevronTexaco, Shell, Gorgon Australian LNG, Woodside, the Australian Greenhouse Office and Total Fina Elf.

Contractors: *APCRC Core Participants* – Australian Geological Survey Organization, Australian Petroleum Production and Exploration Association, CSIRO - Petroleum, Curtin University, National Centre for Petroleum Geology and Geophysics, and the School of Petroleum Engineering at the University of New South Wales; *Research Providers* - Alberta Research Council, British Geological Survey, TNO - Netherlands, Australian National University Department of Applied Math, Batelle Memorial Institute.

Budget: U.S. $5 million/4yrs (Australian $10 million/4yrs).

Focus: Broad focus over many areas of research.

Goals: Document feasible areas and model and monitor stored CO_2 behavior.

Approach: Multiple studies including experimental, monitoring, and modeling.

Web Reference: http://www.apcrc.com.au/Programs/geodisc_res.html

Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC)

Beginning July 1, 2003, the CO2CRC will begin an initiative to build upon the GEODISC program by researching the logistical, technical, financial and environmental issues of CO_2 storage. Because GEODISC did not address the issue of how to cost effectively capture and separate the CO_2 prior to geological storage, it was decided in 2001 to use the opportunity of a new round for Cooperative Research Centre (CRC) funding to develop a broadly based research agenda to consider how to capture CO_2 from a range of emissions and store that CO_2 in a secure geological or mineral environment for many years. As a result, a group of researchers, institutions and organizations proposed a Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC).

Research Objectives:

1. To demonstrate the feasibility of safe, long term and effective large scale geological storage of carbon dioxide in Australia.
2. To demonstrate the effectiveness of large-scale geological storage through the development and implementation of one or more major Demonstration CO_2 Storage Projects and a range of related activities.
3. To seek opportunities to store CO_2 and also obtain additional beneficial outcomes or valuable by-products.
4. To develop enhanced systems for the capture of CO_2 using a range of technologies suitable for Australian emissions.
5. To develop regional strategies for decreasing CO_2 emissions and also assessing the opportunities for an emission-free hydrogen economy.

Sponsors and Collaborators: *Industry partners*: Australian Coal Association Research Program, BHPBilliton, BP, Cansyd Australia, ChevronTexaco, the Process Group, RioTinto, Stanwell Corporation Ltd, Shell, URS, and Woodside Australian Energy; *Research parties*: CSIRO, Curtin University, Geoscience Australia, Monash University, the University of Adelaide, the University of Melbourne and the University of NSW; *Government parties*: The Australian Greenhouse Office, the Western Australia Department of Mineral and Petroleum Resources, and the South Australia Department of Primary Industries and Resources (PIRSA); *International collaborators*: Alberta RC and the University of Regina (Canada); the British Geological Survey, CO2Net, IEA (UK); NASCENT (Denmark); SACS (Norway); TNO (Netherlands); RITE and Meji University (Japan); Institute of Geological and Nuclear Sciences (New Zealand); Advanced Resources International (ARI), Carbon Capture Program (CCP), Lawrence Livermore, Massachusetts Institute of Technology (MIT) and NETL/US DOE (USA).

Budget: $120 million over seven years.

Focus: The two major themes: 1) CO_2 capture and 2) CO_2 storage.

Goal: Achieve a demonstration project within the term of the CRC.

Web Reference: http://www.co2crc.com.au/geodisc_f.htm

Saline Aquifer CO_2 Storage (SACS)

The Sleipner project is the world's first commercial-scale storage of CO_2. Statoil injects the CO_2 into a large, deep saline reservoir, the Utsira formation, 800m below the bed of the North Sea. Geologic data around the injection point is being gathered and simulations are being developed on the reservoir. Various experiments and simulations are examining the geochemistry of the reservoir as well. Data will be collected for three years to model and verify the distribution of the injected CO_2. The goals of the Sleipner CO_2 injection and the SACS project include:

- Verification under what circumstances CO_2 storage in an aquifer is safe and reliable
- Validation models for geology, geochemistry, geophysics and reservoir tools
- Initiation new R&D related to above topics
- Development of "Manual of Good Practice"

The project is split into 5 areas:

- Description of the reservoir geology
- Reservoir simulation
- Geochemistry
- Assessment of need and cost for monitoring wells
- Geophysical modelling

Sponsors: *Industrial* – Statoil (operator), BP, ExxonMobil, Norsk Hydro, TotalFinaElf, and Vattenfall; *Government Co-Funding* – The European Union and national authorities in Denmark, The Netherlands, Norway, and the United Kingdom.

