DEVELOPING RECOMMENDATIONS FOR THE MANAGEMENT OF GEOLOGIC STORAGE OF CO_2 IN CANADA

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This report has been prepared for Environment Canada, Saskatchewan Industry and Resources, Alberta Environment, and British Columbia Energy and Mines. In addition to discussion with the sponsors, consultation was also held with a number of interested parties and informed individuals. The statements made in this report are, however, the views of the authors alone.

EXECUTIVE SUMMARY

This document provides recommendations that we hope will assist the management of CO_2 storage in geological settings in Canada. The report was sponsored by the governments of Canada, Alberta and British Columbia. It does not try to develop a set of regulations; instead, it examines the issues and suggests alternatives that the sponsors may discuss with interested stakeholders. While this document of necessity deals with the monitoring and mitigation of risk, we believe that geologic storage can—if appropriately managed—provide a safe, effective and publicly acceptable means to achieve deep reductions in CO_2 releases into the atmosphere over the coming decades.

We have made no attempt to look upstream of the wellbore; issues related to the capture and transport are well covered in other regulations that deal with the construction, operation and emergency management. Similarly, we do not address issues surrounding ownership of the pore spaces in which the CO_2 is stored, matters of jurisdiction, or the long-term monitoring of such storage locations. To date, only one major storage project has been started (i.e. a project explicitly designed to store CO_2 for extended periods for the purpose of avoiding atmospheric emissions), and there has been no experience in the application of long-term monitoring for low levels of leakage. This is a topic that will need further discussion and assessment.

Most of our recommendations are applicable to geologic storage in any setting. The exceptions are caverns and disused mines, which, while they could be used for storage, are likely to be prohibitively expensive. Caverns and old mines are also the only geological setting in which very rapid, catastrophic release of stored gases is possible. In other circumstances, the CO_2 would be stored in a porous media that restricts the rate of outflow of the bulk of the stored gas even if a path to the surface is opened. Caverns and mines may, however, have value as reaction vessels for the precipitation of carbonates, but this is not likely to occur in the near future.

Over time, with dissolution of the gas in the formation brines or with adsorption onto the surface of coal, the stability of the CO_2 in the subsurface increases. Ultimately, mineralization will result in permanent sequestration of the CO_2. Estimates suggest (Bradshaw et al., 2002, presentation) that dissolution (a reaction in which CO_2 mixes with subsurface brines) would take a long time, likely thousands of years.

There are numerous uncertainties surrounding the measurement of possible leakage of CO_2 from subterranean reservoirs, particularly because the rates are likely to be very small and the dispersion as the gas migrates upward through the geological column may result in a wide surface distribution of emissions at the surface if they occur. Estimating the potential CO_2 flux and monitoring for dispersed leakage will be problematic. The opportunities for developing such expertise will need to be carefully investigated. Nevertheless, we judge that sufficient knowledge exists today to enable sound management of CO_2 storage. Moreover, important work in this area is already under way in Canada and elsewhere. The Weyburn Monitoring Project, for example, will help to assess the monitoring techniques and the tools used to determine the fate of CO_2 as it moves through the geological column.

At least on shorter timescales, the primary leakage route is likely to be along the injection wellbore or existing wellbores that penetrate the storage horizon. In this document, we focus on this aspect and on the need to evaluate ways to determine and remediate such leakage. When new injection wells are drilled, we suggest ways to minimize the risk of leakage along the man-made routes to the surface.

Geologic sequestration promises to reduce the cost of achieving deep reductions in CO_2 emissions over the next few decades. To fulfill this promise, CO_2 capture must evolve from a collection of individual technologies into a large-scale technological system for managing carbon from fossil fuels. A successful system must include a suite of technologies linked by a network of institutions, financial systems and regulations that is able to achieve broad public understanding and acceptance. Development of the required technologies is a necessary, but insufficient, requirement for the success of geologic sequestration.

Our aim is to identify the issues that need to be discussed as regulations for storage of CO_2 in the subsurface are developed. We provide a set of recommendations as the basis for this discussion so that the end product is a regulatory structure that serves the public interest while meeting the needs of the industry. This discussion will be of interest to the public, who will have concerns about health and safety issues; to the regulators, who will need to enforce regulations; and to the politicians, who will have to respond to their various client groups. The eventual regulations will also form the basis for verifying emissions storage for the purposes of national inventory. We recognize that the size of the project and the nature of the storage medium will be important issues, and we provide recommendations for dealing with these issues.

This study is an early step on a long journey. As basis for further action, we recommend the following:

- Transparency of regulations and public access to information collected is vital for large CO_2 storage projects, which will likely attract significant public interest.
- Effective management requires that the regulatory agencies learn-by-doing; such learning will require coordination and cooperation between jurisdictions.
- Discussion should be initiated with the major interest groups regarding the development of regulations. These interest groups include the Canadian Association of Petroleum Producers (CAPP) and individual oil and gas producers, regulators, inventory groups, environmental groups and government agencies. This document should be distributed as the basis for discussion. The public should also be informed, but through a separate mechanism. A shorter version of this document should be prepared for broader public discussion.
- Based on the outcomes from a broader round of consultations, a set of draft regulations could be prepared to ensure acceptability.
- Jurisdictions should cooperate on the development of regulations to ensure equivalent treatment of CO_2 storage within provinces and across provincial boundaries. It should not be possible for industry to “shop” for the best regulatory scheme to allow CO_2 storage (i.e. using Enhanced Oil Recovery (EOR) or other regulations to get away from stringency of requirements or incremental costs that may be a part of storage regulations).
- Canada has taken a lead role in research into geologic storage of CO_2. This, combined with our expertise in regulation of the oil and gas industry, positions Canada to take an international lead in the development of acceptable standards for the storage of CO_2. In particular, Canada should take a leading role in developing standards to incorporate CO_2 storage in national and international inventories and in carbon trading systems.

- Where scientific uncertainties hinder the development of a regulatory regime, such as in the development of leakage estimates and the nature of the leakage pathways, research must be appropriately directed to resolve these uncertainties. The eventual needs of science-based regulation have not systematically been considered in designing current research programs. We recommend that existing and future research projects (such as the Weyburn Monitoring Project, the Enhanced Coal Bed Methane Recovery Project and other possible future EOR or Acid Gas disposal projects) be reviewed in light of the questions raised here and those that emerge from future efforts to develop a regulatory protocol. Such reviews should probably be undertaken in cooperation with agencies such as the IEA Greenhouse Gas R&D Program.
- Work should be initiated to assess what a longer-term monitoring initiatives might look like and to decide who should be responsible for this work.
- To ensure that this work is undertaken, a team should be created and given adequate resources. This team would be responsible for advancing the work on regulation development and informing all relevant interest groups of its progress. A consortium of government, industry and environmental groups would be the best mechanism, perhaps modeled on such mechanisms as the Clean Air Strategic Alliance.

CONTENTS

1 INTRODUCTION

Canada has taken a leadership role in understanding the technical aspects of CO_2 storage in geological settings. In particular, the national research effort focuses on the CO_2 storage in a mature oil and gas fields (Weyburn, Saskatchewan) and in deep coal seams (Alberta Research Council). In addition, CO_2 is being stored as part of the disposal of acid gas by deep injection in Alberta, British Columbia and, soon, Saskatchewan.

The development of acceptable policy and regulations for the storage of CO_2 will allow Canada to use CO_2 storage as a means of meeting its commitments to reduce greenhouse gas emissions under the United Nations Framework Convention on Climate Change (UN-FCCC). In particular, clear policy guidance is needed to allow Canada to count stored CO_2 as non-emitted when constructing and reporting emission inventories under the UN-FCCC.

If regulation is to be based on high-quality science, efforts to understand and improve the regulatory environment for geological sequestration should not wait until the technology is ready for large-scale application.

Appropriate regulations are needed to allow the development of an industry centered on CO_2 storage. While a CO_2 storage industry will ultimately be driven by government actions that place an effective price on CO_2 emissions, this industry will not likely flourish unless the regulatory framework provides sufficient transparency and stability concerning storage requirements. Finally, for the regulatory framework to be successful, it must give the public confidence that this method of emissions reductions is sufficiently safe from the human health, safety and environmental perspectives, and that it is able to provide an acceptable alternative to other methods of reducing emissions.

Because there has been little international work on the regulatory aspects of CO_2 storage, early efforts to develop a regulatory framework will put Canada at the forefront of policy and regulatory development internationally. In turn, this will position Canada favorably to take a leadership role in setting acceptable standards for the geologic storage of CO_2 and incorporating storage into national emissions inventories.

2 Scope and organization of this report

This report was sponsored by the governments of Canada, Alberta, British Columbia and Saskatchewan to guide the development of a protocol for geologic storage of CO_2. The purpose of such a protocol is to enable governments to manage and regulate geologic storage and to account for stored CO_2 in emissions inventories. This report is ***not*** a draft regulatory protocol—the responsibility of preparing regulations rests with the government. Rather, this report identifies crucial issues to be resolved and recommends procedures that will enable regulators to ensure the acceptable subsurface storage of CO_2.

As a central element of the effort that produced this report, we convened two workshops at which participants discussed the issues and commented on draft protocols. In addition, we consulted independently with a number of experts and are grateful to everyone who contributed. Where possible, we have made this report consistent with the expert judgment we received. This is not, however, a consensus document. It does not necessarily reflect the views of the sponsors or of the experts with whom we consulted.

In this report, we deal with the protocols for the storage of CO_2 in the subsurface, taking the CO_2 from the wellhead to injection and storage in the subsurface through to the abandonment of the project at conclusion of injection. We first summarize the risks that need to be managed (Section 3) and then explore the crucial issues that need to be addressed in developing policy and regulations to manage these risks. In Section 4, we survey the issues that describe the policy choices and trade-offs, without offering definitive judgments about which choices are best. Finally, in Section 5, we complement the general discussion presented in Section 4 with specific examples that illustrate how a protocol might be constructed.

We aim to address all use of CO_2 storage as a means to avoid CO_2 emissions. This includes the development of greenfield sites, the use of depleted and mature oil and gas fields, and caverns, and the use of unmineable coal seams. The issue of disused mines and caverns is not covered further than issues of safety because these are unlikely to be storage mechanisms in the immediate future.