Contractors: British Geological Survey, BRGM, Geological Survey of Denmark and Greenland (GEUS), Institut Français du Petrole, NTIG-TNO, SINTEF Petroleum Research, and the Nansen ERS Centre.

Budget: U.S. $4.6 million/3yrs.

Focus: Monitoring of the Utsira Formation in the Sleipner field during and after CO_2 injection.

Goals:

1. Verify under what circumstances CO_2 storage in an aquifer is safe and reliable.
2. Validate models for geology, geochemistry, geophysics and reservoir tools.
3. Initiate new R&D related to above topic.
4. Start development of "Manual of Good Practice".

Approach: Seismic monitoring.

Web Reference: http://www.ieagreen.org.uk/sacshome.htm

The RECOPOL Project

The RECOPOL project is an ECBM-CO_2 research and demonstration project funded by the EU to investigate the possibility of permanent subsurface storage of CO_2 in coal. RECOPOL stands for "Reduction of CO_2 emission by means of CO_2 storage in coal seams in the Silesian Coal Basin of Poland" and it is the first field demonstration experiment of its kind outside Northern America. The RECOPOL project began at the end of 2001 and is scheduled for completion in 36 months (duration of the field experiment is 18 months).

The main questions to be answered by the RECOPOL project are:

- Is subsurface storage of CO_2 in coal, while simultaneously producing CBM, a technically viable option under European conditions?
- Is subsurface storage of CO_2 in coal a safe and permanent solution?
- How much CBM is produced for each tonne of injected CO_2?
- Can subsurface storage of CO_2 in coal be applied on a larger scale in an economical and social acceptable way?
- What are the main criteria (geological/technical/economical/social) for any coal basin, in or outside Europe, to be suitable for this technique?

The seven work packages laid out by the RECOPOL Project are:

- Geological Model (Site evaluation)
- Laboratory work (standard and advanced)
- Simulation I (Data integration and model assessment)
- Feasibility test (Design – Operation – Data Gathering)
- Simulation II (History Matching)
- Socio- Economical and Future-Technological evaluation
- Dissemination of results, summary of results, and reporting

Sponsors: The European Union 5th Framework Programme (50%), 10 partners (50%).

Partners: TNO-NITG (Netherlands), Aachen Univ. of Tech. (Germany), Delft Univ. of Tech. (Netherlands), Central Mining Institute (Poland), Institut Français du Petrol (France), CSIRO (Australia), DBI-GUT (Germany), Gaz de France (France), Gazonor (France), IEA GHG

Budget: U.S. $3.1 million/3yrs (3.5 million EURO/3yrs).

Focus: Investigating the possibility of permanent subsurface storage of CO_2 in coal. The project is located in the Upper Silesian Basin, Poland (best location for ECBM-CO_2 in Europe).

Goals: The main objective of this project is to evaluate the feasibility of greenhouse gas emission reduction by CO_2 sequestration in subsurface coal seams under European conditions. This main objective will be reached by answering the five main questions listed above.

Approach: System modeling and demonstration of a full-scale field experiment.

Web Reference: http://www.nitg.tno.nl/eng/appl/g_resources/natural/recopol.shtml

Battelle Memorial Institute Projects

The sequestration research underway at Battelle focuses on the injection of CO_2 in deep saline sandstone formations, in conditions typical of the Midwestern United States. Initial work focused on reviewing the status of existing technologies for handling CO_2 and the development of a preliminary engineering concept and the estimation of the costs for sequestration in the Mt. Simon Aquifer. Another aspect of Battelle's work is the evaluation and examination of factors that affect chemical reactions in underground saline formations. Another area of interest is the study of issues of seismic activity induced by CO_2 injection in deep saline aquifers. Battelle's most recent project, announced in November 2002, involves a study of CO_2 injection and storage at the Mountaineer Power Plant in West Virgina. Together with American Electric Power, Battelle will explore the suitability of deep CO_2 injection into sandstone. The details of this project are as follows:

Objectives:
1. Maximize acquisition of defensible scientific data
2. Apply state of the art technology
3. Construct a well for a currently unknown set of operating conditions
4. Minimize risks
5. Maintain budget

Sponsors*:* U.S. DOE

Contractors and Collaborators: Battelle Memorial Institute, American Electric Power (AEP), Pacific Northwest Laboratory, Ohio Coal Development Office of The Ohio Department of Development, BP, Schlumberger, Ohio Geological Survey and West Virginia University

Budget: U.S. $ 4.2 Million

Focus: Examine the feasibility of injecting carbon dioxide emissions into sandstone formations nearly two miles underground and determine whether the geological conditions are suitable for injecting and storing carbon dioxide underground permanently.