We restrict the scope of this report to the development of policy and regulations regarding the storage of CO_2 in the subsurface. We do not look at the capture of CO_2, which is covered by existing regulations for the health, safety and environmental protection of industrial activities. Nor do we deal with the transportation of CO_2, which is also covered under existing regulations and performance standards set for the transport of acid gases. The approval of a CO_2 pipeline, the Souris Valley Pipeline bringing gas from the United States to Canada, was given by the National Energy Board in 1998 (Report MH-1-98) and likely sets precedent for any transboundary movement of CO_2 into and within Canada. Pipelines within individual provinces will be covered by provincial regulations.

While we deal with the management of the risks of geologic storage, we do not address the ownership of underground pore space. To the extent that pore space is a finite resource that may be used for CO_2 storage, governments will need to design appropriate fiscal structures to manage its use by private parties. With mineral rights assigned to provincial governments, we implicitly assume that the regulations governing pore space will mimic mineral rights, with both Crown and freehold ownership.

Finally, in this report we do not make any recommendations regarding the distribution of jurisdiction (federal versus provincial) over the storage of CO_2.

3 RISKS

The ultimate objective of a regulatory regime is to manage the risks associated with geologic storage of CO_2. We briefly review these risks here.

The risks fall in two categories: one, local environmental risks; two, global risks arising from leaks that return stored CO_2 to the atmosphere (Figure 1). Global risks may alternatively be viewed as uncertainty in the effectiveness of CO_2 containment. Local heath, safety and environmental risks arise from three processes: the elevated CO_2 concentrations associated with the flux of CO_2 through the shallow subsurface to the atmosphere; the chemical effects of dissolved CO_2 in the subsurface; and effects that arise from the displacement of fluids by the injected CO_2.

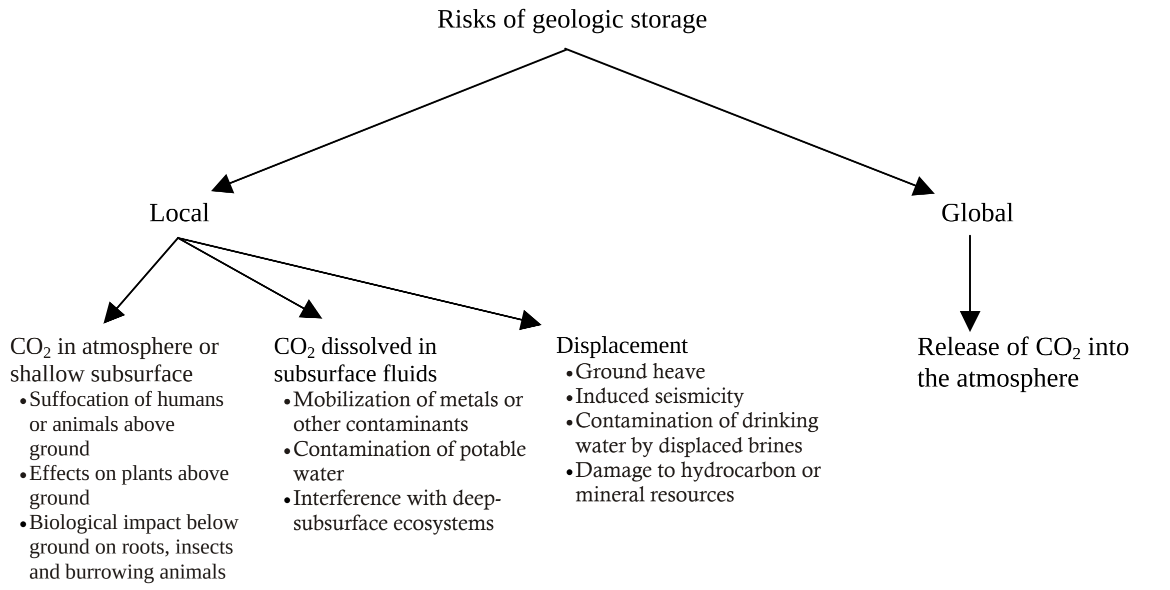

Figure 1: The risks of geologic storage: taxonomy

The most important local risks could arise from elevated concentrations of CO_2 in near-surface soils and in the atmosphere, where it can asphyxiate exposed people or animals, and can damage local biota. The most obvious local risk is catastrophic leaks such as well blowouts, pipeline ruptures or subsurface events that result in sudden releases of CO_2. Catastrophic events can also be caused by slow leaks from deep CO_2 reservoirs if the CO_2 is temporarily confined in the near-surface environment and then suddenly released. In 1986, for example, the water in Lake Nyos (Cameroon) turned over, releasing about 100 kt of CO_2 that had accumulated from volcanic vents that had gradually saturated the lake with CO_2. Because CO_2 is denser than air, it can flow downhill and create asphyxiating conditions near ground level far from the initial release.
At lake Nyos, the CO_2-rich cloud travelled more than 10 km and killed more than 1,700 people (Clarke, 2001). While the specific mechanism that produced the Lake Nyos event can only occur in tropical lakes (because they do not turn over annually), there may be other mechanisms that could confine slowly leaking CO_2 in the subsurface, thus potentially enabling sudden releases.

While catastrophic releases have attracted the most attention, slow leaks may pose risks that are more difficult to manage. Biological impacts in the shallow subsurface must be seriously considered, recognizing possible detrimental effects on flora and fauna, particularly burrowing fauna. Because surface air is far better ventilated than soils, it may well be that significant biological impacts, such as tree kills due to CO_2 in the shallow subsurface, may occur at CO_2 fluxes smaller than those required to produce appreciable harm to above-ground organisms.

Slow leaks of natural CO_2 are known to cause impacts. A leak of ~100 t CO_2/day at Horseshoe Lake in California has killed trees across many hectares. Slow leaks of CO_2 from shallow coal beds in Saskatchewan, where the CO_2 has built up in confined areas such as old pits and adits, have also caused fatalities.

The global risks stem from the release of stored CO_2 into the atmosphere. Due to the energy penalties involved in CO_2 capture and storage, more CO_2 will be produced per unit of delivered energy using capture and storage than would have been emitted if the fossil fuels had been used without capture. In the worst case, therefore, a failed storage system can increase CO_2 emissions. Using more reasonable assumptions, it is possible that in the future, assuming very large volumes of CO_2 stored in the subsurface, even small leakage rates could result in significant amounts of CO_2 leaking into the atmosphere. In the near term, however, with comparatively small amounts of CO_2 stored, small leak rates pose a challenge for accounting but will not have a significant global effect.

4 GENERAL ISSUES

4.1 Adaptability and learning

Current technical understanding of geologic storage is uneven. There is reason for optimism that geologic storage can provide a secure and affordable means of avoiding atmospheric emissions. There is also, however, sufficient uncertainty that we cannot today implement a robust system for managing injection activities at a scale required to store a significant fraction of Canada's emissions.

Current understanding of geologic storage is grounded in real-world experience. The technology required to inject large quantities of CO_2 into geological formations is well established. Industrial experience with CO_2-EOR and with the disposal of CO_2-rich acid gas streams, as well as related experience with natural gas storage and the underground disposal of other wastes,[1] allows confidence in predictions about the cost of CO_2 injection and suggest that the risks will be low. Once injected, evidence from natural CO_2 reservoirs as well as from numerical models suggest that CO_2 can—in principle—be confined in geological reservoirs for timescales well in excess of 1,000 years, and that the risks of geologic storage can be small.

Notwithstanding this reasonable optimism, there are important gaps in the technical understanding of the fate of CO_2 injected underground. While EOR projects demonstrate that tens of Mt/year of CO_2 can be safely injected underground, the existing projects yield little data about crucial questions, such as the rate of leakage through caprocks and artificial penetrations, the migration of CO_2 in reservoirs, and the rate at which CO_2 dissolves in brine-filled reservoirs or reacts with minerals in the reservoir rock.

Leaks are inevitable if large quantities (i.e. gigatonnes) of CO_2 are injected underground, yet we lack sufficient understanding of the processes that will determine the impacts of CO_2 that leaks to the surface. Such processes include the biological effects of CO_2 in soils and the transport of CO_2 through the vadose zone to the atmosphere. We cannot, therefore, make robust predictions of the rate of leakage from deep reservoirs to the subsurface, or of the risks posed by leaks that do occur.

If CO_2 capture and geologic storage is to play a significant role in mitigating global CO_2 emissions, then the quantity of CO_2 placed in geologic storage will need to approach 10 Gt/year worldwide—roughly 300 times the current rate of CO_2 injection for EOR. This huge difference in scale suggests that the experience with EOR cannot serve as the sole basis for managing the much larger volumes that may eventually be injected.

[1] There is, for example, extensive experience with underground disposal in the United States. In addition to the ~34 Mt of CO_2 injected each year for EOR, the injection rates for other waste streams are 500 Mt/yr of municipal waste water, 2.7 Gt/yr of brines from oil and gas operations and 34 Mt/yr of hazardous wastes.

While targeted research and development is necessary, perhaps the most important way to reduce uncertainty about CO_2 storage is to implement some large-scale projects and observe the fate of CO_2 injected underground. Among other factors, the value of such projects depends on length of observation. Measurements over less than a decade, for example, will have limited value as a basis for predicting the fate of CO_2 over a century; observations spanning a few decades after injection will have substantially greater value. There is, therefore, a strong public interest in getting some large-scale projects started early to enable better decision-making a few decades hence, when we may need to make very deep reductions in CO_2 emissions.

Our approach to managing geologic storage should be adaptive and should emphasize learning-by-doing. In the near term, a regulatory protocol for managing geologic storage must therefore make projects serve two purposes: they must provide acceptably safe CO_2 storage while maximizing our ability to learn though experience.

4.1.1 Adaptability

The active phase of storage projects will often span several decades, so we must anticipate that there will be significant improvements in our knowledge over the lifetime of a single project. A protocol should therefore be able to effectively incorporate knew knowledge as it emerges. There are, however, trade-offs. A protocol that too easily incorporates new knowledge might impose a shifting set of requirements on operators, thus raising their costs, increasing their uncertainty, and reducing their ability to take advantage of learning-by-doing. Similarly, an overly adaptable protocol might reduce the ability of regulators and non-governmental organizations to monitor a company's compliance.

Many of these problems might be avoided by "grandfathering" facilities under the rules that applied at the time of initial permit application. However, the unfettered use of grandfathering would frustrate adaptation by removing the opportunity to make changes. In practice, even if grandfathering is granted, it could still be revoked if serious problems are discovered. Perhaps the best compromise is to couple grandfathering with the use of explicit, pre-defined trigger conditions that would allow retroactive changes.

Finally, it is easier to loosen regulatory stringency than to tighten it, so it makes sense to start with a conservative protocol and aim to relax it if evidence from ongoing projects and research confirms the optimistic expectations about the safety of the geologic storage of CO_2.

4.1.2 Learning

The protocol should aim to maximize the amount of knowledge generated because one of the most important public benefits of early CO_2 storage projects may be the improvement in our ability to predict the migration of CO_2 in geological formations. Incentives or requirements to generate public data must, however, be balanced against the legitimate rights of private companies to protect their intellectual property.

Existing CO_2-EOR or acid gas injection projects were started for reasons unrelated to CO_2 storage and are managed under existing regulations that cover injection and disposal wells. More such projects will likely start before there is a well-developed management regime for CO_2 storage. Collectively, these projects present important opportunities to learn about the fate of acid gases injected underground. If researchers had full access to these projects, the knowledge gained could reduce crucial uncertainties about CO_2 storage. Access to such sites is problematic, however, because the companies have little incentive to allow it. There are also two other strong disincentives: the risk of revealing private information that grants the company competitive advantage; and the risk that if the research reveals problems, such as leakage, the regulatory authorities might demand remediation or even revoke the permit for injection. It is noteworthy that there is at least one strong economic incentive as well. In the case of the Weyburn project, where the company (Encana) has granted open access to the site and to data, the information gathered provides a benefit to the company because it can be used by the company to improve its EOR performance. In the case of acid gas disposal projects, however, there is generally no revenue-producing component and thus no possibility of benefits to counterbalance the risks.

Because of the significant public benefits, regulators should look for methods to facilitate access to current CO_2 injection sites. One method would be to review all data that is normally collected (or legally collectible) under the current regulations and, if all was well, formally indemnify the operator against problems that might be discovered by subsequent research.

When governments impose restrictions on CO_2 emissions, such as taxes, tradable permits or credits, then operators of existing facilities that inject CO_2 underground will have an incentive to have those facilities formally accepted as CO_2 storage in order to reduce their regulatory burden. Provisions related to access to data—including the ability to gather new data—might be built into the rules under which existing facilities would be incorporated into a CO_2 storage protocol.

Finally, the need to gain experience with early projects means that there is a significant public benefit associated with such projects, and therefore that public assistance to the private sector may be warranted in the case of some early, large-scale projects. If public funds play a significant role in facilitating projects, then regulators should ensure open access to data.

4.2 Flexibility

In addition to being adaptable in response to changing knowledge (Section 4.1.1), a protocol must also be flexible to enable effective management of the diverse array of possible storage projects, accommodating the diversity in scale and in geological setting.

4.2.1 Scale and stringency

The scale of storage projects ranges from existing acid gas disposal operations that inject CO_2 at a rate of roughly 1 to 100 kt/year to the Weyburn EOR project, which injects nearly 2 Mt-CO_2/year. Future projects involving capture from large power plants or from several hydrogen production facilities might inject quantities greater than 10 Mt/year. An effective protocol needs to impose requirements proportionate to the scale of the project. For small projects, such as the existing acid gas facilities, very little may be needed to certify or credit them as a CO_2 storage facility, whereas large projects will justify a more stringent protocol.

The stringency of requirements should scale with the size of a project because the risks that the protocol aims to manage are, presumably, roughly proportional to the total injected volumes. Moreover, given the pubic benefit of CO_2 storage, the protocol should—where compatible with public safety—avoid imposing requirements that make projects uneconomical. It is appropriate therefore, that the additional costs imposed by the protocol be in proportion to the size of the project. Consider a project involving CO_2 capture from a large power plant for which the cost of the capture facility will likely exceed $1 billion. For such a project, the storage protocol may require extensive reservoir modeling, ongoing seismic monitoring, and the drilling of many new monitoring wells, without significantly altering the economics of the overall project.

4.2.2 Addressing the diversity of geological conditions

Sites proposed for geologic storage span a wide diversity of geological settings, including aquifers, oil and gas reservoirs, coal beds and salt caverns. In addition, sites will vary greatly with respect to the kind of caprock, the existence of traps in the target reservoir, and the number of overlying aquifers and aquitards that might impede the movement of CO_2 to the surface. Sites will also vary in the number of pre-existing wells that penetrate or overlie the target formation. Finally, risks posed by surface leakage will depend on the surface topography and land use; urban areas, for example, will present larger risks, whereas offshore injection of CO_2 under the seabed would present smaller risks.

It is also possible to modify existing sites and vary injection techniques. For example, one might use foams or gels to modify CO_2 movement and improve storage efficiency, or grouts and reactive injectants to modify the geometry of the reservoir itself.

It is implausible that a protocol could specify prescriptive rules for all cases. As we discuss in Section 4.4, we advocate a hybrid approach in which specific prescriptive rules allow the use of a small class of sites without a performance analysis, and a broad performance-based provision allows consideration of the full diversity of storage sites.

4.3 Transparency

The management of CO_2 storage should be transparent. Information should be available and public input allowed wherever possible. The permitting process must demonstrate that the regulators have undertaken due diligence in the issuance of permits for disposal and abandonment. Large-scale storage of CO_2 in the subsurface will raise concerns of risk to the public. While CO_2 storage is most likely a very safe way of removing emissions to the atmosphere, the process should be more transparent to the public than are current oil and gas regulations, particularly for early projects, because of the great public visibility of CO_2 management.

In addition to local risks, there are concerns about the wisdom of using CO_2 storage as a means to continue the use of fossil fuels while avoiding atmospheric emissions. While these concerns arise independently of the risks of CO_2 storage, they may play an important role in motivating opposition to storage projects.

Because of these concerns, the first large-scale CO_2 storage projects may well have enormous public visibility. It is therefore vital that the management process be well organized and transparent from the outset.

4.4 Regulatory structure: Performance-based versus prescriptive approaches

In theory, the cleanest and most economically efficient way to construct regulations is to directly specify the important performance goals that the regulated process must meet, and leave decisions about the means of satisfying these goals to the operators. Such regulations are called performance-based. Most current regulations, however, are prescriptive rather than performance-based. Rather than specifying a goal, prescriptive regulations specify detailed procedures that must be followed.

Under a prescriptive system, the operator's primary responsibility is to follow the detailed rules, while responsibility for ensuring that the rules—if followed—produce the desired outcome rests with the government. For example, an operator of a disposal well in Alberta must follow specific design rules and perform specific well integrity tests in accordance with Alberta Energy and Utilities Board (AEUB) regulations; it is the responsibility of AEUB to design the rules so that they provide adequate protection for public health and safety. In contrast, under a performance-based system, the operators are directly responsible for achieving the desired outcome, and must convince the regulator of their ability to achieve these performance standards. Alberta's regulations for SO_2 emissions from gas-processing plants, for example, are in the form of a performance standard that specifies the maximum emission rates and that leaves the operator free to employ various technologies to meet this standard.

While performance-based regulations may offer important advantages, such as increased economic efficiency and greater flexibility, there are several drawbacks to their use in managing CO_2 storage. Performance-based regulations ultimately hang on our ability to infer performance from parameters that can be directly measured. In the case of the SO_2 emissions regulations mentioned above, regulatory agencies could, in principle, verify compliance by performing unannounced spot-checks to measure actual emissions. For CO_2 storage, however, a performance-based approach would have to specify quantities, such as the maximum rate of leakage over the next century, that cannot—even in principle—be directly measured, but must instead be inferred from models.

When the use of models is central to assessing performance, it may be very difficult to determine if the operator is complying with the standard. Where the use of models is well accepted, as is the case for models that predict the structural performance of large buildings, a model-based performance standard can work well. In a public process in which the modeling methods are less well accepted, particularly in an adversarial public process, it can be very difficult to prove compliance. Such has been the case for nuclear waste disposal.

A public permitting process must balance two competing objectives: one, it should be objective, transparent and open to public input; two, it must also be able to deliver 'closure' in the form of definitive answers in a reasonable period of time. We recommend that a CO_2 storage protocol articulate some overall performance goals, but that the regulatory system for permitting individual projects use a mixture of performance and prescriptive rules. This compromise could allow orderly decision-making about specific projects using prescriptive rules, while simultaneously allowing public debate about the ability of prescriptive rules to ensure that permitted projects comply with the overall performance goals.

A hybrid system can be a powerful tool for achieving the demands of flexibility discussed in Section 4.2. It might, for example, give the operators a choice of complying with either a conservative prescriptive specification that restricts the choice of storage reservoir (by requiring, for example, specific caprock thickness, permeability and continuity) or a performance specification that specified overall targets for leak rate that were applicable to any kind of storage system.

4.5 Division of public and private responsibility

Because of the long timescales involved in geologic storage, the ultimate responsibility for CO_2 stored in geological reservoirs should rest with governments. Although it is tempting to claim that liability for failures of a storage facility should remain in private hands, such a position is not credible. Companies do not "live" long enough to make private liability an acceptable policy. Moreover, even long-lived companies often transfer their outstanding liabilities to smaller companies with shorter life spans.

Putting responsibility for stored CO_2 in public hands reflects the fundamentally public nature of the risks and benefits of this type of storage. If a company chooses CO_2 storage as the least costly way to do business while meeting emissions constraints—such as taxes or tradable permits—then one may view the lowered compliance cost as a private benefit. Nevertheless, the ultimate benefit of storage is the (comparatively) low overall economic impact of reducing CO_2 emissions into the atmosphere, and the ultimate risks are future emissions of CO_2 due to leaks and harm to the surface environment. Both benefits and risks extend over centuries and, with the exception of local impacts, both are ultimately global. They are, therefore, naturally public.