Goals: To characterize the site and its vicinity for CO_2 storage potential in various geologic reservoirs.

Approach: Engineering studies and stakeholder outreach.

References: Smith, Larry, Neeraj Gupta, Bruce Sass, and Thomas Bubenik, *Carbon Dioxide Sequestration in Saline Formations – Engineering and Economic Assessment*, Final report for DE-RAC26-98FT35008, US DOE, National Energy Technology Center, July 9 (2001).

Gupta, Neeraj, James Dooley, Mike Mudd, Charles Byrer, T.S. Ramakrishnan and Charles Christopher, Planning for Geologic Storage Demonstration in the Ohio River Valley Region, presented at the Second Annual Conference on Carbon Sequestration, Washington DC, May 5-8, (2003).

Appendix D – Alternatives to Geologic Storage

Ocean Storage

The ocean represents the largest potential sink for anthropogenic CO_2. It contains approximately 40,000 GtC (billion metric tons of carbon) compared with only 750 GtC in the atmosphere and 2200 GtC in the terrestrial biosphere. Eventually, over 80% of today's anthropogenic emissions of CO_2 will be transferred to the ocean over a 1000 year period through naturally occurring processes. Ocean storage via direct injection would accelerate this ongoing but slow natural process and would reduce both peak atmospheric CO_2 concentrations and their rate of increase.

The two primary methods for ocean storage include 1) dissolving CO_2 at depths of 1500-3000 meters by injecting it from a bottom mounted pipe from shore or from a pipe towed by a moving ship, or 2) injecting CO_2 below 3000 m, where it will form a "deep lake". The dissolution method is advantageous as it relies on existing technology while the resulting plumes can be made to have high dilution to minimize any local environmental impacts due to increased CO_2 concentration or reduced pH. A CO_2 lake is presumed to better minimize leakage to the atmosphere.

Ocean Fertilization

Some scientists hypothesize that by fertilizing the ocean with limiting nutrients such as iron, the growth of marine phytoplankton will be stimulated, thus increasing the uptake of atmospheric CO_2 by the ocean. The presumption is that a portion of the phytoplankton will eventually sink to the deep ocean, but this presumption is highly controversial. Researchers have targeted "high-nutrient-low-chlorophyll" (HNLC) ocean regions, specifically the eastern Equatorial Pacific, the northeastern Subarctic Pacific, and the Southern Oceans.

Mineralization

Several minerals (e.g. calcium and magnesium silicates) found on the surface of the earth uptake CO_2 from the atmosphere with the formation of carbonates, and thus permanently storing CO_2. The challenge for researchers is to speed up the reaction in order to be able to design an economically viable process. While some reaction pathways have shown progress, none has yet resolved all the issues necessary to make mineralization a commercial process.

Utilization

Utilization as a CO_2 reduction strategy hinges on the idea that CO_2 from fossil fuel could be utilized as a raw material in the chemical industry for producing commercial products that are inert and long-lived, such as vulcanized rubber, polyurethane foam and polycarbonates. Estimates of the world's commercial sales for CO_2 is less than 0.1 GtC equivalent, compared to annual emissions of close to 7 GtC equivalent. It has been suggested that CO_2 could be recycled into a fuel. This would create a market on the same scale as the CO_2 emissions. However, to recycle CO_2 to a fuel would require a carbon-free energy source. If such a source existed, experience suggests that it would be more efficient and cost-effective to use that source directly to displace fossil fuels rather than to recycle CO_2.

Information for Appendix D was taken from Herzog, H.J. and D. Golomb, "Carbon Capture and Storage from Fossil Fuel Use," *contribution to Encyclopedia of Energy*, to be published (2004).

Appendix E – Definitions and Conversion Factors

Definitions

CO_2	Carbon dioxide
Bbl	Barrels of Oil
EOR	Enhanced Oil Recovery
EUB	Alberta Energy and Utilities Board
H_2S	Hydrogen sulfide
IL	Informational Letter
MMBO	Million barrels of oil
MMcf	Million Cubic Feet
TCEQ	Texas Commission on Environmental Quality
Tcf	Trillion Cubic Feet

Conversions

18,000 standard cubic feet (scf) = 1 tonne CO_2
1 million scf = 55.5 tonnes CO_2