If storage facilities are operated by private companies, the protocol for managing geologic storage must have an orderly way for transferring responsibility from private to public hands. We call such a transfer "project abandonment." It is analogous to the current practice of abandoning individual wells, but might impose more stringent and more general conditions on the private operator. The requirements for abandoning a well, for example, pertain only to the well itself, whereas the procedure for abandoning a large CO_2 storage project might require demonstration of overall system performance, such as testing for confinement of the CO_2 in specific areas of the target reservoir.

Without a clear and orderly method for transferring liability to public entities, private companies may be very reluctant to commit resources to geologic storage projects, even in the face of direct incentives for CO_2 storage or strong constraints on CO_2 emissions. The disincentive to private action that arises from uncertainty about long-term liability may be a particularly important problem in the near term, if we accept that there are important public benefits that arise from starting CO_2 storage projects early in order to maximize the opportunities for learning that would inform future actions (Section 4.1.2).

4.6 Lifetime

How long should stored CO_2 remain underground? This is perhaps the most important single question in managing geologic storage of CO_2. There is, of course, no unique answer. Any answer turns on predictions about the global carbon cycle as well as assumptions about climate policy, energy technology and economic development over the course of several centuries.

Among the most important assumptions or parameters that drive the answer:

- the acceptable concentration of CO_2 in the atmosphere;
- the amount of CO_2 that will ultimately be placed underground;
- the existence of technologies that can remove CO_2 either by enhancing natural carbon sinks or by engineering new kinds of sinks; and
- the weight given to small annual increases in CO_2 concentrations on millennial timescales.

To illustrate the way in which estimates of the acceptable leak rate are driven by assumptions, consider the two kinds of answer below: the first rooted in science, the second in economics.

- If we ignore technological change and economic discounting, and assume that the answer is driven by the impacts of increased carbon concentrations in the atmosphere and oceans independent of when they occur, then the overall impact of CO_2 depends on the ratio of the time constant for leakage compared with the time-constant for removal of carbon from the ocean to stable oceanic sediments. Under this framing, one can argue that storage lifetimes need to exceed 10,000 years.

- Alternatively, if one adopts the economic framework common in models of optimal climate policy—often called integrated assessment models—and if one accepts that technological change will eventually reduce the cost of engineering carbon sinks, then the storage lifetime required to achieve most of the benefits of permanent storage can be as short as a hundred years.

In practice, we judge that concerns about local risks make retention times of a few hundred years or less unacceptably short, and that a 1,000-year retention time is likely to be widely accepted.

The retention time we are discussing here is the *minimum* acceptable retention time from the perspective of long-run climate policy. It is *not* based on an estimate of practically achievable retention times of real geologic storage systems. There is wide, though not universal, agreement that retention times over 10,000 years ought to be readily achievable in practice. It is crucial to the success of a geologic storage regime that the *minimum* acceptable retention time—perhaps embodied as a performance specification in a regulatory protocol—be substantially smaller than the predicted retention times of actual storage systems.

4.7 Treatment of uncertainty in estimating CO_2 transport and surface risks

The performance-based specifications may require use of a reservoir model driven by a probabilistic model of subsurface conditions to produce probabilistic estimates of leakage rates. A requirement to systematically incorporate uncertainty in modeling the subsurface transport of CO_2 would push current technical abilities to, or beyond, their limits. Given known subsurface conditions, it is possible, though computationally difficult, to produce probabilistic estimates of transport. Existing methodologies do not, however, allow for systematic, probabilistic estimation of subsurface conditions (e.g. permeability and porosity) from measured data (e.g. well logs and seismic images).

If a regulatory protocol includes performance-based specifications, it may have to define specific guidelines for such modeling and, more importantly, specific guidelines describing the amount of data that must be gathered and the means of inferring subsurface conditions from data.

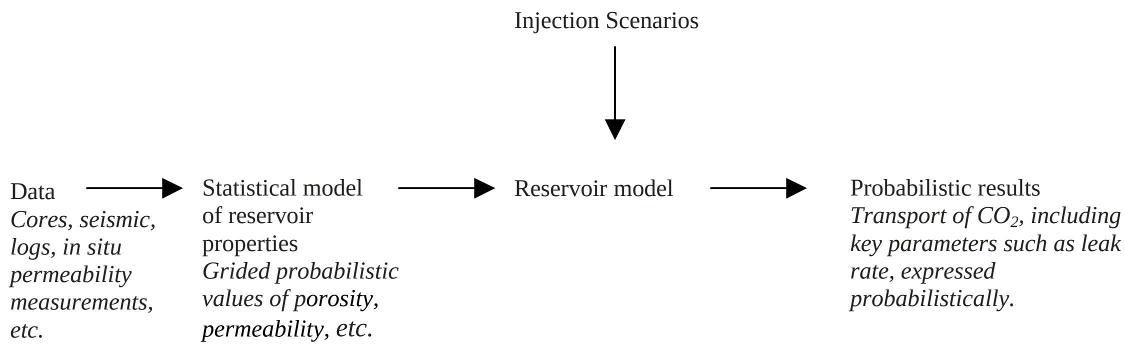

Figure 2: Schematic illustration the crucial elements in a probabilistic model of CO_2 storage

5 SPECIFIC RECOMMENDATIONS FOR A GEOLOGIC STORAGE MANAGEMENT PROTOCOL

5.1 Introduction

In the previous section, we examined the general constraints and desiderata that should shape the development of policy and regulations for geologic storage of CO_2. This section moves beyond generalities to describe specific elements of a protocol. Our intention is to illustrate the above discussion by articulating the more important elements of a regulatory protocol. It is *not* our intention that this framework protocol serve as a draft version of the eventual regulations.

The framework protocol starts by identifying the requirements for determining whether a reservoir is adequate for the storage of CO_2. It then develops requirements for drilling and/or testing wells for CO_2 injection, including the siting of these wells with respect to surface and target zones. Next, it examines permitting the abandonment of the project and conditions for transfer of liability to the public sector. Monitoring and reporting on progress are key components. As discussed in Section 4.1.2, there is a need to learn from experience, as knowledge is gained with storage in different environments. This will be accomplished through appropriate analysis and reporting of the data collected to regulatory authorities.

Where appropriate, this framework protocol includes numerical details such as a specific minimum injection depth. These details are there to aid our presentation of the framework protocol and to stimulate the discussion that will be needed to refine this framework. To provide a good basis for discussion on the storage of CO_2 in the subsurface, we believe that there is a need to provide as much detail as possible and to push the limits of our technical capability in our recommendations for performance-based standards. The specific numbers should be regarded as illustrations rather than judgments.

This framework protocol includes performance-based standards. As discussed in Section 4.4, the use of performance standards simplifies the text of the protocol. Such standards, however, pose difficult challenges: there are questions about the technical ability to do the modeling required to implement such standards, and about the wisdom of including them at the project level.

The recommendations in the following sections are broken down into phases using a hypothetical storage project. An alternative would be to look at a breakdown into performance-based regulations, prescriptive regulations and modeling/risk assessment aspects. It would also be possible to set up recommendations based on the nature of the storage site (oil or gas field, greenfield site or coal seam). This latter approach would likely result in too much duplication.

The framework protocol focuses on oil and gas reservoirs and aquifers. While we expect that other systems (particularly coal seams) may be important, we have for the sake of simplicity restricted the discussion to the cases that are most likely to go forward early. Coal seams represent a different form of storage in that the CO_2 is rapidly adsorbed on the surface of the coal. While sequestration occurs more rapidly with coal, there remains a need to examine the caprock and overlying formations should movement of the CO_2 occur.

In each case in the development of this protocol, we have implicitly assumed that the project under discussion is large (more than 1 $MtCO_2$/year). As discussed in Section 4.2.1, smaller projects might face less stringent requirements and this should be kept in mind when discussing this document. As noted, however, the regulations that are developed should preclude “shopping” for a different regulatory regime while retaining the right to claim the storage of CO_2.

At this stage, we are continuing to learn more about the storage of CO_2. Current acid gas injection projects could be an important source of knowledge in this regard, but the volumes injected are small relative to the CO_2 volumes considered for injection over the coming decades if we are to make deep cuts in emissions to the atmosphere. In this regard, it is easier to go deeper under ground to reduce the risks; as well, knowledge of the reservoir would be less of an issue because the plume will not be as large or migrate as far. Projects like the Weyburn Monitoring Project will provide information about reservoir integrity, monitoring and reporting techniques, and the use of a mature oil field. Because they are not set up for monitoring, other storage/EOR projects do not provide a great deal of information on integrity, modeling, etc. As a result, part of the monitoring and analysis component of the permit requirements should be designed to increase our knowledge of modeling and risk assessment techniques, and to help determine future monitoring and reporting requirements. In this regard, the requirements should tend to be inclusive rather than too conservative in setting the standards. This is because changing standards to become more stringent in the future will be difficult.

5.2 Project phases and overall structure of the protocol

The recommendations cover four defined periods:

- A *pre-injection* phase, which covers the project application, drilling and completion of the injection well.
- The *injection* phase, which covers the period during which injection into the reservoir occurs.
- The *pre-abandonment* phase, which covers the period following cessation of injection operations, but before permission is given to abandon the project.
- The *post-abandonment* phase, which covers the transfer of responsibility from the private sector (or operator) to the public sector.

In addition to recognizing a number of phases within the project life cycle, the recommendations also impose three requirements:

1. A set of procedural or prescriptive rules governing certain aspects of the operation. This includes the completion, operation and abandonment of the wells. It also includes one option for meeting specific guidelines for an acceptable storage location.

2. A performance-based set of recommendations for determining an acceptable subsurface location for the storage of CO_2. This requires the proponent to demonstrate with reasonable certainty that CO_2 will be retained for a period of time, defined as achieving dissolution in the formation fluids. Other standards may need to be developed in the event of constrained storage and the likely increase in the life of the CO_2 plume.

3. A performance-based set of recommendations regarding the movement of CO_2 from the subsurface to the surface. In this possible zone of CO_2 migration, the buoyancy forces will increase, and because geological knowledge is typically less well defined, there is a risk of CO_2 entering the fresh water zone or being released to the surface in an uncontrolled fashion. There is also the issue of dissipation of the CO_2 during upward migration. The bottom line is the need to set confidence levels for the potential release of CO_2 in such concentrations that it causes health and safety concerns on the surface.

These requirements assume that upon dissolution of the CO_2 in the formation fluids, particularly the water, the risk of migration due to the buoyancy forces is effectively eliminated. Indeed, the waters will increase in density, reducing the probability of movement to surface still more. The protocol considers the CO_2 to be effectively trapped once dissolution occurs and that there are no further concerns about the integrity of storage.

5.3 Phase 1: Pre-injection

5.3.1 Site selection and screening

As discussed in sections 4.2.2 and 4.4, the operator can either meet prescriptive requirements or demonstrate by modeling that the performance requirements will be met. We first discuss prescriptive requirements for two cases: greenfield aquifers, and oil and gas reservoirs.

The first criterion for reservoir acceptability is its depth. The protocol should include a requirement that the injection depth be greater than 800 m unless the operator can demonstrate that some alternative performance-based specification is satisfied.[2] In reservoirs with typical pressure and temperature profiles, the density increases quickly with depth up to about 500 m, and then more slowly as depth increases further to reach a density plateau below 1 km. All else being equal, greater depths mean less risk because the buoyancy decreases with increasing density. For EOR, maintaining miscibility is important, but this need not be relevant if storage is the goal, and will be irrelevant in aquifers.

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[2] The value is somewhat arbitrary. A range from 500 to 1000 m seems plausible. The density of CO_2 injected into reservoirs with normal pressure and temperature profiles reaches a density of some 700–800 kg/m^3 below the 800 m level.

The second major screening criterion is caprock integrity. In the case of a greenfield site, including coal seams, the proponent should demonstrate to the regulatory agency that the reservoir is able to meet certain basic requirements of gas storage. The reservoir should have a caprock at least 50 m thick with a demonstrated permeability of less that 0.001 millidarcies over a distance that the CO_2 plume could be reasonably expected to migrate until dissolution. The purpose of this is to have the operator demonstrate confidence in the continuity of the caprock for a considerable distance updip of the injection point or along the direction of plume migration.

A comprehensive geophysical survey, including a detailed 3-D seismic profile, should be run to determine the nature and extent of the target horizon and caprock, particularly along the expected direction of migration of the plume. While such surveys may be inappropriate for small projects, they are reasonable for large projects (see comments in Section 5.1) where they will add little to the overall project costs. Estimates by Myer et al. (The Greenhouse Gas Technology Conference, Kyoto, 2002, presentation) suggest that incremental costs for geophysical surveys for large projects represent a few cents per tonne of stored CO_2.

Ideally, the caprock should be tested by coring in the case of a greenfield site. In the case of existing reservoirs, the nature of the caprock and all test reports should be included in the reporting provided by the proponent. The caprock can then undergo geomechanical and geochemical testing to determine its resistance to leaks by physical or chemical processes. It should also be tested for permeability, particularly vertical permeability; determining vertical, horizontal and relative permeabilities to CO_2 and other fluids would also increase confidence in the integrity of the host horizon, given the small number of wells likely to be drilled.

Pressure testing and geochemical analysis of the fluids above and below the caprock (i.e. the target zone and the succeeding saline aquifer) will give some indication of any hydrodynamic continuity between the two zones and indicate the presence of a discontinuity that allows fluid movement between the zones.

The basic caprock screening requirement for an oil and gas reservoir should not necessarily be as stringent as for a greenfield saline aquifer site because we know more about the nature of the caprock and we can see that hydrocarbons have been stored for a considerable period of time. It would, therefore, be reasonable to accept thinner cap rocks. In the case of an oil and gas reservoir, however, the screening will of necessity include the development of a complete profile of the existing wells, both currently producing and abandoned. This will need to include a statement about the completion practices, abandonment techniques, cement bond logs conducted, horizontal well completions, etc., to give regulators a sense of the integrity of the wells that penetrate the formation targeted for storage. This will include any wells that have been drilled through the formation for oil, gas or minerals below the reservoir.

In the evaluation of the target zone, the nature of the sediments between the top of the caprock and the base of the vadose zone should also be evaluated. Ideally, this zone should have a number of aquitards/aquicludes to provide a succession of barriers to vertical migration of CO_2 and of CO_2-laden fluids following the dissolution of the CO_2. (This may be difficult to assess, particularly from a modeling perspective. The goal is to assess the frequency, nature and lateral extent of the aquitards overlying the target horizon from logs and drill cuttings and from other wells drilled in the vicinity.) This is particularly important to understand, as the CO_2 density decreases with decreasing depth. As the liquid CO_2 rises, its density will decrease, which will enhance the buoyancy forces and consequently increase in the rate of movement to the surface.

The nature of the barriers in this zone will be important to understanding the lateral dissipation of the CO_2 and its possible concentration on the surface or leakage into fresh water zones.

In the performance-based approach, the reservoir model would be used to demonstrate to the satisfaction of the regulatory authority that the leakage rate would be less than 0.1% per year of cumulative CO_2 injected.

Modeling of the reservoir or saline aquifer will, therefore, include the following: modeling of the target zone itself; an assessment of the risk of leaks over the area of the CO_2 plume; modeling of transfer of CO_2 through the sediments overlying the target zone caprock (or some form of assessment of the pathway that leaking CO_2 will likely take on its way to the surface, to help regulators estimate probable dissipation, reaction and dissolution of the CO_2 along this route); and modeling of effects in the near-surface and surface zone. As noted above, the nature of the sediments overlying the caprock will determine the likely migration path of any CO_2 that does happen to leak through the caprock. In the surface/near-surface zones, the nature of aquifers and the nature of the surface will need to be evaluated to ensure that point releases of CO_2 do not exceed the safety standards set by local authorities for safe working and living environments. It should be shown, with a reasonable degree of certainty, that ambient conditions within surface locations that may be prone to CO_2 build-up will probably remain below safe levels. Human health and safety are paramount, but the potential effects on ecosystem health, including on plants and burrowing fauna, cannot be ignored.

In effect, what is being proposed here for the performance-based standards is a three-part modeling assessment of the injection zone and its overlying geological strata. The first modeling component would be the use of a reservoir-type model to assess the movement of CO_2 in the reservoir, together with an estimation of potential leakage out of this zone and time to dissolution in reservoir fluids. The second modeling component would assess the vertical leakage of any CO_2 leaving the reservoir, looking at barriers to its vertical progress and likelihood of dissolution on the way up. The third component would evaluate the impact of CO_2, should it reach the vadose zone, and the CO_2 flux to the atmosphere. This would include an assessment of potential surface impacts of CO_2 leakage on humans and the ecosystem.

5.3.2 Siting of the injection well(s)

Care should be given to ensuring that the location chosen for the siting of the injection well should avoid built-up areas, or areas likely to be built up, in the life of the permit for injection of CO_2 and other gases contained in the CO_2 stream. Habitation should be at least 1km from the site of the injection well. In the event that other toxics are proposed for injection (in addition to CO_2), the wells close to permanent habitation should not be used for injectants that, in the event of surface leakage or failure of the injection wells, would cause the concentrations of toxics to exceed health and safety standards prescribed by local authorities.

The well head site should be protected from interference. There are regulations in place regarding disposal facilities that would probably apply, as well as operating procedures that ensure operator safety. This requirement may be restricted to high-volume injection sites and may not apply in cases where existing oil fields, gas fields, etc., are being used to store CO_2. Some discussion of the requirements for a safe site needs to be undertaken.

The well site should avoid low points of land where pooling of CO_2 could occur during appropriate atmospheric conditions. Monitoring equipment should be in place to test the ambient conditions in the vicinity of the wellhead and ensure that harmful concentrations of CO_2 or other contaminants do not exceed local health and safety standards.

Some discussion around the geological context of the storage reservoir should be undertaken. In terms of the saline aquifer, we recommend that the injection well be placed such that buoyancy forces of the CO_2 in water cause upward migration of the CO_2 in the subsurface. (See Figure 3 below.) Migration of the front of the CO_2 plume a distance of 10 times the horizontal diameter of the plume will help to ensure effective dissolution of the CO_2 in the reservoir fluids. Work by Lawrence Berkeley National Laboratories suggests that, within this distance, some 90% of the CO_2 will be in solution (Sally Benson, August 2002, personal communication). This would appear to be fully consistent with the current work in Australia as presented by Bradshaw et al., at the last Greenhouse Gas Technology Conference (Kyoto, 2002). In the event of a conventional trap, such as in the case of an oil or gas reservoir or aquifers with a similar geometry, we recommend that CO_2 be injected downdip to allow for as much migration and dissolution as possible during the migration phase.

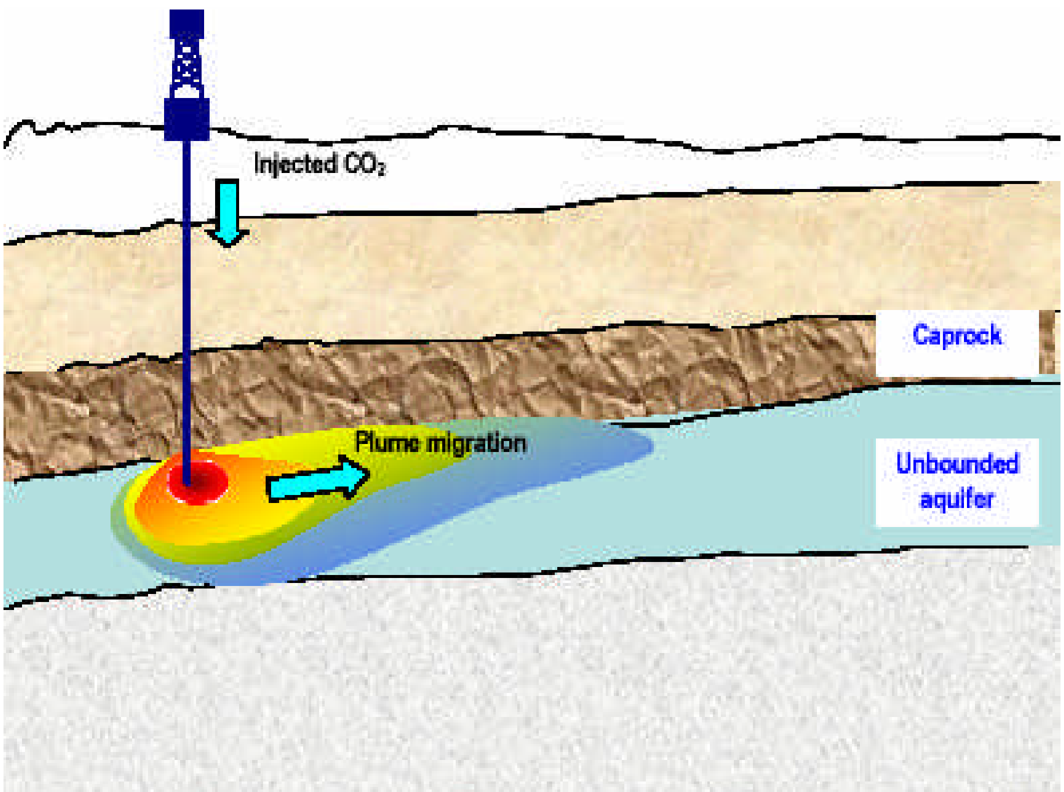

Figure 3. An illustration of the updip migration of the plume to show the efficient contact with reservoir fluids during migration

In some circumstances, where the project proponent can prove to the satisfaction of the regulatory agency that there may be basinward movement of fluids that would cause the CO_2 plume front to migrate less, the guideline for migration updip could be relaxed. This situation certainly occurs in deeper parts of the Western Canadian Sedimentary Basin and could be used to advantage in CO_2 storage. The circumstance of total dissolution of the CO_2 does not necessarily eliminate the risk of migration once dissolution occurs; it merely aids in reducing the time for dissolution to take place.

The basic tenet of the above discussion is that the regulator needs to be aware of the trade-offs that occur when different injection strategies are employed. Trapping CO_2 in an anticline or stratigraphic trap will result in a smaller interface between the CO_2 and formation fluids, thus slowing the rate of dissolution. Under these circumstances, the area of caprock exposed to the CO_2 plume is reduced, but the time during which the CO_2 has an enhanced buoyancy effect is increased. On the other hand, there may be more comfort in the lowered risk that occurs when less caprock is impacted, and more confidence because such a geological situation could be clearly identified as an effective trap.

5.3.3 Operational plan

An operational plan would have been prepared by the proponent before the start of CO_2 injection, which would have been approved by the regulatory authorities. Circumstances might change the actual implementation of the plan during the course of operations (for example, loss of injectivity in a well would require plan flexibility to allow continuation of operations).

Ideally, the reservoir would be of sufficient thickness, extent and permeability to allow effective injection rates to be maintained for an extended period. The screening would include evidence that the reservoir would be capable of holding the proposed cumulative injection volumes. This volume should allow for the migration of the CO_2 plume in such a way that it will be dissolved in the formation fluids over time and that, as a result, buoyancy of the CO_2 will cease to be an issue over time (see Section 5.2). This does not mean that fluids cannot still migrate into adjacent horizons, merely that buoyancy will not play a significant role in the vertical migration of the CO_2.

The proposal for a permit to inject CO_2 into the subsurface would include the elements mentioned above as well as plans for responding to well failure and leakages in the subsurface. Well failure planning would include plans for the evacuation of people in the neighbourhood (should they be in a vulnerable location) and plans for the repair of the well. Leakage should be contained to the gas in the well and back to the nearest automatic shutdown valve in the pipeline. The location of the valve could be determined by setting a theoretical maximum limit for the volume of gas that could be allowed to leak from a total well failure; there are regulations in place that set standards for the distance between valves. Leakage in the subsurface would require remedial action to eliminate the leak. The original proposal should include plans outlining the remedial action for leakage along the injection wellbore, as well as other anthropogenic intrusions into and through the reservoir/aquifer and along natural discontinuities in the subsurface. These plans would include the modeling of leaks and a determination of the risks that such leaks pose at the surface. Significant risk—meaning that the dissipation of the CO_2 in the overlying sediments was inadequate to minimize the risk of potentially problematic concentrations building up at the surface—would trigger remedial action or even, in extreme cases, the cessation of injection.

5.3.4 Drilling and testing of wells

Wells should be drilled in the manner prescribed in the conventional oil and gas regulations. That is, surface casing should be cemented to below the lowest potable water (total dissolved solids less that 10,000 mg/litre), with cement bond logs providing confidence in the cement bonding and isolation of the fresh water zone(s). The well should be drilled to the projected depth and logs run to ensure success. Fluid samples should also be taken from the target horizon to determine its chemistry. (See Appendix 1 for notes.)

Casing should be continuous to the target horizon. The wellbore should be flushed before cementing and the cement should be run to the surface. Cement bond logs should be run to assess the quality of the cement bond with the rock. Setting standards for cement to surface extends the conventional regulations, as noted in the appendices.

In any new well situation, serious consideration should be given to having the perforation accomplished by milling and waterjetting or a similar technique to avoid fracturing the cement by conventional explosive perforating. It has been shown that conventional perforating could lead to fracturing of the cement and possible damage to the seal around the casing. Open hole completion below the caprock also eliminates the potential problems associated with conventional perforating techniques.

If horizontal wells are being used for injection, the wells should be cemented through the caprock. Again, this allows for isolation of the injection horizon.

5.4 Phase 2: Injection operations

Injection should follow the program developed as part of the proposal submitted for the operation of the facility. The procedure would be effectively the same as for the existing regulations for gas injection, particularly acid gas injection. As part of reporting to the regulatory agency, the modeling should be updated regularly, annually or less frequently (timing would depend on the experience gained and with the expectation that modeling would provide new information). The integrity of the injection well should be tested regularly. Injection pressures should be monitored continuously to prevent the injection pressure from exceeding the fracture pressure of the reservoir. Automatic shutdown procedures should be in place in the event that the injection pressures do exceed a predetermined maximum for the reservoir.

Injection operations would follow existing acid gas injection regulations. The injection would be through an injection string. The annulus would be sealed top and bottom, and a positive pressure maintained with an inert gas between the casing and the injection string. Should this pressure be lost, indicating a problem with the integrity of the injection string, the well would automatically shut down until the cause of the problem is determined. All problems resulting in well shutdown should be reported to the regulatory agency, complete with a description of the remedial action taken.

5.5 Phase 3: Post-injection operations and procedures for abandonment

Post-injection refers to the completion of the project rather than the abandonment of a single well within the storage project. In other words, operations would not be considered as complete until injection has ceased in the last operating well of the project. At this point, some time should be spent testing the integrity of the system to ensure that it is to the satisfaction of the regulatory authorities.

To abandon the project, a permit would be required. This step is important because it represents the transfer of responsibility from the private sector to the public sector. The permit to abandon would be issued only after the proponent has provided an appropriate proof of successful abandonment of all wells within the project.

Conventional abandonment calls for the removal of the injection string, a cement squeeze into the producing horizon (injection zone), the setting of a packer at the top of the injection zone, and a minimum of 3 m of cement on the packer. The rest of the well would be filled with fluid containing corrosion inhibitors. In the case of an injection well, the same basic process should be followed, with assurance that the material of the packer is not prone to degradation by liquid CO_2 and that the fluid in the casing string is weighted up to maintain pressure on the cement. At the top, the well should be welded shut and the location effectively recorded so that periodic monitoring can be conducted in the vicinity of the wellbore. (Standard practice calls for the casing to be cut off below the ground surface and welded closed.) Given the longevity of the CO_2 plume in the reservoir/aquifer, regulators may contemplate some variations in techniques. If periodic testing of the integrity of the system is envisaged, then the wells should be left in such a state as to allow monitoring and re-entry to the wellbore should remedial action be required. Alternatively, the wellbore may be plugged in such a way that the risk of any leakage is extremely remote. This latter approach might include cement to surface in the abandoned wellbore (or some other plugging compound that would be more flexible and longer lasting than current cements).

Once abandonment has been achieved and the regulatory authorities are convinced that the risk of leakage from the wellbore is low, the permit to abandon will be issued and the operator will cease to have responsibility for the injection site and formation. At this point, the public takes on the responsibility for any future monitoring. Ongoing monitoring and modeling over the life of the project would be used to assess the probability that the storage horizon has performed as projected, and that it will continue to meet performance specifications in the post-abandonment phase.

5.6 Monitoring

Monitoring should include regular reporting of data related to injection pressures and volumes, and the performance of the injection wells. Annually, there should be testing for mechanical integrity of the well and a pressure fall-off test. Any problems that required shutdown of the well should be reported and remedial action described. This is effectively the same as existing regulations on injection wells.

In addition to monitoring directly associated with the injection well, large projects will need extensive monitoring to assess the overall performance of the storage reservoir. The stringency of monitoring requirements should be proportional to the scale of the project, and should weigh other risk factors, such as the potential for damage to nearby oil and gas or other mineral deposits.

Such monitoring might include:

1. Monitoring ground displacement.

2. Monitoring for induced seismicity in the region of the injection well.

3. Monitoring using seismic imaging. In large projects, it is almost certainly worth requiring periodic seismic surveys to determine the rate of plume expansion and plume migration, and to calibrate the models for plume development.

4. Monitoring should include periodic testing of the fresh water zone(s) in the vicinity of the wellbore as well as testing of soil CO_2 concentrations in the vicinity of the wellbore.

5. In the event that significant discontinuities are determined to exist in the region expected to see CO_2 migration in the reservoir, the surface zone should be tested where the discontinuity would be expected to intersect the surface. Seismic or geological interpretation would be needed to determine the nature of discontinuities that may intersect the target horizon and caprock but not have any surface expression. Discontinuities without surface expression may require the use of monitoring wells to determine leakage, if there is any.

Artificial penetrations of the reservoir/saline aquifer are the most likely avenues for CO_2 migration to the surface. In the case of a greenfield site, this is largely mitigated by careful completion of the well(s) and minimum penetration of the caprock above the target zone. In the event that an existing reservoir is to be used for CO_2 storage, the level of surface monitoring will need to be enhanced. This will include a more extensive monitoring of fresh water above the reservoir and monitoring for soil gas concentration in the vicinity of operating and abandoned wells. It is likely that relatively simple and cheap monitoring equipment can be installed and connected to a data-gathering station. In the event of leakage, the abandoned well could be opened and a slim hole drilled through the cement plug for remedial action to be taken at a reasonable cost. The concept of preventive remedial action could be considered. Where a cement squeeze has occurred as part of the abandonment procedure (in most cases), it would be necessary to drill or perforate beyond the cement squeeze to inject fluids for remedial action (cement or a similar solution that will react with the CO_2 to create an impermeable barrier to further CO_2 migration).

There is some question about the cost and viability of monitoring for leakage in the saline aquifer above the target zone. Monitoring might be accomplished by installing a permanent sampling point from the injection well or by drilling an observation well into the overlying saline aquifer. Either case would be relatively cheap for a large project and could be considered. The identification of CO_2 in the overlying saline aquifer could be used to trigger an increased level of monitoring and possibly remedial action, should the volumes escaping dictate this level of action. It may also be worth looking at the inclusion of such monitoring based on the presumed level of risk of leakage. In other words, where there are a number of penetrations of the caprock, the presence of a number of discontinuities, or significant uncertainty about the lateral continuity and quality of the caprock, the regulatory authorities might consider an observation well(s) to be mandatory. This is in accordance with the principle that the stringency of monitoring should be based on the likely risk of leakage.

5.7 Procedural aspects of project permitting

If the project proponent submits an acceptable proposal to the regulatory authorities, the proponent would be issued a permit to develop and operate an injection facility. The permit should probably be issued for up to 20 years, with an option to renew at the end of this period.

The permit would include all the operating, monitoring and remediation requirements for the operation of the facility. It would also include the terms for abandonment.

Large projects, particularly unconfined saline aquifers, may be difficult to manage under existing land ownership rules. Oil and gas regulations often do not allow the leasing of blocks of land large enough for the disposal of large volumes of a greenhouse gas and its expected migration. Adequate tracts of land will need to be identified and leased out for such storage purposes.

The operation of the facility should be reviewed every 5 to 10 years, based on the monitoring results and their interpretation (and on the updating of the modeling based on the performance of the facility). As discussed elsewhere, there will be a learning phase and the acquired knowledge will lead to better regulation in the future. It is important to keep in mind that there is a balance to be kept between the need to acquire new knowledge and the problem of pricing this technology out of the market.

The permit would also include the rules for changing monitoring requirements, changing operating procedures, remediation work and premature abandonment of the facility. In basic terms, the level of leakage from the target horizon would trigger actions commensurate with the level of leakage and the risks to human and ecosystem health and safety. Severe leaks would result in the cessation of operations and the initiation of remedial actions described in the original proposal. Minor leaks would trigger an increase in the level of monitoring to ensure the protection of health, safety and the environment. Continuation of operation following the triggering of remedial action would be at the discretion of the regulatory authorities and would depend on the preparation of a revised operating plan based on the expected results of the remedial action. Appropriate monitoring would be a key component of the revised operating plan.

A change of operator would require the transfer of the permit to the new operator. This would include the assurance of the technical and financial capability of the new operator to manage the facility and meet the terms of the operating permit. The transfer would not take place until the appropriate financial safeguards are fully in place.

Prior to any CO_2 storage permit being issued, the proponent should put in place a bond that would cover remedial work and abandonment in the event of a catastrophic loss of well integrity and the loss of the company. Before the permit could be transferred to a new project owner, the new owner would be expected to put in place another bond.

Funding for post-injection monitoring and potential remedial work by the public could be handled in a number of ways. It is possible, for example, to make part of the bond non-refundable and to support the monitoring and remediation using those funds. More likely, some form of environmental fund would need to be created to cover the costs of any post-injection requirements. Payments to this fund would be based on the size of the project.

5.8 Phase 4: Post-abandonment operations

At the present time, we are in a learning phase and there is no experience regarding the potential future problems of this type of project. Governments will need to evaluate the public benefit of such projects (the storage of a greenhouse gas) against the risk to public and environment health and safety of projects that will have been returned to the public starting probably 30–40 years from now and expected to be kept safe indefinitely.

Post-abandonment monitoring is again an unknown at this time. It could include remote sensing of surface vegetation to determine the effects of any leakage of CO_2 to the surface; continued monitoring of groundwater; or even the permanent installation of a sampling point in the overlying saline aquifer to detect any leakage beyond the caprock from penetrations of the caprock. CO_2 concentrations in the soil could be monitored periodically to ensure that the site remains within local standards for CO_2 concentration.

5.9 Accounting for stored CO_2 in emissions inventories

Verification of injected CO_2 is relatively straightforward—the gas stream is metered as it enters the wellhead and the information is reported to the regulatory agency on a regular basis. The composition of the gas stream must also be analyzed periodically to determine the nature of the injectant and to be able to calculate the actual volume of CO_2 entering the storage zone. It is very unlikely that the stream will be pure, and the composition may change depending on the source and extraction technology employed. It is the responsibility of the project operator to establish that the gas is entering the appropriate zone.

The requirements of the agency undertaking the inventory will likely be met when the local regulations are met. Assuming reasonable accountability, these inventory numbers will also probably be accepted internationally. In the absence of international rules, there is a need to ensure effective regulation and to have some level of comfort that when regulations are put in place, national inventory standards meet these international standards. In other words, the inventory will account for the volume of gas injected. As long as the gas does not reappear at the surface for a reasonable period of time, the needs of the inventory are met. If gas is released at the surface, then it is added back into the inventory at the time of release. Estimating the volume of gas leakage to the atmosphere will require the development of some acceptable means of estimation.

The regulator must ensure that the gas is injected into and remains in the target zone. It is an issue not just of potential health and safety at the surface, but also of a loss of pore space or possible economic disruption of other zones of interest. If an accidental release happens, the regulator will need to look at the issue of penalties for failure to keep the CO_2 within the zone of interest. If this CO_2 remains below the vadose zone, it is not in the interest of the regulator to fail to accept it as stored in the subsurface, as this is deducted from the national inventory. There is also an issue of leakage below the target zone in cases where the basement barrier to the injection zone is only partially complete. What may be acceptable as credits for the storage of CO_2 is a different question and may be dealt with through commercial means. In other words, verification of storage may stipulate volumes contained within a specific zone as opposed to preventing the release to the atmosphere.

APPENDIX 1: SPECIFIC REQUIREMENTS

Based on the no-migration petitions for disposal of industrial waste in the United States, several detailed aspects of the recommendations can be outlined. These could be used as a basis for determining informational requirements for any proposal to inject and store CO_2.

1. A written description of the regional geology should be prepared. This would be based on all available information, including survey work, project geologist work, existing oilfield or other work, seismic properties, etc. This description would include standard geological descriptions as well as whatever detail is available, or can be inferred from available information, regarding the ductile properties of the material into which injection will occur, as well as the overlying aquitard/aquiclude. Expected discontinuities (presence and nature of faults and fractures) in the aquitard should also be prepared. A description of the underlying aquitard should also be provided, together with a statement addressing the expectation of its continuity over the expected extent of the CO_2 plume.

2. The geological description would take note of the underlying or overlying deposits of potential economic interest, including the brines themselves, and evaluate the risk of sterilizing these deposits.

3. Site-specific maps of the injection area providing an overview of the extent and nature of the sediments in the injection zone—including facies changes, the immediate aquitard and the overlying sediments to the surface—should be prepared. Cross-sections should be prepared along strike and dip. The dip section should extend at least ten times the anticipated cumulative diameter of the plume of injected CO_2, updip from the injection location. The maps should include a regional structure map, isopachs of the injection horizon and the immediately overlying aquitard, and isopachs of the permeability of the injection horizon.

4. Parameters that should be measured are those that impact on the plume migration, plume dissolution and plume containment within the injection zone. These include matrix properties, aquitard properties, brine properties and expected injection fluid properties. The following properties should be collected at a minimum and should be verifiable and conservative:

    - injection zone permeability
    - overlying and underlying aquitard permeabilities
    - injection zone porosity
    - original and/or existing reservoir temperature
    - original and/or existing bottomhole pressure
    - pressure and fluid chemistry in the overlying saline aquifer (determination of crossformational flow)
    - production, injection and/or pressure history (for existing wells)
    - fluid and matrix compressibility
    - matrix and aquitard mechanical properties
    - chemical properties of aquitard
    - reservoir brine density at reservoir conditions
    - reservoir brine viscosity at reservoir conditions
    - other fluid and/or gas properties
    - density and viscosity of injectant at reservoir conditions

- anticipated dissolution rate of injectant in existing reservoir fluids
- anticipated migration rate for the plume
- calculated injectivity of the target horizon and expected injection rate
- hydrodynamic flow within the reservoir
- *in situ* stress fields within the reservoir.

5. The parameters collected should also include the expected rate of dissipation of any gas leaking into overlying formations. This would include a conservative estimate of the dissolution of the gas into overlying brines, the porosity and permeability of the overlying saline aquifers, and the regional continuity of overlying aquitards and their expected permeabilities.

6. In the event that an existing reservoir is utilized, the nature of the existing wells should be recorded. This would include the nature of the abandonment, the level of corrosion in the existing casing, and the existence of collapse or shearing in existing wells.

7. Modeling would include the risk of overpressuring the reservoir, risk of leaking along existing wells, leakage along discontinuities, risk of fault reactivation and thermal or physical stress on the caprock (particularly in the near-wellbore area). This would occur within the context of the expected plume migration distance and rate, and the nature of the overlying sediments for dissipation of the CO_2.

8. Ongoing analysis would allow the original model to be recalibrated based on injection history and discrepancies explained.

APPENDIX 2: SOME EXISTING REGULATIONS RELEVANT TO CO_2 STORAGE

A number of guides and regulations are in place to provide direction for some of the aspects of injection facilities:

1. Alberta Energy Utilities Board (AEUB) Guide 8 (October 1997) provides guidance on the emplacement of surface casing to avoid contamination of near-surface resources, particularly water.

2. AEUB Guide 51 (March 1994) provides guidance on injection and disposal wells. Inert and sour gas fall under AEUB Class III wells. The recommendations provided above go beyond the expectations of Class III wells in terms of proposal preparation, monitoring, etc., in anticipation that the volumes of gas being injected for mitigation of greenhouse gas emissions will be significantly higher than those envisaged in these regulations. Some of the regulations contained in this guide would be transferable and could form the basis for a set of regulations governing the storage of CO_2.

3. AEUB Guide 65 (June 2000) provides guidance on the development of miscible enhanced oil recovery projects and the requirements for applications. It also contains requirements for the conversion of oil or gas fields to acid gas injection, with reference to Guide 51 for the development of the injection wells. The applications described in Guide 65 delineate significant geological detail regarding the injection zone, including adequate expectation of containment of the injected fluid. Standards for safety at surface facilities are referenced in this document.

4. AEUB Guide 20 (March 1996) provides minimum standards for well abandonment and the testing for, and mitigation of, natural gas leaks from the abandoned well. Again, the recommendations above include significantly greater expectations for the operator than anticipated in these regulations.

5. Saskatchewan's The Oil and Gas Conservation Regulations 1985 (with amendments through to 2000) provide minimum standards for the drilling, surface casing and abandonment of wells. It also provides standards for the collection of relevant data from the drilling of wells. These regulations provide for the disposal of saltwater and other oilfield wastes. As in Alberta, these regulations provide the basis for developing regulations for storage of CO_2 but do not anticipate the need for storage of large volumes of an acid gas to mitigate against climate change.

6. Saskatchewan's The Mineral Industry Environmental Protection Regulations 1996 provide some standards for the development of a disposal facility, including a list of the minimum informational requirements for the surface location of the facility, decommissioning and reclamation requirements, and the development of an assurance fund. Again, such regulations can form the basis for development of a comprehensive set of regulations for the storage of CO_2 and the abandonment of a facility at the end of its useful life.

7. The British Columbia Drilling and Production Regulation discusses well completion requirements. Generally, the regulations are similar in nature to those of the other provinces. During the abandonment phase, the regulations are similar but include wording referring to the isolation of “all permeable formations.” In open hole completions, cement plugs at the base need to be 50 m; in cased hole abandonment, there should be a plug with 8 m of cement. At the top of the hole, a 3 m cement plug with a welded plate is required.

8. British Columbia’s Sour Gas Pipeline regulations cover the transport of gases with a concentration of H_2S in excess of 1%. The regulations cover safety and design of the pipeline, making reference to the Canadian Standards Association standard Z731–M91 for emergency planning.

9. For transportation of CO_2 across provincial or international boundaries, the National Energy Board takes jurisdiction. Environmental screenings are conducted under the rules of the Canadian Environmental Assessment Act (CEAA). If an application does not trigger the CEAA, then the Board still considers environmental issues pursuant to its own act, the National Energy Board Act. For onshore applications, pipelines are covered under the Onshore Pipeline Regulations, which set out the technical and safety requirements for all aspects of a pipeline’s life cycle. Many of the standards applied are developed by the Canadian Standards Association. Monitoring of operations includes assurance that the terms of the Canada Labour Code and its regulations are adhered to. Incidents concerning pipelines are reported to the Transportation Safety Board. If this Board deems an investigation appropriate, the National Energy Board is informed and has the right to participate in the investigation.

Appendix 3: Canadian initiatives

Weyburn Monitoring Project: This is a major research project that builds on the major enhanced oil recovery project (EOR) that uses CO_2 as a solvent. The goal of the project is to understand more about the movement and fate of the CO_2 in the reservoir and assess the viability of a depleted oil reservoir as a storage location for CO_2. Work includes the use of a wide variety of techniques to monitor gas movement and to look for potential evidence of leakage to the surface. It is hoped that the project will develop monitoring techniques that are effective and economical for future use. The anticipated conclusion of this phase of the work is 2004. At that time it should be determined if there is a need for a second phase to further evaluate the fate of the CO_2.

For more detailed information on this project, refer to www.ptrc.ca.

Enhanced Coal Bed Methane Recovery: Work is under way in Alberta to test the enhanced recovery for coal bed methane with the injection of CO_2 and CO_2 / H_2 mixtures simulating waste gas streams. This work is being carried out by the Alberta Research Council. To date, several micro-pilot projects have been undertaken and larger scale tests are being proposed, utilizing a number of different large waste industrial gas streams lying directly over coal bed methane reservoirs. The research will assess the effectiveness of the CO_2 in releasing methane and the effectiveness of the coal in sequestering the same gas.

For more detailed information on this project, refer to www.arc.ab.ca.

Assessment of Geological Storage Options: The Alberta Geological Survey has been undertaking studies in the Western Canadian Sedimentary Basin to determine the storage capacity and location of sites favourable for storage. A basin-scale and regional-scale suitability analysis has identified large regions of the basin within which it will be possible to focus on the smaller scale studies on specific oil, gas, coal and salt reservoirs / caverns. Deep saline aquifers are treated as large-scale continuous features, which frame the plumbing in the basin and have correspondingly large CO_2 storage capacities. This work is particularly focused on deep saline aquifers.

For more information, there are a number of open file reports on regional hydrogeology at www.ags.gov.ab.ca.

Coal Bed Storage Capacity of Western Canada: The Geological Survey of Canada has been undertaking studies and mapping of the coal beds of western Canada to assess the storage capacity of these beds for CO_2.

For more information, see www.nrcan.gc.ca/gsc. (Please note that this Web site requires password for entry.)

APPENDIX 4: GLOSSARY

AEUB – Alberta Energy and Utilities Board, the body in Alberta with regulatory authority over the oil and gas industry and responsibility for permitting waste storage in the subsurface.

annulus – the space between the well casing and the injection string.

aquiclude – body of rock or sediment that is relatively impermeable and forms an effective barrier to fluid movement.

aquifer – body of rock or sediment containing water, a reservoir for water in the subsurface. Saline aquifer is one containing water of high salinity, unusable as potable water.

aquitard – body of rock or sediment that slows the movement of fluid. Aquitards will not stop the movement of fluid, but will slow its progress.

bottomhole pressure – pressure measured at the bottom of the well, the pressure in the injection zone.

caprock – the rock forming a seal above an oil-, gas- or water-bearing horizon.

dip – the angle of repose of a rock formation, usually given as the angle of the slope and the direction down slope.

ductile – the ability of the sediment to deform prior to breakage or fracturing.

EOR – Enhanced Oil Recovery, the process of increasing the recovery of oil from the reservoir. This is usually accomplished by adding chemicals or solvents to the reservoir to increase the flow of oil to the production well.

facies – nature of the sediment within a sedimentary horizon due to changes in the depositional environment. It can change the porosity and permeability of the sediment.

fault – major fractures or breakages in the rock, generally measurable over some distance and with some movement of the rock on each side of the fault.

fractures – breakage of the rock, usually along clearly defined stress directions within the rock. These breaks are usually relatively local in extent and frequently end where the rock type is more pliable. Fractures form good fluid migration pathways within the rock.

fracturing – the action of breaking or fracturing the rock. Fracturing is deliberately undertaken in some oil reservoirs to increase the inflow of oil to the production well. Fracturing occurs when fluids are injected above the pressure required to break the rock; this action is to be avoided in storage situations.

geophysical survey – a technique for remotely determining the nature of sediments in the subsurface. A typical geophysical survey is undertaken using sound waves generated on the surface and reflected off the sedimentary layers in the subsurface. Geophones on the surface measure the returning waves that have been reflected from the sedimentary layers and other features. The nature of the sedimentary column is determined from this pattern of returned waves.

greenfield site – a site that has not been utilized before, in this case a saline aquifer that has not been used for industrial purposes in the past.

injectant – the fluid being injected into the reservoir, in this case generally CO_2 with or without impurities or fluids designed to react with the CO_2 or reservoir fluids to create barriers to further fluid movement.

injection string – the tubing inserted in the well to allow fluid movement down the wellbore.

injectivity **-** the ability of the sediment/sedimentary rock to accept the fluid being injected. This is a function of reservoir permeability, fluid viscosity, etc.

isopach – a contour depicting lines of equal thickness. This would generally be the thickness of the reservoir, the caprock, etc.

matrix – the body or "skeleton" of the sedimentary rock within which the fluid is contained.

No-migration Petitions – the proposal submitted to the Environmental Protection Agency (EPA) requesting approval to sequester liquid industrial wastes in the subsurface. The onus is on the petitioner to prove the containment of the fluid for a period of 10,000 years.

perforating – when a well is cased and cemented, there is a need to punch holes to allow fluid production or injection to occur. This is typically achieved by lowering a device with explosive charges into the hole to create a hole through the casing and cement, and into the reservoir rock.

permeability – a measurement of the ability of the rock to transmit fluid or gas through fractures and the matrix—effectively the interconnectedness of the pores within the rock.

plume – the volume of CO_2 within the injection horizon.
porosity – the space within the matrix of the rock in which fluids can be stored. Measured as a percentage of the total rock volume.

Saskatchewan Industry and Resources – the government agency in Saskatchewan responsible for regulating the oil and gas industry and for permitting the injection of waste fluids into the subsurface.

seismicity – movement within the rock. It is possible for injection of fluids to induce movement in the rock (induced seismicity), potentially creating fractures in the rock. This seismicity is measured in the same way as a geophysical survey, with geophones located at the surface.

slim hole – a narrow diameter hole drilled primarily for exploration or observation purposes. These holes are considerably cheaper than conventional holes drilled for production or injection purposes.

structure – the subsurface form of a sedimentary horizon, showing the elevation of the horizon, identifying faults, etc.

UNFCCC – United Nations Framework Convention on Climate Change, negotiated in Rio de Janeiro in 1992. The goal of this convention was to encourage the reduction of greenhouse gas emissions. The Kyoto Protocol has been developed as a result of this convention.

viscosity – a measurement of the ability of a fluid to flow, compared with water.

wellbore – the hole drilled through sediments to a production or injection horizon. This well is typically completed with steel casing to isolate the hole from the surrounding rocks. Production equipment, etc., is dropped down this hole to the production/injection horizon.

wellhead – the top of the well and the hardware that allows production or injection to occur.

APPENDIX 5: REFERENCES CITED

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